Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5700
Fax: (416) 345-5870
Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

September 16, 2014

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

Dear Ms. Walli:

EB-2014-0140 – Hydro One Networks Inc. 2015-2016 Transmission Revenue Requirement Application – Application, Settlement Agreement and Evidence

The Hydro One Networks' Application, Evidence and Settlement Agreement in support of a proposed transmission revenue requirement to be implemented on January 1, 2015 and January 1, 2016, have been submitted using the Ontario Energy Board's Regulatory Electronic Submission System. This application is pursuant to a comprehensive Settlement Agreement between the stakeholders and Hydro One Networks. It is also our intention to post electronic copies of the Application, Settlement Agreement and supporting evidence on the Hydro One Networks website for public access.

At a time convenient to the Board, Hydro One Networks is prepared to provide the Board with a presentation on this Application. The presentation would provide an overview of the Settlement process, the evidence provided and the comprehensive settlement that was reached.

The confirmation of successful submission slip is provided with this letter and two (2) paper copies of the application, settlement agreement and evidence will be sent to the Board office shortly.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK
Susan Frank

Attach.

TABLE OF CONTENTS

III.	iii.	**I**	2	12	CME Interrogatory #12
				13	CME Interrogatory #13
				1	LPMA Interrogatory #1
				2	LPMA Interrogatory #2
			3	3	LPMA Interrogatory #3
				4	LPMA Interrogatory #4
				5	LPMA Interrogatory #5
				6	LPMA Interrogatory #6
				7	LPMA Interrogatory #7
				8	LPMA Interrogatory #8, plus Attachments 1 to 8
				9	LPMA Interrogatory #9, plus Attachment 1
				10	LPMA Interrogatory #10
				11	LPMA Interrogatory #11
				12	LPMA Interrogatory #12
				13	LPMA Interrogatory #13
				14	LPMA Interrogatory #14
				15	LPMA Interrogatory #15
				16	LPMA Interrogatory #16
				17	LPMA Interrogatory #17
				18	LPMA Interrogatory #18
			4	1	EP Interrogatory #1
				2	EP Interrogatory #2
				3	EP Interrogatory #3, plus Attachment 1
				4	EP Interrogatory #4
				5	EP Interrogatory #5, plus Attachments 1 and 2
				6	EP Interrogatory #6
				7	EP Interrogatory #7
				8	EP Interrogatory #8
				9	EP Interrogatory #9
				10	EP Interrogatory #10
				11	EP Interrogatory #11, plus Attachment 1
				12	EP Interrogatory #12
				13	EP Interrogatory #13
				14	EP Interrogatory #14
				15	EP Interrogatory #15
				16	EP Interrogatory #16
				17	EP Interrogatory #17
				18	EP Interrogatory #18
				19	EP Interrogatory #19
				20	EP Interrogatory #20
				21	EP Interrogatory #21
				22	EP Interrogatory #22
				23	EP Interrogatory #23
				24	EP Interrogatory #24

III.	iii.	**I**	4	25	EP Interrogatory #25
				26	EP Interrogatory #26
				27	EP Interrogatory #27
				28	EP Interrogatory #28
				29	EP Interrogatory #29
				30	EP Interrogatory #30
				31	EP Interrogatory #31
			5	1	SEP Interrogatory #1
				2	SEP Interrogatory #2, plus Attachments 1 to 5
				3	SEP Interrogatory #3
				4	SEP Interrogatory #4
				5	SEP Interrogatory #5
			6	1	VECC Interrogatory #1
				2	VECC Interrogatory #2
				3	VECC Interrogatory #3
				4	VECC Interrogatory #4
				5	VECC Interrogatory #5
				6	VECC Interrogatory #6
				7	VECC Interrogatory #7
				8	VECC Interrogatory #8
				9	VECC Interrogatory #9
				10	VECC Interrogatory #10
				11	VECC Interrogatory #11
				12	VECC Interrogatory #12
				13	VECC Interrogatory #13
				14	VECC Interrogatory #14
				15	VECC Interrogatory #15
				16	VECC Interrogatory #16
				17	VECC Interrogatory #17
				18	VECC Interrogatory #18
			7	1	PWU Interrogatory #1
				2	PWU Interrogatory #2
				3	PWU Interrogatory #3
				4	PWU Interrogatory #4
				5	PWU Interrogatory #5
				6	PWU Interrogatory #6
				7	PWU Interrogatory #7
				8	PWU Interrogatory #8
				9	PWU Interrogatory #9
				10	PWU Interrogatory #10
				11	PWU Interrogatory #11
				12	PWU Interrogatory #12
				13	PWU Interrogatory #13

III.	iii.	**I**	7	14	PWU Interrogatory #14
				15	PWU Interrogatory #15
				16	PWU Interrogatory #16
				17	PWU Interrogatory #17
				18	PWU Interrogatory #18
				19	PWU Interrogatory #19
				20	PWU Interrogatory #20
				21	PWU Interrogatory #21
				22	PWU Interrogatory #22
			8	1	OPG Interrogatory #1
				2	OPG Interrogatory #2
			9	1	AMPCO Interrogatory #1
				2	AMPCO Interrogatory #2
				3	AMPCO Interrogatory #3
				4	AMPCO Interrogatory #4
				5	AMPCO Interrogatory #5
				6	AMPCO Interrogatory #6
				7	AMPCO Interrogatory #7
				8	AMPCO Interrogatory #8
				9	AMPCO Interrogatory #9, plus Attachment 1
				10	AMPCO Interrogatory #10
				11	AMPCO Interrogatory #11
			10	1	SEC Interrogatory #1
				2	SEC Interrogatory #2
				3	SEC Interrogatory #3
				4	SEC Interrogatory #4
				5	SEC Interrogatory #5
				6	SEC Interrogatory #6
				7	SEC Interrogatory #7
				8	SEC Interrogatory #8, plus Attachment 1
				9	SEC Interrogatory #9, plus Attachment 1
				10	SEC Interrogatory #10
				11	SEC Interrogatory #11
				12	SEC Interrogatory #12
				13	SEC Interrogatory #13, plus Attachment 1
				14	SEC Interrogatory #14, plus Attachment 1
				15	SEC Interrogatory #15, plus Attachment 1
				16	SEC Interrogatory #16, plus Attachment 1
				17	SEC Interrogatory #17, plus Attachment 1
				18	SEC Interrogatory #18
			11	1	APPrO Interrogatory #1
				2	APPrO Interrogatory #2

III.	iii.	**I**	11	3	APPrO Interrogatory #3
				4	APPrO Interrogatory #4
				5	APPrO Interrogatory #5
				6	APPrO Interrogatory #6
				7	APPrO Interrogatory #7
				8	APPrO Interrogatory #8
				9	APPrO Interrogatory #9
				10	APPrO Interrogatory #10
				11	APPrO Interrogatory #11
				12	APPrO Interrogatory #12
				13	APPrO Interrogatory #13
				14	APPrO Interrogatory #14
				15	APPrO Interrogatory #15
			12	1	CCC Interrogatory #1
				2	CCC Interrogatory #2
				3	CCC Interrogatory #3
				4	CCC Interrogatory #4
				5	CCC Interrogatory #5
				6	CCC Interrogatory #6
				7	CCC Interrogatory #7
				8	CCC Interrogatory #8
				9	CCC Interrogatory #9
				10	CCC Interrogatory #10
				11	CCC Interrogatory #11
				12	CCC Interrogatory #12
				13	CCC Interrogatory #13
				14	CCC Interrogatory #14
				15	CCC Interrogatory #15
				16	CCC Interrogatory #16
				17	CCC Interrogatory #17
				18	CCC Interrogatory #18
	iv.	**TCJ**			**Technical Conference Undertaking Responses**
			1	1	July 23rd Information Session – Question #1 – CCC
				2	July 23rd Information Session – Question #2 – SEC
				3	July 23rd Information Session – Question #3 – SEC
				4	July 23rd Information Session – Question #4 – VECC
				5	July 23rd Information Session – Question #5 – EP
			2	1	July 29th Information Session – Question #1 – VECC
				2	July 29th Information Session – Question #2 – VECC
				3	July 29th Information Session – Question #3 – VECC
				4	July 29th Information Session – Question #4 – APPrO
				5	July 29th Information Session – Question #5 – APPrO

1

SECTION I

APPLICATION REFLECTING THE PROPOSED SETTLEMENT AGREEMENT

APPLICATION REFLECTING THE PROPOSED SETTLEMENT AGREEMENT

ONTARIO ENERGY BOARD

IN THE MATTER OF *the Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving rates for the transmission of electricity.

1. The Applicant is Hydro One Networks Inc. ("Hydro One"), a subsidiary of Hydro One Inc. Hydro One is an Ontario corporation with its head office in Toronto. The Applicant carries on the business, among other things, of owning and operating transmission facilities in Ontario. The transmission business of Hydro One will be referred to as "Hydro One Transmission".

2. Hydro One hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 78 of the *Ontario Energy Board Act, 1998,* for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity, to be implemented on January 1, 2015. This application is pursuant to a comprehensive Settlement Agreement between the stakeholders and Hydro One Networks.

3. Hydro One seeks approval of a revenue requirement of $1,577 million and $1,660 million for the test years 2015 and 2016, respectively. Taking into account the increased load forecast, the resulting increase in Hydro One Transmission Rates would be 1.1% and 1.7%, respectively. The estimated increase on the average customer's total bill is 0.1% in 2015 and 0.1% in 2016. The transmission

component represents 7.4% of an average distribution connected customer's total bill.

4. Hydro One seeks approval of an OM&A cost expenditure level of $432 million in 2015 and $437 million in 2016.

5. Hydro One seeks approval of an in-service capital additions amount of $821 million in 2015 and $673 million in 2016. Hydro One also seeks approval of Rate Base levels of $10,177 million for 2015 and $10,558 million for 2016.

6. Hydro One seeks approval of regulatory assets totaling ($36.1) million as at December 31, 2014. Hydro One seeks approval to refund this balance in 2016 and to reduce the revenue requirement accordingly.

7. Hydro One seeks approval of an Export Transmission Service (ETS) rate of $1.85/MWh for 2015 and 2016.

8. Hydro One seeks approval to continue the following deferral accounts: the Excess Export Service Revenue Account; the External Secondary Land Use Revenue Variance Account; the External Station Maintenance, E&CS and Other Revenue Variance Account; the Tax Rate Changes Account; the Rights Payments Variance Account; the Pension Cost Differential Account; the External Revenue – Partnership Transmission Projects Account; the East West Tie Deferral Account; the LDC CDM and Demand Response Variance Account (for settling 2013 and 2014 balances) and the Long Term Future Corridor Account.

9. Hydro One seeks approval to create a net cumulative asymmetrical variance account for 2014, 2015, and 2016 to track the impact on revenue requirement of

any in-service capital additions shortfall compared to Board approved amounts, for disposition in a future rates application.

10. Hydro One also requests that the Board amend the Uniform Transmission Rates to allow for recovery of the proposed revenue requirements for 2015 and 2016, effective January 1st of each year.

11. Hydro One continues to work on a commercial transaction with the Saugeen Ojibway Nation ("SON") regarding the Bruce to Milton line. When a commercial transaction is completed, Hydro One will file a separate application to effect the changes resulting from the commercial transaction.

12. This Application is supported by a comprehensive Settlement Agreement and supporting evidence.

13. The persons affected by this Application are the ratepayers of Hydro One's transmission business. It is impractical to set out their names and addresses because they are too numerous.

14. Hydro One requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:

Ms. Erin Henderson
Regulatory Coordinator – Regulatory Affairs
Hydro One Networks Inc.

Address for personal service: 7th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5

Mailing Address:	7th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Telephone:	(416) 345-4479
Fax:	(416) 345-5866
Electronic access:	regulatory@HydroOne.com

b) The Applicant's counsel:

Mr. Michael Engelberg
Hydro One Networks Inc.

Address for personal service:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Mailing Address:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Telephone:	(416) 345-6305
Fax:	(416) 345-6972
Electronic access:	mengelberg@HydroOne.com

DATED at Toronto, Ontario, this 16th day of September, 2014.

HYDRO ONE NETWORKS INC.

By its counsel,

ORIGINAL SIGNED BY MICHAEL ENGELBERG

Michael Engelberg

HYDRO ONE NETWORKS INC.
A corporation incorporated under the laws of Ontario
(hereinafter, "Hydro One")

OFFICER'S CERTIFICATE

TO: THE ONTARIO ENERGY BOARD

The undersigned, Susan Frank, being the Vice-President and Chief Regulatory Officer of Hydro One Networks Inc., hereby certifies for and on behalf of the Applicant that:

1. I am a senior officer of Hydro One Networks Inc.;

2. This certificate is given pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Transmission Rate Applications (last revised on January 2, 2014)*; and

3. The evidence submitted in support of Hydro One Networks Inc.'s 2015-2016 Transmission Rate Application filed with the Ontario Energy Board is accurate, consistent and complete to the best of my knowledge.

DATED this 16th day of September, 2014.

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Vice-President &
Chief Regulatory Officer

SUMMARY OF PROCESS AND FILING

1.0 PROCESS

On June 25, 2014, Hydro One initiated an open and transparent process to discuss potential settlement of the Transmission rate impacts on 2015 and 2016. At the initial discussion on June 25, Mr. Ken Rosenberg, who was retained by Hydro One to facilitate the discussion, described the key elements of this process and established dates for further sharing of supporting data and initiation of negotiations.

Those invited were Intervenors that participated in the Hydro One 2013-2014 Transmission Rate case (EB-2012-0031) and representatives from Board Staff. The purpose of this first meeting was to inform Stakeholders of Hydro One's proposal and provide an opportunity for Stakeholders to better understand the proposal. A copy of the slides presented at the June 25th session can be referenced in Section III, i, 2. a. of this Application.

During the June 25 session, Hydro One agreed to provide additional, more detailed, information. This information package was provided on June 27, 2014, and can be referenced in Section III, ii of this application. On or before July 11, 2014, participants provided their Interrogatories to Hydro One. On July 17, 2014, Hydro One provided answers to the Interrogatories, which answers can be referenced in Section III, iii of this Application. On July 23, 29 and 30, non-transcribed technical conferences were held. On July 23, 2014, Hydro One provided a presentation on in-service capital, which can be referenced in Section III, i, 2, b of this Application. Answers to all technical conference undertakings were provided to participants by August 6, 2014, and can be referenced in Section III, iv. of this Application. During the sessions, Hydro One was asked for and provided a list of capital projects that were directed by the OPA, IESO or Government, and this list can be referenced in Section III, i, 3 of this Application.

Participants agreed to use the approved Issues List in EB-2012-0031 as a guide. A Settlement negotiation between Hydro One and the Stakeholders took place on August 12 and August 13, 2014. These negotiations followed the Board's Rules of Practice and Procedure ("Rules") and the Board's Practice Direction on Settlement Conferences. The product of those negotiations is the comprehensive settlement agreement on all issues, which can be referenced in Section II of this Application.

Hydro One and the following participants ("the parties") participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO")
Association of Power Producers of Ontario ("APPrO")
Bruce Power Inc. ("BP")
Building Owners and Managers Association Toronto ("BOMA")
Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Energy Probe Research Foundation ("Energy Probe")
Independent Electricity System Operator ("IESO")
HQ Energy Marketing Inc. ("HQEM")
London Property Management Association ("LPMA")
Ontario Power Generation ("OPG")
Power Workers' Union ("PWU")
School Energy Coalition ("SEC")
Society of Energy Professionals ("SEP")
Vulnerable Energy Consumers Coalition ("VECC")

Board Staff attended and observed the settlement process but are not a party to the Settlement Agreement. Board Staff indicated their intent to file a submission with the Board once this Application and accompanying Settlement Agreement were filed with the Board.

To ensure that Hydro One satisfies the Board's Filing Requirements for Electricity Transmission Applications (January 2, 2014), Hydro One has provided additional information which can be referenced in Section IV of this Application.

2.0 SUMMARY OF REQUEST

2.1 Revenue Requirement

Based on the Settlement Agreement, Hydro One seeks approvals for:

1. A revenue requirement of $1,577 million and $1,660 million for the 2015 and 2016 test years, respectively. Taking into account the increased load forecast, the resulting increase in Hydro One Transmission Rates is 1.1% and 1.7%, respectively. The estimated increase on the average customer's total bill is 0.1% in 2015 and 0.1% in 2016. The transmission component represents 7.4% of an average distribution-connected customer's total bill.

2. In-service capital additions of $821 million in 2015 and $673 million in 2016 and Rate Base of $10,177 million for 2015 and $10,558 million for 2016.

3. An OM&A cost expenditure forecast of $432 million in 2015 and $437 million in 2016, driven by the need to safely deliver transmission reliability at targeted performance levels.

4. An Export Transmission Service (ETS) rate of $1.85/MWh. The forecast for ETS revenue is $30.9 million for 2015 and $31.7 million for 2016.

5. Hydro One seeks approval of regulatory assets totaling ($36.1) million as at December 31, 2014. Hydro One seeks approval to refund this balance in 2016, with no amount refunded in 2015.

2.2 Cost Allocation and Rates

Hydro One is seeking approvals of:

1. The continuation of the Hydro One Transmission's cost allocation methodology.

2. The continuation of a wholesale metering services pool.

3. The revenue to be collected by each Rate Pool and the charge determinant application to each Rate Pool as provided in Appendix C to the Settlement Agreement that can be referenced at section II of this filing.

4. Hydro One requests that the Board amend the Uniform Transmission Rates to allow for recovery of the proposed revenue requirements for 2015 and 2016, effective January 1 of each year.

2.3 Other Proposed Approvals

Hydro One seeks approval to continue the following deferral accounts: the Excess Export Service Revenue Account; the External Secondary Land Use Revenue Variance Account; the External Station Maintenance, E&CS and Other Revenue Variance Account; the Tax Rate Changes Account; the Rights Payments Variance Account; the Pension Cost

Differential Account; the External Revenue – Partnership Transmission Projects Account; the East West Tie Deferral Account; the LDC CDM and Demand Response Variance Account (for settling 2013 and 2014 balances) and the Long Term Future Corridor Account.

Hydro One also seeks approval to add a net cumulative asymmetrical variance account for 2014, 2015, and 2016, to track the impact on revenue requirement of any in-service capital addition shortfall compared to Board-approved amounts, for disposition in a future rates application.

2.4 Causes of the Increase in Revenue Requirement

In 2015, there are a number of key operational and financial factors contributing to the increased revenue requirement over 2014. The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in depreciation, as well as higher cost of debt and allowed ROE. Also contributing to the difference are higher income taxes, lower external revenues, and no regulatory account disposition.

The increase in 2016 rates revenue requirement is primarily due to the increase in core rate base as reflected in the increase in return on capital and depreciation. Other contributing factors include higher income taxes, slightly higher OM&A work program requirements and increased regulatory account disposition.

The increases identified with the Application will ensure that customers with the Province will continue to be supplied in a secure and reliable manner, thereby contributing to the health and competitiveness of the Province’s economy.

3.0 PROPOSED NEXT STEPS

When the Board issues its Notice of Application and Hearing relating to this Application (the "Notice"), Hydro One proposes that Hydro One complete the following actions:

- Arrange for English and French versions of the Notice, to be published on the Ontario Energy Board and Hydro One websites;
- Serve a copy of the Notice directly on Electricity Distributors and other transmission customers served by Hydro One Transmission; on all licensed transmitters in Ontario, and on all intervenors of record in the previous transmission rate application proceeding EB-2012-0031; and
- File with the Board an affidavit proving service of the Notice immediately thereafter.

At a time convenient to the Board, Hydro One is prepared to provide the Board with a presentation on this Application. The presentation would provide an overview of the Settlement process, the evidence provided and the comprehensive settlement that was reached.

Finally, Hydro One proposes that the return on equity for each test year be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board's letter issued in the Fall of 2014 would be used to determine the ROE for Hydro One Transmission. Similarly, the 2016 ROE would be updated to reflect the Board's letter issued in the Fall of 2015.

SECTION II

PROPOSED SETTLEMENT AGREEMENT

SETTLEMENT AGREEMENT

Hydro One Networks Inc.
Test year 2015 and 2016 Transmission Rates

September 16, 2014

TABLE OF CONTENTS

	Capital expenditures to the transmission business appropriate?	
15	Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?	19
16	Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the OM&A and Capital expenditures for 2015/16?	19
Cost Of Capital/Capital Structure		
17	Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?	21
18	Is the forecast of long term debt for 2014-2016 appropriate?	22
Deferral/Variance Accounts		
19	Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?	22
20	Are the proposed new Deferral and Variance Accounts appropriate?	23
Cost Allocation		
21	Is the cost allocation proposed by Hydro One appropriate?	24
Export Transmission Service Rates		
22	What is the appropriate level for Export Transmission Rates in Ontario?	24
Other		
23	Intervenor Proposal for an Independent Cost Benchmarking Study	26

Hydro One Networks Inc.
Test Year 2015 and 2016 Transmission Rates

SETTLEMENT AGREEMENT

PREAMBLE:

This Settlement Agreement ("the Agreement" or "this Agreement") is filed with the Ontario Energy Board ("the Board") in support of an Application for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity by Hydro One Networks Inc. ("Hydro One") to be implemented on January 1, 2015, and January 1, 2016.

On June 25th, 2014 Hydro One convened a meeting with Stakeholders to present its 2015-2016 Transmission rates and revenue requirement. Those invited were Intervenors that participated in the Hydro One 2013-2014 Transmission Rate case (EB-2012-0031) and representatives from Board Staff. The purpose of the meeting was to inform Stakeholders of Hydro One's proposal and provide an opportunity for Stakeholders to better understand the proposal. A copy of the slides presented can be referenced in Section III, i, 2. a. of this application. During the session, Hydro One agreed to provide additional, more detailed, information. This information package was provided on June 27. On or before July 11, participants provided their Interrogatories to Hydro One. On July 17, Hydro One provided answers to the Interrogatories. On July 23, 29 and July 30, technical conferences were held. Answers to all technical conference undertakings were provided to participants by August 6.

A Settlement negotiation between Hydro One and the Stakeholders took place on August 12 and August 13. The product of those negotiations is the comprehensive settlement on a proposed revenue requirement and resulting transmission rates over the 2015-2016 period, the approvals for which Hydro One will apply to the Board.

These negotiations followed the *Ontario Energy Board Rules of Practice and Procedure* ("Rules") and the Board's Practice Direction on Settlement Conferences.

Hydro One and the following participants ("the parties") participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO")
Association of Power Producers of Ontario ("APPrO")
Bruce Power Inc. ("BP")
Building Owners and Managers Association Toronto ("BOMA")

Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Energy Probe Research Foundation ("Energy Probe")
Independent Electricity System Operator ("IESO")
HQ Energy Marketing Inc. ("HQEM")
London Property Management Association ("LPMA")
Ontario Power Generation ("OPG")
Power Workers' Union ("PWU")
School Energy Coalition ("SEC")
Society of Energy Professionals ("SEP")
Vulnerable Energy Consumers Coalition ("VECC")

Ontario Energy Board Staff attended and observed the settlement process but are not a party to this Agreement.

All issues were completely resolved.

The positions taken by the various parties on each of the settled issues are identified throughout the Agreement. A party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue and takes no position on the settlement reached or on the sufficiency of the evidence filed to date.

The Agreement provides a brief description of each of the settled issues and rationales for the settled position, together with references to the evidence filed. The applicable parties agree that the evidence filed in support of each settled issue contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached. The parties are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

The Board's Practice Direction on Settlement Conferences (p.4) requires the parties to consider whether a settlement agreement should include an adjustment mechanism for any settled issue that may be affected by external factors. Hydro One and the other parties who participated in the Settlement Conference consider that no settled issues require such an adjustment mechanism other than those expressly set forth in this Agreement.

Finally, unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the parties are without prejudice to the rights of parties to raise the same issue and/or to take any position thereon in any other proceedings.

The Settlement Conference commenced with an information package and two presentations made by Hydro One. Interrogatories were then posed by the other parties, undertakings were asked for by the other parties, and Hydro One provided answers, including documents, to respond to all the interrogatories and satisfy the undertakings.

All of the foregoing information, documents and responses are public and have been posted on Hydro One's website. Subject to the foregoing, the parties have agreed that all positions, negotiations and discussions that took place during the Settlement Conference to facilitate settlement are strictly confidential, without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Agreement. The parties intend that the confidentiality of these negotiations be determined in accordance with the Board's Practice Direction on Settlement Conferences, interpreted as if this Agreement were the result of a Board-ordered settlement conference. It was agreed that parties will not withdraw from this Agreement under any circumstances except as provided under Rule 30 of the Board's Rules of Practice and Procedure, interpreted as if this Agreement were the result of a Board-ordered settlement conference.

It is fundamental to the Agreement that items 1-21 and 23 are not severable. Item 22 (Export Transmission Service Rate Issue), while settled, can be severed if required by the Board. With the exception of the Export Transmission Service Rate Issue, if the Board does not accept the provisions of the Agreement in their entirety, there is no settlement and no Settlement Agreement unless the parties agree to the contrary.

For the Board's ease of reference, a List of Approvals Sought is attached as Appendix A.

OVERVIEW:

The parties were able to reach agreement on all issues, including Operations, Maintenance & Administration (OM&A) costs, Capital In-service, Rate Base, Export Transmission Rates and all other Revenue Requirement related issues.

Overall rate impacts were a guiding principle that led to the Agreement. Hydro One was proposing a 3.2% increase in 2015 transmission rates and a 3.3% increase in 2016 transmission rates. The parties efforts were focused on determining an appropriate Revenue Requirement and resulting rate levels for 2015 and 2016, while balancing Hydro One's need to continue to safely and reliably operate and to fund its work program.

The overall financial impact of the Settlement Agreement is to reduce the revenue requirement from $1,617.1M to $1,577.2M in 2015 and from $1,689.2M to $1,659.7M in 2016, or by $39.9M and $29.5M respectively. When combined with the load increase resulting from issue 3, the resulting overall rate impact is a 1.1% rate increase in 2015 and 1.70% rate increase in 2016, down from 3.2% and 3.3% rate increases in the original proposal. The financial rate impact calculation is attached to this Agreement as Appendix B.

The impact on transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. The total bill impact for a typical, medium density (R1), residential customers consuming 800kWh monthly for 2015 is 0.1% of total bill or $0.11, and 2016 is 0.1% of total bill or $0.18

As noted above, all parties agree that the Agreement is a broad package proposal. Thus, except for the Export Transmission Service Rate item, individual components of the Agreement ought not be considered or reviewed in isolation. All parties agree that the overall package of the Agreement represents a fair and reasonable agreement that balances the interests of all stakeholders, including the ratepayers, the intervenors, concerns previously noted by the Board and Hydro One's need to maintain and operate a safe and reliable transmission system.

The particulars of the Agreement are detailed below by issue.

GENERAL

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

Settled

The only Board directive to Hydro One Transmission from the previous transmission proceeding was to prepare an Export Transmission Service Cost Allocation Study. This study is provided in Exhibit H1, Tab 5, Schedule 1, Attachment 1.

All parties agree that the study was provided as directed by the Board.

Evidence: The evidence in relation to this issue includes the following:

H1-5-1	Rates for Export Transmission Service
I-2-1	CME Interrogatory #1
I-2-2	CME Interrogatory #2
I-10-1	SEC Interrogatory #1
I-12-1	CCC Interrogatory #1

Supporting Parties: AMPCO, APPrO, BOMA, BP, CME, CCC, Energy Probe, HQEM, IESO, LPMA, OPG, PWU, SEC, SEP and VECC
Parties taking no position: None

2. Is the overall increase in 2015 and 2016 revenue requirement reasonable?

Settled

As proposed in the information package provided to all the parties, Hydro One was seeking revenue requirement of $1,617.1M in 2015 and $1,689.2M in 2016. The resulting rate increase would have been 3.2% in 2015 and 3.3% in 2016, after adjusting for the load forecast.

For the purposes of reaching a settlement, the parties agree that the settled revenue requirement before adjustment of $1,577.2M in 2015 and $1,659.7M in 2016 is reasonable. This represents a decrease of $39.9M in 2015 and a decrease of $29.5M in 2016 from Hydro One's original request. The resulting rate increase will be 1.1% in 2015 and 1.7% in 2016, versus 3.2% and 3.3% as proposed originally, after adjusting for the settlement on the load forecast.

The parties agree that the return on equity for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board's letter issued in the Fall of 2014 will be used to determine the ROE for Hydro One Transmission. Similarly, the 2016 ROE would be updated to reflect the Board's letter issued in the Fall of 2015. In addition the long term debt will be updated to reflect the actual debt issues.

Hydro One will also implement any applicable outcomes from the 2014 OEB Cost of Capital Review.

The following table summarizes what the parties have agreed upon:

Hydro One Transmission Revenue Requirement Settlement Agreement

	2014*	**2015**	**2016**
OM&A		432.0	437.4
Depreciation		394.2	404.0
Income tax		68.1	82.0
Cost of capital		682.9	736.3
Revenue requirement	**1,535.3**	**1,577.2**	**1,659.7**
		2.7%	5.2%
Less: External revenues		-31.8	-32.2
Less: Export revenue credit		-30.9	-31.7
Less: "Tx Riders"		0.0	-36.1
Add: LVSG (ow voltage switch gear)		12.9	13.5
Rates Revenue Requirement	**1,446.4**	**1,527.4**	**1,573.3**
		5.6%	3.0%
Estimated impact of load change		- 4.5%	- 1.3%
Rate Impact		**1.1%**	**1.7%**

* 2014: OEB approved

Evidence: The evidence in relation to this issue includes the following:

E1-1-1 Revenue Requirement
I-2-3 CME Interrogatory #3
I-2-11 CME Interrogatory #11
I-4-1 Energy Probe Interrogatory #1

I-10-2	SEC Interrogatory #2
I-12-4	CCC Interrogatory #4
TCJ1.5	Undertaking Response #1.5
TCJ2.6	Undertaking Response #2.6
TCJ3.2	Undertaking Response #3.2

Supporting Parties: AMPCO,BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU and SEP

LOAD FORECAST AND REVENUE FORECAST

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

Settled

Hydro One proposed to use the same load forecasting methodology previously approved by the Board in EB-2012-0031. Hydro One has continued to work with the Ontario Power Authority to incorporate the latest CDM forecast in the load forecast, consistent with the 2013 Long Term Energy Plan for the test years.

Hydro One continues to believe that applying a 31-year average methodology for weather normalization is appropriate. This methodology for applying weather normalization to forecasts is an area of concern for intervenors. Intervenors believe that 20-year load trending is more appropriate for determining weather normalization.

All parties accept Hydro One's load forecast as set out in Exhibit A, Tab 15, Schedule 2, except for how weather normalization is applied. For purposes of reaching a settlement, the parties agreed that weather normalization will be based on the mid-point between the 20-year load trending information and the 31-year average load information. The impact of this change is a 0.5% increase in the charge determinants used for calculating transmission rates and a 0.5% decrease in the assumed rate impact.

Evidence: The evidence in relation to this issue includes the following:

A-15-1	Economic Indicators
A-15-2	Business Load Forecast and Methodology
I-03-01	LPMA Interrogatory #1
I-03-11	LPMA Interrogatory #11
I-03-12	LPMA Interrogatory #12
I-03-13	LPMA Interrogatory #13

I-04-09	EP Interrogatory #9
I-06-03	VECC Interrogatory #3
I-06-04	VECC Interrogatory #4
I-06-05	VECC Interrogatory #5
I-06-06	VECC Interrogatory #6
I-06-07	VECC Interrogatory #7
I-09-02	AMPCO Interrogatory #2
I-09-03	AMPCO Interrogatory #3
I-09-04	AMPCO Interrogatory #4
I-10-02	SEC Interrogatory #2
I-12-06	CCC Interrogatory #6
I-12-11	CCC Interrogatory #11

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU, and SEP

4. Are Other Revenue (excluding export revenue) forecasts appropriate?

Settled

Hydro One proposed external revenues of $28.4M in 2015 and $28.8M in 2016. These amounts cover secondary land use, station maintenance and other external revenues.

For the purposes of reaching a settlement, the parties agree that the external revenue forecast will be increased by $3.4M in each year which are more consistent with historical actuals. This results in external revenues of $31.8M in 2015 and $32.2M in 2016. The table below summarizes the changes:

External Revenue ($M)	***2015***	***2016***
Hydro One's original request	28.4	28.8
Settlement Agreement	31.8	32.2
Change Proposed	3.4	3.4

Hydro One will continue to use the existing symmetrical variance account to track any differences in Other External Revenue.

Evidence: The evidence in relation to this issue includes the following:

E1-2-1 External Revenues

I-3-6 LPMA Interrogatory #6
I-6-1 VECC Interrogatory #1
I-12-17 CCC Interrogatory #17

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU, and SEP

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Overall OM&A Settlement and its Rationale

All issues relating to Operations, Maintenance and Administration costs have been settled. The parties focused on overall spending levels for OM&A expenditures, rather than focusing on any one particular aspect of those costs. Transmission OM&A is grouped into the following investment categories: Sustaining, Development, Operations, Common Corporate, and other OM&A. The rationale for the settlement of Issues 5 and 6, as well as the underlying Human Resources costs in Issue 7 is outlined below.

Hydro One proposed OM&A expenditures of $452.0M and $457.4M in 2015 and 2016, respectively.

For purposes of reaching a settlement, the parties agree to reduce spending levels in each of the test years by $20.0M (from $452.0M to $432.0M in 2015 and from $457.4M to $437.4M in 2016). These final settled amounts compare to the 2013 actual OM&A spending level of $431.6M. The parties recognize the need for OM&A constraint and agree to hold the OM&A expenditures relatively flat in 2015 and 2016, compared to the actual 2013 level.

The table below summarizes the changes:

OM&A ($M)	***2015***	***2016***
Hydro One's original request	452	457
Settlement Agreement	432	437
Change Proposed	-20	-20

5. Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2015 and 2016 appropriate, including consideration of factors such as system reliability and asset condition?

Settled

The Sustaining OM&A represents investments required to maintain existing transmission lines and stations facilities so that they will continue to function as originally designed. Development OM&A funds research and development as well as the development of new standards. Operations OM&A funds the Central Transmission Operations activities at Hydro One's Ontario Grid Control Centre. Sustaining, Development, and Operations items are included in OM&A which was settled on a combined basis.

Evidence: The evidence in relation to this issue includes the following:

A-18-1	Cost Efficiencies/Productivity
C1-2-1	Summary of OM&A Expenditures
C1-2-2	Sustaining OM&A
I-2-8	CME Interrogatory #8
I-3-14	LPMA Interrogatory #14
I-4-21	EP Interrogatory #21
I-4-22	EP Interrogatory #22
I-4-23	EP Interrogatory #23
I-4-24	EP Interrogatory #24
I-4-25	EP Interrogatory #25
I-4-26	EP Interrogatory #26
I-5-3	SEP Interrogatory #3
I-5-4	SEP Interrogatory #4
I-5-5	SEP Interrogatory #5
I-7-1	PWU Interrogatory #1
I-7-2	PWU Interrogatory #2
I-7-3	PWU Interrogatory #3
I-7-4	PWU Interrogatory #4
I-7-9	PWU Interrogatory #9
I-10-6	SEC Interrogatory #6
I-12-8	CCC Interrogatory #8
I-12-9	CCC Interrogatory #9

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU, and SEP

6. Are the proposed spending levels for Common Corporate and Other OM&A in 2015 and 2016 appropriate?

Settled

The Common Corporate Costs and other OM&A program includes: Common Corporate Functions and Services (Finance, People & Culture, Corporate Communications, Legal, Regulatory Affairs, Security, Audit, and Real Estate), Asset Management, Information Technology, Cost of Sales, and other OM&A (Overheads Capitalized). These items are included in OM&A which was settled on a combined basis.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Summary of Common Corporate Costs - OM&A
C1-3-3	Common Corporate Functions and Services & Other OM&A
C1-6-1	Common Corporate Costs, Cost Allocation Methodology
I-2-13	CME Interrogatory #13
I-3-15	LPMA Interrogatory #15
I-4-13	EP Interrogatory #13
I-4-15	EP Interrogatory #15
I-5-1	SEP Interrogatory #1
I-10-1	SEC Interrogatory #1
I-10-7	SEC Interrogatory #7

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU, and SEP

7. Are the 2015/16 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Settled

The Human Resources related costs underlie the OM&A expenditures which was settled on a combined basis.

Evidence: The evidence in relation to this issue includes the following:

A-15-1	Economic Indicators
A-18-1	Cost Efficiencies/Productivity
C1-3-3	Common Corporate Functions and Services & Other OM&A
C1-6-1	Common Corporate Costs, Cost Allocation Methodology

I-2-5	CME Interrogatory #5
I-3-2	LPMA Interrogatory #2
I-3-9	LPMA Interrogatory #9
I-3-10	LPMA Interrogatory #10
I-4-3	EP Interrogatory #3
I-4-4	EP Interrogatory #4
I-5-1	SEP Interrogatory #1
I-5-2	SEP Interrogatory #2
I-9-5	AMPCO Interrogatory #5
I-9-6	AMPCO Interrogatory #6
TCJ3.03	Undertaking Response #3.03
TCJ3.04	Undertaking Response #3.04
TCJ3.07	Undertaking Response #3.07

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU, and SEP

8. Are the methodologies used to allocate Common Corporate OM&A costs to the transmission business and to determine the transmission overhead capitalization rate for 2015/16 appropriate?

Settled

The parties agree that Hydro One has appropriately used the Corporate Cost Allocation Methodology previously accepted by the Board in prior Hydro One Networks Inc. Transmission Rate Applications to allocate Common Corporate Costs. Similarly, Hydro One has appropriately followed the overhead capitalization rate methodology previously accepted by the Board. Both of these have been updated for the current proposal (2015-2016 Tx Rates). The parties thus agree that the methodologies used to allocate Common Corporate and Other O&M costs to the transmission overhead capitalization rate for 2015 and 2016 are appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-6-1	Common Corporate Costs, Cost Allocation Methodology
C1-6-2	Overhead Capitalization Rate
C1-6-3	Common Asset Allocation
I-2-6	CME Interrogatory #6
I-4-11	EP Interrogatory #11
I-10-8	SEC Interrogatory #8

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

9. Are the amounts proposed to be included in the 2015 and 2016 revenue requirements for income and other taxes appropriate?

Settled

Hydro One proposed income taxes amounts of $71.8 million in 2015 and $82.8 million in 2016.

The parties agree that the income tax amounts be adjusted based on the most recent cost of capital forecast available. This results in income tax amounts of $68.1 million and $82.0 million in 2015 and 2016, respectively.

The table below summarizes the changes:

Income Tax ($M)	***2015***	***2016***
Hydro One's original request	71.8	82.8
Settlement Agreement	68.1	82.0
Change Proposed	-3.7	-0.8

The parties agree that the income tax amounts in each test year will be updated to reflect the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board's letter issued in the Fall of 2014 will be used to determine the ROE for Hydro One Transmission. Similarly, the 2016 ROE would be updated to reflect the Board's letter issued in the Fall of 2015.

Evidence: The evidence in relation to this issue includes the following:

C1-8-1	Payments in Lieu of Corporate Income Taxes
E1-1-1	Revenue Requirement
I-2-8	CME Interrogatory #8
I-3-8	LPMA Interrogatory #8

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU and SEP

10. Is Hydro One Networks' proposed depreciation expense for 2015 and 2016 appropriate?

Settled

In accordance with the Board's Decision (EB-2006-0501), Hydro One Transmission used the Foster methodology, updated to reflect the results from the new Depreciation Study completed in 2014, for determining the depreciation rates used in the calculation of depreciation expenses for 2015 and 2016.

Hydro One's proposed depreciation expense using the approved methodology is $394.2 million for 2015 and $404.0 million for 2016.

The parties agree that Hydro One's proposed depreciation expense for 2015 and 2016 is appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-7-1	Depreciation and Amortization Expenses
I-2-10	CME Interrogatory #10
I-4-16	EP Interrogatory #16
I-10-9	SEC Interrogatory #9

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

CAPITAL IN SERVICE ADDITIONS AND RATE BASE

All issues relating to Capital In Service Additions and Rate Base have been settled. The parties focused on overall Capital In Service Additions and Rate Base levels, rather than focusing on any one particular aspect of those costs. The rationale for the settlement of Issues 11, 12, 13 and 14 is outlined below.

Hydro One proposed forecast Capital Expenditures of $899.4M and $866.3M in 2015 and 2016, respectively. No agreement of Capital Expenditures was sought or reached. The parties agreed that the determination of revenue requirement and rates was based on the Rate Base forecast, which is essential to a complete settlement.

Hydro One also proposed a rate base of $10,176.5M and $10,558.0M in 2015 and 2016, based on in-service capital additions (ISA) of $863.3M in 2014, $821.4M in 2015 and $673.3M in 2016.

The parties expressed concern, regarding Hydro One's historic ISA levels compared to Board-approved ISA levels. To address this concern, parties agreed to create a net cumulative asymmetrical variance account for 2014, 2015, and 2016 to track the impact on revenue requirement of any ISA shortfall compared to Board approved amounts, for disposition in a future rates application.

For illustration purposes, assume that Hydro One's actual ISA falls short of the Board-approved amounts by $5 M in each of 2014 and 2015. Also assume that Hydro One's actual ISA exceeds the Board-approved amount by $2M in 2016. Hydro One would calculate the annual revenue requirement impact for the variance in rate base for the years 2014, 2015 and 2016. The following table provides the entries into the variance account for this illustrative example:

Illustrative Example			
	2014	**2015**	**2016**
ISA variance	-5.0	-5.0	2.0
Impact on rate base (half year rule) of:			
2014 ISA variance		-5.0	-5.0
2015 ISA variance		-2.5	-5.0
2016 ISA variance			1.0
Total impact on rate base		**-7.5**	**-9.0**
Impact on revenue requirement: *		-0.8	-0.9
End of year cumulative balance in variance account		-0.8	-1.7

*For simplicity, assume that the impact of any rate base change as a result of the ISA variances results in a 10% impact on revenue requirement. A detailed calculation will be performed for purposes of any entries in the net cumulative asymmetrical variance account.

If the cumulative amount of ISA exceeds the cumulative Board-approved amount for the period 2014 to 2016, no entry would be made in the variance account.

This approach ensures that customers pay only for assets in service.

The parties accept the levels of capital in service additions and Rate Base proposed by Hydro One are appropriate and consistent with historical spend.

11. Are the amounts proposed for rate base in 2015 and 2016 appropriate?

Settled

The parties accept the levels of Rate Base proposed by Hydro One is appropriate as consistent with the rationale as stated in Capital In Service Additions and Rate Base.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Rate Base
D1-1-2	In-Service Capital Additions
D2-1-1	Statement of Utility Rate Base
I-2-7	CME Interrogatory #7
I-3-16	LPMA Interrogatory #16
I-4-2	Energy Probe Interrogatory #2
I-4-17	Energy Probe Interrogatory #17
I-4-18	Energy Probe Interrogatory #18
I-4-19	Energy Probe Interrogatory #19
I-9-7	AMPCO Interrogatory #7
I-10-11	SEC Interrogatory #11
I-10-12	SEC Interrogatory #12
I-10-16	SEC Interrogatory #16
I-12-12	CCC Interrogatory #12
I-12-13	CCC Interrogatory #13
I-12-14	CCC Interrogatory #14
TCJ1.1	Undertaking Response #1.1
TCJ1.2	Undertaking Response #1.2
TCJ1.3	Undertaking Response #1.3
TCJ3.1	Undertaking Response #3.1
TCJ3.6	Undertaking Response #3.6
TCJ3.8	Undertaking Response #3.8

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU and SEP

12. Are the proposed 2015 and 2016 Sustaining, Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Settled

Hydro One Transmission Capital is grouped into four investment categories: Sustaining, Development, Operations, and Common Corporate Costs. Sustaining

Capital consists of expenditures to refurbish or replace transmission system components which are end of life to ensure the system will continue to function as originally designed. Transmission Development Capital funds projects related to new or upgraded transmission facilities. Operations Capital investments funds enhancements and replacements of facilities required to operate Hydro One's transmission system and to meet requirements established by operating agreements, market rules, and regulatory authorities. Sustaining, Development, and Operations items are included in Capital In Service Additions which was settled on a combined basis.

Evidence: The evidence in relation to this issue includes the following:

D1-3-1	Summary of Capital Expenditures
D1-3-2	Sustaining Capital
D1-3-3	Development Capital
D1-3-4	Operations Capital
I-2-6	CME Interrogatory #6
I-4-20	EP Interrogatory #20
I-4-21	EP Interrogatory #21
I-4-22	EP Interrogatory #22
I-4-23	EP Interrogatory #23
I-4-24	EP Interrogatory #24
I-4-25	EP Interrogatory #25
I-4-26	EP Interrogatory #26
I-6-16	VECC Interrogatory #16
I-6-17	VECC Interrogatory #17
I-6-18	VECC Interrogatory #18
I-8-1	OPG Interrogatory #1
I-10-11	SEC Interrogatory #11
I-10-12	SEC Interrogatory #12
I-10-14	SEC Interrogatory #14
I-10-15	SEC Interrogatory #15
I-12-5	CCC Interrogatory #5
TCJ1.03	Undertaking Response #1.03

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU and SEP

13. Are the proposed 2015 and 2016 levels of Common and Other Capital expenditures appropriate?

Settled

Common Corporate Costs Capital include information technology, software, and computer equipment, buildings, office equipment, transportation and work equipment, and service equipment. Common Corporate Cost items are included in Capital In Service Additions which was settled on a combined basis.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Summary of Common Corporate Costs Capital
I-2-13	CME Interrogatory #13
I-5-1	SEP Interrogatory #1
I-10-1	SEC Interrogatory #1

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU and SEP

14. Are the methodologies used to allocate Common and other capital expenditures to the transmission business appropriate?

Settled

Hydro One used the Black and Veatch study to define the use of shared assets amongst the business units. This methodology was endorsed by the Board in EB-2012-0031. The methodology used to allocate common and other capital expenditures to the transmission business was settled as part of the agreement on Capital In Service Addition and Rate Base.

Evidence: The evidence in relation to this issue includes the following:

C1-6-1	Common Corporate Costs, Cost Allocation Methodology
I-4-11	EP Interrogatory #11

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

15. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

Settled

Hydro One proposed to adopt the inputs and methodology recommended by Navigant to determine the working capital component of the rate base. The approach follows the one approved by the Board in EB-2012-0031.

The parties agree that the inputs and methodology used by Hydro One to determine the working capital component of the rate base are appropriate.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1 Rate Base
D2-1-1 Statement of Utility Rate Base

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

16. Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2015/16?

Settled

Exhibit D1, Tab 2, Schedule 1 (Transmission Assets Investment Overview) provides a summary of the overriding requirements of the sustaining programs and the reliability statistics that are critical to understanding how performance of various assets impact the power system and customers. It also provides a longer term asset-centric view of the key transmission assets and their primary risk factors such as: demographic, performance, and condition information. These three dimensions together provide information to support the 2015 and 2016 Sustaining OM&A and Capital expenditures proposed.

Hydro One used the investment planning process previously accepted by the Board in prior Hydro One Networks Inc. Transmission Rate Applications.

For the purpose of settling the OM&A and In Service Capital the parties accept that Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets in support of the OM&A and Capital expenditures for 2015 and 2016.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Transmission Assets Investment Overview
I-6-18	VECC Interrogatory #18
I-7-5	PWU Interrogatory #5
I-7-6	PWU Interrogatory #6
I-7-7	PWU Interrogatory #7
I-7-8	PWU Interrogatory #8
I-7-9	PWU Interrogatory #9
I-7-10	PWU Interrogatory #10
I-7-11	PWU Interrogatory #11
I-7-12	PWU Interrogatory #12
I-7-13	PWU Interrogatory #13
I-7-14	PWU Interrogatory #14
I-7-15	PWU Interrogatory #15
I-7-16	PWU Interrogatory #16
I-7-17	PWU Interrogatory #17
I-7-18	PWU Interrogatory #18
I-7-19	PWU Interrogatory #19
I-7-20	PWU Interrogatory #20
I-10-13	SEC Interrogatory #13
I-12-5	CCC Interrogatory #5

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

COST OF CAPITAL/CAPITAL STRUCTURE

17. Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

Settled

Hydro One updated the cost of capital to reflect the most recent forecast available (June 2014).

The following table provides the original proposed and the amounts that reflect the most recent forecast available:

	Original Proposal				As Per Settlement Agreement			
	2015		2016		2015		2016	
Amount of Deemed	Cost Rate (%)	Return ($M)	Cost Rate (%)	Return ($M)	Cost Rate (%)	Return ($M)	Cost Rate (%)	Return ($M)
Long-term debt	5.02%	286.0	5.08%	300.5	4.97%	283.5	5.00%	295.9
Short-term debt	3.19%	13.0	4.45%	18.8	2.27%	9.3	4.00%	16.9
Common equity	9.71%	395.3	9.96%	420.6	9.46%	385.1	9.91%	418.5
Total	6.82%	694.3	7.01%	739.9	6.66%	677.9	6.93%	731.3

The parties agree that the return on equity and short-term debt for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board's letter issued in the Fall of 2014 will be used to determine the ROE for Hydro One Transmission. Similarly, the 2016 ROE would be updated to reflect the Board's letter issued in the Fall of 2015. In addition the long term debt will be updated to reflect the actual debt issues.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Cost of Capital
I-2-4	CME Interrogatory #4
I-3-3	LPMA Interrogatory #3
I-3-4	LPMA Interrogatory #4
I-9-1	AMPCO Interrogatory #1
I-10-5	SEC Interrogatory #5
I-12-3	CCC Interrogatory #3

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

18. Is the forecast of long term debt for 2015-2016 appropriate?

Settled

The parties agree that the amount of long-term debt proposed by Hydro One for 2015 and 2016 is appropriate.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Cost of Capital
B1-2-1	Cost of Third Party Long-Term Debt
I-3-5	LPMA Interrogatory #5
I-4-5	Energy Probe Interrogatory #5
I-4-6	Energy Probe Interrogatory #6
I-4-7	Energy Probe Interrogatory #7
I-4-8	Energy Probe Interrogatory #8

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

DEFERRAL/VARIANCE ACCOUNTS

19. Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Settled

Hydro One proposed a forecast total balance at the end of 2014 of $36.1M in the following regulatory accounts:

- Excess Export Service Revenue
- External Secondary Land Use Revenue
- External Station Maintenance, E&CS Revenue and Other External Revenue
- Tax Rate Changes
- Rights Payments
- Pension Costs Differential

- Long Term Future Corridor

Parties agreed to the recovery of $36.1 million for the recovery of Regulatory accounts.

To smooth the rate impacts, the parties agree that the balance of $36.1 million will be refunded to customers in 2016 with no amount refunded in 2015.

The methodology to allocate regulatory assets to rate classes is consistent with the approach previously approved with the Board.

Evidence: The evidence in relation to this issue includes the following:

F1-1-1	Regulatory Accounts
F1-1-3	Planned Disposition of Regulatory Accounts
I-3-17	LPMA Interrogatory #17
I-3-18	LPMA Interrogatory #18
I-4-27	Energy Probe Interrogatory #27
I-4-28	Energy Probe Interrogatory #28
I-10-17	SEC Interrogatory #17
TCJ3.11	Undertaking Response #3.11

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

20. Are the proposed new Deferral and Variance Accounts appropriate?

Settled

Hydro One did not propose any new Deferral or Variance Accounts.

Parties agreed to create a net cumulative asymmetrical variance account as set out in the Capital In Service Addition and Rate Base section. This variance account is to capture the over collection of revenue requirement which would cumulatively occur between January 1, 2015 and December 31, 2016 if the actual 2016 year-end rate base is lower than the level agreed to in this settlement agreement. Hydro One's request for an Accounting Order to establish this new Variance Account is attached to this Agreement as Appendix D.

Evidence: See evidence for issue 11 to 14.

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU and SEP

COST ALLOCATION

21. Is the cost allocation proposed by Hydro One appropriate?

Settled

Hydro One proposed to continue to use the cost allocation methodology previously approved by the Board. The parties agreed that the cost allocation proposed by Hydro One is appropriate.

Attached at Appendix C is an updated Draft Summary Uniform Transmission Rates and Revenue Disbursements Factors for 2015 and 2016.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation and Charge Determinants
H1-2-1	Transmission Customers Load Forecast
H1-3-1	Charge Determinants
H1-4-1	Rates for Wholesale Meter Service
I-04-29	EP Interrogatory #29
I-04-30	EP Interrogatory #30
I-06-02	VECC Interrogatory #2
I-06-10	VECC Interrogatory #10

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC, SEP and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG and PWU

EXPORT TRANSMISSION SERVICE RATES

22. What is the appropriate level for Export Transmission Rates in Ontario?

Settled

Hydro One proposed to adopt an Export Transmission Service ("ETS") Rate of $1.7 per MWh for 2015 and 2016, as recommended in the Elenchus Study filed as Attachment 1 to Exhibit H1, Tab 5, Schedule 1.

For purposes of reaching a settlement, all parties agreed to an ETS rate of $1.85 per MWh for 2015 and 2016. The Parties further agree that agreement on the level of ETS rate of $1.85 per MWh shall not be construed as acceptance of the methodology, assumptions, or scenarios used in the Elenchus Study.

Because this is the first case where a cost allocation study was filed in evidence to inform the ETS Rate, the parties observe that the cost allocation methodology proposed by the Elenchus Study remains untested and the parties do not necessarily agree with that methodology. The parties therefore agreed on the ETS rate on the understanding that the methodologies, assumptions and scenarios used in the Elenchus Study do not have precedential value and may be challenged in subsequent proceedings.

The impact on revenue requirement to move to $1.85MWh from $2.00MWh increases the rate revenue requirement by $2.5 million in 2015, and $2.6 million in 2016.

Evidence: The evidence in relation to this issue includes the following:

H1-5-1 Rates for Export Transmission Service
H1-5-1 Attachment #1 Elenchus Export Transmission Service Rate – Cost Allocation Methodology
I-02-12 CME Interrogatory #12
I-04-31 EP Interrogatory #31
I-06-08 VECC Interrogatory #8
I-06-09 VECC Interrogatory #9
I-06-11 VECC Interrogatory #11
I-06-12 VECC Interrogatory #12
I-06-13 VECC Interrogatory #13
I-06-14 VECC Interrogatory #14
I-09-09 AMPCO Interrogatory #9
I-09-10 AMPCO Interrogatory #10
I-09-11 AMPCO Interrogatory #11
I-10-18 SEC Interrogatory #18
I-11-01 APPrO Interrogatory #1
I-11-02 APPrO Interrogatory #2
I-11-03 APPrO Interrogatory #3
I-11-04 APPrO Interrogatory #4
I-11-05 APPrO Interrogatory #5
I-11-06 APPrO Interrogatory #6
I-11-07 APPrO Interrogatory #7
I-11-08 APPrO Interrogatory #8
I-11-09 APPrO Interrogatory #9

I-11-10	APPrO Interrogatory #10
I-11-11	APPrO Interrogatory #11
I-11-12	APPrO Interrogatory #12
I-11-13	APPrO Interrogatory #13
I-11-14	APPrO Interrogatory #14
I-11-15	ApprO Interrogatory #15
I-12-18	CCC Interrogatory #18
TCJ1.04	VECC Technical Conference #1 Response #4
TCJ2.01	VECC Technical Conference #2 Response #1
TCJ2.02	VECC Technical Conference #2 Response #2
TCJ2.03	VECC Technical Conference #2 Response #3
TCJ2.04	APPrO Technical Conference #2 Response #4
TCJ2.05	APPrO Technical Conference #2 Response #5
TCJ2.06	VECC Technical Conference #2 Response #6
TDJ2.07	EP Technical Conference #2 Response #7

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, IESO, LPMA, SEC, VECC, APPrO, HQEM and OPG
Parties taking no position: PWU and SEP

OTHER

23. Intervenor proposal for an independent cost benchmarking study.

Settled

Intervenors want to better understand the cost of Hydro One's work relative to similar companies. A cost benchmarking study would also be supportive of the Board's Renewed Regulatory Framework. Hydro One agrees to complete an independent Transmission Cost Benchmarking Study that will be filed with Hydro One's next Transmission rates application.

Intervenors and Board Staff will be consulted, and agreement will be sought, in defining the Terms of Reference that will be included in the Request for Proposal document. The Request for Proposal document will be used in the selection process for the independent party that will complete the Study. After Hydro One selects the independent party that will complete the Study, Intervenors and Board Staff will review the Study proposal provided by the independent party to help ensure that the proposal meets the requirements of the Terms of Reference.

Intervenors and Board Staff will also be provided with an opportunity to review and provide comments on the preliminary results prior to finalizing the Study. Hydro One agrees to fund Intervenors for their participation as consistent with Hydro One's past practice.

Evidence:

Not applicable

Supporting Parties: AMPCO, BOMA, BP, CME, CCC, Energy Probe, LPMA, SEC and VECC
Parties taking no position: APPrO, HQEM, IESO, OPG, PWU and SEP

LIST OF APPROVALS SOUGHT

1. An Order pursuant to section 78 of the *Ontario Energy Board Act, 1998,* approving the 2015 and 2016 Revenue Requirement for the transmission of electricity to be implemented on January 1, 2015.

2. As a result of the Settlement Proposal, Hydro One Networks Inc. (“Hydro One”) seeks approval of a revenue requirement of $1,577 million and $1,660 million for the test years 2015 and 2016, respectively. Taking into account the increased load forecast, the resulting increase in Hydro One Transmission Rates is 1.1% and 1.7%, respectively. The estimated increase on the average customer’s total bill is 0.1% in 2015 and 0.1% in 2016. The transmission component represents 7.4% of an average distribution-connected customer’s total bill.

3. Hydro One seeks approval of regulatory assets totaling ($36.1) million as at December 31, 2014. Hydro One seeks approval to refund this balance in 2016 and to reduce the annual revenue requirement accordingly.

4. Hydro One also requests that the Board amend the Uniform Transmission Rates to allow for recovery of the proposed revenue requirements for 2015 and 2016, effective January 1 of each year.

5. Hydro One seeks approval to continue the following deferral accounts: the Excess Export Service Revenue Account; the External Secondary Land Use Revenue Variance Account; the External Station Maintenance, E&CS and Other Revenue Variance Account; the Tax Rate Changes Account; the Rights Payments Variance Account; the Pension Cost Differential Account; the External Revenue – Partnership Transmission Projects Account; the East West Tie Deferral Account; and the Long Term Future Corridor Account.

6. For 2015 and 2016, Hydro One is requesting that the Board approve the establishment of a new variance account, the In-Service Capital Additions Variance Account.

Draft Rate Increases	**Original Proposal** ROE 9.36%	ROE 9.71%	ROE 9.96%	**Settlement** ROE 9.36%	ROE 9.46%	ROE 9.91%
	2014**	2015	2016	2014	2015*	2016*
Revenue requirement						
OM&A		452.0	457.4		432.0	437.4
Depreciation on fixed assets		394.2	404.0		394.2	404.0
Return on debt		299.0	319.3		292.8	312.8
Return on equity		395.3	420.6		385.1	418.5
Income tax		71.8	82.8		68.1	82.1
AFUDC		5.0	5.0		5.0	5.0
Revenue requirement	1,535.3	1,617.2	1,689.2	1,535.3	1,577.2	1,659.8
	5.4%	5.3%	4.4%	5.4%	2.7%	5.2%
Less: External revenues	(36.6)	(28.4)	(28.8)	(36.6)	(31.8)	(32.2)
	1,498.7	1,588.8	1,660.4	1,498.7	1,545.4	1,627.6
	5.9%	6.0%	4.5%	5.9%	3.1%	5.3%
Less: Export revenue credit	(34.1)	(33.4)	(34.3)	(34.1)	(30.9)	(31.7)
	1,464.6	1,555.4	1,626.1	1,464.6	1,514.5	1,595.9
	6.0%	6.2%	4.5%	6.0%	3.4%	5.4%
Less: "Tx Riders"	(30.3)	(17.6)	(17.6)	(30.3)	-	(36.1)
	1,434.3	1,537.8	1,608.5	1,434.3	1,514.5	1,559.8
	6.6%	7.2%	4.6%	6.6%	5.6%	3.0%
Add: LVSG (low voltage switch gear)	12.1	13.2	13.9	12.1	12.9	13.5
Rates Revenue Requirement	**1,446.4**	**1,551.0**	**1,622.4**	**1,446.4**	**1,527.4**	**1,573.3**
	6.6%	7.2%	4.6%	6.6%	5.6%	3.0%
Estimated impact of load change		-4.0%	-1.3%		-4.5%	-1.3%
Assumed Rate Impact		**3.2%**	**3.3%**		**1.1%**	**1.7%**

* Subject to the final Board issued Cost of Capital Report
** OEB Approved

Uniform Transmission Rates and Revenue Disbursement Factors for 2015 and 2016

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2015

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI (Note 3)	$3,830,379	$834,985	$1,661,725	$6,327,089
CNPI (Note 4)	$2,792,343	$608,703	$1,211,397	$4,612,443
GLPT (Note 5)	$22,994,359	$5,012,542	$9,975,595	$37,982,496
H1N (Note 1)	$924,519,236	$201,536,019	$401,082,266	$1,527,137,521
All Transmitters	$954,136,318	$207,992,248	$413,930,983	$1,576,059,549

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI (Note 3)	187.120	213.460	76.190	
CNPI (Note 4)	583.420	668.600	668.600	
GLPT (Note 5)	3,445.341	2,461.434	455.652	
H1N (Note 2)	246,888.000	238,332.000	204,816.000	
All Transmitters	251,103.881	241,675.494	206,016.442	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.80**	**0.86**	**2.01**	
FNEI Allocation Factor	**0.00401**	**0.00401**	**0.00401**	
CNPI Allocation Factor	**0.00293**	**0.00293**	**0.00293**	
GLPT Allocation Factor	**0.02410**	**0.02410**	**0.02410**	
H1N Alocation Factor	**0.96896**	**0.96896**	**0.96896**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Hydro One Networks (H1N) 2015 Revenue Requirement as per Settlement Agreement
Note 2: Hydro One Networks (H1N) 2015 Charge Determinants as per Settlement Agreement
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement per Board Decision and Order on EB-2012-0300 dated on December 19, 2013, and GLPT Charge Determinants per Board Decision and Order on EB-2012-0300 dated on November 1, 2012.
Note 6: Calculated data in shaded cells.

Hydro One Networks Inc.
Implementation of OEB Settlement Agreement

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2016

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI (Note 3)	$3,775,283	$856,500	$1,695,306	$6,327,089
CNPI (Note 4)	$2,752,179	$624,387	$1,235,877	$4,612,443
GLPT (Note 5)	$22,663,611	$5,141,699	$10,177,186	$37,982,496
H1N (Note 1)	$938,636,973	$212,948,816	$421,498,734	$1,573,084,523
All Transmitters	$967,828,046	$219,571,402	$434,607,104	$1,622,006,551

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	3,445.3	2,461.4	455.7	
H1N (Note 2)	249,552.0	241,956.0	207,936.0	
All Transmitters	253,767.9	245,299.5	209,136.4	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.81**	**0.90**	**2.08**	
FNEI Allocation Factor	**0.00390**	**0.00390**	**0.00390**	
CNPI Allocation Factor	**0.00284**	**0.00284**	**0.00284**	
GLPT Allocation Factor	**0.02342**	**0.02342**	**0.02342**	
H1N Alocation Factor	**0.96984**	**0.96984**	**0.96984**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Hydro One Networks (H1N) 2016 Revenue Requirement as per OEB Settlement Agreement
Note 2: Hydro One Networks (H1N) 2016 Charge Determinants as per OEB Settlement Agreement
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement per Board Decision and Order on EB-2012-0300 dated on December 19, 2013, and GLPT Charge Determinants per Board Decision and Order on EB-2012-0300 dated on November 1, 2012.
Note 6: Calculated data in shaded cells.

Hydro One Networks Inc. Request for an Accounting Order to Establish a Variance Account relating to the Transmission Revenue Requirement Impact of In-Service Capital Shortfalls

1.0 BACKGROUND

Hydro One Networks Inc. ("Hydro One") has agreed in its Settlement Agreement for 2015 and 2016 Transmission Rates to establish a net cumulative asymmetrical variance account to track the impact on Transmission Revenue Requirement of any in-service capital additions ("ISA") shortfalls compared to the Ontario Energy Board ("the Board") approved in-service amounts for 2014, 2015 and 2016.

2.0 CALCULATION OF ENTRIES TO THE VARIANCE ACCOUNT

Hydro One agreed to create a net cumulative asymmetrical[1] variance account for 2014, 2015, and 2016 ISA to track the impact on 2015 and 2016 revenue requirement of any ISA shortfall compared to Board approved amounts.

3.0 ACCOUNTING AND CONTROL PROCESS

The variance account requested above will be managed in the same manner as existing Hydro One variance and deferral accounts. It will be updated annually and interest applied consistent with the Board-approved rate. Balances will be reported to the Board as part of the reporting process. The outstanding balance will be submitted for approval to the Board as part of a future Transmission rate filing.

[1] Asymmetrical: If the cumulative amount of ISA exceeds the cumulative Board-approved amount for the period 2014-2016, no entry would be made in the variance account.

Draft accounting entries for the transactions related to the proposed Variance Account are included below:

PROPOSED ACCOUNTING ENTRIES

1) Capital In-Service Additions Shortfall Transmission Revenue Requirement Variance Account

USofA # Account Description

Dr: 4305 Other Regulatory Debits (Income Statement)
Cr: 2405 Other Regulatory Liabilities – Sub account "Capital In-Service Additions Shortfall Revenue Requirement Variance Account"

To record the impact on 2015 and 2016 Transmission Revenue Requirement due to the difference between the Board-approved in-service capital additions and the actual capital in-service additions in 2014, 2015 and 2016.

Dr: 6035 Other Interest Expense
Cr: 2405 Other Regulatory Liabilities – Sub account "Capital In-Service Additions Shortfall Revenue Requirement Variance Account"

To record interest accretion on the principal balance of the, "Capital In-Service Additions Shortfall Revenue Requirement Variance Account".

SECTION III

INFORMATION PROVIDED DURING SETTLEMENT

Information in Section III has appeared on Hydro One Networks Inc. external website in support of the Transmission Settlement Agreement as of the dates indicated in the document headers.

SUMMARY OF PROPOSED APPLICATION

Hydro One has initiated a process to discuss potential settlement of the Transmission rate impacts on 2015 and 2016. At the initial discussion on June 25, Ken Rosenberg, who has been retained by Hydro One to facilitate the discussion, described the key elements of this process and established dates for further sharing of supporting data and initiation of negotiations. The communication on the schedule issued by Ken is attached.

At the meeting, Hydro One also introduced Gordon Kaiser who is assisting Hydro One from a strategic perspective. Hydro One shared an overview of the Transmission Revenue Requirement and Rates that the company requires for 2015 and 2016. The power point presentation used on June 24 is also included. When establishing the dates for further discussion, Hydro One clearly indicated that while it is hopeful that a settlement can be reached, it needs to file an application in September with or without a settlement.

To assist parties to better understand the costing underlying Hydro One's requirements for 2015 and 2016 rates, the parties at the June 25th meeting requested that the company provide key information supporting the 2015 and 2016 revenue requirement and rates. The company has included the scope of the proposed application in the following section which also provides a guide to where additional details are provided. In addition, at the June 25th meeting, Hydro One was requested by Bill Harper to identify which capital projects were directed by the OPA, IESO or Government. This list is included below.

The materials have been organized in a format that is consistent with previous Transmission revenue requirement and rate applications including the exhibit numbers used. As part of this process there may be areas where additional or clarifying information would be beneficial to the parties, Hydro One proposes that it will update the exhibits to improve the quality of the information prior to preparing the application. If a settlement is not reached the attached exhibits might be updated to capture these improvements or other developments that occur in the interim.

1.0 SCOPE OF PROPOSED APPLICATION

The scope of this Proposed Application includes:

- the review of Hydro One Transmission's evidence in support of the revenue requirements for 2015 and 2016, and
- the review of the charge determinants by rate pools to assist in the development of Uniform Transmission Rates.

This proposal reflects Hydro One Transmission's plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability; system growth requirements; and initiatives to facilitate renewable generation connection. Details of Hydro One Transmission's capital expenditures are provided in schedules within Exhibit D1, Tab 3.

Hydro One Transmission's OM&A expenditures have been determined on the basis of an examination of required work programs to ensure the most appropriate, cost-effective solutions are undertaken to meet public and employee safety objectives, maintain transmission reliability at targeted performance levels, and to comply with regulatory requirements, environmental requirements and Government direction. These expenditures are provided in Exhibit C1.

Hydro One assesses the condition of its Transmission assets on an ongoing basis, and the results of these assessments are used to determine the Sustainment OM&A and capital plans set out in Exhibits C and D. Sustainment planning is described at Exhibit C1, Tab 2, Schedule 2 and at D1, Tab 3, Schedule 2.

This Proposed Application by Hydro One Transmission is substantively consistent with the Filing Requirements for Transmission Applications (the "Filing Requirements") issued by the Board on January 2, 2014.

This Proposed Application addresses all outstanding Board directives with respect to its Transmission Business.

Hydro One has used the Corporate Cost Allocation Methodology as accepted by the Board in previous Hydro One Distribution and Transmission Applications and updated for this current filing, to allocate the costs of shared services of OM&A and Common Assets between Transmission and Distribution.

The 2015-2016 overhead capitalization rate has been calculated consistent with the methodology accepted in previous Hydro One Distribution and Transmission Applications and updated for this current filing.

Hydro One has incorporated the methodologies of the Lead Lag study, based on the methodology accepted by the Board in previous Distribution and Transmission Applications and updated for this current filing.

Hydro One has applied the deemed capital structure of 60% debt and 40% common equity, approved by the Board in its EB-2012-0031, in determining its 2015 and 2016 revenue requirement. Hydro One is currently requesting an equity return of 9.71 % for the 2015 test year and 9.96 % for 2016. The equity returns have been derived using the latest Board formulaic methodology from the EB-2009-0084 proceeding issued on December 11, 2009, applied using the September 2013 Consensus Forecast and Bank of Canada.

The Company expects that the return on equity (ROE) and other Cost of Capital (CoC) parameters for 2015 and 2016 will be updated to reflect the September 2014 and September 2015 Consensus Forecasts and Bank of Canada data available in October of 2014 and 2015 as described at Exhibit B1, Tab 1, Schedule 1.

This Proposed Application provides information on Hydro One Transmission’s revenue requirement and charge determinants by rate pools to assist in the development of provincial uniform transmission rates at Exhibit H1.

2.0 PROPOSED APPROVALS REQUESTED

2.1 Revenue Requirement

Respecting Hydro One’s revenue requirement in the years 2015 and 2016 for its Transmission Business, the Company is proposing to seek approvals for:

1. A revenue requirement of $1,617 million and $1,689 million for the 2015 and 2016 test years, respectively. Taking into account the increased load forecast, the resulting increase in Hydro One Transmission Rates is 3.2% and 3.3%, respectively. The estimated increase on the average customer’s total bill is 0.2% in 2015 and 0.2% in 2016. The transmission component represents 7.4% of an average distribution connected customer’s total bill.

2. Total capital expenditures of $899 million in 2015 and $866 million in 2016.

3. An OM&A cost expenditure forecast of $452 million in 2015 and $458 million in 2016, driven by the need to safely deliver transmission reliability at targeted performance levels.

4. The Proposed Application assumes the existing Export Transmission Service (ETS) rate of $2/MWh to be continued and disbursed through a decrease in revenue requirement for the Network Pool. The forecast for ETS revenue is $33.4 million for 2015 and $34.3 million for 2016. The ETS rate is discussed in Exhibit H1, Tab 5, Schedule 1. Hydro One was directed by the Board to prepare an ETS cost allocation study in its EB-2012-0031 Decision and Order. The completed study is provided in Exhibit H1, Tab 5, Schedule 1, Attachment 1.

5. Hydro One Networks seeks approval of regulatory assets totaling ($36.1) million as at December 31, 2013. Hydro One seeks approval to refund this balance over a two year period and to reduce the annual revenue requirement accordingly as discussed at Exhibit F1, Tab 1, Schedule 3.

6. Hydro One Transmission's Rate Base of $10,177 million for 2015 and $10,558 million for 2016 is discussed in Exhibit D1, Tab 1, Schedule 1.

2.2 Cost Allocation and Rates

The Company is seeking approvals of:

1. The continuation of the Hydro One Transmission’s cost allocation methodology.

2. The continuation of a wholesale metering services pool.

3. The revenue to be collected by each Rate Pool as discussed in Exhibit G1, Tab 1, Schedule 1.

4. The charge determinant application to each Rate Pool as discussed in Exhibit H1, Tab 3, Schedule 1.

5. Charges for the provision of wholesale metering services and export transmission services performed by the utility as set out at Exhibit H1, Tab 4, Schedule 1 and Exhibit H1, Tab 5, Schedule 1, respectively. The disposition of the balances accumulated in Regulatory Accounts as shown in Exhibit F1, Tab 1, Schedule 3.

6. Hydro One Networks will request that the Board amend the Uniform Transmission Rates to allow for recovery of the proposed revenue requirements for 2015 and 2016, effective January 1st of each year.

2.3 Other Proposed Approvals

1. Hydro One Networks seeks approval to continue the following deferral accounts including: the Excess Export Service Revenue Account; the External Secondary Land Use Revenue Variance Account; the External Station Maintenance, E&CS and Other Revenue Variance Account; the Tax Rate Changes Account; the Rights Payments Variance Account; the Pension Cost Differential Account; the External Revenue – Partnership Transmission Projects Account; the East West Tie Deferral Account; the LDC CDM and Demand Response Variance Account (for settling 2013 and 2014 balances) and the Long Term Future Corridor Account.

3.0 CAUSES OF THE INCREASE IN REVENUE REQUIREMENT

In 2015, there are a number of key operational and financial factors contributing to the increased revenue requirement over 2014. The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in depreciation, as well as higher cost of debt and allowed ROE. Also contributing to the difference is higher income taxes, lower external revenues, and reduced regulatory account disposition.

The increase in 2016 rates revenue requirement is primarily due to the increase in core rate base as reflected in the increase in return on capital and depreciation. Other contributing factors include higher income taxes and slightly higher OM&A work program requirements. Exhibit G1, Tab 1, Schedule 1 provides information on how the rates revenue requirements will be recovered through rates.

The increases identified within the Proposed Application will ensure that customers within the Province will continue to be supplied in a secure and reliable manner while supporting the Government's connection of renewable generation initiatives, thereby contributing to the health and competitiveness of the Province's economy.

SECTION III

SUBSECTION i 2a

2015/2016 TRANSMISSION RATES APPLICATION PRESENTATION ON JUNE 25, 2014

2015/16 Transmission Rates Application Presentation

*****Confidential*****

Wednesday, June 25, 2014

OEB North Hearing Room

Objectives

- Review Hydro One 2015/16 Rates Proposal
- Determine if participants are interested in pursuing a negotiated settlement

Context

- 2 year cost of service
- Rates primarily driven by increases in rate base for key capital projects/programs
- Focus on sustaining activity in the test years
- Maintaining current reliability levels while becoming more productive

Issues

1. Is the overall revenue requirement increase in 2015 and 2016 reasonable?

2. Is the load forecast methodology appropriate?

3. Are the proposed spending levels for Sustaining, Development, Operations, Common Corporate and Other OM&A in 2015 and 2016 appropriate?

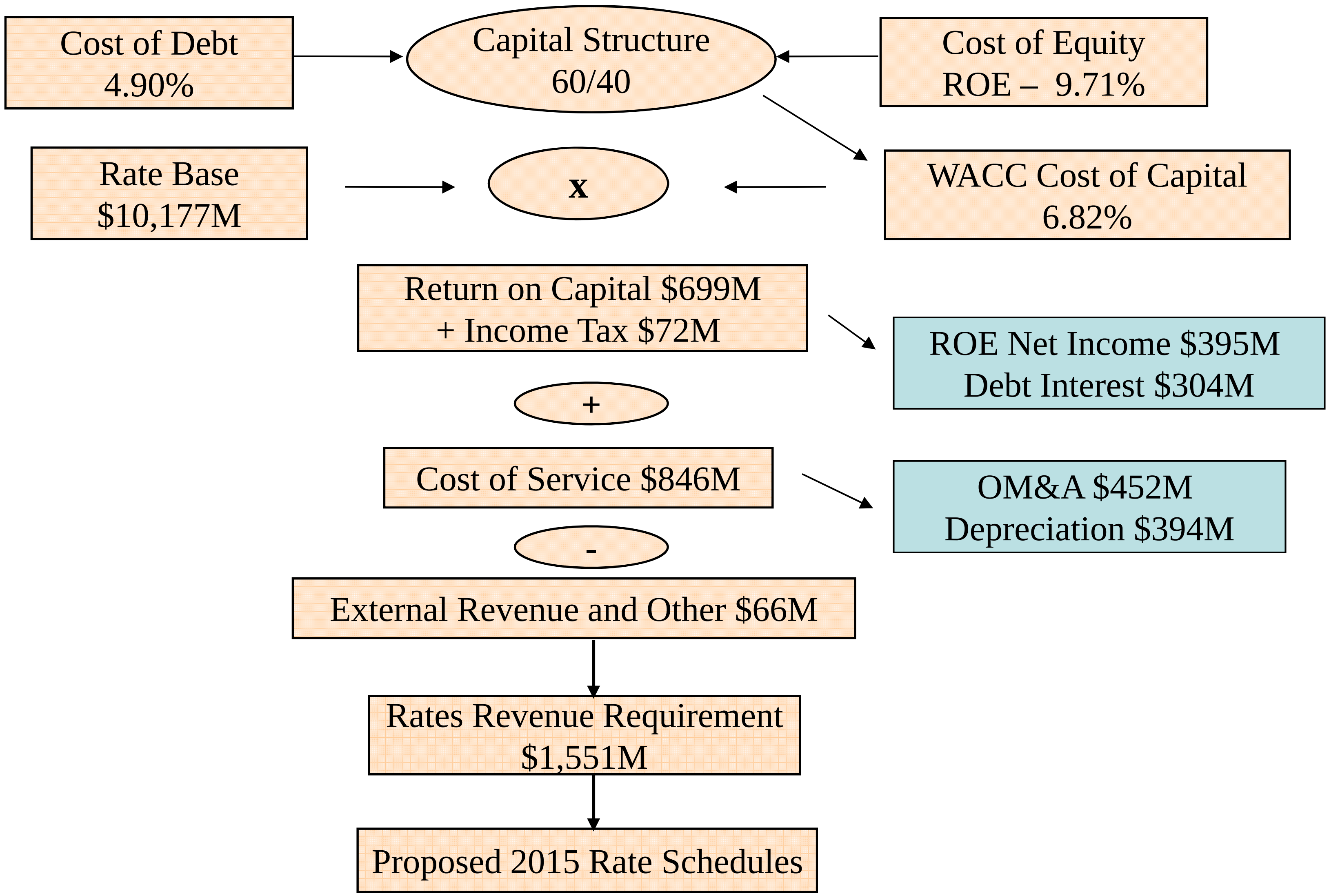
4. Are the amounts proposed for rate base in 2015/16 appropriate?

5. Are the proposed levels for Sustaining, Development, Operations, Common Corporate and Other Capital Expenditures in 2015/16 appropriate?

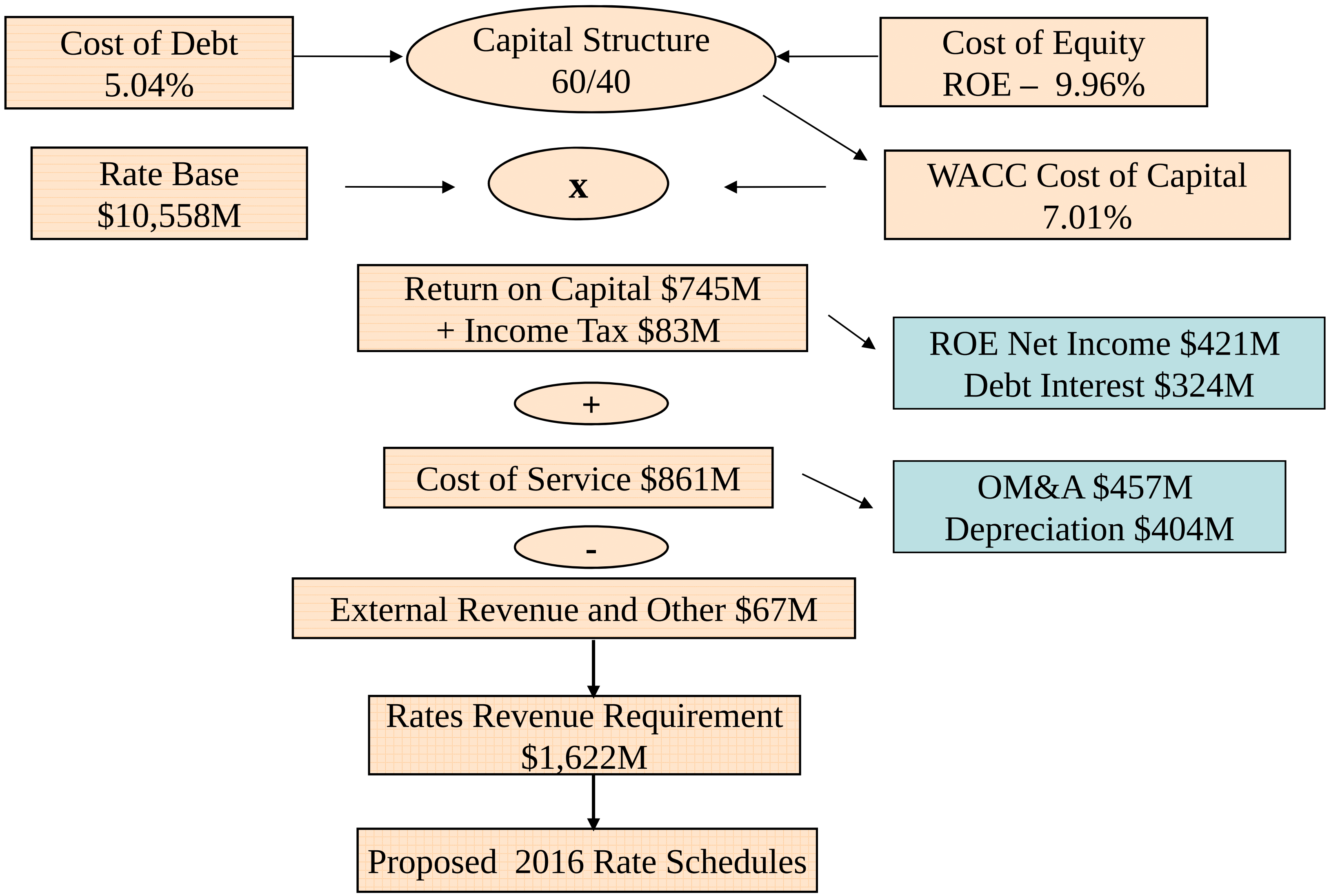
6. Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

7. What is the appropriate level for Export Transmission Rates in Ontario?

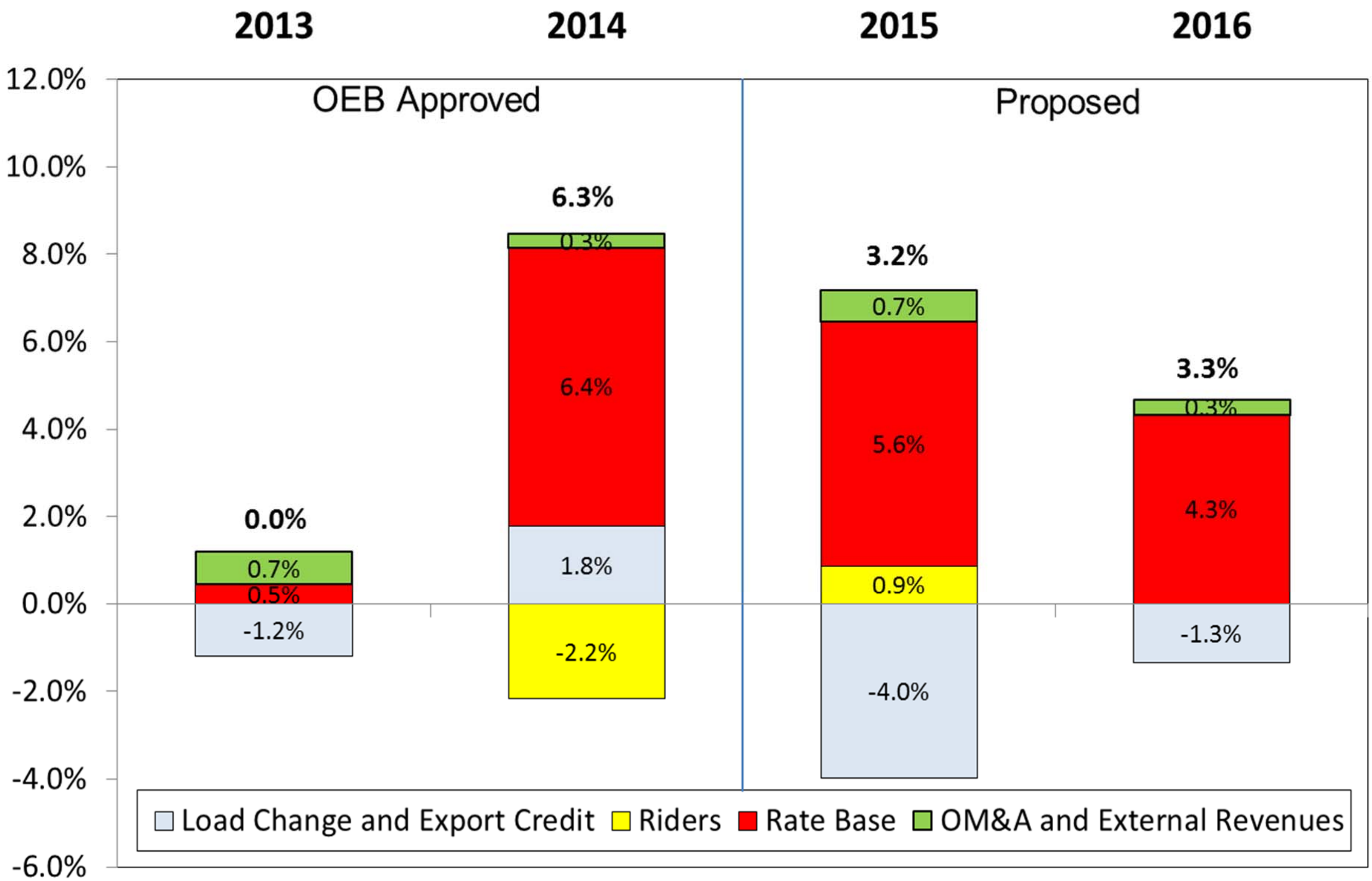
Proposed 2015 Transmission Revenue - Cost of Service Requirement



Proposed 2016 Transmission Revenue - Cost of Service Requirement



Transmission Rate Increase



Total Bill Impact:	0.0%	0.5%	0.2%	0.2%

OM&A Expenditures 2013 to 2016 ($ millions)

	2013		2014		Test Years	
	Actual	OEB Approved	Bridge	OEB Approved	2015	2016
Sustaining	221.0	235.7	236.2	246.5	238.7	241.1
Development	8.6	13.7	12.9	14.7	12.9	13.4
Operations	56.7	57.7	57.4	58.0	58.5	59.1
Customer Care	5.3	4.9	5.8	4.7	5.5	5.5
Common Corporate and Other OM&A	75.8	61.9	70.6	59.0	70.2	71.3
Property Taxes & Rights Payments	21.2*	66.0	65.6	66.8	66.3	67.0
Total	**388.4**	**440.3**	**448.6**	**449.7**	**452.1**	**457.5**

* Reflects One-time Property Tax Credit of $43 million

- OM&A Increase – Primarily from Sustaining
  - Aging transmission system
  - Expanding transmission system
  - Standard requirements
  - Inflation

- Efficiency and productivity savings – mitigate the increase

Productivity ($ millions)

	2014 Bridge	2015 Proposed	2016 Proposed
OM&A	$449	$452	$457
Productivity Savings	$42	$46	$49
Productivity Savings %	9.30%	10.10%	10.70%
OM&A without Productivity	$491	$498	$507

In-Service Capital Additions 2013 to 2016 ($ millions)

	2013		2014		Test Years	
	ISA Actuals	OEB Approved	Bridge	OEB Approved	2015	2016
Sustaining	403.8	443.3	588.4	701.1	572.2	480.9
Development	231.7	261.8	177.3	205.8	134.7	119.4
Operations	5.9	15.1	19.0	48.0	50.4	10.0
Common & Other	62.4	64.0	78.7	68.0	64.1	63.1
Total	**703.8**	**784.2**	**863.3**	**1,023.1**	**821.3**	**673.3**
Rate Base	**9,209**	**9,353**	**9,671**	**9,934**	**10,177**	**10,558**

- In-Service Capital Additions:
  - Sustaining – Completion of large projects/programs in 2014/15
  - Development – Completion of large projects in recent years
  - Operation – Network Management System (and others) coming in service in 2015

Achieving In-Service Capital Additions

Factors Impacting 2013/14 Performance

- Outages
- Construction
- Shift of priority
- Efficiency savings

Achieving In-Service Capital Additions in 2015/16

- Projects/Programs under way or approved:
  - A significant portion (over 80%) of sustaining projects/programs
  - Midtown Transmission Reinforcement ($62 M in service in 2015)
  - Guelph Area Transmission Reinforcement ($94 M in service in 2016)
  - Network Management System Upgrade ($35 M in service in 2015)

- 2015 and 2016 figures match historical level

Capital Expenditures 2013 to 2016 ($ millions)

	2013		2014		Test Years	
	Actual	OEB Approved	Bridge	OEB Approved	2015	2016
Sustaining	480.0	589.2	579.3	695.3	581.9	548.6
Development	171.7	277.8	195.6	306.2	209.7	211.8
Operations	17.7	35.2	38.5	56.5	38.4	37.4
Common & Other	49.1	80.2	85.8	63.5	69.4	68.5
Total	**718.5**	**982.5**	**899.2**	**1,121.5**	**899.4**	**866.3**

- Capital Expenditures in 2015 and 2016 will continue at 2014 level

Major Sustaining Capital Projects/Programs ($ millions)

	2013	2014	2015	2016
Station Work	$355	$459	$450	$430
• *Station Re-investment*	*$89*	*$158*	*$241*	*$160*
• *Protection, Control, Monitoring & Telecom*	*$84*	*$117*	*$92*	*$96*
Lines Work	$125	$121	$132	$119

Major Development Capital Projects ($ millions)

	2015	2016
Clarington TS: Build new 500/230kV Station (2017)	$92	$101
Midtown Transmission Reinforcement Plan (2015)	$22	$0
Guelph Area Transmission Reinforcement (2016)	$48	$30
Supply to Essex County Transmission Reinforcement (2017)	$25	$38

Capital Projects Not Included

- East West Tie Expansion – Station Work
- Northwest Bulk Transmission Line Project
- GTA Reactors

Other Components

- Depreciation
  - Foster Associates has completed a new Depreciation Study for Hydro One Transmission in support of its 2015 and 2016 application which recommends an increase in depreciation for Transmission Operations and Common Operations.
  - This would increase depreciation by about $16 million in 2015.

- Income Taxes
  - The combined income tax rate continues to be 26.5% for 2015 and 2016, comprised of a Federal rate of 15% and an Ontario rate of 11.5% as a result of the Ontario budget bill enacted on June 20, 2012.

Other Components

- Cost of Capital
  - Hydro One Transmission’s deemed capital structure for rate making purposes is 60% debt and 40% common equity. The capital structure assumptions have not changed.
  - Hydro One Transmission’s application reflects a return of 9.71% for the test year 2015 and 9.96% for the test year 2016, per the Board’s formulaic approach.
  - The return on equity for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case.

Disposition of Regulatory Account Balances ($ millions)

Particulars	Balance as at Dec 31, 2013	Forecast Balance as at Dec 31, 2014
	(a)	(b)
Excess Export Service|Deferred Revenue	(41.9)	(23.5)
External Secondary Land Use Revenue	(32.8)	(18.5)
External Stations, EC&S Revenue and Other Revenue	(6.4)	(1.3)
Tax Rate Changes Account	(3.6)	0.8
Rights Payments	(3.6)	(1.9)
Pension Cost Differential	20.8	8.2
Long-Term Transmission Future Corridor Acquisition and Development	0.1	0.1
Total Regulatory Accounts	**(67.4)**	**(36.1)**

(a) 2013 interest is based on the OEB prescribed rates.
(b) 2014 includes disposition amounts ($30.3 M) as approved by the Board in EB 2012-0031 and forecast interest improvement for 2014.

Annual Credit: $18 M in 2015 and $ 18.1 M in 2016

ETS Rate

- Current ETS Rate = $2/MWh
- Stakeholder session held on March 24, 2014 where Elenchus explained their methodology
- Final report completed by Elenchus
- Proposed cost allocation methodology determines the ETS rate based on cost causality principles
- Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of $1.70/MWh be implemented for 2015/16

ETS Rate

- ETS revenues in this application ($33.4m in 2015 and $34.3M in 2016) are determined based on the current approved tariff of $2/MWh and the 3 year historical average volume of electricity exported from, or wheeled-through, Ontario over its transmission system.
- Hydro One proposes to revise its rates revenue requirement to reflect the OEB's decision and order with respect to the ETS tariff as part of the Draft Rate Order to be submitted in connection with finalizing the 2015 UTR to be approved.

Bruce to Milton Partnership

- The Saugeen Ojibway Nation (SON) agreed to purchase from Hydro One an approximately 34% equity interest in the assets of Bruce to Milton Project. The transaction is expected to close in 2014.

- The assets will be removed from Hydro One Networks' rate base and transferred to a new partnership (to be called B2M LP)

- The net book value of the assets is approximately $530 million.

- Hydro One Networks' revenue requirement will be reduced by approximately $42 million (-3% transmission rate reduction for Hydro One Networks)

- Next Steps:
  - ➢ Finalizing Financing arrangements
  - ➢ Rate approval from the OEB

SECTION III

SUBSECTION i 2b

IN-SERVICE CAPITAL PRESENTATION ON JULY 23, 2014

AS

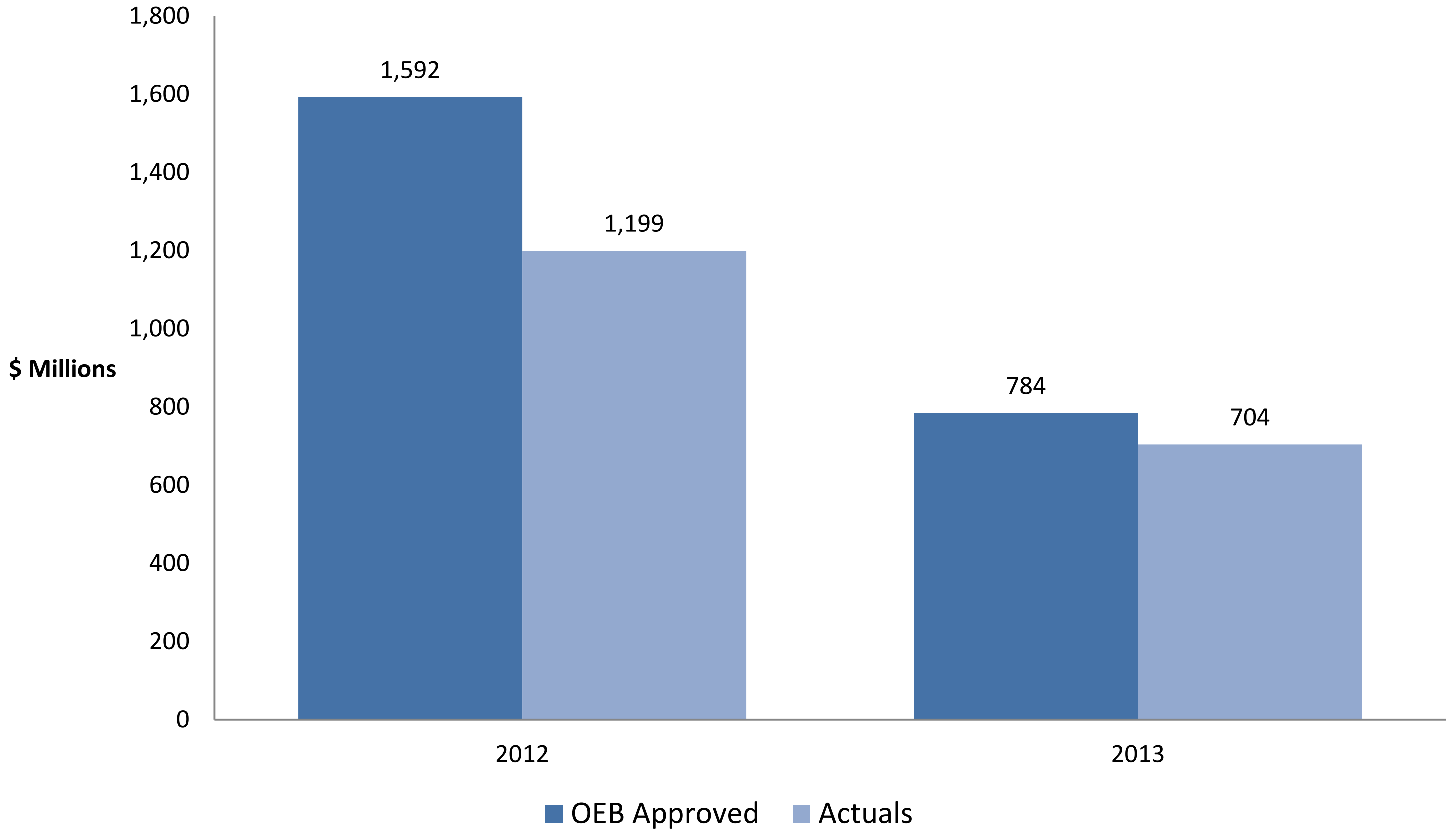
"OVERVIEW OF 2012-2013 ISA AND 2015-2016 ISA"

Hydro One 2015-2016 Transmission Rates

Overview of 2012-2013 ISA and 2015-2016 ISA

July 23, 2014

Transmission In-Service Additions



- 2012 Variance: -$393M, 25%
- 2013 Variance: -$80M, 10%

Variance Causes

- Variances are due to project timing, as opposed to total project cost.
- Typically a very small number of projects out of overall work program have issues resulting in ISA variances
- Typical factors which result in ISA variances
  - Construction delays/advances resulting in costs getting booked behind/ahead of plan
  - Increased stakeholder consultation (IESO, First Nations, etc.)
  - Land / Real-Estate Rights, difficult to predict timing
  - Outage availability
  - Unforeseen issues during construction

Substantial Changes for the 2015-16 Plan

- Improved enterprise engagement during development of plan *(project timing, outage availability)*
- Leveraging new systems and tools during development and execution of plan *(project timing, outage availability)*
- Better upfront consideration to outage planning
- Only externally-driven projects with a high degree of certainty of proceeding are included in the plan

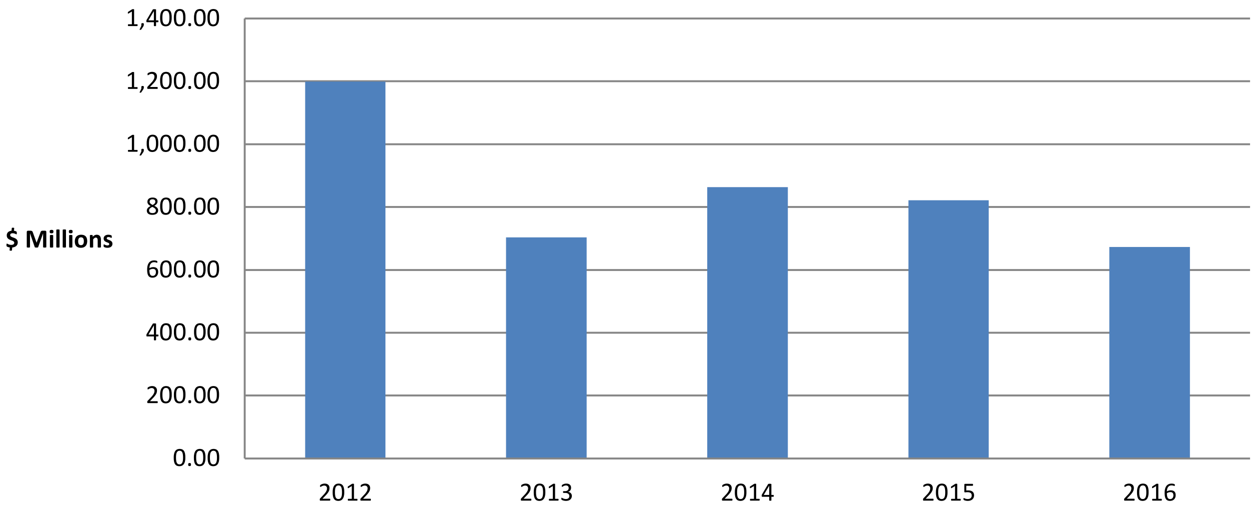
Results:

<u>**More Realistic Completion Dates = more accurate ISA forecasts**</u>

Looking to 2015-16 ISA

- Large portion of the ISA planned for 2015-16 are projects in later stages of development → less risk around completion dates given maturity of projects
- 2015 and 2016 ISA amounts are in-line with historic actuals

Transmission In-Service Additions
2012-13 Actuals, 2014 Brdige Forecast, 2015-16 Forecast



SECTION III
SUBSECTION i 3
LIST OF CAPITAL PROJECTS THAT WERE DIRECTED BY THE ONTARIO POWER AUTHORITY, INDEPENDENT ELECTRICITY SYSTEM OPERATOR, OR GOVERNMENT

List of Capital Projects* that were directed by the Ontario Power Authority, Independent Electricity System Operator or Government

Project Name	CAP EX ($ millions) 2015	2016
New 500 kV Bruce to Milton Double Circuit Transmission Line	3.3	3.2
Clarington TS: Build new 500/230kV Station	91.7	101.1
Installation of Shunt Capacitor Banks at Cherrywood TS	0.1	3.4
Guelph Area Transmission Reinforcement	48.3	29.9
Preston TS Transformation	10.0	4.6
Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	5.7	3.9
Hawthorne TS: Replace two existing Transformers	1.0	7.0
York Region – Increase Transmission Capability for B82V/B83V Circuits	5.0	7.0
Supply to Essex County Transmission Reinforcement	25.0	37.5
Napanee Gas Generation Connection	1.0	4.5
Transmission Station P&C Upgrades for DG	17.5	18.0

* All projects listed are development projects

SECTION III

SUBSECTION ii

INFORMATION PACKAGE PROVIDED ON JUNE 27, 2014

2015-2016 TRANSMISSION RATES PROPOSAL

INFORMATION PACKAGE CONTENTS

Exhibit	Tab	Schedule	Contents
H1	5	1	Attachment 1 – Elenchus Export Transmission Service Rate – Cost Allocation Methodology

FINANCIAL SUMMARY

1.0 INTRODUCTION

Hydro One Transmission is proposing this Application requesting approval of an appropriate revenue requirement in support of just and reasonable transmission rates for 2015 and 2016.

This proposed Application provides information required to support revenue requirement and related transmission rates for the test years 2015 and 2016. The submission also provides historical information for 2011, 2012 and 2013, along with 2014 bridge year information.

The Company is proposing to recover a total revenue requirement of $1,617.1 million from its customers for the 2015 test year and $1,689.2 million for the 2016 test year.

Hydro One Transmission's capital structure was approved by the Board as part of its November 8, 2012 Decision on Hydro One's Transmission Rate Application (EB-2012-0031). This is consistent with the Board's report on the cost of capital: see the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 (EB-2009-0084). Hydro One Transmission's evidence reflects a return of 9.71% in 2015 and 9.96% in 2016, as specified by the formula in the report above. Hydro One Transmission's evidence in support of its Cost of Capital and Cost of Third Party Long Term Debt appears at Exhibit B1, Tab 1, Schedule 1 and Exhibit B1, Tab 2, Schedule 1.

Hydro One Transmission's OM&A expenditures have been determined through an examination of required work programs to ensure the most appropriate, cost-effective solutions are employed to meet corporate objectives. The proposed OM&A expenditures are $452.0 million in 2015 and $457.4 million in 2016, driven by the need to safely deliver transmission reliability at targeted performance levels. These expenditures are discussed throughout Exhibit C1. Hydro One has used the Corporate Cost Allocation Methodology, based on the methodology accepted in EB-2012-0031 and previous proceedings and updated for this current filing, to allocate the costs of shared services OM&A between Transmission and Distribution. The 2012 update is described in Exhibit C1, Tab 6, Schedule 1.

Depreciation and amortization expense of $394.2 million for 2015 and $404.0 million for 2016 have been determined based on the results of the Foster's methodology accepted by the Board in Hydro One's Transmission's previous proceedings. An update to the depreciation study has been completed in 2013 for Hydro One Transmission in support of its 2015 and 2016 proposed application. These costs are described in Exhibit C1, Tab 7, Schedule 1.

The Company has also incorporated the methodology of the Lead Lag study, submitted and accepted by the Board in previous proceedings, in its derivation of Rate Base in 2015 and 2016.

Hydro One Transmission's forecast Rate Base of $10,176.5 million for 2015 and $10,558.0 million for 2016 is discussed in Exhibit D1, Tab 1, Schedule 1.

This submission reflects Hydro One Transmission's plan to invest its network assets to meet objectives regarding public and employee safety, regulatory and legislative compliance, maintenance of system security and reliability, and meeting system growth requirements. The Company is forecasting total capital expenditures of $899.4 million in 2015 and $866.3 million in 2016. Details of Hydro One Transmission's capital budget are provided in schedules filed at Exhibit D1, Tab 3.

Hydro One Transmission earns approximately 2% of its revenues from sources other than its transmission tariff. As the costs incurred to generate these revenues are included in the Company's cost of service, these external revenues of $28.4 million in 2015 and $28.8 million in 2016 are recorded as an offset to the respective revenue requirement. External revenues are discussed at Exhibit E1, Tab 2, Schedule 1.

In accordance with standard regulatory practice, Hydro One Transmission has incurred prior costs for which it is requesting approval in this submission. Hydro One Transmission is requesting approval of actual Regulatory Asset values of $(36.1) million as at December 31, 2014 which includes the principal balances as at December 31, 2013 and forecasted interest and dispositions for 2014. The Company's submissions regarding these account balances and their proposed disposition appear at Exhibit F1, Tab 1, Schedule 1 and Exhibit F1, Tab 1, Schedule 3, respectively.

Tables 1 and 2 below, summarize the financial highlights for the 2015 and 2016 Test Years.

Table 1
Financial Highlights 2015

Line No.		*Deemed Capital Structure ($ millions)* (a)	*Total Rate Base Percent* (b)	*Cost Rate (%)* (c)	*Exhibit*
1	Total Debt	6,105.9	60.0%	4.90%	
2	Common Equity	4,070.6	40.0%	9.71%	
3	Total Rate Base	10,176.5	100.0%	6.82%	

Line No.		*$ millions*	*Exhibit*
1	Total OM&A Expense	452.0	
2	Depreciation & Amortization	394.2	
3	Capital Expenditures	899.4	
4	Rate Base	10,176.5	
5	Revenue Requirement	1,617.1	
6	External Revenues	28.4	
7	Return on Capital	694.3	
8	Regulatory Assets Recovery	(18.0)	

Table 2
Financial Highlights 2016

Line No.		*Deemed Capital Structure ($ millions)* (a)	*Total Rate Base Percent* (b)	*Cost Rate (%)* (c)	*Exhibit*
1	Total Debt	6,334.8	60.0%	5.04%	
2	Common Equity	4,223.2	40.0%	9.96%	
3	Total Rate Base	10,558.0	100.0%	7.01%	

Line No.		*$ millions*	*Exhibit*
1	Total OM&A Expense	457.4	
2	Depreciation & Amortization	404.0	
3	Capital Expenditures	866.3	
4	Rate Base	10,558.0	
5	Revenue Requirement	1,689.2	
6	External Revenues	28.8	
7	Return on Capital	739.9	
8	Regulatory Assets Recovery	(18.1)	

SUMMARY OF TRANSMISSION BUSINESS

1.0 INTRODUCTION

Hydro One Networks Inc. is licensed by the Ontario Energy Board (the "OEB" or the "Board") to own, operate and maintain transmission facilities in the Province of Ontario. Hydro One's transmission system is one of the largest in North America based on net book value and includes facilities that service connected customers and other transmitters' province wide. These facilities comprise approximately 97% of the licensed transmission facilities in Ontario and are used to serve customers province wide.

The purpose of the transmission system is to transmit electricity between supply points (such as generators, interconnections with other jurisdictions, and load customers with sufficient embedded generation to result in injections into the transmission system) and delivery points (load customers, including Local Distribution Companies ("LDCs"), end-use transmission customers and interconnections with other jurisdictions) and integrated with electrical storage facilities (flywheel and battery technology).

This exhibit provides a summary of Hydro One Transmission's (the "company") business in Section 4, a discussion of the business model implemented within the company in Section 5, and the manner in which investment programs are managed is set out in Section 6.

2.0 HYDRO ONE'S VALUES

Hydro One is driven by the values of Health & Safety, Stewardship, Excellence and Innovation. The company works in an environment that can be dangerous for both workers and the public, and so safety is of the utmost importance. The stewardship of critical provincial assets is a serious responsibility. The company demonstrates sound stewardship in a manner that respects both customers' needs, as well as the environment. Excellence is achieved through continuous improvement and staff development to ensure the company is prepared and equipped to deliver high quality and affordable service. The company values innovation and views it as a key success factor for its future, allowing the company to find better ways to meet the needs of our customers.

Customers expect and deserve reliable power at reasonable rates. Hydro One Transmission's strategy and business plan must ensure rates that can balance the financing of investment in infrastructure while maintaining affordable and reliable service. While customer satisfaction with the company's performance remains strong, customers face a growing array of changes and challenges, and they increasingly look to Hydro One Transmission to help them manage use of power, maintain high levels of service reliability and keep prices reasonable. The company is prepared to meet customers' expectations, continue its commitment to asset stewardship, and ensure alignment with new policy objectives brought forth by the Government.

3.0 STRATEGIC GOALS AND PERFORMANCE TARGETS

The company's strategic objectives commit it to:

- Creating an injury-free workplace and maintaining public safety;
- Satisfying our customers;
- Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system;
- Building and maintaining reliable, cost-effective transmission and distribution systems;
- Protecting and sustaining the environment for future generations;
- Championing people and culture;
- Maintaining a commercial culture that increases value for our shareholder; and
- Achieving productivity improvements and cost-effectiveness.

These strategic objectives are inextricably linked. They drive the fulfillment of the Company's mandate and the achievement of its mission and vision, which is:

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

The company will operate with clear operational and financial performance targets. Where data is available, Hydro One will benchmark its performance against that of other North American utilities and implement plans and programs to achieve its vision. The five year goals associated with the company's strategic objectives are shown in Table 1.

Table 1
Five Year Goals Associated with Hydro One Networks Inc. Strategic Objectives

STRATEGIC OBJECTIVES	FIVE-YEAR VISION
Creating an injury-free workplace and maintaining public safety	Achieve world-class standing for medical attentions for utilities
Satisfying our customers	Achieve an on average of 90% customer satisfaction across all segments
Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system	Meet 100% of advanced distribution system plan
Building and maintaining reliable, affordable transmission and distribution systems	Maintain the current levels of reliability relative to comparable utilities, while we improve customer service and satisfaction
Protecting and sustaining the environment for future generations	Reduce our environmental footprint
Championing people and culture	Achieve and maintain employee engagement at top quartile of comparable utilities
Maintaining a commercial culture that increases value for our shareholder	Achieve the Return on Equity allowed by the Ontario Energy Board and maintain an “A” credit rating
Achieving productivity improvements and cost-effectiveness	Achieve top-quartile unit costs against comparable utilities

The strategic objectives identified in Table 1 underpin and drive the Company's business planning process and all of its activities going forward.

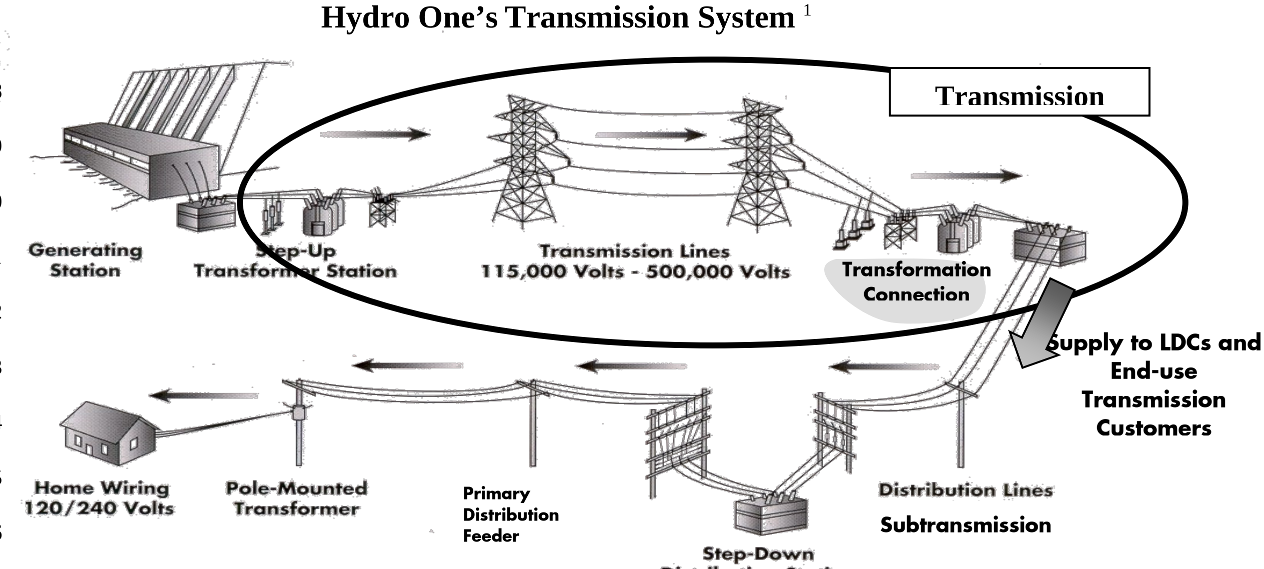
4.0 HYDRO ONE'S TRANSMISSION BUSINESS

4.1 Transmission System Background

Hydro One Transmission's business comprises a high voltage system that operates at 500 kV, 230 kV and 115 kV with minor lengths operating at 345 kV and 69 kV. There are 103 generating stations, 47 LDCs and 92 end-use transmission customers connected directly to Hydro One's Transmission system, as of the end of December, 2013. In 2013, Hydro One transmitted approximately 141 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario.

A simplified figure of the Transmission System is provided in Figure 1 below.

Figure 1
Hydro One's Transmission System [1]



The Hydro One Transmission system includes approximately 29,000 circuit kilometers of high voltage transmission lines and 289 transmission stations. These lines are located in

[1] For illustrative purposes only, actual configuration may vary from case to case and may include generators within LDCs and end-use transmission customer facilities.

lands owned by the Ontario government, Hydro One Transmission or by other parties with whom Hydro One Transmission has agreements regarding occupancy and access rights. The major components of the transmission lines are overhead conductors, underground cables, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems. The major components of transmission stations are transformers, circuit breakers, switches, bus bars, insulators, reactors, capacitors, connecting hardware, associated protection and control equipment, grounding systems and revenue meters.

A summary of the key physical assets on Hydro One Transmission's system is provided in Table 2.

Table 2

Hydro One Transmission System Assets[2] At December 31, 2011 *(unless where otherwise noted)*	
Fixed Assets (Net Book Value)	$11.8 Billion
Operating Centres[3]	2
Transmission System Voltages (kV)	500, 345, 230, 115, 69
Overhead Transmission Lines (circuit km)	28,636
Underground Transmission Cables (circuit km)	291
Transmission Stations[4]	289
Breakers[5]	4,490
Step-down Power Transformers[5,6]	572
Auto-Transformers[5,6]	134
Other Transformers[7]	13

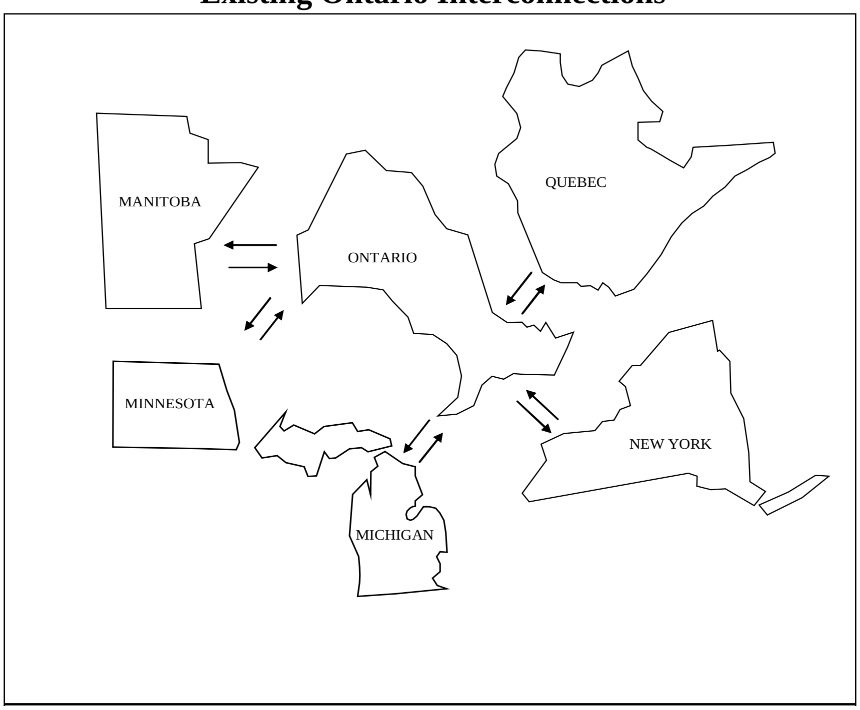
Transmission assets also include facilities required for operation, protection, control, and monitoring functions necessary for the effective and efficient operation of the transmission system. These facilities include extensive telecommunication system, protection and control equipment, the Ontario Grid Control Centre ("OGCC") and the

[2] Includes 25- and 60-cycle systems for transmission circuit km
[3] One Ontario Grid Control Centre (OGCC) and one Integrated Telecommunication Management Centre (ITMC)
[4] 254 Transformer Stations & 35 Switching Stations
[5] The number of transformers and circuit breakers are at the equivalent three-phase banks
[6] Excludes lower voltage station service, grounding and operating spare transformers
[7] Other transformers include 5 phase shifters and 8 high-voltage regulators.

back-up operating facilities which serve as a fully redundant back-up to the OGCC. The OGCC monitors and controls the operation of the transmission system.

As shown in Figure 2, Hydro One Transmission is linked to five adjoining jurisdictions (Manitoba, Quebec, Minnesota, Michigan and New York) through 26 interconnections, through which we can accommodate imports of about 6510MW and exports of approximately 6,070 MW of electricity in the summer. These interconnection facilities are designed to facilitate the transfer of electrical energy between Ontario and these jurisdictions. Actual import and export capabilities of the interconnections depend on limitations at the interface as well as within Hydro One Transmission's system and transmission systems in other jurisdictions.

Figure 2
Existing Ontario Interconnections



Hydro One Transmission's system is also connected to other transmitters, namely Great Lakes Power, Canadian Niagara Power and Five Nations Energy, representing the remaining 3% of licensed transmission facilities in Ontario. Due to a change in policy in

Ontario that enabled competitive transmission (see section 4.3.2), a number of new licensed transmitters emerged in Ontario including: AltaLink Ontario Management Ltd., Iccon Transmission Inc., Oncor Electric Delivery Company LLC, RES Canada Transmission LP, TransCanada Power Transmission Ontario LP, Upper Canada Transmission, and EWT LP (East-West Tie partnership is an equally-shared limited partnership of Great Lakes Transmission, Bamkushwada LP (a number of First Nations in the area of the East-West Tie), and Hydro One).

4.2 Transmission Business Activities

Hydro One Transmission's business activities are regulated and consist of expanding, maintaining, operating and sustaining assets to meet reliability standards and satisfy regulatory, environmental and legal requirements. In particular, Hydro One Transmission implements system expansion to:

- accommodate load growth and connection of new generation;
- accommodate distributed generation resulting from the feed-in tariff program and other green initiatives advocated through the Ontario Government's Green Energy and Green Economy Act, 2009 (GEGEA).
- alleviate internal system constraints,
- increase interconnection capabilities with neighbouring utilities; and
- facilitate the development of a modern and smart grid.

The Company's regulated business activities include the management of its transmission assets, which includes operations, maintenance, construction and engineering services, customer service activities and supporting research, environmental, and public/employee health and safety programs. The costs of all these activities are included in the revenue requirements for Hydro One Transmission.

These activities are performed by a multi-disciplined workforce capable of performing tasks related to operating, maintaining and expanding the transmission business. A number of service centers are located throughout the Province to provide the required operating, maintenance, construction and restoration services.

In order to carry out the work, these service centers provide base locations for the mobile workforce and contain essential infrastructure components such as:

- land and buildings for staff accommodation,
- transport and work equipment, including large work vehicles, off-road vehicles, small vehicles (trucks, cars and vans), and specialized units (snowmobiles, chippers, trailers), and
- minor fixed assets, including computers, test equipment, construction and maintenance tools and office furniture.

Included in the regulated transmission business revenue requirement are expenditures for common services that are shared with the distribution business (for the purpose of cost efficiency), such as internal audit, human resources, asset management, legal, general counsel and secretary, finance, information management, performance management, regulatory, environment, planning and corporate affairs. The nature and costs associated with these corporate functions and services are discussed in Exhibit C1, Tab 3, Schedules 1 to 7.

4.3 Electricity Industry and Regulatory Framework

4.3.1 Industry and Regulatory Environment in Ontario

In the restructured Ontario electricity industry the Ministry of Energy sets legislative and regulatory requirements through changes to the *Electricity Act, 1998* and the *Ontario*

Energy Board Act, 1998. The OEB sets transmission rates, issues codes and licenses, and grants approval for construction of new transmission lines greater than two kilometers.

The Independent Electricity System Operator ("IESO") administers the electricity market and directs the operation of the power system in Ontario. The transmission assets owned by Hydro One Transmission form approximately 97% of the IESO controlled transmission grid, which is essential for the operation of the IESO administered markets. The IESO controlled grid provides the infrastructure for transmitting large volumes of electrical energy from major generation sources to major load centers. In the restructured Ontario electricity industry, Hydro One Transmission provides transmission capacity. The IESO makes that capacity available to market participants.

The Ontario Power Authority ("OPA") establishes new electricity supply contracts, sets provincial Conservation and Demand Management targets, forecasts long-term demand/supply requirements and identifies the new or upgraded transmission required to incorporate new generation, relieve constraints on the transmission system and accommodate increasing electricity demand on an area supply basis.

The Transmission System Code ("TSC"), issued by the OEB, sets out the obligations of electricity transmitters with respect to their customers. It includes a Connection Agreement which covers the technical and commercial responsibilities of both transmitters and their customers. The Code also addresses standards for the operation, maintenance, management and expansion of transmission systems.

The TSC and the market rules require all customers directly connected to the transmission system to enter into a connection agreement with their transmitter. Accordingly, Hydro One Transmission has established Connection Agreements with its transmission customers. Each Connection Agreement is comprised of two main parts; general information, such as equipment standards, operational and maintenance requirements, reporting protocol, dispute resolution methodology and disconnection process, and specific information, including connection point description (diagrams, protection requirements, technical specification for customer's equipment), contact data for both the customer and appropriate Hydro One Networks' staff, and description of applicable transmission charges. In addition, the TSC requires Hydro One Transmission to enter into commercial agreements with directly connected load and generation customers to provide new or modified Hydro One Transmission owned connection facilities and to recover the related costs.

Depending on the configuration and ownership of facilities, Hydro One Transmission provides customers with one or more of the four main types of transmission service: network, line connection, transformation connection and wholesale meter service.

4.3.2 Competitive Transmission

On August 26, 2010, the OEB released its new policy entitled "Framework for Transmission Project Development Plans". This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open process.

On March 29, 2011, the Minister expressed the Province's interest in the OEB commencing a designation process for the East–West Tie Line. The East-West Tie project is the first network line expansion covered under the new approach. The OPA's proposed route is a 400 km, 230 kV double-circuit line to run beside an existing Hydro One transmission corridor along the north shore of Lake Superior between Hydro One's transformer stations at Wawa in the east and Lakehead in the west.

On August 7, 2013, the OEB issued its Decision (EB-2011-0140) that the designated transmitter for the development phase of the proposed East-West Tie line is Upper

Canada Transmission Inc. (UCT) a partnership of NextEra Energy Canada (a wholly owned subsidiary of NextEra Energy Resources LLC), Enbridge Inc. and Borealis Infrastructure Management. Hydro One will coordinate with UCT to effect the connection to the bulk transmission system in Northern Ontario at transformer stations owned by Hydro One.

4.3.3 North American Reliability Framework

The National Electric Reliability Council ("NERC") was established in the United States in 1968 in response to the 1965 blackout. On January 1, 2007, the National Electric Reliability Council became the North American Electric Reliability Corporation (same acronym). NERC's mission is to ensure the reliability of the bulk power system in North America. To achieve this, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future transmission and generation adequacy; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants. NERC is subject to oversight by governmental authorities in Canada and the U.S.

NERC works with eight Regional Entities to improve the reliability of the bulk power system, the North East Power Coordinating Council (NPCC) being one of them. Hydro One is a member of NERC and NPCC and is registered with NERC's compliance registry.

The U.S. Energy Policy Act of 2005 authorized the creation of a self-regulatory Electricity Reliability Organization (ERO) that would span North America, with the Federal Energy Regulatory Commission (FERC) oversight in the U.S. The legislation stated that compliance with reliability standards would be mandatory and enforceable. In July 2006 FERC certified NERC as the ERO in the United States. In October 2006 the

OEB signed a Memorandum of Understanding with NERC recognizing NERC as the ERO in Ontario.

Voluntary compliance was expected as a matter of good utility practice through the first set of NERC standards (effective January 2005). The standards later became mandatory and enforceable in the United States in June 2007.
As a licensed Transmitter, Hydro One is required to comply with the IESO Market Rules. Those Rules require compliance with applicable reliability standards adopted by NERC and NPCC.

According to the regulatory framework in the Province of Ontario, Hydro One is not subject to the Compliance Monitoring and Enforcing Program (CMEP) of NERC and NPCC. The Ontario Market Rules and the Memorandum of Understanding (MOU) signed by the IESO, NERC and NPCC (October 2006), assign the IESO as the only entity in Ontario that is subject to the CMEP. The IESO, by way of its Market Assessment and Compliance Division (MACD), is responsible for monitoring and enforcing the reliability standards in Ontario. Under the Market Rules, MACD can apply monetary sanctions for breaches, which include violations of reliability standards.

To date, NERC has developed 113 standards including 550 requirements. 46 of these standards apply to Hydro One.

4.3.4 Regional Planning for Electricity Infrastructure

The OEB, in 2011, launched a consultation (EB-2011-0043) aimed at "promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters." The Board held a consultation with stakeholders which resulted in a Board Staff Discussion Paper in November, 2011.

In response to inquiries received by the Board, the Ontario Power Authority (OPA) provided an explanation of their regional planning process. It described that transmitters were represented on each Study Team that develops a regional plan. As well, regional plans can be initiated by transmitters. Hydro One is often a participant in regional planning development by the OPA.

In May 2013, the Board issued a Notice of Proposal to Amend the Transmission System Code (TSC) and the Distribution System Code (DSC) to enable:

- the establishment of a process in order to move to a more structured approach to regional infrastructure planning; and
- the determination of the appropriate redefinition of certain line connection assets and modifications to the TSC cost responsibility rules to facilitate regional planning and the execution of regional infrastructure plans.

Following the comment period, the Board issued in August, 2013 its Notice of Amendments to both TSC and DSC to implement the Board’s policies related to Regional Infrastructure Planning. The Board also issued a Supplementary Proposed Amendment to a Code related to the TSC cost responsibility rules.

Hydro One’s participation in Regional Planning is discussed in Exhibit A, Tab 16, Schedule 9.

5.0 ASSET MANAGEMENT MODEL

Hydro One has adopted an Asset Management model in designing the processes used to plan, approve and implement work. The key principles include having functions primarily responsible for defining the work requirements (Asset Management functions) and functions primarily responsible for delivering asset and customer based services in accordance with the defined work (Work Execution functions). Primary responsibility for planning and decision making associated with the management of transmission and distribution assets falls under the Asset Management functions, whereas primary responsibility for providing engineering, design, estimating, construction, maintenance, operating, and customer care services falls under the Work Execution functions.

Both components of the business actively participate in all phases of work planning and implementation. However, the focus created by this approach allows Hydro One Transmission to better create the competencies and cost-efficiencies to effectively plan and implement the work.

5.1 Asset-Centric Investment Reviews to Improve Investment Planning (IP)

Continuing improvements in Asset Analytics have improved our ability to consider the needs of an asset fleet in its entirety - especially as it regards the performance and demographics of the fleet, providing a comprehensive overview of all work impacting that particular asset fleet. This has facilitated the development of a more comprehensive investment strategy for each asset fleet.

5.2 Asset Management Function

Hydro One’s transmission business strives to continually improve the efficiency and effectiveness of the regulated wires assets. The Asset Management function is responsible for effectively operating, maintaining and upgrading existing transmission and distribution assets and ensuring consistent, cost-efficient and effective decision making that balances customer needs and stakeholder expectations with Hydro One objectives for its assets and systems.

In preparing investment plans and prioritizing work activities, the Asset Management function utilizes tools and planning procedures outlined in Exhibit A, Tab 16, Schedules 3 to 6.

In addition to maintaining a strong stewardship role of Hydro One assets, the asset management strategies, processes and policies are evolving to proactively plan for and invest in the necessary system infrastructure to accommodate increased levels of renewable energy development. These objectives align with the green energy initiatives set forth by the GEGEA and ensure that necessary operational and planning flexibilities are in place to respond to changing system needs.

A more detailed account of the roles and responsibilities of the Asset Management function as a shared service can be found in Exhibit C1, Tab 3, Schedule 4.

5.3 Work Execution Functions

The work execution functions provide engineering, design, estimating, construction, maintenance and operating services. Customer relationship management and support services and supporting research, environmental, and public/employee health and safety programs are also provided by these functions. These activities are performed by a multi-disciplined workforce capable of performing tasks related to operating, maintaining and expanding the transmission business. There are three primary work execution functions within Hydro One: Customer Operations, Grid Operations and Engineering and Construction.

5.3.1 Customer Operations

The Customer Operations function is responsible for line construction and maintenance work, including forestry and customer care support services. As well, the Customer Operations function has accountability for planning and connecting new retail customers to the transmission system and to address local system planning issues.

Lines and Forestry services provide for the maintenance of overhead and underground transmission lines and for vegetation management. The vegetation management program is necessary to ensure that clearances to energized equipment are maintained and that these clearances provide a sustainable level of reliability.

Customer care services can be divided into the following high-level functions: meter reading; billing; settlements; customer contact handling and collections.

5.3.2 Grid Operations

The Grid Operations function provides maintenance and technical services for stations and protection and control, as well as central operations and services for the transmission operating function which includes operation from the OGCC.

The OGCC monitors the integrity of the transmission system in real time to ensure reliable performance of the network under present conditions while recognizing potential contingencies and providing immediate response to customers. The OGCC also reviews, approves, performs and/or authorizes all switching and control actions on Hydro One's Transmission system and issues work permits in accordance with the Utility Work Protection Code to provide employees with a safe working area. In addition, the OGCC coordinates an extensive outage program with various internal stakeholders and external customers to support Hydro One's distribution expansion and maintenance programs. Required outages are assessed and coordinated to minimize their impact on reliability and customer operation.

Grid Operations also maintains back-up operating facilities which serve as a fully redundant back-up to the OGCC.

5.3.3 Engineering and Construction

The Engineering and Construction function provides services ranging from engineering and design to the construction and commissioning of new or enhanced facilities. These projects include engineering, estimating, project management and construction of stations, system protection and control, as well as engineering services as required.

6.0 INVESTMENT CATEGORIES

In organizing and planning its work programs, Hydro One Transmission has three main investment categories of work: Sustainment, Development and Operations, which are described below. These categories are used for both the OM&A and Capital components of the investment plan.

6.1 Sustainment

Sustainment work is defined as the work required by the transmission business to maintain the existing infrastructure and facilities at their required performance level. The OM&A component of the sustainment work addresses preventative and breakdown (corrective) maintenance within the useful life span of the asset including mid life overhauls which are required to achieve the expected life span of the equipment. The capital component of the sustainment work deals with replacement of assets at end of life.

Sustainment work is designed to maintain customer delivery reliability system-wide while meeting all legislative, regulatory, safety and environmental requirements. The strategy uses a life cycle management approach, which aims at optimizing performance and cost over the service life of assets.

The Sustainment OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively.

6.2 Development

Development work is defined as the work required by the transmission business to increase the capacity and capability of the transmission system by constructing additional transmission facilities or upgrading existing facilities. Development work provides the additional capacity and enhanced capability:

- to meet the needs of load or generation customers, including connecting new loads or new generating plants, adding capacity to supply increases in existing loads or output of existing generating plants;
- to reinforce the transmission networks in Ontario or on the interconnections with neighbouring utilities in order to maintain adequate customer supply and system security and to alleviate restrictions to power transfers in accordance with approved plans and directives; and
- to meet customer reliability/power quality service standards, system security standards, or equipment/facilities design standards in a manner consistent with the transmission business asset management strategy and regulatory obligations.
- to facilitate the modernization of a smart grid in Ontario and enhance transmission infrastructure to effectively deliver renewable power from distributed generation.

The Development OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Schedule 3 respectively.

6.3 Operations

Transmission operating activities are carried out centrally at the OGCC. The Operations function manages the transmission assets to ensure day to day flow of electricity within the capability of the transmission system, coordinates and schedules planned outages, and monitors and reports on the performance of the transmission system.

Capital investments are required to enhance, refurbish and replace transmission system computer management systems and data acquisition systems, including automatic system controls, which monitor and control the operation of the transmission system.

OM&A expenditures are required to maintain transmission system computer management systems and data acquisition systems, including automatic system controls, and to fund the resources required to perform the activities necessary for centralized operation of the transmission system.

The Operations OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 4 and Exhibit D1, Tab 3, Schedule 4, respectively.

ECONOMIC INDICATORS

1.0 INTRODUCTION

This exhibit provides the costing assumptions underlying the 2013 Business Plan.

2.0 ECONOMIC INDICATORS

2.1 Transmission Cost Escalation for Construction, Operations and Maintenance

The Transmission Cost Escalation for Construction, Operations & Maintenance provides a broad average measure of the industry-wide yearly price changes by tracking a representative basket of equipment and labour for these areas of business. This basket of goods is comprised of the following types of equipment and labour:

- Operation;
- Supervision and Engineering;
- Load Dispatching;
- Station Expenses;
- Lines;
- Meters;
- Customer Installations;
- Maintenance;
- Structures;
- Station Equipment;
- Overhead Lines;
- Underground Lines;

- Line Transformers; and
- Miscellaneous.

The data in Table 1 was provided by Global Insight's January 2013 forecast.

Table 1
Global Insight's January 2013 forecast
(%)

	Historical Years				Bridge Year	Test Years	
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Transmission Cost Escalation for Construction	1.9	3.7	1.6	1.9	2.1	2.4	1.6
Transmission Cost Escalation for Operations & Maintenance	1.6	3.7	2.1	1.5	2.0	2.4	2.9

The Transmission Cost Escalation for Construction, Operations & Maintenance is used as a planning tool to predict expenditure level changes for transmission materials and services.

2.2 Consumer Price Index

The Consumer Price Index ("CPI") provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation. Hydro One Transmission operates wholly in the Province of Ontario, Canada. As a result, the CPI–Ontario exhibits the inflationary environment in which Hydro One Transmission operates. The CPI forecast is from Global Insight's February 2013 forecast and can be found in Table 2.

Table 2
Ontario CPI
(%)

	Historical Years				**Bridge Year**	**Test Years**	
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
CPI – Ontario	2.4	3.1	1.4	0.9	1.9	2.0	2.0

The CPI is used as a planning tool to forecast expenditure level changes for items such as fleet and sundry costs.

2.3 Exchange Rate (CDN$ per US$)

The historic rates in Table 3 are the average exchange rates for 2010, 2011 and 2012 from the Bank of Canada. The exchange rate forecasts for 2013 to 2016 are based on the February 2013 edition of the Global Insight Forecast.

Table 3

Exchange Rate

(CDN$ per US$)

Description	Historical Years				Bridge Year	Test Years	
	2010	2011	2012	2013	2014	2015	2016
Exchange Rate	1.030	0.989	1.000	1.001	1.047	1.084	1.096

While the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

3.0 INTEREST RATES

Interest rate forecasts are used to determine the cost of capital for Hydro One Transmission. Please refer to Exhibit B2, Tab 1, Schedule 2 for historical and forecast debt rates.

3.1 Interest Capitalized

Consistent with the Board’s decisions in EB-2008-0408, effective January 1, 2012, no allowance for funds used during construction (AFUDC) rate is specified for use by Hydro One. In place of the AFUDC rate, Hydro One will base its interest capitalization rate on its embedded cost of debt used to finance the capital expenditures made. This is consistent with Hydro One’s adoption of United States Generally Accepted Accounting Principles (US GAAP) per the Board’s decision in EB-2011-0399 and US GAAP requirements for determination of interest capitalized. The rates used in calculating capitalized interest for the bridge and test years represent the effective rate of Hydro One Transmission's forecasted average debt portfolio during the year.

Prior to 2012, consistent with its Decision in EB-2006-0117, the OEB prescribed that the AFUDC rate to use for CWIP would be the Scotia Capital All-Corporate Mid-Term Yield, as published on the Bank of Canada website and updated quarterly. As a result, the 2010 to 2011 historical years reflect the average quarterly prescribed AFUDC interest rate.

The interest capitalization/AFUDC rates underlying Hydro One's Business Plan are filed at Exhibit D1, Tab 6, Schedule 1.

4.0 INCOME AND CAPITAL TAX RATES

Please refer to Exhibit C1, Tab 8, Schedule 1 for the historical and forecast tax rates.

5.0 LABOUR ESCALATION RATES

(a) Society Staff and PWU Staff

Planned salary increases are consistent with ratified collective agreement over the length of the agreement. Years following the effective collective agreement are assumed to be 2% net annual increase.

(b) MCP staff

2% annual increase per year in base pay for the entire period. Details regarding management compensation are provided in Exhibit C1, Tab 4, Schedule 2

(c) Incentive Plan Payouts

All incentive plans have been discontinued, with the exception of the MCP Short Term Incentive Plan. Payout under that plan is assumed to be 15% in all years.

6.0 COST RATES FOR BENEFITS

These rates are applied to the forecast labour rates.

Table 4

Burden Rates

(%)

Company	Category	2013	2014	2015	2016
Networks	**Non-Regular Staff**				
	% of total earnings*	6.34%	6.35%	6.45%	6.39%
	Regular Staff				
	% of total earnings*	6.34%	6.35%	6.45%	6.39%
	% of base pensionable earnings**	29.30%	29.51%	27.88%	25.12%
	% of base pensionable earnings***	0.39%	0.41%	0.38%	0.37%
		29.69%	**29.92%**	**28.27%**	**25.49%**
	Pension				
	% of base pensionable earnings	30.97%	30.91%	30.84%	30.78%

*CPP, Emp, Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums

**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, OPRB (for Inergi where applicable), Ontario Health Premiums (OHP)

*** OPRB - Inergi

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

The "burden rate," expressed as a percentage, estimates employee current and future cost rates for benefits which are attributable to labour in the current period, and allocates such costs across Hydro One legal entities. The benefit costs include:

a) Other post-retirement benefits ("OPRB"), such as future health and dental costs;
b) Other post-employment benefits ("OPEB"), such as long-term disability;
c) Supplementary pension plan ("SPP");
d) Pension (funding) contributions;

e) Employee benefit costs during active employment; and
f) Statutory benefit payments, such as CPP, EI, etc.

Cost items a) through d) are actuarially determined by Hydro One Inc.'s external actuaries, Mercer Consulting Inc., using assumptions recommended by the actuaries and accepted by Hydro One Inc.'s management. Assumptions are determined with reference to past experience and industry norms.

Cost item e) is based on estimates from Mercer, and from Hydro One Inc.'s insurance provider Great West Life, as to anticipated escalation factors of health and dental costs. These estimates are compared to past experience.

Cost item f) is based on government schedules of premium rates for CPP, EI, etc.

BUSINESS LOAD FORECAST AND METHODOLOGY

1.0 INTRODUCTION

This Exhibit discusses Hydro One Transmission system load forecast and the related methodology. The key load forecast supporting Hydro One Networks' Transmission rate case is the hourly demand load forecast by customer delivery point. This forecast is used to prepare the charge determinant forecast for the following rate categories: network pool, line connection pool, and transformation connection pool. The load forecast in support of this proposed application was prepared in April, 2014 using economic and forecast information that was available in March, 2014.

Hydro One Transmission forecast of average 12-month peak load for 2015 and 2016 for Ontario as a whole and for its three rate categories are shown in Table 1. The impacts of conservation and demand management (CDM) and embedded generation (EG) are included.

Table 1
Hydro One's Load Forecast
(12-Month Average Peak in MW)

	Ontario Demand	**Hydro One Rate Categories (Charge Determinants)**		
		Network Connection	**Line Connection**	**Transformation Connection**
2015	20,595	20,457	19,752	16,975
2016	20,814	20,676	20,050	17,231

Hydro One worked with the Ontario Power Authority (OPA) and used their latest CDM assumptions in preparing the load forecast in this proposed rate application. A detailed report was prepared and is provided as Attachment 1 to this Exhibit and the summary results are discussed in Section 3.6.

2.0 A SUMMARY OF HYDRO ONE'S LOAD FORECAST METHODOLOGY AND ASSUMPTIONS

Hydro One Transmission uses a number of methods, such as econometric models, end-use models; customer forecast surveys and hourly load shape analyses to produce the forecasts required for its transmission business. This is the same load forecast methodology used and approved by the Board in previous Hydro One Networks' Transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031). All forecasts presented in this Exhibit are weather-normal, that is, abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years.

All forecasts produced are internally consistent. Therefore forecasts for all customer delivery points add up to the total for the entire customer base served by Hydro One Transmission's system. Hydro One Transmission's forecasting methodology comprises a combination of elements that include consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and efficiency improvement standards.

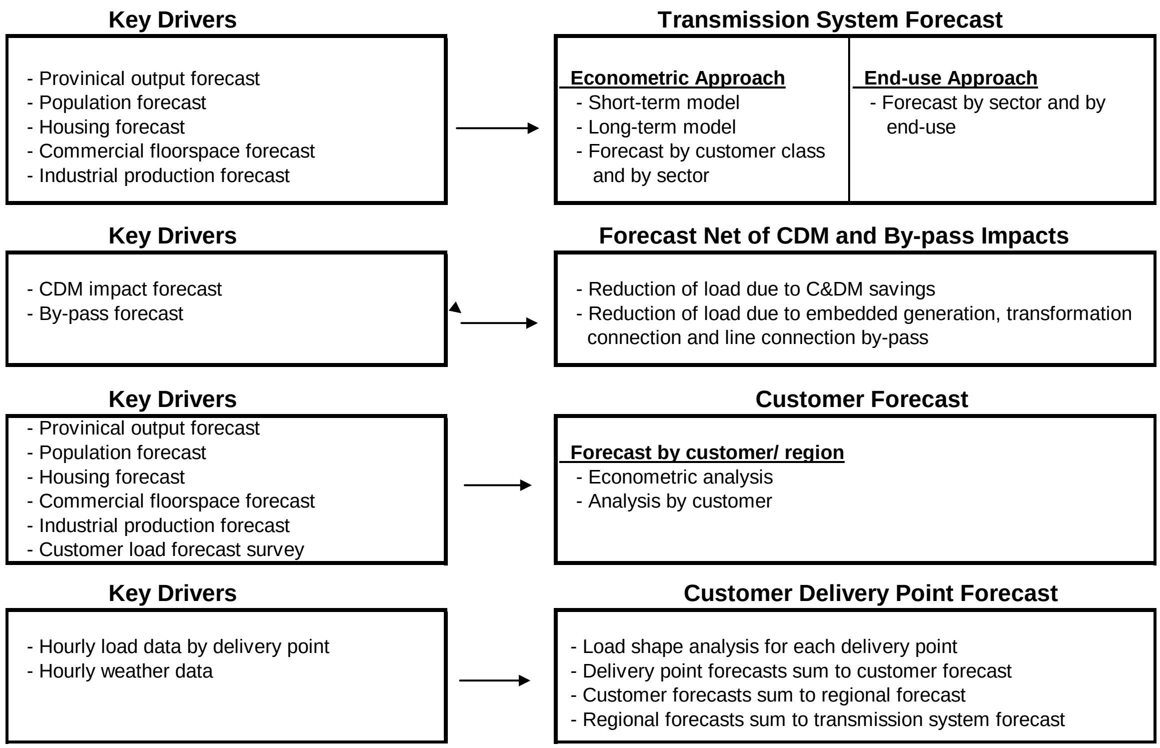
The forecasts presented in this Exhibit are consistent with the economic assumptions used in the business planning process and described in Exhibit A, Tab 15, Schedule 1. Section 3 discusses in detail, the various economic inputs taken into consideration when applying the methodology for deriving the load forecasts. Economic inputs are based on analyses prepared by major economic establishments in the country, such as IHS Global Insight, the Conference Board of Canada, the Centre for Spatial Economics and the University of Toronto. Efficiency standard assumptions used in the end-use models are based on discussions with the OPA staff. Specific customer development is based on forecast survey results from major customers. Inputs from these entities form the economic database (referred to henceforth as the economic forecast) that is used to establish Hydro One Transmission's load forecast.

3.0 KEY ASSUMPTIONS THAT INFLUENCE HYDRO ONE NETWORKS' LOAD FORECASTS

Key assumptions must be taken into account in the process of developing load forecasts and in the application of forecasting methodologies. The elements of the forecasting process used by Hydro One Transmission are based on the knowledge of how the major economic drivers that affect the usage of electricity demand are likely to evolve over the forecast period of 2014 to 2016. Consequently for the purpose of this Proposed Application, the focus is on the short term and the load forecast will reflect those impacts that are likely to have a major effect in this respect. The key assumptions used in the analysis are summarized in Figure 1.

Figure 1

Key Assumptions Used in the Forecast



Key information used in the analysis includes Ontario GDP, provincial demographic, industrial production and commercial floor space forecasts and regional analysis included in the economic forecast. Also taken into consideration are the provincial CDM plans and by-pass risks, which have a direct impact on Networks' system energy demands.

3.1 Provincial GDP Forecast

The provincial GDP forecast is a key driver for the load forecast. The high Canadian dollar, the recent recession and the slow recovery of the U.S. economy and the European Union had an adverse impact on the provincial manufacturing sector. Nearly all manufacturing segments were negatively affected in recent years. In the last two years, the GDP grew by 1.3 percent in 2012 and 1.2 percent in 2013. Based on the consensus forecast, the Ontario GDP is expected to grow by 2.2 percent in 2014, 2.6 percent in 2015, and 2.7 percent in 2016 as the economy recovers. Appendix E provides the details of the consensus forecast for Ontario GDP.

3.2 Provincial Population Forecast

The Ontario population grew 1.0 percent in 2011, 1.1 percent in 2012, and 0.9 percent in 2013. Population growth in Ontario is forecast to grow at about the same pace as the nation in the forecast period. The economic forecast indicates that the Ontario population is expected to grow at about 1.0 percent per year between 2014 and 2016. Steady population growth contributes positively to the load forecast.

3.3 Provincial Housing Forecast

Helped by population growth and low interest rates, housing demand in Ontario continued moderate growth during the past three years. Housing starts statistics showed growth of 68,000 houses in 2011, 77,000 in 2012 and 61,000 in 2013. The consensus forecast calls for 59,000 housing starts in 2014, 60,000 in 2015, and 69,000 in 2016. Appendix E provides the details of the consensus forecast for Ontario housing starts.

3.4 Commercial Floor Space Forecast

Commercial construction activities slowed down during the last three years from 1.4 percent growth in 2011, to 1.3 percent in 2012 and 0.9 percent in 2013. The economic forecast shows commercial floor is going to continue moderate growth over the forecast horizon. The forecast calls for 0.9 percent growth in 2014 and 1.1 percent in 2015 and 1.0 percent in 2016. The forecast for commercial floor space additions is an important contributor to the commercial sector load forecast.

3.5 Industrial Production Forecast

Due to the slow world economic recovery and high Canadian dollar, the industrial recovery from the 2009 recession did not last long. The growth in industrial production declined from 4.4 percent in 2011 to 1.3 percent in 2012, and -2.4 percent in 2013. Industries that were hit hardest during the past three years were pulp and paper, textile, plastic and rubber, and electrical and computer products. The economic forecast calls for moderate growth of 0.6 percent in 2014, 1.9 percent in 2015 and 2.3 percent in 2016. The industrial production forecast is an important contributor to the industrial sector load forecast but it is also prone to economic cycles.

3.6 Conservation and Demand Management Forecast

In EB-2010-0002, the Board directed Hydro One to "work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA." In EB-2012-0031, Hydro One worked with the stakeholders and the OPA to satisfy this directive and the report "Incorporating CDM Impacts in the Load Forecast" (EB-2012-0031 Exhibit A-15-2 Attachment 1) was approved.

In December of 2013, the Ministry of Energy released the updated Long-Term Energy Plan, *Achieving Balance* ("the 2013 LTEP"). The detailed breakdown of assumptions underpinning the 2013 LTEP was released by the OPA in February 2014. Hydro One has adopted the OPA's province-wide conservation forecast and used a similar methodology to incorporate these CDM impacts into the load forecast. Hydro One adopted three CDM categories that are consistent with the OPA's 2013 LTEP information: Energy Efficiency Programs, Codes and Standards, and demand reduction from Demand Response (DR) Resources. Details of the information provided by the OPA and the methodology used by Hydro One to derive the CDM impacts for the 3 charge determinants are documented in Attachment 1 of this Exhibit.

Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2016. These CDM peak impacts are consistent with the 2013 LTEP.

Table 2

Load Impact of CDM on Ontario Demand (MW)

Year	Cumulative CDM Impact on Peak Demand *	Cumulative CDM Impact on 12-month Average Peak Demand **
2006	520	431
2007	893	711
2008	1,208	900
2009	1,215	825
2010	1,255	795
2011	1,539	990
2012	1,756	1,164
2013	2,619	1,543
2014	2,865	1,723
2015	3,014	1,872
2016	3,250	2,087

* The figures represent the load impact of CDM on summer peaks.

** The figures represent the load impact of CDM on monthly peaks, averaged over 12 months in the year.

3.7 By-Pass Forecast

Hydro One Transmission collects its transmission revenue through four types of Board-approved transmission charges (networks, line connection, transformation connection, and wholesale meter). When Hydro One Transmission's customers get power from their own embedded generation or build their own transformation station or line connections to their distribution system, Hydro One Transmission charges cannot be applied. The following summarizes the by-pass forecast assumptions used in the test years:

Embedded Generation By-pass

A total of 471 MW of embedded generation (EG) was assumed to be in place in 2013. An additional 91 MW in 2014, 104 MW in 2015, and 102 MW in 2016 of new embedded generation is assumed in the load forecast, which reflects renewable energy projects initiated by the OPA.

Transformation and Line Connection By-pass

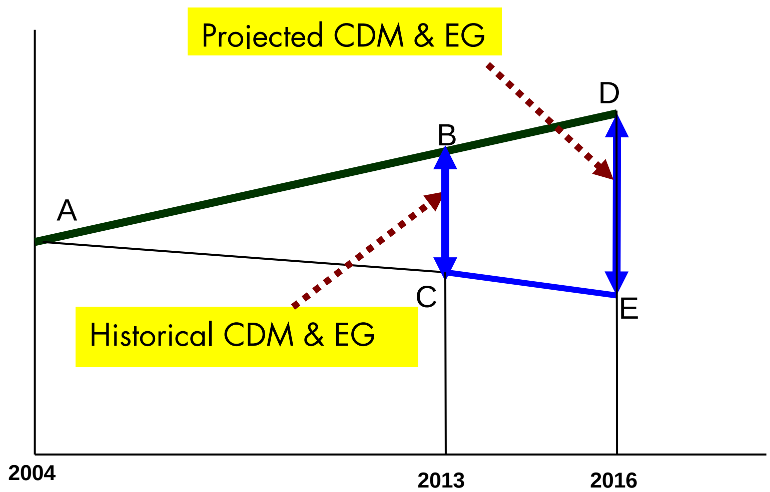
No transformation and line connection by-pass is assumed in the load forecast in this rate application.

4.0 LOAD FORECASTING METHODOLOGY

Hydro One Transmission's system load forecast is developed using both econometric and end-use approaches. The forecast base year is corrected for abnormal weather conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized base year value. The load impacts of CDM and EG are added back to the historical values during the modeling process (see Figure 2 and Section 4.2).

Figure 2

Incorporation of CDM and EG in the Load Forecast



A: 2004 actual load

B: Estimated Load without CDM and EG impacts in 2013

The derivation of each of the Customer Forecast and the Customer Delivery Point Forecast is then addressed in Sections 4.3 and 4.4, respectively.

4.1 Weather Correction Analysis

Weather correction analysis is a statistical process that removes the abnormal or extreme weather effects from the load data to yield average conditions that reflect the more normal or expected weather that is used in the forecast. This is essential because the volatility of abnormal or extreme weather conditions can adversely impact the provision of a consistent and meaningful forecast for load growth. Hourly load data and hourly weather data of various weather stations across the province are used in the analysis.

4.1.1 Hydro One Networks' Weather Correction Methodology

Hydro One Transmission's weather correction methodology was originally developed by the forecasting and meteorology staff of the former Ontario Hydro. This weather correction method was used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One Transmission is a proven technique that has performed well in the past years. The same methodology was reviewed and approved by the Board in previous Hydro One Networks' Transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031).

Normal weather data is based on the average weather conditions experienced over the last thirty-one (31) years. This methodology is consistent with the approach used by the IESO and the OPA. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year.

Hydro One Transmission's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction should best be done on a daily basis, rather than weekly, monthly or annual basis as timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over a longer period of time. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than any single day's impact.

The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings. Across Ontario, the penetration rate of such loads varies widely. Weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay, so it is important to use data from the appropriate weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects. Weather data analyzed include temperature, wind speed, cloud cover and humidity. Data for five weather stations across Ontario are used in the analysis. They include Toronto, Windsor, Ottawa, North Bay and Thunder Bay. Each delivery point is linked to the closest weather station.

4.1.2 Weather Correction Practices in Other Jurisdictions

Hydro One Transmission completed a study on weather normalization practices by surveying over 50 utilities in North America in 2008. The study was submitted to the Board for review in the transmission rate case (EB-2008-0272). Major findings of the study are summarized below:

- Most utilities use long term weather data to calculate the weather normal conditions; about 75% of utilities are currently using 20 years or more for weather normalization.
- The most commonly used period for weather normalization is at least 30 years; no utilities use less than 10 years of weather data to do weather normalization.
- Weather normalization surveys undertaken by Edison Electric Institute, BC Hydro and ITRON show similar results as Hydro One Transmission's survey.
- Most utilities update their weather data set and weather normalization analysis on an annual basis.
- Very few utilities have changed their weather normalization practices in recent years in response to global warming or other reasons.

- The survey results were supportive of Hydro One Transmission's weather-normalization methodology, which is based on the use of 31 years of weather data to define normal weather conditions.

The above study confirms that the weather normalization methodology used by Hydro One Transmission is appropriate. In light of the increased volatility on peak in recent years, the energy to peak relationships are reviewed and updated on an on-going basis, and has been done for this application.

Figures 3 and 4 below present the maximum and minimum daily temperature since 1953 as a measure of peak-generating weather conditions during summer and winter respectively.

Figure 3. Toronto Pearson International Airport: Maximum of Average Daily Temperature

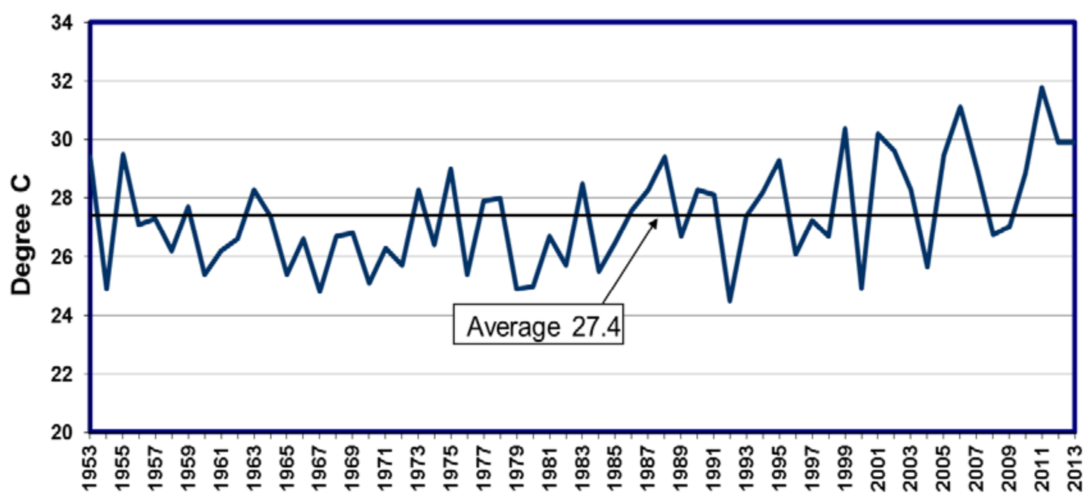
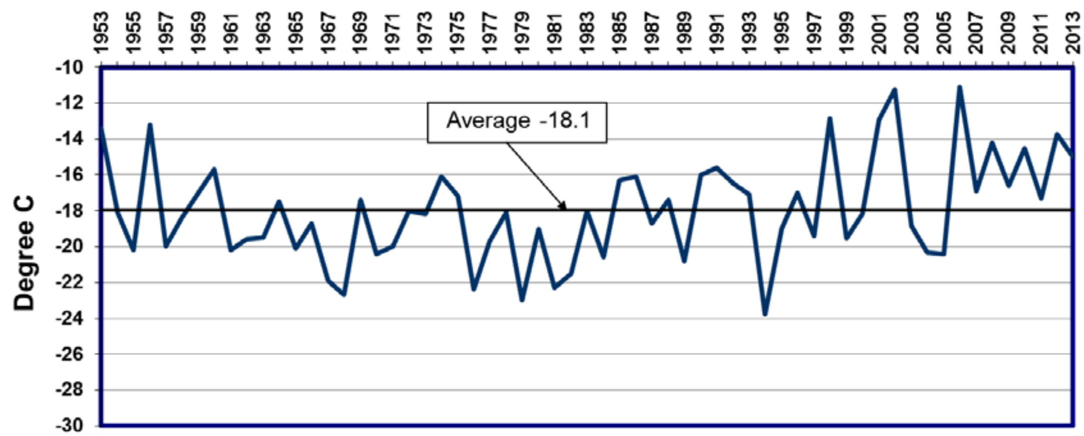


Figure 4: Toronto Pearson International Airport: Minimum of Average Daily Temperature



4.2 Hydro One Transmission Forecasting Methodology

Hydro One Transmission uses econometric (top-down) and end-use (bottom-up) models to forecast the transmission system load. For the top-down approach, both monthly and annual econometric models are used. For the bottom-up approach, end-use models are used to analyse the transmission system load by sector (i.e. residential. commercial and industrial customers). Key information used in the analysis includes economic data, demographics, industrial production and commercial floor space forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. The forecasting methodology used here was reviewed and approved by the Board in previous Hydro One Networks' Transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031).

4.2.1 Monthly Econometric Model

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the total transmission system load. The model links monthly energy consumption to Ontario GDP and residential building permits, taking into account the August, 2003 blackout. The load impacts of CDM and embedded generation are added back to the historical data set during the modelling process. The transmission system load used in the model is weather-normal. Appendix A provides the detailed regression equations and definitions.

4.2.2 Annual Econometric Model

The annual econometric models cover five sectors of the economy: residential, commercial, industrial, agriculture, and transportation. Appendix B provides the detailed regression equations and definitions.

The residential sector is modelled as a two-equation system for saturation and usage of electric equipment. Explanatory variables used include energy prices, personal disposable income per household and weather conditions as measured by heating degree days. As in monthly and end-use models, the load impact of CDM and embedded generation is added back to historical figures.

The commercial sector links energy usage to electricity price, commercial GDP and weather conditions as measured by heating and cooling degree days.

The industrial model consists of an equation for total energy and a two-equation model to determine shares of electricity usage. Total energy is modelled as a function of energy price and industrial GDP. Energy shares are linked to relative energy prices. Dummy variables are used to capture unusual changes in energy growth in the 70's and early 80's and to measure the impact of technical change on energy shares.

The agricultural sector is modelled in relation to electricity price and income, while accounting for cyclical and trend changes.

The transportation sector, which consists mainly of pipeline and road transport, is modelled by an equation relating electricity usage to income, electricity price, and a dummy variable to capture a change in load pattern since 1997.

4.2.3 End-Use Models

The end-use models cover the residential, commercial, industrial, agricultural and transportation sectors. As in the monthly and annual econometric models previously discussed, the load impact of CDM and embedded generation is added back to historical figures. Appendix C provides details of the methodology used in the end-use analyses.

In the residential sector, the end-uses analysed include space heating, water heating, air conditioning, and base load. The forecast of each end-use is based on the number of households having that end-use and unit energy consumption of the equipment.

The commercial model analyses energy use by building type. Key drivers used in the analysis are the commercial sector floor space and the intensity of end-use demand per unit of floor space.

The industrial forecast is based on analysis for each major industrial segment, energy intensity and expected economic growth.

The agricultural and transportation sector models are based on base year electricity consumption and the expected growth rates for each sector and segment.

4.3 Methodology for Customer Forecast

Both econometric and customer analyses based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

In February 2014, Hydro One Transmission conducted a customer load forecast survey with customers having more than 5 MW of load. The survey also covered the station service load requirements of generating stations when they are not producing electricity. In addition to questions relating to the total load of the customer, information at each of the delivery points was also collected. The customer survey results are used in preparing the customer forecast.

In addition to the information contained in the customer survey, a number of forecasting techniques are used to prepare the load forecast by customer. For large utility customers, each customer is modeled individually using the econometric approach. The drivers used in these models include provincial economic variables such as Ontario GDP, population, number of household, energy prices, as well as local demographic and economic variables such as population and related industrial and commercial loads. The impact on load of weather conditions is also taken into account. The best subset of the drivers is selected on the basis of regression criteria.

For industrial customers, several information sources are used to prepare the forecast. They include:

- historical load profile of the customer;

- knowledge of the customer through industry monitoring;
- forecast provided by customer through the survey;
- company information through Hydro One Transmission account executives, industry and company forecasts from industry associations and government agencies; and
- production and industry forecasts provided in the economic forecast.

4.4 Methodology for Customer Delivery Point Forecast

This section discusses the forecasting methodology for the customer delivery point forecast. Electricity Power Research Institute (EPRI)'s Hourly Electric Load Model (HELM) is used to normalize the hourly load for each of the transmission customer delivery points, removing abnormal weather effects and abnormal load patterns. Key information used in analyzing the load shape for each delivery point includes hourly load and weather data. The load growth for each delivery point is linked to the customer forecast discussed above. The forecasts for all customer delivery points add up to the regional and the total transmission system forecast.

The most updated customer totalization table is used to retrieve hourly peak electricity demand data for each of the customer delivery points connected to the transmission system. The totalization table reflects the latest records from Hydro One Transmission and the IESO. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. Hourly weather data is also retrieved to prepare weather sensitivity analysis as discussed in Section 4.1.

In preparing the database for the load shape analysis, missing values are estimated by load on a similar day and hour during the same month. For weather-sensitive load, local weather conditions are also taken into account in estimating the missing values.

EPRI's HELM is used to prepare the hourly weather response analysis by each delivery point. The model takes into account differences in load depending upon time of use (weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such are forecast in relation to load on a similar day and hour during the historical period. The customer forecast is used to drive the customer delivery point forecast. The resulting customer delivery point forecast is therefore consistent with the customer load forecast and the total transmission forecast as discussed above. The charge determinant forecasts at the delivery point level add up to the total charge determinant forecasts presented in Table 4 in the next section. The customer delivery point forecast uses the latest customer totalization table that shows which customers pay Network, Line Connection and Transformation Connection service to determine the charge determinant forecast for each transmission service tariff. The basis for determining the transmission charges applicable to each customer delivery point is further discussed in Exhibit H1, Tab 3, Schedule 1.

5.0 LOAD FORECAST FOR 2015 AND 2016

Hydro One Transmission's charge determinant forecast is derived from the Ontario peak demand forecast based on the econometric, end-use, and customer forecasts. Before deducting the load impact of CDM and embedded generation, the 12-month average charge determinant forecasts grow from 2013 in a manner consistent with the growth of the 12-month average peak for Ontario. Table 3 presents the forecast before and after deducting the load impacts attributed to embedded generation and CDM for the 2013-2016. The charge determinant forecast is based on the methodology approved by the OEB in its decisions for EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031. Appendix D provides the historical actual and weather-corrected charge determinant data for 2002-2013.

Before deducting for the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 22,700 MW in 2014 (12-month average peak), rising to 23,133 MW in 2015, and 23,668 MW in 2016.

After deducting the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 20,415 MW in 2014 (12-month average peak), rising to 20,595 MW in 2015, and 20,814 MW in 2016.

The forecast is weather-normal and the actual load could be below or above the forecast depending on the weather conditions and/or a different economic growth pattern. Table 4 of this Exhibit presents the upper and lower bands of one standard deviation for the charge determinant forecast. Based on historical data, there is a two-in-three chance that the actual load in 2014, 2015, and 2016 will fall within the upper and lower bands. The bands are derived using Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.

Table 3

Load Forecast Before and After Embedded Generation and CDM

(12-Month Average Peak in MW)

Year	Ontario Demand (MW)	Charge Determinant: Network Connection (MW)	Charge Determinant: Line Connection (MW)	Charge Determinant: Transformation Connection (MW)
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2013	22,375	22,212	20,797	17,874
2014	22,700	22,535	21,099	18,135
2015	23,133	22,965	21,502	18,480
2016	23,668	23,496	21,999	18,908
Load Impact of Embedded Generation				
2013	471	459	10	10
2014	562	548	10	10
2015	666	649	10	10
2016	768	749	10	10
Load Impact of CDM				
2013	1,543	1,533	1,465	1,259
2014	1,723	1,711	1,602	1,377
2015	1,872	1,858	1,740	1,495
2016	2,087	2,071	1,939	1,667
Load Forecast after Deducting Embedded Generation and CDM				
2013	20,360	20,220	19,322	16,606
2014	20,415	20,276	19,488	16,748
2015	20,595	20,457	19,752	16,975
2016	20,814	20,676	20,050	17,231

Note. All figures are weather-normal.

Table 4

One Standard Deviation Uncertainty Bands for Hydro One Transmission's Charge Determinants (Using Current Rates) (MW)

Year	Lower Band	Forecast	Upper Band
Network Connection			
2013 (Actual)	20,220	20,220	20,220
2014	19,906	20,276	20,649
2015	19,966	20,457	20,949
2016	20,121	20,676	21,229
Line Connection			
2013 (Actual)	19,322	19,322	19,322
2014	19,133	19,488	19,844
2015	19,278	19,752	20,228
2016	19,514	20,050	20,587
Transformation Connection			
2013 (Actual)	16,606	16,606	16,606
2014	16,444	16,748	17,054
2015	16,568	16,975	17,383
2016	16,771	17,231	17,690

Note: All figures are weather-normal.

6.0 VARIABILITY OF HYDRO ONE'S LOAD FORECASTS

Hydro One Transmission has significant expertise in preparing Provincial electricity demand forecasts as well as hourly load shape analysis. As part of the load research work associated with EB-2005-0317, Hydro One prepared the load shape analysis for over 80 LDCs in Ontario for use in their distribution rate applications to the Board. The performance of Hydro One Transmission's system load forecast since 1999 has been consistently accurate as shown in Table 5.

Table 5
Comparison of Average Monthly Transmission Peak Demand Forecast with Actual
(Variance of forecast as percentage of actual on weather corrected basis)

Forecast made In Year	Forecast for current year	Forecast for 2nd Year	Forecast for 3rd Year
1999	-0.92%	-2.22%	-2.30%
2000	0.18%	0.26%	0.22%
2001	-0.14%	-0.29%	0.41%
2002	0.15%	0.36%	-0.14%
2003	0.25%	0.09%	0.83%
2004	0.08%	0.59%	0.89%
2005	0.17%	0.36%	0.97%
2006	-0.69%	0.41%	0.15%
2007	0.93%	0.18%	0.70%
2008	-0.38%	0.24%	0.24%.
2009	-0.23%	-0.88%	0.83%
2010	1.00%	0.32%	-0.28%
2011	-0.40%	-1.35%	-2.58%
2012	-0.05%	-0.20%	n.a.
2013	-0.22%	n.a.	n.a.
Mean	-0.02%	-0.15%	-0.13%
One standard deviation (+/-)	1.60%	2.43%	2.67%

Note. The forecasts are net of the load impact of CDM and embedded generation and are compared to the weather corrected actual.

Between 1999 and 2013, the average variance of the transmission peak demand forecast compared to the weather corrected actual peak is well within one standard deviation meaning there is a one-in-three chance that the actual will be outside the plus or minus range. The use of the one standard deviation as a measure of forecasting accuracy is an accepted standard in the utility industry.

Forecast accuracy for previous Board-approved forecasts of charge determinants are presented in Table 6. The figures reflect the percent deviation of forecast for each charge determinant over the forecast period compared to the historical actual on a weather corrected basis. The 2006-2008 forecasts were approved by the Board in EB-2006-0501. Similarly, the 2008-2010 forecasts were approved in EB-2008-0272, 2010-2012 in EB-2010-0002, and 2013-2014 in EB-2012-0031. Detailed comparison of forecasts for each forecast year separately is provided in Appendix F and Tables 6a to 6c.

Table 6
Historical Board Approved Forecasts
vs. Historical Actual-Weather Corrected

	Difference from Actual-Weather Corrected (%) *				
Type of Connection	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012-0031 Forecast	**Average**
Network	-0.49	-0.45	-0.42	-0.60	**-0.49**
Line	-0.71	0.79	0.68	0.38	**0.29**
Transformation	-1.02	0.16	0.52	0.68	**0.09**
Average	**-0.74**	**0.17**	**0.26**	**0.15**	**-0.04**
One Standard Deviation (+/-) **	2.26	2.26	2.26	1.96	

* A negative (positive) variance shows that the forecast was below (above) actual.
** Reflects expected deviation of forecast from actual-weather corrected based on historical variations. For EB-2006-0501, EB-2008-0272, and EB-2010-0002 forecasts 3-year standard deviation is shown, and for EB-2012-0031 forecast, 2-year standard deviation. All forecasts are within one standard deviation.

As shown in Table 6, the deviations of previous Board-approved charge determinant forecasts from historical actuals on a weather-corrected basis are all within one standard deviation of errors, and the average deviation over the past four Board-approved forecasts (EB-2006-0501, EB-2008-0272, EB-2010-0002 and EB-2012-0031) is close to zero.

TRANSMISSION OUTLOOK

As per Section 2.4.2.2 of the Board's Filing Requirements for Transmission Rates issued on January 2, 2014, Table 1 below provides a summary of Hydro One's Transmission capital expenditures over the past five historical years, which includes the bridge year, and for five future years including the test years.

Details of all the Sustaining, Development, Operations and Common Corporate Cost capital investments required in the test years are provided in Exhibit D1 and details of all large projects greater than $3 million are provided in Exhibit D2, Tab 2, Schedule 3. The summary of capital expenditures in Table 1 for the years 2017 to 2019 shows spending at the program level. Additional details of spending for this period beyond the test years is not available.

- Sustaining capital expenditures increase significantly in the 2013 to 2015 period to deal with the continued growth in the number of assets that are beyond their expected service life and require replacement to maintain system performance at acceptable levels. The level of spending in the 2016 to 2019 period varies based on program priorities such as the number of stations requiring reinvestment.
- Development expenditures are generally declining over the ten year period as large projects like Bruce to Milton and other projects to accommodate renewable generation have been completed. As explained in Exhibit D1, Tab 3, Schedule 3, Section 3.9 there are four large transmission projects that may require significant capital expenditures in the 2015 – 2019 period. The expenditures are not included in this proposed application as the spending in the test years is too uncertain to forecast and the project schedules are driven by external parties including the Board and the OPA.

- Operations spending increases in the 2014 to 2017 period mainly due to the NMS Sustainment project, the new Back Up Control Centre facility and upgrades to computer and network systems.
- Common Corporate Costs increase in 2014 due to higher IT spending for the completion of the Cornerstone project and Facilities and Real Estate costs, and then expenditures decline over the 2015 to 2019 period.

Overall Capital expenditures remain flat in 2015 and decline over the 2016 to 2019 period. The four large Development projects referred to above include the East-West Tie Expansion, TransCanada's Energy East Pipeline project, the Northwest Bulk Transmission Line project and the GTA Reactors project. While these projects could require significant capital expenditures in the test years, the in-services dates for these projects will be beyond the test years so there will be no impact on the rates requested in this application. Per Section 2.4.2.2, Hydro One's treatment of contributed capital, which is particularly relevant for the Energy East Pipeline project, is shown for specific projects in Exhibit D2, Tab 2, Schedule 3. The treatment of Construction Work in Progress (CWIP) in the four historical years, including the bridge year and in the two test years is shown in Exhibit D2, Tab 3, Schedule 3. Information on the treatment of CWIP beyond the test years is not available.

Table 1

Transmission Capital Expenditures

Transmission Capital ($ millions)	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Budget 2014**	**Budget 2015**	**Budget 2016**	**Budget 2017**	**Budget 2018**	**Budget 2019**
Sustaining Capital										
Transmission Stations										
Circuit Breakers	29.6	29.2	11.2	23.4	23.0	13.5	24.5	20.3	23.2	24.9
Station Reinvestment	17.9	36.4	62.1	89.0	157.6	241.0	159.7	216.0	251.2	161.2
Power Transformers *(including Strategic Transformers)*	106.8	81.1	78.4	87.0	84.0	30.6	75.3	37.0	51.0	93.4
Other Power Equipment	13.9	16.2	28.3	26.5	24.8	23.7	25.9	26.5	27.0	27.9
Ancillary Systems	13.3	13.5	16.4	15.6	24.2	19.0	19.4	19.8	18.3	18.6
Stations Environment	4.0	7.0	7.6	6.6	8.3	11.3	10.8	11.0	11.2	11.4
Protection, Control, Monitoring, and Telecommunications	66.8	61.6	95.0	84.4	116.9	92.2	95.6	95.4	78.9	83.4
Transmission Site Facilities and Infrastructure	32.3	17.8	23.4	22.9	20.1	18.1	18.5	26.0	26.4	26.7
Total Transmission Stations Capital	284.7	262.7	322.5	355.3	458.8	449.5	429.7	451.9	487.3	447.6
Transmission Lines										
Overhead Lines Refurbishment and Component Replacement	54.0	52.4	55.5	74.2	67.9	67.4	74.5	77.3	79.8	81.0
Transmission Lines Reinvestment	16.2	17.1	9.7	17.8	33.2	36.8	29.3	52.9	54.0	55.5
Underground Lines Cable Refurbishment & Replacement	1.4	1.0	1.6	32.8	19.4	28.1	15.1	15.4	15.7	16.0
Total Transmission Lines Capital	71.6	70.6	66.8	124.8	120.5	132.4	118.9	145.5	149.5	152.5
Total Sustaining Capital	**356.3**	**333.2**	**389.3**	**480.0**	**579.3**	**581.9**	**548.6**	**597.4**	**636.7**	**600.1**
Development Capital										

	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017	Budget 2018	Budget 2019
Inter Area Network Transfer Capability	392.8	269.1	117.8	41.7	59.3	96.1	109.7	73.6	45.0	65.0
Local Area Supply Adequacy	58.5	57.5	86.4	54.0	70.9	84.4	67.4	41.5	47.0	66.0
Load Customer Connection	33.8	51.1	60.6	24.7	22.2	17.2	27.6	25.3	16.7	16.7
Generator Customer Connection	3.9	0.1	-0.2	-0.3	9.7	0.1	0.0	0.0	0.0	0.0
Performance Enhancement & Risk Mitigation	19.6	19.0	18.3	27.7	23.7	6.3	2.9	2.8	2.8	2.8
TS Upgrades to Facilities Distribution Generation	12.5	10.3	33.1	13.9	0.3	0.0	0.0	0.0	0.0	0.0
P&C Enablement for Generation Connections	2.1	3.1	2.5	1.2	3.9	2.6	4.2	4.8	4.9	5.0
Smart Grid	0.0	5.8	10.7	8.8	5.5	3.1	0.0	0.0	0.0	0.0
Total Development Capital	**523.1**	**415.9**	**329.4**	**171.7**	**195.6**	**209.7**	**211.8**	**148.0**	**116.4**	**155.5**
Operations Capital										
Grid Operating and Control Facilities	3.6	3.7	3.4	11.3	18.1	14.2	12.5	9.2	9.2	4.8
Operating Infrastructure	4.0	5.0	11.9	6.4	20.5	24.1	24.9	35.2	16.0	14.0
Total Operations Capital	**7.6**	**8.8**	**15.2**	**17.7**	**38.5**	**38.4**	**37.4**	**44.4**	**25.2**	**18.8**
Capital Common Corporate Costs and Other Costs										
Transport, Work & Service Equipment	17.1	13.1	14.6	18.8	22.9	19.8	21.3	19.7	20.9	19.9
Information Technology (including Cornerstone)	24.7	32.9	30.5	22.9	34.6	20.8	22.6	21.1	19.6	17.2
Facilities & Real Estate	7.6	7.8	11.6	7.4	28.3	28.9	24.7	17.2	19.9	19.9
Other (including CDM)	-0.2	-1.5	-14.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital Common Corporate Costs and Other Costs	**49.1**	**52.3**	**42.1**	**49.1**	**85.8**	**69.4**	**68.5**	**58.0**	**60.4**	**57.0**
Total Transmission Capital	**936.1**	**810.2**	**776.0**	**718.5**	**899.2**	**899.4**	**866.3**	**847.8**	**838.8**	**831.4**

COST EFFICIENCIES/PRODUCTIVITY

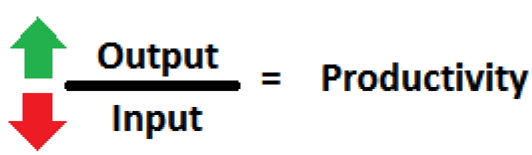
1.0 INTRODUCTION

Productivity at Hydro One remains an integral part of the Corporation's strategy and business objectives. This exhibit outlines the historical (2011 – 2013), present (2014) and future (2015 – 2016) productivity initiative results within the Corporation. Productivity initiatives typically show results over a number of years and Hydro One continues to realize material cost reductions and avoidances, throughout the test years all of which are of direct benefit to Hydro One customers.

Productivity Definition

For the purpose of this analysis, the Hydro One definition of productivity is;

"The effectiveness of productive effort, is measured in terms of the rate of output per unit of input"



An example of Productivity can be demonstrated by improvements made in the Transmission Structure Replacement Program. The Transmission Structure Replacement Program has seen consistent unit cost reductions resulting from:

- strategic scheduling of work to decrease mobilization and demobilization occurrences to save time and travel costs;

- the use of composite structures to decrease maintenance costs and extend the life cycle;
- benefits from right-of-way clearances that greatly reduce complications in installation; and
- increased proficiency in the assembly of composite structures.

In 2012 the transmission structure replacement unit price was $39,582. It is expected the unit price in 2016 will be $35,384. This is a cost reduction of $4198 per structure.

OM&A Expenditures

OM&A expenditures over the two test years, demonstrate more productivity; if not for these initiatives, Hydro One would be requiring more than 10% additional revenue per year. This is illustrated in Table 1.

Table 1:

Impact to Revenue Requirement Inclusive and Exclusive of Annual OM&A Productivity Savings

	2013 Actual	2014 Bridge	2015 Test	2016 Test
OM&A per application	388,446,478.0	448,609,208	452,095,281	457,530,316
YoY growth		15.5%	0.8%	1.2%
Add: Productivity Savings	37,466,766	41,855,121	45,784,676	49,057,059
Productivity Percentage	9.6%	9.3%	10.1%	10.7%
OM&A without Productivity	425,913,244	490,464,329	497,879,957	506,587,375
YoY growth		15.2%	1.5%	1.7%

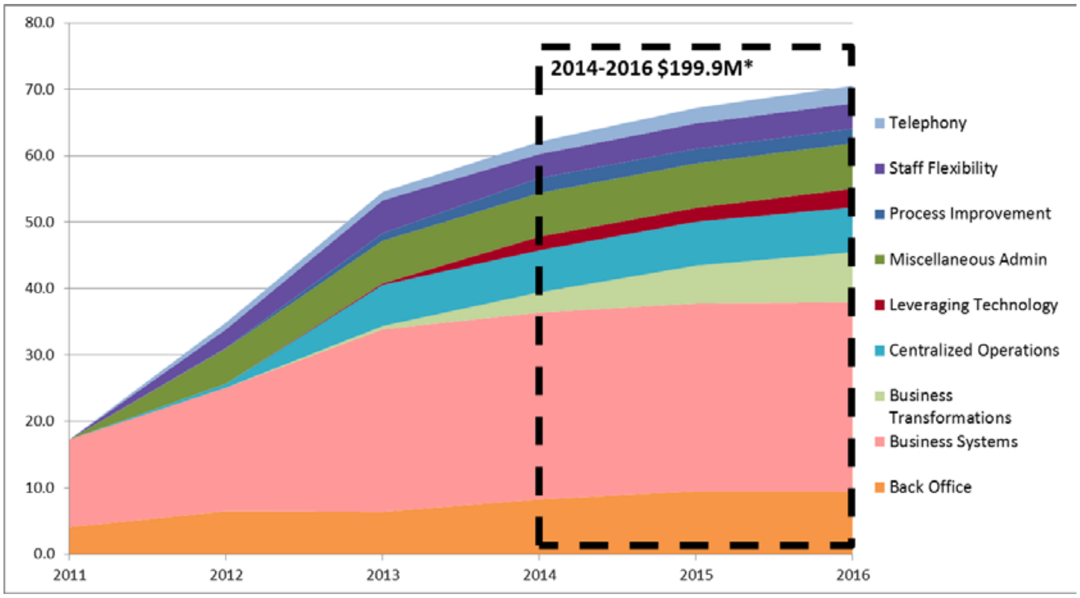
2.0 PRODUCTIVITY EFFICIENCY INITIATIVES

The Corporation's strategic objectives include a commitment to achieve productivity and cost-effectiveness improvements. Table 1 identifies the major categories of productivity initiatives currently underway along with the estimated cost savings achieved from 2011 to 2013, and forecasted savings for 2014 to 2016 for Hydro One Transmission. While all savings estimates are for gross cost savings, it should be noted that the implementation costs are taken into consideration as part of the business planning process discussed in Exhibit A, Tab 16, Schedule 1.

Using the actual savings numbers from historical years (2011 to 2013) and the forecast savings for the bridge (2014) and test years (2015 and 2016), Hydro One Transmission will realize $308.7 million in savings. For initiatives that are common to Transmission and Distribution, a common cost allocation was used consistent with the Black and Veatch studies provided in Exhibit C1, Tab 6, Schedule 1 and Exhibit C1, Tab 6, Schedule 3. $199.9 million has been forecast in savings for the bridge and test years for Transmission as shown in Figure 1 and Table 2.

Figure 1:

Transmission Productivity Savings



* Total productivity savings for forexcast years.

Table 2:

Total Annual Savings -Transmission ($ Million)

Description	Historical			Year	Test Years		Cumulative
	2011	2012	2013	2014	2015	2016	2014 - 2016
Back Office	4.1	6.5	6.4	8.3	9.5	9.5	27.3
Business Systems	13.2	18.6	27.5	28.1	28.3	28.4	84.8
Business Transformations	0.0	0.0	0.5	3.0	5.7	7.5	16.2
Centralized Operations	0.0	0.6	6.2	6.3	6.6	6.8	19.7
Leveraging Technology	0.0	0.0	0.2	2.1	2.1	2.8	7.0
Miscellaneous Admin	0.0	5.3	6.4	6.5	6.7	6.8	20.1
Process Improvement	0.0	0.1	1.1	2.3	2.2	2.2	6.7
Staff Flexibility	0.0	2.8	5.0	3.6	3.8	3.8	11.2
Telephony	0.0	1.0	1.2	1.9	2.3	2.6	6.9
Total	**17.3**	**34.9**	**54.6**	**62.1**	**67.2**	**70.5**	**199.9**

2.0 PRODUCTIVITY INITIATIVE KEY SUCCESS STORIES

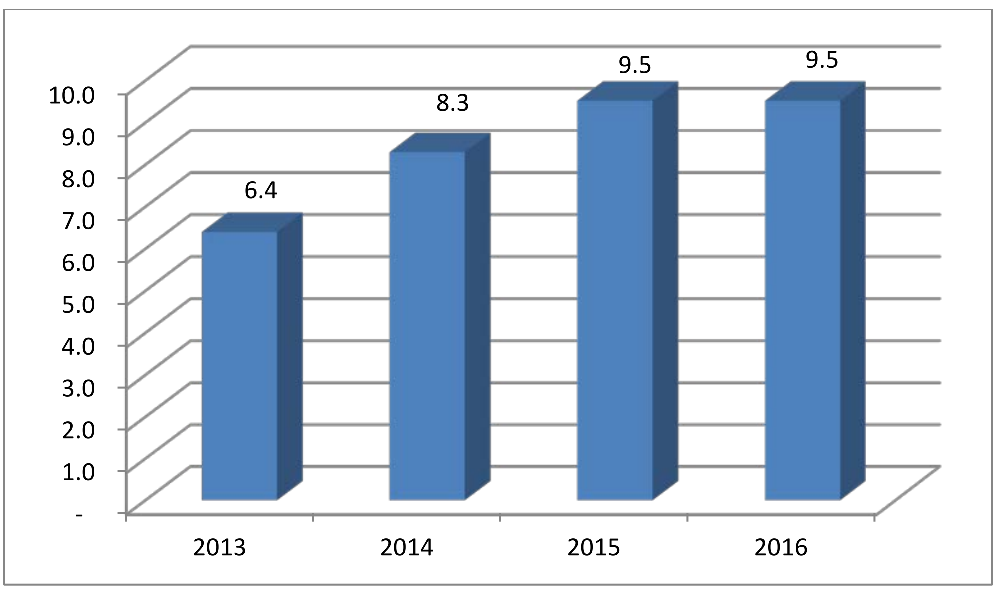
This section discusses the productivity categories and provides greater detail on how Hydro One is making improvements in an effort to provide greater value to the customer. Some key success stories have been provided to demonstrate the commitment Hydro One has made to reduce costs and improve productivity while maintaining or improving its output.

2.1 Back Office

Back Office productivity initiatives are related to the reduction in costs of the administrative and support functions that have been outsourced. The savings are shown in Figure 2.

Figure 2:

Back Office Savings (in $Millions)



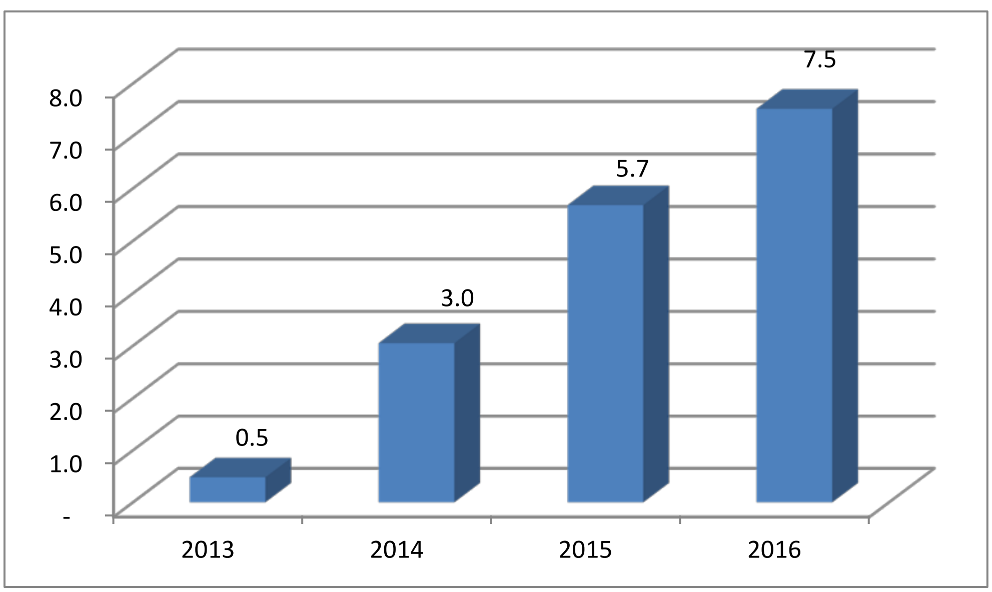
Hydro One negotiated a multi-year outsourcing contract for back office work programs primarily focused on information technology, call service operations, supply management services, finance and accounting, and payroll administration. The contract which was originally setup in 2002 had an established annual price decline for the baseline services. The contract was subsequently renegotiated in 2009 with an end date at the start of 2015. This extended contract included improved service levels and a steeper annual price decline for the five years as a result of negotiated cost reductions and commitments to new business system (SAP) implementation**.** Hydro One expects to continue to outsource back office elements beyond 2015 through a new competitively bid contract that will result in further savings as discussed in Exhibit C1, Tab 3, Schedule 2.

2.2 Business Transformation

Business Transformation productivity initiatives are business unit led large IT projects that streamline processes and increase efficiencies. The savings are shown in Figure 3.

Figure 3:

Business Transformation Savings (in $Millions)



Examples of Business Transformation Savings initiatives include:

- Business Process Consolidation - The automation of the current, very manual process for annually compiling budget baselines and preparing financial information. This initiative will reduce time and effort in the data handling as well as in the intensive quality assurance checking currently required.

- Asset Analytics Value Realization - The Asset Analytics Project is also part of the overall information technology ("IT") strategy to improve business practices. Asset Analytics is a powerful software package that allows thorough analysis of the huge volume of Hydro One data. The system shows prioritized lists of assets requiring maintenance and / or replacement. Use of this tool will ensure asset investments will be made in areas that have the highest priority based on our system information. This will ensure the assets with the greatest need for maintenance or replacement are completed first which will avoid costly failures in the field that result in much higher costs and customer inconvenience. For further details on the Asset Analytics tool, see Exhibit A, Tab 16, Schedule 3.

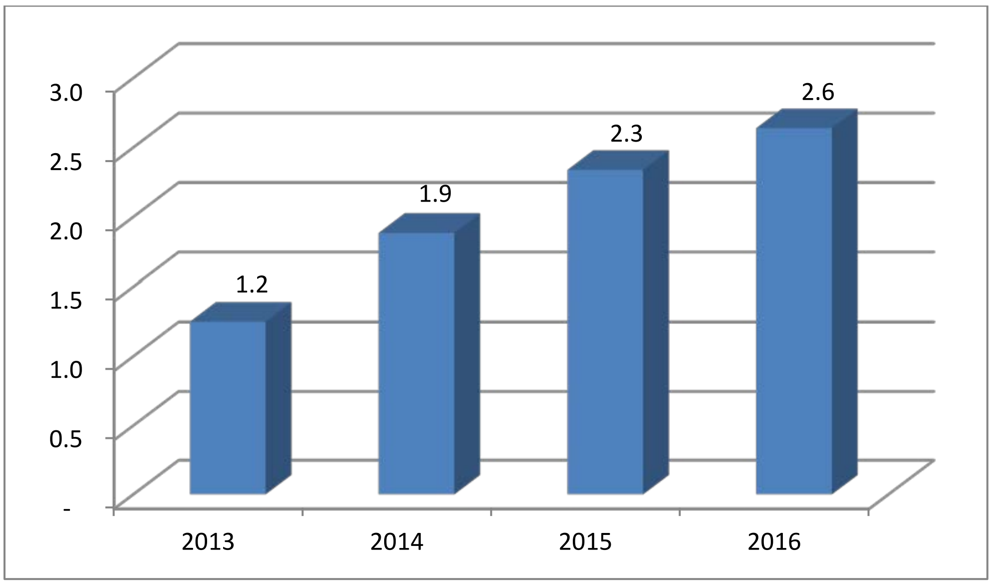
- Engineering Design Tools - Hydro One is employing new engineering design tools such as the 3D Standardized Model-Based Design Application and the E3 Engineering Design Program. These new tools are used to streamline the design process and auto-wiring design application by automating complex, repetitive design and drafting tasks, which will ultimately ensure consistent quality and efficiency of the work execution. This will allow Hydro One to produce designs with greater accuracy and consistency in less time, thus realizing a productivity improvement cost savings. Standard designs also benefit the commissioning phase of an asset's life. Further details can be found in Exhibit A, Tab 16, Schedule 6.

2.3 Telephony

Telephony productivity initiatives enhance and rationalize services to reduce the monthly expenses for phone and data services. The savings from this category are shown in Figure 4.

Figure 4:

Telephony Savings (in $Millions)



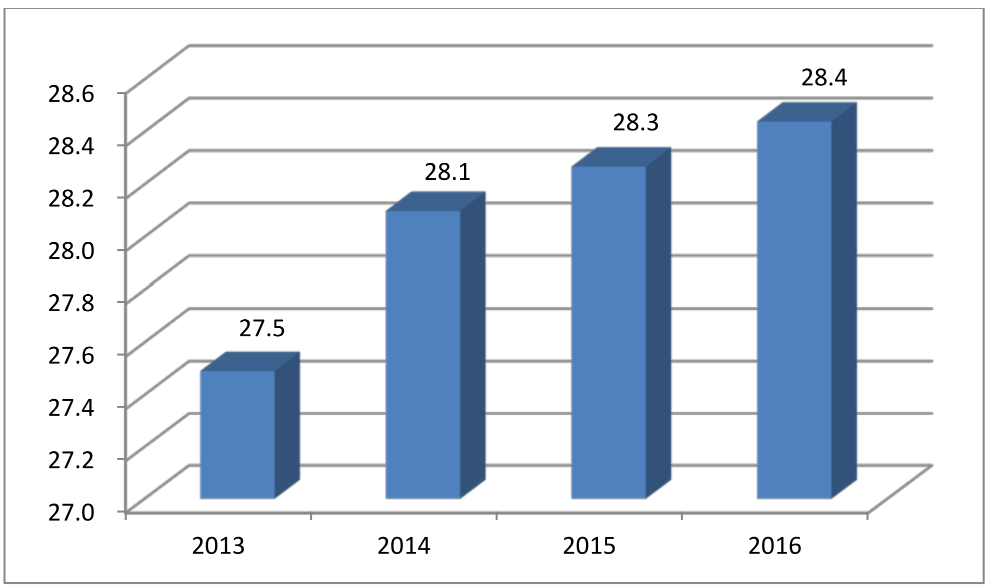
Standardization of cell phone contracts through the adoption of Government subsidized cell phone plans are directly reducing costs by lowering voice and data rate plans and eliminating the paper billing process. Enhancements to telephone, video and web conferencing are reducing travel costs as more and more employees utilize the technology to replace costly physical meetings when appropriate. Utilization of the Telecom Expense Management software will enable Hydro One to rationalize the number of voice and data line circuits as well as power system circuits (e.g. metering, provincial mobile radios, station phones, SCADA and satellite) across the province.

2.4 Business Systems

Business Systems productivity initiatives encompass savings realized from the incorporation of more efficient processes facilitated by the installation of more technically advanced computer systems. The savings from the Business Systems category are shown in Figure 5.

Figure 5:

Business Systems (in $Millions)



Hydro One has replaced its main business systems with SAP and will continue to gain efficiencies from these improved systems. Implementation started in 2007 and the platform was completed in 2010. The system modules that were implemented include Work Management, Supply Chain, Finance, Project Systems and Payroll, realizing value in areas such as Productivity, Cost Effectiveness, Process Efficiency, Better Decision Making, Compliance and Employee Engagement. Since then the Business Consolidation, Customer Information System and Asset Analytics system modules have been implemented. Examples of savings being realized include:

- Strategic Sourcing - Considerable savings have been realized by consolidating purchases for volume discounts, ensuring maximum value for equipment life cycle, improving security of supply through longer term agreements and fixed pricing, better planning with supplier as well as streamlining standards which simplifies procurement and lowers inventory levels. Other Supply Chain efficiency initiatives include consolidated warehouse operations and an investment recovery program. For further details of Supply Chain productivity initiatives see Exhibit C1, Tab 5, Schedule 1.

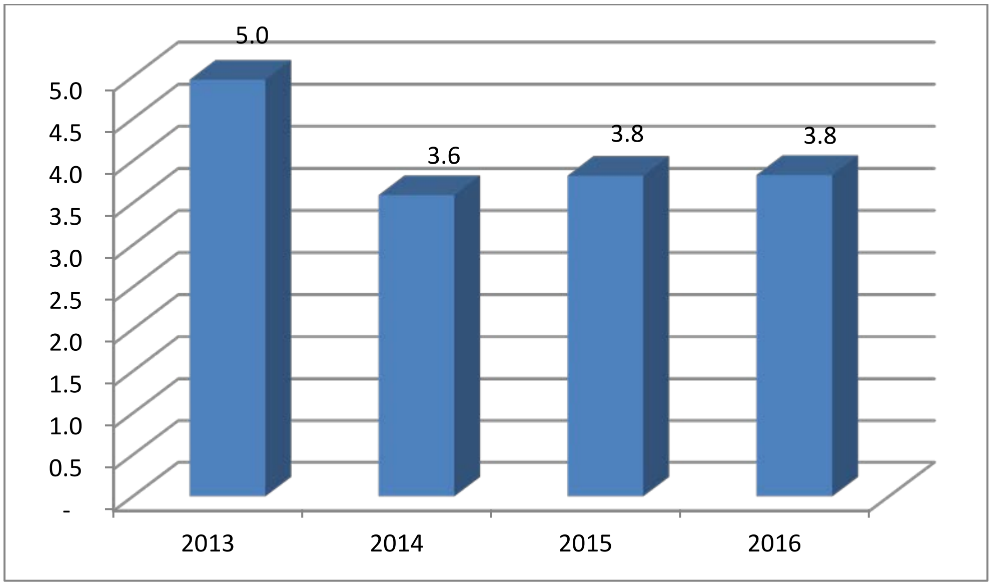
- Rationalization of Legacy IT Systems - There has been a reduction in IT application, database, licensing fees and support costs with the decommissioning of over 450 business software applications and system tools. The replacement of PeopleSoft, Congo's and SAS applications with modern Enterprise Resource Planning and Business Integration solutions has resulted in an integrated enterprise suite that has further enabled more effective information access and productivity within the company.

2.5 Staff Flexibility

Staff Flexibility productivity savings are realized from the more efficient use of skilled and non-skilled labour and through the use of Purchase Service Agreements (PSAs) signed with the Unions to clear backlogs. The transmission portion of the savings realized from cost efficiencies in the Staff Flexibility Savings category is shown in Figure 6.

Figure 6:

Staff Flexibility Savings (in $Millions)



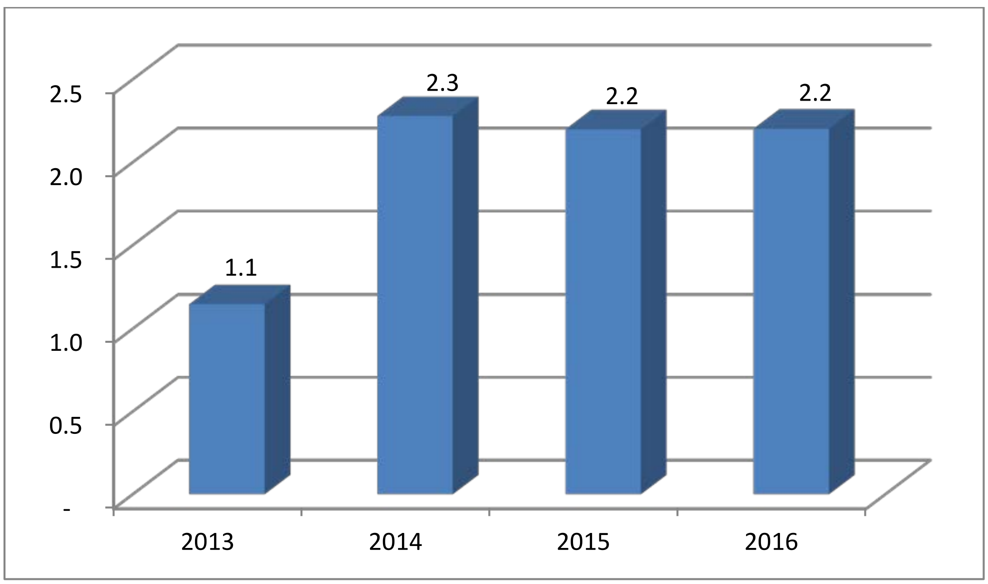
*Elevated savings for 2013 are due to the outsourcing of simple engineering diagrams to clear a backlog. As the backlog is cleared, the savings realized are reduced as fewer drawings are being outsourced.

Hydro One continues to capitalize on staffing resource availability. Where safe and possible, lower skilled and/or contract resources are used to undertake less complex work leaving highly skilled resources to focus on complex work activities. Better use of highly skilled labour in a supervisory role has increased work accomplishment capability. This has resulted in better prioritization and more cost effective completion of the work programs. For further details of the corporate staffing strategy see Exhibit C1, Tab 4, Schedule 1. Another example of staff flexibility savings includes the outsourcing of non-core Facilities operations.

2.6 Process Improvement

Hydro One has identified opportunities for improvement in internal processes including more thorough and interactive advanced planning on complex projects and optimal designs that can be determined prior to project approval. Advanced scheduling reduces potential design changes or rework. The cost efficiency savings due to process improvements is shown in Figure 7.

Figure 7:
Process Improvement Savings (in $Millions)



Hydro One is also implementing improved work methods in the field. For example:

- Local Material Stocking - The stocking of frequently used materials at strategic locations will reduce labour costs associated with material delays due to shortages or manufacturing lead time of materials. Hydro One is also realizing savings from more efficient restocking of materials left over from major projects. See Exhibit C1, Tab 5, Schedule 1 for additional details.

- Work Prioritization, Planning and Bundling - An improved investment prioritization process that assesses asset risk as well as station-centric work releases for sustainment work, will allow Hydro One to utilize resources more efficiently as detailed on Exhibit A, Tab 16, Schedule 6.

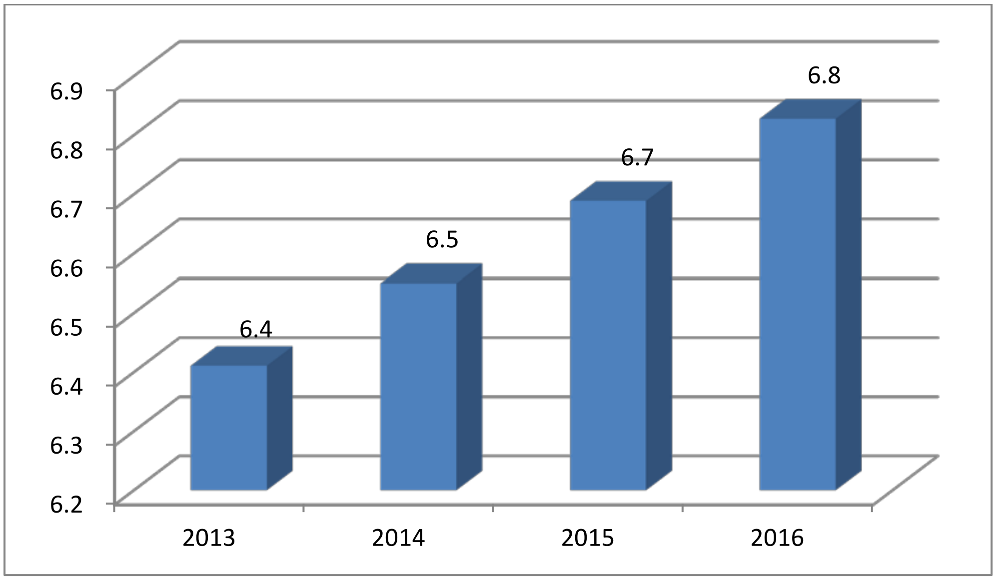
- Earlier and Multi-Year Work Releases - Earlier and multi-year work releases for Sustainment capital and Operations, Maintenance and Administration (OM&A) programs will allow service groups to plan and execute work more efficiently, including scheduling work changes and outages when site conditions are optimal, as detailed on Exhibit A, Tab 16, Schedule 6.

2.7 Miscellaneous Administration

Miscellaneous Administration productivity savings are being recognized with tighter controls and better communication of requirements. The savings from miscellaneous administration processes are shown in Figure 8.

Figure 8:

Miscellaneous Administration Savings (in $Millions)



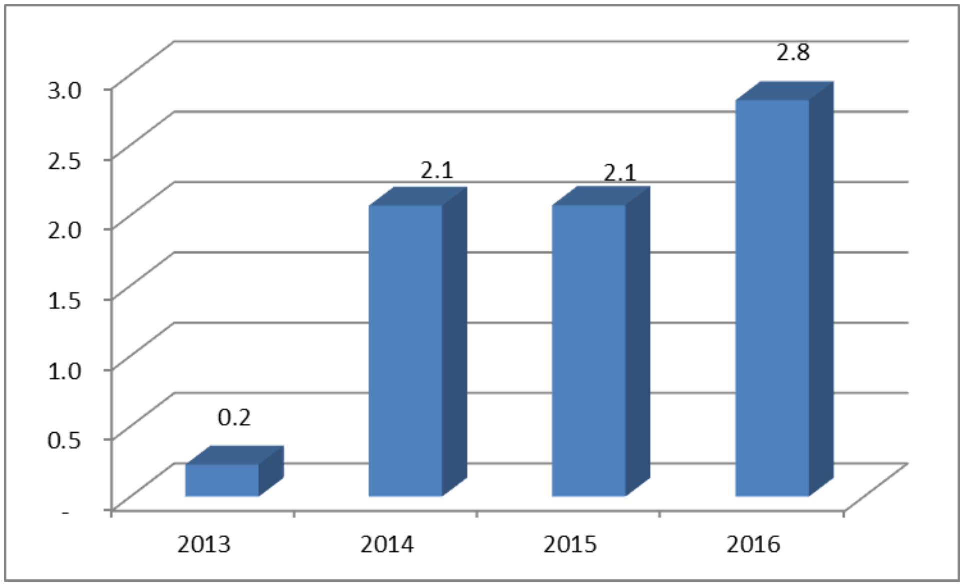
Over the past 3 years there have been administration cost decreases between three to five percent across business units. The main areas where reductions have been implemented are in travel, meals and mileage. This was accomplished by implementing spend limits on meals, fixed mileage rates that decrease with increased mileage and reduced travel expenses by reducing number and improving scheduling of meetings.

2.8 Leveraging Technology in the Field

Leveraging Technology productivity savings involves making better use of modern technology and equipment in order to accomplish work faster and more efficiently. Savings realized in this category are illustrated in Figure 9.

Figure 9:

Leveraging Technology Savings (in $Millions)



Examples of savings realized from the use of technology include:

<u>Global Positioning System (GPS) / Telematics</u> - The use of GPS/Telematics in Hydro One vehicles has allowed for improved travel time through planned route optimization. This leads to increased fuel efficiency and a reduction in greenhouse gases. It also allows for increased fleet response time, and automated tracking of vehicle condition. Hydro One is also using energy efficient vehicles and retrofitting facilities with energy efficient equipment where possible.

<u>Smart meter Network Operating (SMNO)</u> - Recent transformation in the electricity utility industry has been centered on Smart Grid. For Hydro One, Smart Grid commenced with the provincial smart meter mandate. Hydro One recognized that implementing smart meters in a primarily rural geography would be challenging due to the then-existing

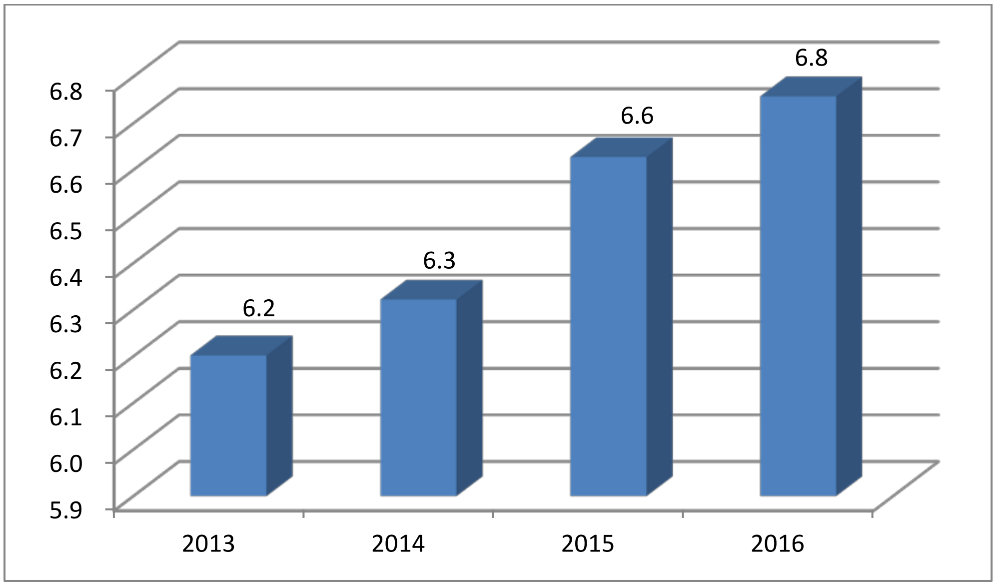
limitations in metering technology and the lack of metering communications options for data transfer. Hydro One undertook to influence the market to develop robust back office metering solutions with standards-based communications to enable the daily aggregation of over a million meters. This culminated in Hydro One leading Canadian utilities in acquiring dedicated spectrum for the use of the electrical sector. The improved telecommunications reach and connectivity for critical electricity operations enabled the use of mobile technologies to optimize field work execution. It allows information, systems and tools to be available to the workforce when they need them and allows reporting of the completion of work in real-time thus getting information to asset planners and to customers in a more timely and accurate manner.

<u>Work Program Optimization (Transmission System Outage Grouping – TSOG)</u> - The optimization of the preventative maintenance work program by bundling will result in reduced outages, increased productivity per outage and increase the customer communication and involvement. This is further discussed in Exhibit A, Tab 4, Schedule 1.

2.9 Centralized Operations

Centralized Operations involve consolidating and reorganization groups within Hydro One to create efficiencies in work processes that lead to a reduction in labour time. Figure 10 depicts the savings from this category.

Figure 10:
Centralized Operations



Hydro One is focusing on ensuring as much field work gets done as possible by centralizing and reducing support functions. For example;

- replacing classroom training with E-Learning courses designed to be completed online at times that do not interfere with critical work activities; and
- Leveraging the provincial government contract through the Ministry of Transportation Ontario to capitalize on additional fuel rebates.

3.0 SUMMARY

Hydro One is developing a culture where productivity, efficiency and the customer are considered in every corporate process, practice and policy. With better tracking of cost efficiencies and productivity, accountabilities and expectations, Hydro One will continue to strive to achieve its missions and vision as a company:

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

COST OF CAPITAL

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing Hydro One Transmission's capital requirements for the 2015 and 2016 test years.

2.0 CAPITAL STRUCTURE

Hydro One Transmission's deemed capital structure for rate making purposes is 60% debt and 40% common equity. This capital structure was approved by the Board as part of its December 23, 2010 Decision on Hydro One's Transmission Rate Application (EB-2010-0002). This is consistent with the Board's report on the cost of capital: see the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 (EB-2009-0084). The 60% debt component is comprised of 4% deemed short term debt and 56% long term debt.

3.0 RETURN ON COMMON EQUITY

Hydro One Transmission's evidence reflects a return of 9.71% for the test year 2015 and 9.96% for the test year 2016, per the Board's formulaic approach in Appendix B of the Cost of Capital Report dated December 11, 2009. For 2015 and 2016 the return on equity calculation is based on the October 2013 Long Term Consensus Forecast.

Hydro One assumes that the return on equity for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board would determine the ROE for Hydro One Transmission based on the September 2014 Consensus Forecasts and Bank of Canada data which would be available in October 2014. Similarly, the 2016 ROE would be updated to reflect the September 2015 Consensus Forecasts and Bank of Canada data available in October 2015.

4.0 DEEMED SHORT-TERM DEBT

The Board has determined that the deemed amount of short-term debt that should be factored into rate setting be fixed at 4% of rate base. The Board has indicated in Appendix D of the December 11, 2009 Cost of Capital Report that, once a year, in January, Board Staff will obtain real market quotes from major banks, for issuing spreads over Bankers' Acceptance (BA) rates to calculate an average spread. The short term debt rate will be calculated as the average BA rates for the 3 months in advance of the effective date for the rates, plus the average spread obtained as described above. Variable rate debt which pays interest based on the BA rate, has been included as part of the deemed short term debt amount of 4% of rate base. The deemed short-term rate is 3.19% for 2015 and 4.45% for 2016 using the June 2013 Global Insight BA rate plus the average annual BA spread as per the OEB's Cost of Capital Parameters, dated February 14, 2013, for Rates Effective May 1, 2013. Hydro One assumes that the deemed short term debt rate for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board would determine the deemed short term debt rate for Hydro One Distribution based on the September 2014 Bank of Canada data which would be available in October 2014 plus the average spread obtained by Board Staff in 2014. Similarly, for 2016, the Board would determine the deemed short term debt rate for Hydro One Distribution based on the September 2015 Bank of Canada data which would be available in October 2015 plus the average spread obtained by Board Staff in 2015.

5.0 LONG-TERM DEBT

The Board has determined that the deemed amount of long-term debt that should be factored into rate setting be fixed at 56% of rate base. The long term debt rate is calculated to be 5.02% for 2015 and 5.08% for 2016. The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2014, 2015 and 2016 as discussed in Exhibit B1, Tab 2, Schedule 1. Details of Hydro One Transmission's long term debt rate calculation for the 2015 and 2016 test years are identified at Exhibit B2, Tab 1, Schedule 2, pages 9 to 12. A detailed discussion of Hydro One Transmission's debt and forecast interest rate is provided at Exhibit B1, Tab 2, Schedule 1.

Historical long-term debt cost information is filed at Exhibit B2, Tab 1, Schedule 2, pages 1 to 12.

As discussed in this exhibit, forecast interest rates will be updated consistent with the methodology used for the return on common equity and deemed short term interest rate. In addition Hydro One assumes that long term debt rate will be updated to reflect and take into account the actual issuances of debt since the time of original application consistent with the OEB Decision on Hydro One Transmission 2013 and 2014 rate application in EB-2012-0031.

As Hydro One Transmission has a market determined cost of debt, the weighted average long term debt rate is also applied to any notional debt that is required to match the actual amount of long term debt to the deemed amount of long term debt consistent with the Board's Decision in EB-2012-0031.

6.0 COST OF CAPITAL SUMMARY

Hydro One Transmission's 2015 rate base is $10,176.5 million which results in an after-tax required return of 6.82%. The 2016 rate base is $10,558.0 million, which results in an after-tax required return of 7.01%, as shown in Table 1, below:

Table 1
2015 and 2016 Cost of Capital

	2015				2016			
Amount of Deemed	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
Long-term debt	5,698.8	56.0%	5.02%	286.0	5,912.5	56.0%	5.08%	300.5
Short-term debt	407.1	4.0%	3.19%	13.0	422.3	4.0%	4.45%	18.8
Common equity	4,070.6	40.0%	9.71%	395.3	4,223.2	40.0%	9.96%	420.6
Total	10,176.5	100.0%	6.82%	694.3	10,558.0	100.0%	7.01%	739.9

Historical, bridge and test year debt and equity summary schedules have been provided at Exhibit B2, Tab 1, Schedule 1.

COST OF THIRD PARTY LONG-TERM DEBT

1.0 HYDRO ONE TRANSMISSION LONG-TERM DEBT

The debt portfolio for Hydro One Transmission, as set out in Exhibit B2, Tab 1, Schedule 2, is based on debt issued by Hydro One Networks Inc. to Hydro One Inc., of which the Transmission business is mapped a portion. Hydro One Networks Inc. issues debt to Hydro One Inc., reflecting debt issues by Hydro One Inc. to third party public debt investors.

Third party public debt investors hold all of the long term debt issued by Hydro One Inc. Hydro One Inc.'s debt financing strategy takes into consideration the objectives of cost effectiveness, distributing debt maturities evenly over time, and ensuring the term of the debt portfolio is compatible with the long life of the Company's assets.

Hydro One Inc. has a Medium Term Note ("MTN") Program that provides ready access to issue debt with a term greater than one year into the Canadian debt capital markets. The standard maturity terms in the area of five, ten and thirty years are preferred by investors and represent the main financing which Hydro One Inc. utilizes to execute its financing strategy and raise the required funds. The short form base shelf prospectus for the current $3.0 billion MTN Program is provided in Exhibit A, Tab 13, Schedule 2.

2.0 CREDIT RATINGS

As Hydro One Inc. issues medium term notes in the Canadian public debt markets, credit ratings are a requirement. The credit ratings of Hydro One Inc.'s debt obligations by Dominion Bond Rating Service, Moody's Investors Service and Standard & Poor's Rating Services are as follows:

Table 1
Credit Ratings for Hydro One Inc.

Rating Agency	Short-term Debt	Debt
Standard & Poor's Rating Services (S&P)	A-1	A+
Dominion Bond Rating Service (DBRS)	R-1(middle)	A(high)
Moody's Investors Service (Moody's)	Prime-1	A1

The most recent rating agency reports are provided in Exhibit A, Tab 12, Schedule 1.

3.0 COST OF LONG-TERM DEBT

The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2014, 2015 and 2016. The weighted average rate on long term debt rate is 5.02% for 2015 and 5.08% for 2016. Details of Hydro One Transmission's long term debt rate calculation for the 2014 bridge year and 2015 and 2016 test years are identified at Exhibit B2, Tab 1, Schedule 2, pages 9 to 12.

The amount of each Hydro One Networks Inc. debt issue that is mapped to the Transmission business is based on its most recent forecast of borrowing requirements. Borrowing requirements are driven mainly by debt retirement, capital expenditures net of internally generated funds, and the maintenance of its capital structure. For example, in January of 2012, Hydro One Inc. issued $300 million of ten-year notes with a 3.20% coupon rate, of which $154 million was mapped to Hydro One Transmission, as shown on line 25 of Exhibit B2, Tab 1, Schedule 2, page 10.

The interest rates of debt issues mapped to the Transmission business, as shown in Exhibit B2, Tab 1, Schedule 2, are equal to the actual interest rates on debt issued by

Hydro One Networks Inc. to Hydro One Inc., and by Hydro One Inc. to third party public debt investors.

3.1 Embedded Debt

The Board has determined in its Cost of Capital Report that for embedded debt, the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt. Hydro One Transmission's embedded long term debt, which was issued during the period from 2000 to 2013, is shown on lines 1 to 34 of Exhibit B2, Tab 1, Schedule 2, page 5 to 6. The rates on these embedded debt issues were approved by the Board as part of the Board's 2014 Rate Order in EB-2012-0031, dated January 9, 2014.

3.2 New Debt

The Board has determined in its Cost of Capital Report that the rate for new debt that is held by a third party will be the prudently negotiated contract rate. This would include recognition of premiums and discounts.

3.3 Forecast Debt

Hydro One Transmission's forecast borrowing requirements are $206 million for 2014, $478 million for 2015 and $592 million for 2016. For planning purposes it is assumed that debt issuance will be evenly distributed over the standard terms in the area of five, ten and thirty years, which are preferred by investors, while limiting total annual maturities for Hydro One Inc. to $750 million to avoid undue refinancing risk.
Table 2 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2014, and will be mapped to the Transmission business, as shown on lines 33 to 35 of Exhibit B2, Tab 1, Schedule 2, page 8.

Table 2
Forecast Debt Issues for remainder of 2014

2014		
Principal Amount ($Millions)	**Term (Years)**	**Coupon**
68.5	5	3.10%
68.5	10	4.09%
68.5	30	4.93%

Table 3 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2015, and 2016 will be mapped to the Transmission business, as shown on lines 34 to 39 of Exhibit B2, Tab 1, Schedule 2, page 12.

Table 3
Forecast Debt Issues for 2015 and 2016

2015			2016		
Principal Amount ($Millions)	**Term (Years)**	**Coupon**	**Principal Amount ($Millions)**	**Term (Years)**	**Coupon**
159.3	5	3.80%	197.5	5	4.30%
159.3	10	4.79%	197.5	10	5.29%
159.3	30	5.63%	197.5	30	6.13%

3.3 Interest Rates for 2014, 2015 and 2016 Forecast Debt Issues

Transmission business borrowing will be financed at market rates applicable to Hydro One Inc. Table 4 summarizes the derivation of the forecast Hydro One Inc. yield for each of the planned issuance terms for 2014, 2015 and 2016.

Table 4
Forecast Yield for 2014-2016 Issuance Terms

	2014		
	5-year	**10-year**	**30-year**
Government of Canada	2.23%	2.90%	3.40%
Hydro One Spread	0.87%	1.19%	1.53%
Forecast Hydro One Yield	3.10%	4.09%	4.93%
	2015		
	5-year	**10-year**	**30-year**
Government of Canada	2.93%	3.60%	4.10%
Hydro One Spread	0.87%	1.19%	1.53%
Forecast Hydro One Yield	3.80%	4.79%	5.63%
	2016		
	5-year	**10-year**	**30-year**
Government of Canada	3.43%	4.10%	4.60%
Hydro One Spread	0.87%	1.19%	1.53%
Forecast Hydro One Yield	4.30%	5.29%	6.13%

Each rate is comprised of the forecast Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2014 is based on the average of the 3 month and 12 month forecast from the September 2013 Consensus Forecast. The ten-year Government of Canada bond yield forecast for 2015 and 2016 is based on the average of the October 2013 Long Term Consensus Forecast. The five- and 30-year Government of Canada bond yield forecasts are derived by adding the September, 2013 average spreads (five-year to ten-year for the five-year forecast and 30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for September, 2013 obtained from the Company's MTN dealer group for each planned issuance term.

Hydro One assumes that forecast debt issuance interest rates for each test year will be updated consistent with the ROE methodology, upon the final decision in this case. For rates effective January 1, 2015, the forecast interest rate for Hydro One Transmission debt issues will based on the September 2014 Consensus Forecasts and the average of indicative new issue spreads for September 2014 which will be obtained from the Company's MTN dealer group for each planned issuance term. For rates effective January 1, 2016, the forecast interest rate for Hydro One Transmission debt issues will be based on the September 2015 Consensus Forecasts and the average of indicative new issue spreads for September 2015 which will be obtained from the Company's MTN dealer group for each planned issuance term. In addition Hydro One assumes that long term debt rate will be updated to reflect and take into account the actual issuances of debt since the time of original application consistent with the OEB's Decision on Hydro One Transmission's 2013 and 2014 rate application in EB-2012-0031 and changes in the interest rate forecast.

3.4 Treasury OM&A Costs

Treasury OM&A costs are incurred to:

- execute borrowing plans and issue commercial paper and long term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage the company's daily liquidity position, control cash and manage the company's bank accounts;
- settle all transactions and manage the relationship with creditors; and
- communicate with debt investors, banks and credit rating agencies.

These costs are $1.6 million for both 2015 and for 2016 as shown on line 39, page 10 and line 41, page 12 of Exhibit B2, Tab 1, Schedule 2.

3.5 Other Financing-Related Fees

Column (e) of Exhibit B2, Tab 1, Schedule 2 ("Premium, Discount and Expenses") represents the costs of issuing debt. These costs are specific to each debt issue and include commissions, legal fees, debt discounts or premiums on issues or re-openings of issues relative to par, and hedge gains or losses.

Other financing related fees, $2.9 million in 2015 and $3.0 million 2016, identified on line 40, page 10 and line 42, page 12 of Exhibit B2, Tab 1, Schedule 2, include the Transmission allocation of Hydro One Inc.'s standby credit facility, annual credit rating agency, banking, custodial and trustee fees.

SUMMARY OF OM&A EXPENDITURES

1.0 SUMMARY OF OM&A EXPENDITURES

The proposed OM&A expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place. This process is described in detail at Exhibit A, Tab 16.

The proposed OM&A programs represent the work required to meet public and employee safety objectives, maintain transmission reliability at targeted performance levels, and to comply with regulatory requirements (such as specified within the Transmission System Code), environmental requirements and Government direction.

The development of asset maintenance programs, as described in the following schedules of this Exhibit, is based on equipment specifications coupled with comprehensive asset condition information, as well as information on asset demographics, component performance and reliability, and equipment utilization.

Hydro One Transmission's OM&A budget is grouped into different investment categories: Sustaining, Development, Operations, Customer Care, Common Corporate and Taxes Other than Income Taxes. Table 1 provides a summary of Hydro One Transmission's OM&A expenditures for the historical, bridge and test years.

Table 1
Summary of Transmission OM&A Budget ($ Million)

Description	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Sustaining	227.6	204.7	221.0	236.2	238.7	241.1
Development	12.6	8.5	8.6	12.9	12.9	13.4
Operations	57.3	54.8	56.7	57.4	58.5	59.1
Customer Care	5.2	4.4	5.3	5.8	5.5	5.5
Common Corporate and Other OM&A	44.2	80.7	75.8	70.6	70.2	71.3
Property Taxes & Rights Payments	67.5	62.1	21.2	65.6	66.3	67.0
TOTAL	**414.5**	**415.2**	**388.4**	**448.6**	**452.1**	**457.5**

Total OM&A expenditures for test year 2015 are forecast to increase by $3.5 million, or approximately 0.8% over the 2014 bridge year. Total OM&A expenditures for test year 2016 are forecast to increase by $5.4 million, or 1.2%, over 2015. The test year expenditures are required to address the increasing maintenance requirements of an aging and expanding transmission system.

2.0 SUSTAINING

The Sustaining OM&A budget represents investments required to maintain existing transmission lines and stations facilities so that they will continue to function as originally designed. The proposed investments are intended to ensure that the overall reliability of the system is maintained, that customer commitments are achieved, and that all legislative, regulatory, environmental and safety requirements are met. Details are provided at Exhibit C1, Tab 2, Schedule 2.

3.0 DEVELOPMENT

The Development OM&A budget funds research and development, as well as the development of new standards. The Development OM&A is described in detail at Exhibit C1, Tab 2, Schedule 3.

4.0 OPERATIONS

The Operations OM&A program represents the annual expenditures required for the Central Transmission Operations function, operated out of Hydro One's Ontario Grid Control Centre. The Transmission Operations function is concerned with the real time operations of the Hydro One Transmission system equipment, including the monitoring, control, detection and response to equipment operational issues. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 4.

5.0 CUSTOMER CARE OM&A

Hydro One Transmission’s Customer Service OM&A investments fund work activities required to develop, implement and monitor the Corporation’s plans to positively influence customer relationships and ensure affordability and overall value for the products and services offered to them. These work activities will enable Hydro One to foster a relationship based on transparency and trust. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 5.

6.0 COMMON CORPORATE COSTS AND OTHER OM&A

The Common Corporate Costs and other OM&A program includes: Common Corporate Functions and Services (CCFS), Asset Management, Information Technology, Cornerstone, Cost of Sales and Other OM&A expenses. CCFS includes Corporate

Management, Finance, Human Resources, Corporate Communications and Services, Legal, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate. Common Asset Management services include System Investment, Business Performance, and Asset Strategies. IT and Cornerstone activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure. Other OM&A programs include credits for overheads capitalized as capital projects are built and the cost of goods sold in support of external revenues. Details of the expenditures under this program are filed at Exhibit C1, Tab 3, Schedules 1 through 6.

7.0 TAXES OTHER THAN INCOME TAXES

This program consists of property and proxy taxes, and indemnity payments to the Province. Details of the expenditures under this program are filed at Exhibit C1, Tab 3, Schedule 7.

8.0 COMPARISON OF OM&A COSTS TO BOARD APPROVED

Table 2 compares 2013 actual costs to the 2013 OM&A expenditures approved by the Board in their Decision on Hydro One Transmission's previous application in Proceeding EB-2012-0031.

Table 2
2013 Board Approved versus 2013 Actual OM&A Expenditures

OM&A Categories	2013 Board Approved ($ million)	2013 Actuals ($ million)	Variance ($ million)
Sustaining	235.7	221.0	(14.8)
Development[1]	13.7	8.6	(5.1)
Operations	57.7	56.7	(1.0)
Customer Care	4.9	5.3	0.4
Common Corporate & Other Costs	61.9	75.8	13.9
Taxes other than Income Taxes	66.0	21.2	(44.8)
Total OM&A	**440.3**	**388.4**	**(51.6)**

Hydro One Transmission's actual 2013 OM&A costs were $51.6 million lower than the $440.3 million approved by the Board in Proceeding EB-2012-0031. The reduction in the Sustaining, Development, and Operations work program spend reflects Cornerstone savings (both are included in the Board Approved Shared Services and Other total in Table 2). The large reduction in the Taxes other than Income Taxes area is mainly because the company recognized a one-time Property tax rebate in 2013.

Table 3 compares 2014 projected costs to the 2014 OM&A expenditures approved by the Board in their Decision on Hydro One Transmission's previous application in EB-2012-0031.

[1] Development costs are net of Licence Amendment to Upgrade TS's to Facilitate Renewable Generation amounts

Table 3
2014 Board Approved versus 2014 Projected OM&A Expenditures

OM&A Categories	**2014 Board Approved** ($ million)	**2014 Projected** ($ million)	**Variance** ($ million)
Sustaining	246.5	236.2	(10.3)
Development[2]	14.7	12.9	(1.8)
Operations	58.0	57.4	(1.6)
Customer Care	4.7	5.8	1.1
Common Corporate & Other Costs	59.0	70.6	11.6
Taxes other than Income Taxes	66.8	65.6	(1.2)
Total	**449.7**	**448.5**	(1.2)

Hydro One Transmission's projected 2014 OM&A costs are $1.2 million less than the $449.7 million approved by the Board in Proceeding EB-2012-0031. The 2014 Board Approved amounts include the envelope OM&A adjustment as part of the settlement in EB-2012-0031.

The reduction in the Sustaining, Development, and Operations work program spend was driven by the need to stay within the overall Transmission business OM&A envelope approved in the Board's last Decision, and also reflects Cornerstone savings. These variances are partially offset by an increase in Common Corporate and Other Costs primarily in the Real Estate and Facilities area.

[2] Development costs are net of Licence Amendment to Upgrade TS's to Facilitate Renewable Generation amounts

SUSTAINING OM&A

1.0 INTRODUCTION

Sustaining OM&A consists of expenditures required to maintain existing transmission system facilities so that they continue to function as originally designed. The expenditures covered under Sustaining OM&A are intended to maintain equipment performance at appropriate levels, thereby maintaining the overall reliability and service quality while satisfying all legislative, regulatory, environmental and safety requirements.

Hydro One Transmission manages its Sustaining OM&A program by dividing the program expenditures into three categories:

- Stations, which funds the work required to maintain existing assets located within transmission stations including existing protection, control, and telecommunication facilities;

- Lines, which funds the work required to maintain overhead transmission lines and underground cables, including vegetation management on transmission line rights-of-way;

- Engineering and Environmental Support, which funds the specialized and administrative support needed to assist with decision making processes in managing the transmission assets.

A summary of Hydro One Transmission's Sustaining OM&A programs and proposed spending levels for the test years 2015 and 2016 are described herein.

2.0 SUSTAINING OM&A SUMMARY

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 16, Schedules 1 to 5, has been completed for all Sustaining OM&A programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

The selection of planned Sustaining OM&A investments is guided by the asset risk assessment process described in Exhibit A, Tab 16, Schedule 7. This process takes into account the condition, age, performance, criticality and utilization of specific assets. An economic evaluation is also performed as part of the process. At times, the economic evaluation may determine that it is more cost-effective to replace an asset rather than to continue to repair or maintain it. These capital replacement activities are described in Exhibit D1, Tab 3, Schedule 2.

Sustaining transmission assets is essential to the long term viability and performance of these assets and this is reinforced by the Transmission System Code that requires Hydro One Transmission to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments". Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One Transmission and its customers. As outlined in Exhibit D1, Tab 2, Schedule 1, a greater portion of Hydro One's transmission system is reaching an age where the deterioration in condition is taking place at an increasing rate. This will place added cost pressures on future maintenance programs to maintain equipment performance and reliability until such time that the assets can be replaced. In addition, the transmission system continues to expand and there is a need for increased maintenance expenditures when these new assets are placed into service. At the same time, Hydro One Transmission is continuously looking for improvement opportunities that improve the Hydro One transmission system, minimizing risk and adding value for

Hydro One's customers. OM&A expenditures proposed in this exhibit will sustain the assets needs over the test years. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future.

The required funding for the Sustaining OM&A in the test years, along with the spending levels for the bridge and historic years are provided in Table 1 for each of the major sustaining categories.

Table 1
Sustaining OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Stations	166.2	146.5	159.9	165.5	169.0	171.6
Lines	49.4	48.6	50.4	58.8	57.8	58.8
Engineering and Environmental Support	12.0	9.5	10.7	11.9	11.9	10.8
Total	**227.6**	**204.7**	**221.0**	**236.2**	**238.7**	**241.1**

The overall Sustaining OM&A requirements for the test year 2015 have increased 1% over projected spending in the bridge year 2014. The spending requirements for 2016 continue to increase by 1% over the 2015 requirements. The increase in overall spending in the test years relative to historic and bridge year expenditures is largely attributed to:

- Increased environmental remediation work to deal with legacy contamination in transmission stations; and
- Increased work in the area of cyber security following approval of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Version 5 standards.

While some Sustaining programs are growing through the test years due to asset demographics and regulatory requirements (as mentioned above), a number of initiatives are being undertaken to contain increases in maintenance costs associated with the aging system and increased regulatory requirements. These include:

- Optimized maintenance frequencies impacting overall costs and resource utilization, and additional moves to condition based maintenance;
- Increased bundling opportunities through alignment of maintenance activities and improved visibility of bundling opportunities. These provide efficiencies in the planning and execution of outages as well as with staff mobilization; and
- Increased capital replacement of assets mitigating the need for increases in corrective maintenance costs and equipment refurbishment activities through addressing worse performing assets and facilitating the integration of new equipment with lower lifecycle maintenance costs.

3.0 STATIONS

Transmission Station facilities are used for the delivery of power, voltage transformation, switching, and serve as connection points for both load customers and generators. Station facilities contain many of the following major components: power transformers, circuit breakers, disconnect switches, bus work, insulators, potheads, surge arrestors, capacitor banks, reactors, instrument devices, protection and control systems, station service systems, grounding systems, site infrastructure and buildings.

Stations Sustaining OM&A funding covers expenditures required to maintain the performance of the assets located within transmission stations. Hydro One Transmission manages its Stations Sustaining OM&A program by dividing the program into six categories:

1. Land Assessment and Remediation, a specific program that focuses on identification, mitigation and remediation of historical contamination located both inside and outside the station fence;

2. Environmental Management, an on-going program that focuses on the mitigation and remediation of contamination located both inside and outside the station fence and manages, tests for and disposes of PCB and other regulated waste that develops as part of Hydro One Transmission's normal business practices;

3. Power Equipment Maintenance, which focuses on sustaining power equipment performance through planned and corrective maintenance work and equipment refurbishment;

4. Ancillary Systems Maintenance, which focuses on sustaining the performance of ancillary systems through planned and corrective maintenance work;

5. Protection, Control, Monitoring, Metering and Telecommunications Maintenance, which focuses on sustaining the power system protection, control, monitoring, metering and telecommunication facilities through planned and corrective maintenance work and providing Hydro One Transmission with the information, and communication necessary to operate the transmission system; and

6. Site Infrastructure Maintenance, which focuses on maintaining the infrastructure at stations through planned and corrective maintenance work.

Required funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years are provided in Table 2 for each of these categories.

Table 2
Stations Sustaining OM&A
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Land Assessment and Remediation	1.5	1.9	3.1	2.6	3.1	2.9
Environmental Management	15.2	11.3	11.9	15.3	14.9	16.0
Power Equipment Maintenance	68.1	55.7	60.2	59.2	60.7	59.7
Ancillary Systems Maintenance	11.2	10.1	10.1	10.5	10.0	10.0
Protection, Control, Monitoring, Metering and Telecommunications Maintenance	43.9	44.9	49.4	50.1	51.7	53.7
Site Infrastructure Maintenance	26.4	22.7	25.2	27.8	28.5	29.3
Total	**166.2**	**146.5**	**159.9**	**165.5**	**169.0**	**171.6**

The overall Stations Sustaining OM&A expenditures for the test year 2015 have increased 2% over projected spending in 2014. The spending requirements for 2016 continue to increase by approximately 2% over the 2015 requirements. Spending increases are in areas including:

- Cyber Security of protection, control, and telecommunications assets, which is required to meet NERC regulatory requirements, and
- Mitigation and remediation work which is required to address contamination resulting from past operations.

3.1 Land Assessment and Remediation

3.1.1 Introduction

The Land Assessment and Remediation ("LAR") program is primarily focused on the mitigation and remediation of historical discharge of contaminates from transmission station sites that may pose a risk to the public or Hydro One Transmission staff. On-site management controls are typically implemented to eliminate or mitigate on-site contamination that could result in unacceptable risks to staff, the public and/or the environment should no action be taken.

As a responsible steward committed to protecting the environment for current and future generations, Hydro One Transmission manages its operations in an environmentally responsible manner. The LAR program meets Hydro One Transmission’s environmental policy objectives by assessing and mitigating on and off property historical contamination at transmission station sites. The LAR program also funds assessment and remediation work to address contamination at real estate facilities which include field service centres, administrative buildings and garage facilities.

3.1.2 Investment Plan

The LAR program utilizes a multi-phased approach involving successive levels of environmental site assessments, risk evaluation and prioritization, and remedial option evaluations leading to the selection of the preferred remedial or mitigating solution. The prioritization and selection process for environmental site assessment and remediation work is based on two factors: type and level of contamination that exceeds Ministry of the Environment (“MOE”) standards; and the potential for the contaminants to cause adverse effects on human health and/or the environment. The MOE supports Hydro One Transmission's risk-based approach and planned programs.

The LAR program consists of: Site Management, Site Assessment, and Remediation work. Site management is required once a site has been assessed or remediated, as there are often regulatory requirements imposed by the MOE to monitor groundwater quality in the area of the former contamination to ensure that groundwater is not impacted. The station-specific groundwater monitoring program may be required for a period of 3 to 5 years, and typically involves well installations, MOE registration, groundwater measurements and sample analysis, and eventual decommissioning of the monitoring wells. Site management plans are developed to monitor and manage residual on-site contamination and to manage installed controls, such as barriers and long-term treatment systems.

Site assessment is planned at a number of transmission stations that have been identified as potential remediation sites. The assessment involves gathering information to identify actual or potential contamination and sources of contamination. This is done through a review of the site records, previous environmental reports and by analyzing soil and groundwater extracted from and around Hydro One Transmission properties. Soil and water samples are taken as surface grab samples or by drilling to obtain samples from various depths. The information is analysed, risks assessed and sites prioritized for remediation. Considering the 2011 update to the regulations that placed a higher standard for environmental management, it is expected that the outcome of the work planned in the test years will result in increased future expenditures to address those sites determined to be contaminated above thresholds.

Where contamination is identified, a remediation plan is developed and implemented to treat, remove or otherwise manage the contamination. The primary focus of the LAR program is to address off-site impacts and mitigate or manage on-site contamination. Where appropriate, co-ordination of LAR work with end of life refurbishment and capital upgrade projects are considered.

3.1.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $3.1 million and $2.9 million respectively. Spending on this program fluctuates year to year depending on the number of sites selected for remediation and the extent of the remediation work required at each site to meet environmental obligations. When expenditures in this program are incurred, there is a corresponding credit to OM&A to demonstrate the fact that the cost is reflected in revenue requirement as an amortization expense and not as OM&A, as detailed in Exhibit C1, Tab 7, Schedule 1.

A reduction in this program may impact Hydro One Transmission's ability to maintain compliance with MOE requirements, and will result in deferral of prudent remediation activities that could have financial and environmental impacts to Hydro One Transmission properties and neighbouring sites in future years.

3.2 Environmental Management

3.2.1 Introduction

Environmental Management focuses on mitigation and remediation of contamination located both inside and outside the station fence. This program enables Hydro One Transmission to satisfy obligations relating to environmental regulations and environmental policies pertaining to transmission station equipment.

3.2.2 Investment Plan

The Environmental Management program consists of four activities. Table 3 outlines the proposed funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

Table 3
Environmental Management OM&A
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
PCB Retirement and Waste Management	5.2	4.3	5.2	5.5	5.0	4.9
Transformer Oil Leak Reduction	2.2	2.4	3.2	3.5	3.6	4.6
Preventive and Corrective Maintenance	6.8	3.4	2.7	5.2	5.4	5.5
Environmental Compliance and Emergency Response Plan Updates	0.9	1.1	0.8	1.0	1.0	1.0
Total	**15.2**	**11.3**	**11.9**	**15.3**	**14.9**	**16.0**

PCB Retirement and Waste Management

In response to Environment Canada’s PCB Regulations enacted in 2009, Hydro One Transmission initiated the PCB retirement program to identify and phase-out its PCB inventory to comply with the regulation’s end-of-use requirements. In accordance with the regulations, oil-filled power equipment (transformers, breakers, instrument transformers, and associated capacitors, bushings, reclosers) located at Hydro One’s transmission stations that contain greater than 500 ppm PCB are to be retro-filled or replaced by December 31, 2014 (based on an extension granted to Hydro One by Environment Canada). Furthermore, the regulation also mandated that oil-filled power equipment that contain greater than 50 ppm PCB are to be retro-filled or replaced by December 31, 2025.

Hydro One Transmission and CEA-member utilities are lobbying for a regulatory amendment related to bushings and instrument transformers containing greater than 500 ppm PCB contamination due to outage and resource constraints. The proposed expenditures are based on anticipated regulatory relief from Environment Canada to extend the end-of-use date for these bushings and instrument transformers to 2025. Discussions are on-going with Environment Canada, yet Hydro One is confident the regulations will be amended in 2014.

In addition to the PCB contaminated oil, Hydro One Transmission's daily activities also generate regulated waste, such as lead, cadmium, mercury, etc. that are required to be managed and disposed of in accordance with Provincial and Federal regulations.

The PCB retirement and waste management program funds the inspection, testing and retro-filling of equipment to reduce PCB contaminated oil; disposal and decommissioning of PCB contaminated equipment, as well as disposal of non-contaminated oil and other wastes.

<u>Transformer Oil Leak Reduction</u>

As transformers age, they are susceptible to leaks along seal gaskets and access covers, due to the effects of thermal cycling and gradual gasket deterioration. The main tank, access covers and fittings on most power transformers built prior to the mid-1980s utilize organic seal components as gaskets between flanges to retain oil; which begin to leak oil after performing well for the first 20 to 25 years.

Oil leaks are one of the most common deficiencies on transformers, and are a significant contributor to transformer forced outages. Multiple transformer failures have been attributed to aged gasket systems that can allow oil to leak out, and free water (in the form of snow and rain) to enter the transformer.

Transformer oil leaks are repaired on a temporary basis when first discovered under the demand program in order to expeditiously respond to the environmental risks. These repairs are usually stop-gap measures until a more permanent solution is implemented. Permanent repairs generally require outages and staff with a specific skill set to work on transformers.

Preventive and Corrective Maintenance

The preventive maintenance program is in place to ensure that spill containment systems are inspected and operate as designed; underground oil piping within transmission stations that is no longer in use is removed to eliminate risk of contaminating the surrounding environment, and non-functioning mechanical components (pumps, sensors, relays) used in oil/water separators that control effluent from the transformer spill containment pits are repaired or replaced.

The corrective maintenance program includes repairing spill containment systems, maintaining spill containment capacity for non-functioning spill containment systems by removing and disposing of the rainwater, containing and cleaning up insulating fluid spills as they occur and all other actions necessary to mitigate environmental risks posed by transmission equipment problems and failures.

Preventive and corrective maintenance allows Hydro One Transmission to meet its Environmental Policy objectives, maintain compliance with the MOE, minimize the risk to human health and the environment, and mitigate corporate exposure to legal and reputation risks.

Environmental Compliance and Emergency Response Plan Updates

The environmental compliance program encompasses activities necessary to allow Hydro One Transmission to remain in compliance with MOE Environmental Compliance Approvals ("ECAs"), formerly known as Certificate of Approvals, for various transmission stations throughout the province. Hydro One Transmission is required by the MOE to regularly test effluent as a requirement of site specific ECA documents.

Emergency Response Plans ("ERPs") are documents that contain important station specific information that are kept at each transmission station. The ERPs are an effective tool for planning and responding to emergencies and contain important internal and external contact information, station maps and drawings as well as emergency response and evacuation procedures. The plans ensure that risk of harm to employees, contractors, the public, the environment and the physical assets of Hydro One Transmission is minimized. Funding under this program ensures that all ERPs contain up to date and accurate site-specific information.

3.2.2 Summary of Expenditures

The overall planned expenditure for environmental management in 2015 and 2016 is $14.9 million and $16.0 million respectively. This represents an average increase of 20% compared to the historic years, but is generally in-line with the 2014 bridge year expenditures of $15.3 million. This increase from historic years is required to:

- Complete additional transformer leak reductions to meet environmental obligations, as well as mitigating defects which could result in transformer failures impacting customers,

- Decommission additional underground oil handling systems which are no longer in use, and
- Complete additional refurbishment work on spill containment systems.

3.3 Power Equipment Maintenance

3.3.1 Introduction

The maintenance of Hydro One Transmission's power equipment is the most significant program within the Stations Sustaining OM&A category of expenditures. Hydro One's transmission power equipment includes 722 transformers, 4,604 circuit breakers, as well as switches, insulators, bus work, instrument transformers, capacitor banks and reactors at the 286 transmission stations. Maintenance of this equipment is required to sustain in-service power equipment performance.

3.3.2 Investment Plan

The power equipment maintenance program is divided into six categories. Table 4 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

Table 4
Power Equipment Maintenance OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Preventive Maintenance	18.3	19.3	20.0	19.5	20.0	20.4
Corrective Maintenance	26.0	22.2	24.7	21.6	22.1	22.7
500kV Autotransformer Refurbishments	8.8	2.2	2.1	2.2	2.2	1.0
115kV and 230kV Transformer Refurbishments	6.9	6.1	5.6	8.4	8.5	8.5
Breaker Refurbishments	3.3	1.6	4.1	2.8	3.0	2.1
Other Maintenance and Inspection Programs	4.9	4.4	3.6	4.7	4.9	5.0
Total	**68.1**	**55.7**	**60.2**	**59.2**	**60.7**	**59.7**

Preventive Maintenance

Preventive maintenance is conducted to meet Hydro One Transmission’s obligations defined by the Transmission System Code to “inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments”.

Hydro One Transmission's preventive maintenance program for power equipment is based on industry recognized Reliability Centered Maintenance (“RCM”) principles. The RCM principles utilized provide a structured methodology to determine inspection criteria based on known equipment failure modes, to enable equipment functionality to be met in a cost-effective manner. The total number of planned maintenance activities per year in power equipment maintenance is in the order of 9,000.

Hydro One Transmission’s preventive maintenance program places a priority on the completion of condition based monitoring such as visual inspections, oil analysis, function testing and equipment performance monitoring rather than the more intrusive time-based activities. The different power equipment types have varying maintenance activities; examples of maintenance activities for transformers, breakers and switches include:

- Regular visual inspections to identify and record defects,
- Recording of pressures and temperatures to ensure that equipment is operating within appropriate specification; as well as identify oil leaks,
- Function testing of various equipment elements and alarms to ensure continued operation, reliability; as well as top up of oil as required,
- Selective intrusive maintenance to assess equipment condition, check contacts, test components, clean and lubricate, replace seals and complete minor repairs as required, and
- Diagnostic testing which includes: oil analysis for dissolved gas, moisture content, dielectric strength assessment and insulator testing.

The frequencies of these activities vary depending upon the make, model type and condition of the subject equipment. Program expenditure is based on the volume and type of maintenance work required to be completed during the calendar year.

While the demographics and condition of the fleet, as well as the expanding asset base, would typically be indicators of a need for significant increases in these programs, test year expenditures are generally in-line with those from historic and bridge years. This can be achieved through value being realized through a variety of tactics including:

- Shifting to more condition based maintenance (not carrying out costly intrusive maintenance activities until such time that diagnostic testing indicates a condition warranting this inspection),
- Increased Stations Sustaining Capital expenditures, resulting in greater avoided maintenance costs on aged assets that would otherwise require on-going maintenance to preserve equipment reliability,

- Installation of modern technologies with lower life cycle maintenance costs (such as replacing air blast circuit breakers with SF6 breakers which results in a 90% reduction in maintenance costs), and
- Improved ability to bundle activities making the most effective use of outage planning and mobilization of crews.

<u>Corrective Maintenance</u>

Corrective Maintenance work is required to repair equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and unplanned 'demand' work, including emergency response. Planned corrective maintenance addresses defects outside normal preventive maintenance cycles which can be scheduled and perhaps coordinated with other work to leverage efficiencies. Unplanned corrective maintenance results from all unscheduled, non-programmed maintenance necessitated by unforeseen problems and/or equipment failure. Emergency response may include preliminary investigation and minor or make safe repairs following equipment failure. This work is required to address the risk of harm and / or damage to any or all of employee safety, public safety, system reliability or the environment.

As expected, given the unplanned nature of this category of work, there is some variability on the number and severity of corrective maintenance issues addressed each year. However, with the on-going focus on Stations Sustaining Capital to address the worse performing assets, it is anticipated that corrective maintenance will remain in-line with recent historic levels.

<u>500 kV Autotransformer Refurbishments</u>

Refurbishment of the 500 kV autotransformer fleet is required to address the high failure rates of this critical class of equipment. Hydro One Transmission has experienced several 500 kV autotransformer failures on its system. The failure of a 500 kV autotransformer can jeopardize the reliability of the backbone 500 kV system and impact the stability of the electricity system. Interface limits may be affected and/or generation may be constrained. Due to the large amount of energy involved, failures have historically resulted in tank splits and oil spills, creating both safety and environmental hazards.

Investigations, that included third party design reviews, revealed a number of design limitations and highlighted that moisture levels in these units can reach unacceptably high levels leading to catastrophic failure. A remediation program was started in 2006 to address the primary deficiencies and has been successful at reducing the risk of failure until such time the transformers are replaced. As indicated in proceeding EB-2012-0031, further assessment has indicated that there continues to be autotransformers that require varying degrees of modifications to reduce their risk of failure.

<u>115 kV and 230 kV Transformer Refurbishments</u>

Refurbishment of the 115 kV and 230 kV transformer fleet is required to address transformer components, such as: gaskets, gauges, bushings, fans, pumps, etc., that typically require major refurbishment or replacement prior to the expected service life of the transformer. The refurbishments are extensive and include activities such as re-gasketting, replacement or refurbishment of components, painting, and oil processing. These refurbishments are cost effective, and allow the transformer to remain in-service through its expected service life while maintaining equipment and customer reliability.

During the refurbishment, Hydro One Transmission also takes the opportunity to outfit the transformers with modern accessories, leading to various benefits as part of the transformer's life-cycle. For example, modern temperature monitors are installed and wired back to the Ontario Grid Control Centre ("OGCC") to give the operators additional information to make real-time operating decisions with. In the case of transformer temperature, a measured reading is more accurate than a theoretically modelled measurement and may allow for additional transformer loading or alternatively, will ensure that equipment is operating within its ratings as to not unknowingly sacrifice equipment life.

In addition to refurbishments, a number of programs are being implemented to reduce the risk of equipment failure. These programs have been developed as a result of learning from failure investigations or from industry partners. Programs targeted at upgrading fall-arrest safety systems, proactive off-line dry-outs, installation of maintenance-free self-regenerating breathers, installation of under load tapchanger (ULTC) filtration systems, and the planned implementation of manufacturer recommended modifications to ULTCs are examples of such activities.

Breaker Refurbishments

Breaker refurbishments are required to address some specific models of circuit breakers (air blast, oil, GIS, and SF6) to allow them to reach their expected service life. Work planned in the test years focuses on mitigating specific reliability risks to customers or the bulk electricity system. A significant portion of these breaker refurbishment activities are as a result of past failures and the corrective action plans developed during failure investigations. For example, Hydro One Transmission continues to replace a component called the control selector switch on a cohort of breakers known to be at risk. Multiple breakers have been forced out of service due to the failure of this component, and a program has been established to replace the defective elements to reduce the likelihood of impacting customers. The majority of the expenditure in this category of work is specific modifications and upgrades coming as a result of these similar investigations and is performed on air blast, oil, GIS, and SF6 circuit breakers.

Other Maintenance and Inspection Programs

Maintenance activities under this category include nuisance wildlife control, maintenance required for strategic spares and miscellaneous maintenance as outlined below.

Nuisance wildlife control programs are in place to combat the effects of both equipment interruptions and customer outages that can result when wildlife enter Hydro One's transmission stations for various reasons such as shelter, food, breeding and hibernation. Animal related outages have averaged about 25 per year prior to preventive action being taken at targeted sites. The program involves installation of animal controls and barriers to limit the likelihood and consequence associated with animals climbing on electric equipment in a cost effective manner. Since the inception of this industry leading innovative approach, there has been a significant reduction in the number of animal contacts, with outages reduced by about 50% at the targeted sites.

Strategic spares maintenance programs are in place to maintain the inventory of circuit breakers and transformers that support the in-service fleet. The program includes the maintenance required to ensure that these components are available to enable timely response to system component failures and are maintained in a manner that would not to void manufacturer warranties.

Other miscellaneous maintenance programs for power equipment include: capacitor bank maintenance, insulator contamination monitoring and power washing, station string insulator testing program and station asset assessment activities. Although smaller, these activities are important to ensure equipment and customer reliability and manage equipment in a prudent and sustainable manner.

3.3.3 Summary of Expenditures

The overall planned expenditure for power equipment maintenance in 2015 and 2016 is $60.7 million and $59.7 million respectively. This is in line with recent historic spending. Some variations in program spending year over year can be observed, and are generally associated with implementation of specific investments rather than an on-going requirement.

A reduction in this program will result in reduced planned maintenance and refurbishment activities, which are in place to ensure station equipment is operating within specified parameters to ensure the reliability of the transmission system.

3.4 Ancillary Systems Maintenance

3.4.1 Introduction

Ancillary Systems are required at all of Hydro One's transmission stations. These ancillary systems are comprised of station service systems, high pressure air systems, grounding systems, battery and battery charger systems, and oil processing facilities. These systems provide key services and operating support to all of the various station components.

3.4.2 Investment Plan

The ancillary systems maintenance program is divided into three categories. Table 5 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

Table 5
Ancillary Systems Maintenance OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Preventive Maintenance	4.6	4.9	5.4	4.7	4.1	4.0
Corrective Maintenance	4.8	3.5	3.8	4.1	4.1	4.1
Other Maintenance Programs	1.8	1.6	0.9	1.7	1.8	1.8
Total	**11.2**	**10.1**	**10.1**	**10.5**	**10.0**	**10.0**

Preventive Maintenance

Similar to the Power Equipment preventive maintenance program, the preventive maintenance program for Ancillary Systems is founded on RCM principles and is established to allow equipment to reach its expected service life. The maintenance activities include periodic tests and inspections required to satisfy reliability, safety and regulatory requirements. Oversight bodies such as the Technical Standards and Safety Authority, IESO, NPCC, Ministry of Health's *Occupational Health and Safety Act* and the MOE impose these requirements and in some cases mandate specific inspection and testing cycles. The total number of planned maintenance activities per year in ancillary maintenance is in the order of 5,500.

Corrective Maintenance

Similar to the Power Equipment corrective maintenance program, the corrective maintenance program for Ancillary Systems is required to repair equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and unplanned 'demand' work, including emergency response. Corrective maintenance is required to address the risk of harm and / or damage to any or all of employee safety, public safety, system reliability or the environment.

Other Maintenance Programs

Other maintenance activities includes grounding studies, maintenance of Hydro One's oil storage and processing operation at its Central Maintenance Facility, and upgrades to backup diesel generators.

The program also funds the payments for services at facilities shared with OPG or Bruce Power. Hydro One Transmission has a number of sites located within or adjacent to generating stations (Hydraulic, Thermal and Nuclear) where services are purchased directly from the plant in order to maintain switchyard operations. These services include AC/DC station service, water and snow removal. Agreements are in place between Hydro One Transmission and the generating entities with respect to what services are shared and appropriate compensation. Hydro One Transmission is billed on an annual basis for these services.

3.4.3 Summary of Expenditures

The planned expenditure for ancillary systems maintenance in 2015 and 2016 is $10.0 million and $10.0 million respectively. This is a slight decrease from historic spending. The primary factor influencing this positive downward trend is the retirement of air blast circuit breakers which eliminates the need for its ancillary high-pressure air systems which are maintenance intensive. Any further reduction in this program would not be prudent, as the ancillary systems maintenance program is substantially required to satisfy regulatory and/or safety obligations.

3.5 Protection, Control, Monitoring, Metering and Telecommunications Maintenance

3.5.1 Introduction

Protection, Control, Monitoring, Metering and Telecommunications assets are utilized to protect, control and operate the transmission system by sensing and isolating abnormal system conditions, providing real-time operational data and remote equipment control, and capturing detailed records for post-event analysis. The maintenance of these assets is required to sustain equipment performance and maintain compliance with applicable NERC standards.

3.5.2 Investment Plan

The protection, control, monitoring, metering and telecommunications maintenance program is divided into three categories. Table 6 outlines the proposed funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

Table 6
Protection Control, Monitoring, Metering and Telecommunications OM&A
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Protection, Control, Monitoring and Metering Equipment	20.8	19.3	20.4	20.0	19.8	21.2
Cyber Security	3.6	4.9	7.1	8.0	9.3	9.3
Telecommunications	19.4	20.7	21.9	22.1	22.6	23.1
Total	**43.9**	**44.9**	**49.4**	**50.1**	**51.7**	**53.7**

Protection, Control, Monitoring and Metering Equipment

Protection, Control, Monitoring and Metering Equipment maintenance covers the planned and corrective maintenance work required to sustain the performance of protection, control, monitoring and metering equipment.

Protective relays and their associated systems are critical in sensing abnormal system conditions and taking the appropriate actions in response to those conditions. These devices protect local supply, supply within Ontario and the potential impacts of problems on the Hydro One's transmission system to the rest of the interconnected grid.

Wholesale revenue meters are used to measure energy flow between the IESO controlled power grid and metered market participants in accordance with Measurement Canada requirements for transaction settlements.

As such, a significant portion of the Protection, Control, Monitoring and Metering equipment maintenance programs are regulated and non-discretionary. The expenditures for maintenance of Protection, Control, Monitoring and Metering Equipment fall into three activities as outlined in Table 7.

Table 7
Protection, Control, Monitoring and Metering Equipment OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Preventative Maintenance	6.1	5.0	5.3	5.3	4.9	6.1
Corrective Maintenance	7.2	7.3	7.5	6.1	6.2	6.3
Support Processes and Systems	7.5	7.0	7.6	8.6	8.7	8.9
Total	**20.8**	**19.3**	**20.4**	**20.0**	**19.8**	**21.2**

(1) Preventative Maintenance

Preventative Maintenance involves time based routine testing of protection systems and revenue meters. Protection systems spend most of their service life in a dormant state, yet must be relied upon to perform flawlessly during a fault or other abnormal system condition. Routine testing is the only means to maintain a high degree of certainty that the system will operate correctly when called upon. The testing frequency of protection systems that are designated as part of the Bulk Power System are mandated by NPCC guidelines; for the remaining portions of the system Hydro One Transmission follows internal policies that are in accordance with good utility practice.

Revenue Meters require periodic re-verification of their accuracy. These re-verifications are done at a frequency mandated by the *Electricity and Gas Inspection Act* and regulations overseen by Measurement Canada.

Based on the regulation guidelines for testing frequency, there is some variability on the number of protection system and meter tests performed each year.

(2) Corrective Maintenance

All protection, control, monitoring and metering assets experience some rate of failure or defects during their normal useful life. Failures can result in equipment damage as well as wide spread power outages due to the criticality of protection, control, monitoring and metering assets within the system. In addition, this category of work includes addressing problems discovered from analysis of events and defects with certain makes and models of protections which have been identified to be problematic and jeopardize reliability of the electrical system.

Given the unplanned nature of this category of work, there is some variability on the number and severity of corrective maintenance issued addressed each year. However, with the on-going focus on Stations Sustaining Capital to address high risk assets, it is anticipated that corrective maintenance will trend below historic levels.

(3) Support Processes and Systems

Hydro One Transmission maintains a set of support processes and systems for the protection, control, monitoring and metering equipment. The support systems are in place to manage change control of the settings and configuration of protection and control systems, keep records of events, as well as manage the inventory and re-seal schedule for revenue meters. The support processes are in place for carrying out event analyses and follow-up actions, performing routine inspections, managing spare parts and tracking vendor advisories. Hydro One Transmission is incorporating new processes and systems required to meet new or more stringent reliability standards issued by NERC and NPCC, and are in the process of augmenting the condition assessment of protection systems resulting in an increase over historic spending.

Cyber Security

Cyber Security maintenance is required to sustain the systems and facilities in compliance with the NERC Critical Infrastructure Protection (CIP) Standards. Maintenance and system support for Cyber Security includes:

- Maintaining the various Cyber Security assets (e.g. Firewalls, Intrusion Detection Systems, Malware detection systems, Physical Security systems);
- Conducting required annual surveys of critical cyber assets and security perimeters; and
- Managing cyber security systems (e.g. maintaining personnel access lists, patch management, maintaining logs, updating firmware, periodic tests).

As outlined in proceeding EB-2012-0031, the energy sector is categorized as a critical infrastructure by the Canadian and US Federal governments. Acknowledging the importance of protecting the reliability of the interconnected grid, NERC developed an initial set of CIP standards to ensure regular testing and updating of the security systems and procedures for changes that occur in staffing as well as in the transmission assets that require security.

On November 22, 2013 Version 5 of the NERC CIP standards were approved by the Federal Energy Regulatory Commission ("FERC"), extending the applicability of cyber security requirements to additional assets within the Hydro One's transmission system. With the adoption of Version 5, the number of sites for evaluation and inclusion into the NERC CIP cyber security compliance program will increase. Hydro One Transmission will be required to revise change management procedures and increase system management to incorporate these additional requirements.

Telecommunications

Telecommunication systems provide high reliability and high-speed communications required for the protection, monitoring and control of Hydro One's transmission system. Hydro One Transmission's telecommunication system consists of digital fiber-optic networks, power line carrier ("PLC") systems, owned or leased metallic cables, digital microwave, and the associated auxiliary telecommunication equipment for each. The expenditures for telecommunication systems fall into three activities as outlined in Table 8.

Table 8
Telecommunications OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Preventative and Corrective Maintenance	4.5	4.6	5.5	5.4	5.5	5.6
Leased Telecommunication Circuits	8.6	8.9	9.5	9.7	9.8	10.0
Hydro One Telecom Contract	6.2	7.3	6.9	7.1	7.3	7.5
Total	**19.4**	**20.7**	**21.9**	**22.1**	**22.6**	**23.1**

(1) Preventative and Corrective Maintenance

Preventative and corrective maintenance is required to sustain power system telecommunication assets. Hydro One Transmission's telecommunication assets include the terminal equipment for PLC systems, synchronous optical networking equipment, multiplexors, neutralizing transformers, tone equipment, radios and DC power supply for these devices, as well as the microwave radio towers. The maintenance program for these telecommunication assets includes the re-verification of equipment that supports protection systems directly, inspections, repairs and emergency work as well as replenishing spare parts inventories.

(2) Leased Telecommunication Circuits

Hydro One Transmission leases telecommunication circuits in order to support the telecommunication requirements for protection and control of the power system. This program covers the monthly fees associated with leasing of the telecommunication circuits as well as for the provincial mobile radio system. This program is also subject to tariffs for telecommunication services as approved and regulated by the Canadian Radio-television Telecommunications Commission ("CRTC"). With the increasing deployment of new protection, control and monitoring equipment, the number of leased telecommunications circuits and circuit capacity required to support the power system is also increasing.

(3) Hydro One Telecom Contract

Hydro One Networks receives monitoring and alarm response for power system telecommunication circuits, outage management, vendor management, and system analysis services under contract from Hydro One Telecom ("HOT"). This program covers the payment to HOT for these contracted services, as well as the services related to updating the computer systems used in the management of the telecommunications circuits provided by HOT.

3.5.3 Summary of Expenditures

The overall planned expenditure for protection, control, monitoring, metering and telecommunications maintenance in 2015 and 2016 is $51.7 million and $53.7 million respectively. This represents an increase of 3% in 2015 over the bridge year 2014 and an increase of 4% in 2016 over the test year 2015. The main factors contributing to this increase are:

- Cyber Security with the increased change and system management work required due to the expanded applicability of Version 5 of the NERC CIP cyber security requirements to Hydro One Transmission assets, and

- Telecommunication Systems with the increased new and upgraded leased telecommunications services required to support protection, control, monitoring and metering equipment.

A reduction in this program may compromise Hydro One Transmission's ability to comply with reliability and cyber security regulations and result in an increase in equipment failures causing one or more of the following: equipment outages, equipment damage, load interruption and wide spread interruption to the interconnected electrical system.

3.6 Site Infrastructure Maintenance

3.6.1 Introduction

Hydro One Transmission's site facilities and infrastructure systems are comprised of yard drainage, fire protection and detection, structural footings, station buildings, cranes, elevators, heating ventilation and air-conditioning ("HVAC") systems, access roads, water supplies, sewage management, and fences at transmission stations. These systems provide infrastructure and support services to all other station components, prevent unauthorized access, and make the station site functional for equipment and staff.

3.6.2 Investment Plan

The Site Infrastructure Maintenance program is focused on the planned and corrective maintenance at transmission stations to ensure that these site facilities and infrastructure systems remain in a safe condition and in compliance with regulations.

The program is extensively driven by assessment of data collected, demand work, as well as regulatory requirements (such as building and fire codes, the *Occupational Health and*

Safety Act and the Ministry of Environment requirements, as well as community by-laws) and corporate standards. The program is divided into three categories. Table 9 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years.

Table 9
Site Infrastructure Maintenance OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Facilities and Infrastructure Maintenance	22.0	18.5	20.3	21.4	21.9	22.4
Grounds Maintenance	4.0	3.4	3.4	5.0	5.1	5.3
Site Perimeter Maintenance	0.4	0.7	1.4	1.4	1.5	1.5
Total	**26.4**	**22.7**	**25.2**	**27.8**	**28.5**	**29.3**

Facilities and Infrastructure Maintenance

This program is focused on the preventative and corrective maintenance of the facilities and infrastructure at the transmission stations. Data and information on the condition of station sites and buildings is collected through regular inspections, as well as information gathered during maintenance work and trouble call response. Contracted inspections and asset surveys are also conducted.

The preventive maintenance program for site facilities and infrastructure addresses a wide variety of activities such as: building maintenance and facility improvements; HVAC maintenance; inspections; janitorial services; water system maintenance and testing; roads, bridges and railway maintenance; station civil geotechnical inspections and maintenance; and asset assessments.

The corrective maintenance program addresses demand work including trouble calls and identified defects related to station infrastructure facilities.

Grounds Maintenance

Grounds maintenance involves the application of herbicides to control weeds and vegetation inside Hydro One's transmission stations. Weed and vegetation control is required to keep step and touch voltages at safe levels for workers and others that enter the station. In addition, grounds maintenance includes snow removal to allow access to and within a station, grass cutting, clean-up and general maintenance that may be required for site drainage and grading.

Site Perimeter Maintenance

The site perimeter maintenance program includes preventive and corrective maintenance at station perimeters, (e.g., fences and gates) to prevent unauthorized access, perimeter measures to keep animals out of stations and reduce likelihood of power interruptions due to animal contact. The activities under this program complement broader corporate security initiatives targeted at safeguarding transmission assets to ensure public and employee safety and maintain equipment and system reliability.

3.6.3 Summary of Expenditures

The planned expenditure for site in 2015 and 2016 is $28.5 million and $29.3 million respectively. This represents an increase of less than 3% in 2015 over the bridge year 2014 and a similar increase in 2016 over the test year 2015. However, this represents an average increase of approximately 17% compared to the historic years. The increase from the historic years is a result of on-going work to address deficiencies with Hydro One's building infrastructure that pose a risk to reliability if not remedied (i.e. leaking roofs, basements, etc.) as well as additional work to maintain station perimeter fences to keep unauthorized individuals and animals out of stations.

A reduction in this program will result in increased number building infrastructure or station perimeter defects going unresolved, which can lead to events impacting the customer or system reliability.

4.0 LINES

Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or to local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One's transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV. Hydro One's transmission system consists of approximately 30,000 circuit km of overhead transmission lines located on about 21,000 km of rights-of-way, and 290 circuit km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shieldwire, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems and grounding systems. The underground transmission lines are generally located in large urban centres.

Lines Sustaining OM&A funding covers expenditures required to maintain existing overhead and underground transmission lines assets. Hydro One Transmission manages its Lines Sustaining OM&A program by dividing the program into three categories:

1. Vegetation Management, which ensures that clearances to energized equipment are maintained and includes brush control, line clearing, condition patrol, demand maintenance and ground maintenance.

2. Overhead Lines Maintenance, which focuses on inspections and testing of overhead lines components to identify defects as well as emergency response and minor component replacement programs.

3. Underground Cable Maintenance, which focuses on inspections, analysis, tests, surveys and diagnostics of cables, vaults, jackets and potheads as well as condition and route patrols, and corrective maintenance.

Required funding for the test years 2015 and 2016, along with spending levels for the bridge and historic years are provided in Table 10 for each category.

Table 10
Lines Sustaining OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Vegetation Management	26.6	27.1	31.1	32.2	32.8	33.2
Overhead Lines Maintenance	16.1	17.9	15.7	21.9	20.2	20.7
Underground Cable Maintenance	6.6	3.6	3.6	4.7	4.8	4.9
Total	**49.4**	**48.6**	**50.4**	**58.8**	**57.8**	**58.8**

The overall Lines Sustaining OM&A expenditures for the test years 2015 and 2016 are in line with the 2014 requirement. However, this represents an average increase of 20% compared to the historic years. Increases from historic years are to account for additional vegetation management inspections required by the NERC standard and additional line clearing and brush control to meet target clearing cycles. There is also a requirement to carry out increased levels of conductor and shieldwire testing and to replace defective u-bolts and conductor dampers.

4.1 Vegetation Management

4.1.1 Introduction

Hydro One Transmission has approximately 30,000 circuit km of overhead transmission lines located on about 21,000 km of rights-of-way. These lands contain varying types of vegetation, from forests to grass lands, some of which can grow into the proximity of transmission lines and threaten system reliability. To ensure a sustainable level of reliability, a vegetation management program is required to ensure that clearances between vegetation and energized equipment are maintained. The program controls vegetation growth in a manner that considers environmental, ecological and social impacts, while responding to reliability and landowners concerns.

4.1.2 Investment Plan

The vegetation management program is divided into six categories. Table 11 outlines the proposed funding for the test years 2015 and 2016; along with the spending levels for the bridge and historic years for each category.

Table 11
Vegetation Management OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Brush Control	17.0	15.5	19.8	18.3	18.6	19.0
Line Clearing	4.3	5.3	5.2	6.4	6.5	6.4
Property Owner Contact	1.2	1.3	1.2	1.8	1.8	1.8
Condition Patrols	1.3	1.4	1.6	1.6	1.6	1.6
Demand Maintenance	1.0	1.4	0.9	1.4	1.4	1.4
Grounds Maintenance	1.9	2.2	2.3	2.8	2.9	2.9
Total	**26.6**	**27.1**	**31.1**	**32.2**	**32.8**	**33.2**

Brush Control

Brush control refers to managing the growth of vegetation on the rights-of-way to ensure the vegetation does not grow to a height that would cause an outage to the transmission line. The brush control also maintains access along the rights-of-way for inspection, maintenance activities, and emergency response. A number of different methods are used to manage rights-of-way vegetation, including selective herbicide application, species management, and mechanical brushing.

Line Clearing

Line clearing refers to the activity of assessing and removing "Danger Trees" that grow at the side of the right-of-way or on the right-of-way as well as trimming of any trees that may pose a threat to the line. Danger trees are trees of questionable soundness and health, which could fall and contact line conductors, causing an outage. In some cases, removed trees are replaced with compatible vegetation to address local and environmental concerns. Line clearing is carried out as a separate activity from brush control, as it requires a higher level of skill to identify and remove trees that may jeopardize the security of a transmission line.

The activities of brush control and line clearing must comply with the requirements of the NERC Vegetation Management Standard (FAC-003-2) which were established to prevent blackout reoccurrences.

Brush control and line clearing are generally performed on a cyclical basis as rights-of-way are maintained on approximately, 6 and 8 year cycles depending on the region and its associated growth cycle (i.e. climate, species composition, etc.) These cycle lengths have been evaluated over time and are considered to be appropriate for the Hydro One transmission system, as they provide a cost-effective and sustainable level of reliability and are generally consistent with past accomplishment.

<u>Property Owner Contact</u>

Property Owner Contact is undertaken to acquire approval for access onto private property, obtain input concerning any restrictions and environmental concerns, and to communicate maintenance plans to property owners. During this activity, job planning and project layouts are completed, a detailed work package is prepared, and approvals are obtained from stakeholders such as property owners, municipalities, and the Ministry of Natural Resources where applicable. This work is done in conjunction with the line clearing and brush control programs, thus any increase in these programs or their complexity with respect to number of property owners, will have a direct impact on the volume of property owner contacts.

Condition Patrols

Condition patrols are conducted along rights-of-way to identify, assess and document potential risks to the security of a line, as well as to obtain information concerning the condition of the vegetation on rights-of-way. Patrols are carried out typically mid-cycle by experienced staff to assess the condition of the rights-of-way and schedule the removal of vegetation that may pose a threat before the next clearing cycle. A mid-cycle condition patrol is considered optimal as it strikes a balance between having to forecast too much future growth in order to schedule the next set of maintenance activities and the risk of leaving excessive growth on the system too long.

During the patrol, data is captured on vegetation growth rates, quantities of danger trees, species of brush and trees, and clearance conditions. Analysis of condition patrol data provides an indication of growth rates, clearances, and other vegetation conditions that will need to be addressed. Vegetation that poses a threat prior to the next scheduled line clearing or brush control treatment is addressed to ensure the reliability of the electrical system. Similarly, if a right-of-way is found to be in good condition despite not having been maintained for a lengthy period of time, then the line clearing and brush control schedule may be lengthened.

In addition to the condition patrols, Hydro One Transmission will be required to inspect applicable lines annually as outlined in the recent revision to the NERC Vegetation Management Standard (FAC-003-2); which became enforceable in 2014.

Demand Maintenance

Demand maintenance work is required to address vegetation management issues that cannot wait until the next scheduled line clearing or brush control maintenance. Issues addressed through demand maintenance arise as a result of problems identified by the public, storm damage, urban development, tree caused outages and problems identified during annual and condition patrols.

Grounds Maintenance

Grounds maintenance includes activities on transmission rights-of-ways such as grass cutting in urban areas, security patrols, maintenance of access barriers and fences, snow removal, and garbage removal. Maintenance is undertaken in consideration of regulatory requirements, local by-laws, and customer requirements. For example, grass cutting must be carried out during the growing season to comply with local by-laws with respect to weed control.

4.1.3 Summary of Expenditures

The overall planned expenditure for vegetation management in 2015 and 2016 is $32.8 million and $33.2 million respectively. This represents an average increase of 20% compared to the historic years, but is generally in-line with the 2014 bridge year expenditures of $32.2 million. The increase from the historic years is a result of the additional inspections required by the NERC Vegetation Management Standard as well as the requirement to perform additional line clearing and brush control to meet target clearing cycles.

A reduction in this program would result in an increased risk of trees and brush encroaching on the minimum clearance distances potentially resulting in outages and regulatory intervention with fines, as well as a decline in customer and system reliability.

4.2 Overhead Lines Maintenance

4.2.1 Introduction

The overhead lines maintenance program is required to maintain the reliability of transmission lines, address safety issues, meet regulatory requirements, and ensure the financial long term viability of the overhead lines system. The program includes activities such as overhead lines inspections to identify defects, emergency response, and the gathering of information that will enable funding to be allocated on a priority basis to maximize the life of the lines assets and maintain performance. The program also provides for repair or replacement of defective equipment and components.

4.2.2 Investment Plan

The Overhead Lines Maintenance program is divided into three activities. Table 12 outlines the proposed funding for the test years 2015 and 2016; along with the spending levels for the bridge and historic years for each category.

Table 12
Overhead Line Maintenance OM&A
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Preventive Maintenance and Asset Assessment	9.0	9.1	7.9	10.0	10.3	10.5
Demand Maintenance	2.9	3.2	3.2	3.4	3.5	3.6
Planned Corrective Maintenance and Projects	4.2	5.6	4.6	8.4	6.4	6.6
Total	**16.1**	**17.9**	**15.7**	**21.9**	**20.2**	**20.7**

<u>Preventive Maintenance and Asset Assessment</u>

Preventive maintenance and asset assessment encompasses a number of activities that are undertaken to keep lines assets in working order and to identify conditions that may impact their operation and reliability, as well as acquiring condition information needed to identify components in need of replacement or refurbishment.

The preventive maintenance activities include foot, helicopter and thermovision patrols; insulator washing; switch maintenance; and the assessment of various transmission line components that include poles, steel towers, insulators, conductors, shieldwires, anchors, and guys. The patrols identify any public safety issues and defects that may jeopardize customer and system reliability. Annual patrols are undertaken by helicopter but in areas where flight restrictions exist, lines are patrolled on foot. The thermovision patrols are carried out with the purpose of identifying “hot spots” (e.g. loose connections) that put line components at risk of failure and that are not visible to the naked eye. Predicting imminent failures has tremendous reliability benefits and as a result, thermovision patrols are conducted on an average 3-year cycle. More critical lines such as those on the 500 kV system, inter-ties (i.e. inter-provincial or international lines), and those servicing critical generating plants have thermovision patrols conducted on an annual basis.

Asset assessment includes a number of activities that have been designed to provide the information needed to manage the transmission lines system and to identify defects that jeopardize public and worker safety and the reliability of the system. Specific activities include:

- Steel tower assessments to examine tower components above ground and at the ground line. Assessments are carried out on those lines that show signs of noticeable corrosion and that have structures in swamps, standing water or are located in known corrosive areas.

- Shieldwire and conductor testing to target conductors that have been in service for more than 50 years and shieldwires in service for more than 30 years. Once tested, those conductors and shieldwires determined to be at end of life, and pose a risk to the reliability of the system as well as a hazard to the public and employees, are scheduled for replacement under the appropriate capital programs.
- Insulator testing is conducted on specific line sections where annual assessments of reliability performance or patrol observations suggest insulator conditions may be deteriorating.
- Periodic field survey of electrical clearances of transmission lines to ensure that clearances are adequate for current operating conditions, or in response to proposed increases in operating conditions.
- Wood pole line assessments that involve detailed helicopter inspections of the condition of cross-arms and pole tops, and individual pole testing to evaluate the soundness of the wood near the ground line. The lines selected for detailed helicopter inspections are identified based on accessibility, pole ages, and reliability information.

Wherever possible, assessment activities are scheduled in a complementary fashion such that cyclical and non-cyclical needs are addressed as efficiently as possible. For example, a line section that requires pole and cross-arm assessments will be scheduled for a detailed helicopter patrol and pole testing such that both assessments are met and the need for the separate cyclical helicopter patrol is avoided.

<u>Demand Maintenance</u>

Demand maintenance is needed to respond to emerging problems and to restore power should it become necessary. Lightning storms, ice build-up on lines and high winds can result in the failure of transmission line components, which requires immediate response and repair. This program also addresses problems identified during line patrols that need a short term response to prevent a potential outage or to address a serious safety issue. This program is reactive in nature and varies due to weather, equipment deterioration and equipment failures.

Planned Corrective Maintenance and Projects

The planned corrective maintenance and projects program includes minor corrective work, larger scale projects, as well as technical support to resolve reliability problems with transmission line assets. The planned corrective maintenance activities and projects are developed using the data collected through the patrols and asset assessment activities, as well as information on equipment reliability performance, and findings of expert analysis.

Planned corrective maintenance addresses ground wire replacements, clearance corrections, and planned defect corrections such as: loose guy wires, broken strands of conductor, damaged insulator strings, dislodged tower members, and broken ground wire.

The larger scale projects address wide spread design, manufacturing, or condition deficiencies; or safety and reliability concerns. Maintenance of this type is targeted to specific locations that have been identified as high risk. Some of the activities include:

- Replacement of worn u-bolts that support the insulator strings and conductors,
- Replacement of dampers that limit vibration of conductor,
- Addition of tower anchor bolt security to deter vandalism,
- Installation of anti-climbing barriers to prevent public access to towers, and
- Replacement of conductor to address damage on several lines as a result of vibrations stemming from aged defective conductor “torsional” damping devices.

4.2.3 Summary of Expenditures

The overall planned expenditure for the overhead lines program in 2015 and 2016 is $20.2 million and $20.7 million respectively. This represents an average decrease of 7% compared with the 2014 bridge year but a marked increase over historic years. The increase from the historic years is to address worn and defective u-bolts and dampers identified in the system; as well as to carry out additional conductor and shieldwire sampling and testing on the aging conductor population.

A reduction in this program will result in defects remaining on the system for extended periods of time and thereby increasing the likelihood of failures resulting in increased reliability risks and public safety issues.

4.3 Underground Cable Maintenance

4.3.1 Introduction

Hydro One Transmission's high voltage underground ("HVUG") cable system consists of 115 kV and 230 kV cables. Underground cables are located in the urban centres of Toronto, Hamilton and Ottawa, with short sections in London, Sarnia, Picton, Windsor and Thunder Bay.

This program reduces the risk of cable equipment failure which can seriously impact service and reliability to a large number of urban areas. The activities within this program ensure that corrective action is taken when component failure is imminent or when defects are discovered during routine inspections, Hydro One Transmission provides timely response to external requests for a cable locate, and the integrity of the cable is maintained by performing cable diagnostics which provide an indication of the state of the cable components since most of the underground facilities are not visible or easily accessible.

4.3.2 Investment Plan

The Underground Cable Maintenance program is divided into three activities. Table 13 outlines the proposed funding levels for the test years 2015 and 2016; along with the spending levels for the bridge and historic years for each category.

Table 13
Underground Cable Maintenance OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Cable Locates	0.8	1.4	1.2	1.2	1.2	1.3
Preventative Maintenance	0.7	0.4	0.9	1.1	1.1	1.2
Corrective Maintenance	5.1	1.8	1.6	2.4	2.5	2.5
Total	**6.6**	**3.6**	**3.6**	**4.7**	**4.8**	**4.9**

Cable Locates

This program responds to external requests for locating Hydro One Transmission's underground cable facilities. Responding to these requests is in everyone's best interest as anyone excavating near a cable may cause damage to these costly assets and harm themselves or members of the public. Hydro One Transmission uses the services of "Ontario One Call" to field requests for cable locates and then completes the field identification as required.

This program is driven by external demand and the costs are not recovered by end use charges, which is consistent with the practice of other utilities. The "no fee" policy is in place to encourage contractors to make use of the service and avoid costly and hazardous situations. The forecast for the future volume of cable locates is based on the analysis of the historical number of requests.

Preventive Maintenance

Preventative Maintenance activities are aimed at determining cable condition and ensuring system reliability. Underground cables are made of a number of components and subsystems, the condition of which can deteriorate during the cables' service life.

Underground cable condition information is determined through a number of activities as listed below.

- Condition patrols focused on underground cables and their auxiliary systems such as the oil pumping plants and cathodic rectifiers.
- Cable pipe polarization spot checks to monitor the corrosion protection that is installed on the cable pipes.
- Cable pipe corrosion surveys on the protective steel pipes that protect many of Hydro One's Transmission cables.
- Oil testing and analysis to determine if there is any accumulation of dissolved gases in the insulating oil, which may be a sign of deteriorating condition.
- Route patrols at ground level to look for any unknown excavations near the cables or any evidence of oil leaks that would indicate a breach in the piping system.
- Jacket tests on cables in the system that are not protected by a steel pipe. These include oil filled cables protected by a metallic sheath and an outer polyethylene jacket.
- Infrared tests on cable components called potheads, which mark the transition of a conductor from overhead to underground, to determine if the materials that make up the pothead are exceeding thermal limits.
- Vault inspections on cable systems having splice locations that are enclosed in a concrete vault.

- Cable diagnostic activities to assess condition and maintain reliability of the cable systems. Tests include oil leak detection, sheath current measurements and laboratory insulation assessment.

The large majority of preventative maintenance activities are cyclical in nature (e.g. route patrols are conducted twice per month). However, condition data and reliability performance may drive the need to adjust the frequency of maintenance activities for specific cables that may be a source of concern.

Corrective Maintenance

Corrective maintenance work includes repairs of defects discovered through preventative maintenance activities, and may involve repairing oil leaks, coating of cable terminations, repairing of cable sheath and pipe coating, and topping up oil levels. These repairs are essential to keep the cables and their associated components in a reliable state of operation.

The activities included under corrective maintenance are primarily reactive and demand in nature, but also include planned corrective activities. Planned corrective work is done where problems arise and there is adequate time to correct defects without significantly jeopardizing reliability and safety. Planned corrective work includes removal and replacement of oil that has unacceptable concentrations of harmful gases, sheath repairs that have been damaged through corrosion, and adjustment and repairs to monitoring equipment.

4.3.3 Summary of Expenditures

The overall planned expenditure for the underground cable program in 2015 and 2016 is $4.8 million and $4.9 million respectively. This represents an average increase of 5% compared to the historic years, but is generally in-line with the 2014 bridge year expenditures of $4.7 million. This increase is required to complete a backlog of more time consuming and complex activities, such as cable jacket tests and polarization surveys on the cable sheaths and pipes which are cycle driven, outage dependent and are critical in order to maintain the expected service life of these aging assets. The corrective costs which are demand driven in the test years 2015 and 2016 are in line with the average costs during the historic years.

A reduction in this program will limit the ability to detect and repair defects, which will shorten the life expectancy of these critical assets, and will cause premature deterioration leading to oil leaks, insulation damage and loss of supply to critical customers in the major urban centres of Ontario. It will also increase environmental risks associated with an increase in oil leaks from these aging cables.

5.0 ENGINEERING AND ENVIRONMENTAL SUPPORT

5.1 Introduction

The engineering and environmental support program is in place to support activities, including management of records and drawings, CAD drawing support, data base management and provision of specific technical information (e.g. preliminary costing of potential investments for selecting the most cost-effective alternative). In addition, this program funds technical support including specialized studies, outage assessments conducted by the IESO, event investigation and incidents response and external consulting services that provide technical expertise not available within Hydro One Transmission.

5.2 Investment Plan

This program is primarily driven by demand and the level work required support the transmission capital work programs. As the capital work program increases, the level of support required is impacted as these projects will require drawings, and in-turn increased drawing maintenance. The technical support and specialized studies are completed on an ad-hoc basis to aid in the decision making process for capital investments.

Table 14 outlines the proposed funding levels for the test years 2015 and 2016; along with the spending levels for the bridge and historic years.

Table 14
Engineering and Environmental Support OM&A
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Engineering and Environmental Support	12.0	9.5	10.7	11.9	11.9	10.8
Total	**12.0**	**9.5**	**10.7**	**11.9**	**11.9**	**10.8**

This program is reviewed annually to assess the level of engineering and environmental support needs to recognize any incremental requirements related to the magnitude and scope of the planned transmission work programs.

5.3 Summary of Expenditures

The planned expenditure for the engineering and environmental support program in 2015 and 2016 is $11.9 million and $10.8 million respectively. This represents an average increase of 6% over the historic years, but is in-line with the 2014 bridge year expenditures of $11.9 million. This increase is required to complete risk assessments and engineering studies of arc flash hazards within Hydro One's transmission stations. These studies are required to ensure safety of employees through identification of potentially unmitigated arc flash hazards and establishment of appropriate barriers and controls. These studies are consistent with the content of the CSA Z462 standard for *Workplace Electrical Safety*. A reduction in this program will result in deferral of these studies to identify and manage safety risks.

SUMMARY OF COMMON CORPORATE COSTS OM&A

Hydro One Common Corporate Costs OM&A is comprised of Common Corporate Functions and Services ("CCFS"), Asset Management Services, Information Technology ("IT"), Cornerstone, Cost of Sales to external parties and Other OM&A.

CCFS includes Corporate Management, Finance, Human Resources, Corporate Communications, Legal, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate. Common Asset Management services include System Investment and Asset Stewardship and Strategies. IT and Cornerstone activities include providing and managing computer systems and installing enterprise IT systems. Other OM&A includes the capitalized overhead credit, the environmental provision credit, indirect depreciation and other costs.

Hydro One utilizes a centralized shared services model to deliver its common services to the Transmission and Distribution businesses within Hydro One Networks Inc., and to the legal entities Hydro One Inc., Hydro One Telecom Inc., Hydro One Networks Brampton Inc., and Hydro One Remote Communities Inc. Many organizations have adopted a common corporate cost model as an effective method of delivering common services to multiple subsidiaries and/or multiple business units. Hydro One adopted this model when it was established in 1999. The additional cost to establish the common functions in each of its subsidiaries would be cost prohibitive.

Table 1 summarizes the Transmission portion of the Common Corporate Cost and Other OM&A Costs over the Historic, Bridge and Test years.

Table 1
Allocated Transmission Corporate common costs and Other OM&A Costs
($ Millions)

Description	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Common Corporate Functions and Services	74.0	80.5	87.7	98.1	96.9	96.4
Asset Management	25.0	32.3	31.8	37.5	37.2	35.7
Information Technology	57.6	60.7	61.1	65.2	63.5	63.5
Cost of Sales	12.8	11.4	13.9	6.8	6.7	6.8
Other OM&A	(125.1)	(104.2)	(118.6)	(136.9)	(134.0)	(131.1)
Total	**44.2**	**80.7**	**75.8**	**70.6**	**70.2**	**71.3**

In the 2009-2014 period, Hydro One applied a cost allocation methodology developed by Black and Veatch Corporation (B&V) which utilizes a breakdown of activities and drivers. In 2013, the Company commissioned B&V to update the methodology to allocate common costs among the business entities using the common services, as discussed in Exhibit C1, Tab 6, Schedule 1. The approach utilizes a further breakdown of activities and drivers and is used in this proposed application.

The increase in OM&A spending in the test years 2015 through 2016 as compared to the historical years is primarily related to the trends described below.

- CCFS costs increase over the test years due to increased HR support for expanded field work programs and succession planning, long-term relationship building with First Nations and Métis communities and funding for the corporate records management project. See Exhibit C1, Tab 3, Schedule 3 for details.

- The work undertaken by Asset Management is expected to increase. Asset Management costs should benefit from productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for the organization. See Exhibit C1, Tab 3, Schedule 4 for details.

- Other OM&A consists of credits associated with capitalized overheads, environmental provisions, indirect depreciation and Other Costs. These credits are explained in Exhibit C1, Tab 3, Schedule 3, Section 3.

COMMON CORPORATE FUNCTIONS AND SERVICES AND OTHER OM&A

1.0 OVERVIEW

Hydro One Networks has identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication. These costs are referred to as Common Corporate Functions and Services ("CCFS"). Included in this exhibit is a discussion of CCFS costs and activities as well as Other OM&A which is comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs.

2.0 COMMON CORPORATE FUNCTIONS AND SERVICES

Table 1 presents, for comparison purposes, the total CCFS costs over the Historic, Bridge and Test years as well as the 2015 and 2016 Hydro One Transmission allocation amounts.

Table 1
Total 2011 - 2016 CCFS Costs and 2015 - 2016
Allocation to Transmission ($ Millions)

Description	Historic Years			Bridge Year	Test Years		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Corporate Management	5.1	5.0	4.9	5.3	5.4	5.4	2.8	2.8
Finance	31.9	35.2	41.9	45.0	44.6	43.8	25.3	24.9
Human Resources	11.0	9.9	11.1	13.1	13.0	12.2	6.9	6.5
Corporate Communications & Services	8.7	11.3	15.0	13.9	12.6	12.6	5.9	5.9
General Counsel and Secretariat	7.4	8.8	9.6	10.1	10.2	10.2	5.4	5.4
Regulatory Affairs	20.1	20.6	20.6	24.1	21.5	22.4	9.3	9.8
Security Management	3.0	3.1	3.4	4.8	4.8	4.6	2.2	2.1
Internal Audit	3.1	3.5	3.4	3.6	3.6	3.6	2.4	2.4
Real Estate & Facilities	51.6	54.6	54.1	60.2	61.4	61.3	36.6	36.6
Total CCF&S Costs	**141.9**	**152.0**	**164.0**	**180.1**	**177.1**	**176.1**	**96.8**	**96.4**

Total CCFS costs increase by $13.1 million from 2013 to 2015 primarily due to the following factors: higher Real Estate costs for additional work space as a result of the growth in the company's work program, increased Finance costs as a result of additional work functions being transferred to the Corporate Controller group previously in other groups and higher Corporate Security and Human Resource expenses. These increases are partially offset by decreased costs related to Outsourcing Contract Management.

From 2015 to 2016, total CCFS costs decrease by $1.0 million primarily due to a decrease in Finance and Human Resource costs.

Details on costs and work in each CCFS function are provided in the following sections.

2.1 Corporate Management

The following Table 2 provides a summary of Corporate Management costs:

Table 2
Corporate Management Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Total Cost	5.1	5.0	4.9	5.3	5.4	5.4	2.8	2.8

Corporate Management represents those functions responsible for providing overall strategic direction to the corporation, including the Board of Directors, Chief Executive Officer ("CEO"), Treasurer's Office, Chief Financial Officer ("CFO") and General Counsel and Corporate Secretariat.

The General Counsel and Corporate Secretariat function provides advice and support to the Board of Directors and Corporate Officers. It provides advice and training, reports on Code of Conduct, reports on activities related to the *Freedom of Information and Protection of Privacy Act* (Ontario) as well as the *Personal Information Protection & Electronic Documents Act* (Canada).

The CFO is responsible for overseeing the finance function and for reporting information to Hydro One Inc.'s subsidiaries, regulators, investors and the shareholder. This includes reviewing and approving financial and investment decisions, business and strategic plans and ensuring the integrity of, and compliance with, internal controls over regulatory, financial and accounting activities.

The allocation of the costs associated with the activities of Corporate Management are governed by service level agreements between Hydro One Inc., Hydro One Networks and their affiliates as outlined in Exhibit A, Tab 9, Schedule 3. This exhibit also describes the activities performed by Hydro One Inc., Hydro One Networks and the amounts allocated to the various subsidiaries.

2.2 Finance

Table 3 provides a summary of finance costs.

Table 3
Finance Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Total Cost	31.9	35.2	41.9	45.0	44.6	43.8	25.3	24.9

2.2.1 Overview

Finance provides strategic advice and services related to planning, processing, recording, reporting and monitoring all financial transactions taking place within the organization. Clients include parties which are both internal and external to the organization, depending on the service provided. Services are provided through the following specialist functions:

- Corporate Controller;
- Corporate Tax; and
- Treasury.

2.2.2 Corporate Controller

The Corporate Controller provides leadership and direction regarding all business planning, performance management, financial reporting, accounting and internal control policies and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles.

This function oversees the development of actual and forecast financial information and manages reporting processes for appropriate audiences or stakeholders. This function is also responsible for managing and providing direction to the company on internal control matters, employing measures such as “organization authority registers” and financial policies and procedures. It also provides leadership on compliance with Ontario securities laws, including Bill 198, and the Multi-Jurisdictional Disclosure System (“MJDS”) rules for a foreign-issuer registered with the U.S. Securities Exchange Commission (“SEC”).

The Corporate Controller function is responsible for establishing and leading the annual business planning and budgeting processes and for presenting the plan to the Board of Directors and the Provincial Government. This function is also responsible for developing and leading strategies and plans that support corporate goals related to the transmission and distribution businesses. This involves conducting special studies in areas like corporate performance, including reliability performance, benchmarking, work program performance, productivity, and cost savings management. Lastly, the Corporate Controller function performs services such as business case review, business valuation, transaction support, and develops and maintains financial models and provides analytical support for a variety of financial planning and reporting processes.
Many routine financial services are outsourced to a third party supplier, such as accounts payable, accounts receivable, fixed asset accounting, general accounting, planning budgeting and reporting support, pension support, human resources pay services and a

number of administrative procedures. The costs of these services comprise a major portion of the Corporate Controller costs.

The total cost of Corporate Controller activities in 2015 is $37.9 million and, in 2016, $37.0 million. The portion allocated to Hydro One Transmission is $21.6 million in 2015 and $21.1 million in 2016.

Corporate Controller costs increased by $7.9 million in 2013 and a further $1.5 million in 2014, mainly due to the addition of certain functions to the Corporate Controller organization made after company filed its transmission rate application EB-2012-0031. In 2013, additional functions were added to the Corporate Controller organization: the performance reporting functions previously included in the Business Performance category within Asset Management, and the Time Reporting Centre and Corporate Charge Card Compliance functions previously included in work program costs. In 2014, Work Management and Project Accounting Specialists were moved to the Corporate Controller's organization. These transfers were made to better align the finance function within the Corporate Controller organization. Beginning in 2016, costs are expected to decrease due to process streamlining, productivity improvements and a decline in outsourcing fees.

2.2.3 Corporate Tax

Corporate Tax manages the tax affairs (compliance, audits and planning), for each taxable entity within the Hydro One group of companies. This includes corporate income taxes, harmonized sales tax (previously, goods and services tax and provincial sales tax), debt retirement charge, payroll and non-resident withholding tax, and the employer health tax. Corporate Tax ensures that internal and external tax compliance requirements are met. Moreover, Corporate Tax provides tax consulting services to other departments with respect to mergers and acquisitions activities, payroll tax, taxable benefits, agreements, financing, and all transactions and information about tax costs for regulatory purposes.

The costs associated with Corporate Tax activities are $2.4 million in 2015 and 2016, with $1.2 million being charged to Transmission annually.

2.2.4 Treasury and Risk

Total annual treasury costs are $6.5 million in 2015 and $6.6 million in 2016. Of these amounts, $2.7 million is incurred annually to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, banks and debt covenants;
- manage the company's daily liquidity position, control cash and manage the company's bank accounts;
- settle all transactions and manage the relationship with creditors;
- communicate with debt investors, banks and credit rating agencies;
- develop business risk management policies, frameworks and processes;
- introduce and promote new techniques for assisting management to identify and evaluate risks within operations;
- prepare corporate risk assessments; and
- maintain a framework of key business risks.

A portion of the Treasury budget is recovered through the cost of long-term debt, as stated in Exhibit B1, Tab 2, Schedule 1.

The remaining $3.7 million for 2015 and $3.8 million for 2016 include costs relating to risk assessment, the negotiation and purchase of insurance policies, and claims management and settlement. These costs cover premiums paid for corporate shared services insurance coverage, including third party liability, fiduciary liability, and directors and officers insurance. They also include the cost of self-insurance for liability exposures that are either not covered by insurance policies or fall below the specified deductibles. The cost of other insurance coverage is paid for and reported by the lines of business to whom the coverage is applicable.

Hydro One Transmission accounts for $2.5 million of the Treasury budget for 2015 and $2.5 million of the budget for 2016.

Table 4 shows the premiums for all of Hydro One Inc.'s insurance policies and the cost of self-insurance for the 2011 to 2016 period. Self-insurance costs for the 2015 and 2016 period take into consideration the company's risks exposures, the long-term historical claims experience, the deductible on the liability policies and the costs of insuring the self-insured exposures. The main driver for self-insurance costs are claims by third parties which can fluctuate from year to year.

Table 4
Hydro One Inc. Insurance Costs ($ Millions)

Description	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Premiums paid for Corporate Functions and Services Insurance Policies *	1.2	1.3	1.4	1.7	1.8	1.8
Self-insurance Cost	0.8	3.2	1.2	2.0	2.0	2.0
Total	**2.0**	**4.5**	**2.6**	**3.7**	**3.7**	**3.8**

*****The cost of other insurance coverage is captured and reported by the lines of business where the coverage is applicable.

2.3 Human Resources – "People & Culture"

Table 5 provides a summary of Human Resources costs:

Table 5
Human Resources Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Total Cost	11.0	9.9	11.1	13.1	13.0	12.2	6.9	6.5

Early in 2013, the Human Resources function was renamed "People and Culture" ("P&C") to highlight, in part, the importance of employees and the cultural transformation that Hydro One Networks is undertaking.

The P&C function exists to ensure that Hydro One Networks has the policies, systems and programs to attract, manage, engage and retain a high performing workforce to execute the corporate strategy. P&C provides consulting, leadership development and recruiting, diversity and resourcing programs, compensation and benefits services, and labour relations services.

One of the greatest challenges facing Hydro One Networks is in an area where P&C will be expected to play a significant role – the dramatic demographic transition that will be occurring in the company's workforce over the next few years. In December 31, 2013, approximately 1,000 active staff members (serving both transmission and distribution businesses) were eligible for undiscounted retirement. The number of employees eligible to retire continues to grow, and the uptake in retirement is growing. Based on employee data today, over 1500 employees will be eligible to retire by 2016. Retirement-eligible employees opting to retire increased by 16% between the period 2011 and 2012, and retirement rates for 2013 continued to show an increase in employees electing to retire.

2.3.1 Human Resource (HR) Operations

Hydro One Networks' HR Operations provide advice and guidance to managers, supervisors, and employees on a myriad of issues related to HR policies and procedures, collective agreement administration, staffing and other large initiatives that impact staff. In addition to general HR consulting, HR Operations also performs a number of 'specialist' support/service activities. The Pension and Benefits Section within HR Operations administers the Hydro One pension plan for approximately 7,100 pensioners. In addition, this Section also administers the benefits programs for all employee groups.

2.3.2 Talent Management

This P&C function recommends and administers policy in areas related to external hiring and leadership development. In addition, it manages all of Hydro One Networks' management/leadership development activities, including the assessment of high-potential succession candidates and miscellaneous specialized one-off hiring initiatives, as required.

2.3.3 Recruitment Solutions & Diversity

This function manages Hydro One Networks' principal[1] cyclical hiring and on-boarding processes - the New Graduate, the Co-Op Student, Internship and Developmental Student Programs, and the Summer Student Hiring Program. Additionally, this function is accountable for managing Hydro One's Two-year New Grad Training and Development Program and implementing the company's Diversity Plan, which includes Aboriginal recruitment and the Women in Leadership Program.

[1] Trades staff are hired through the Power Workers' Union Hiring Hall processes.

2.3.4 Compensation & Benefits

This function manages compensation, benefits, reporting and master data for all Hydro One Networks' employees and pensioners by ensuring the accurate application, record-keeping and security of all such information. The Compensation and Benefits Group also provides regular, strategic reporting to senior management on HR and pay data on topics such as retirement demographics, headcount, overtime reports, data for OEB submissions, etc., as well as participating in industry wide compensation, benefit and pension surveys. The same group also manages the Short Term Incentive for management's compensation.

2.3.5 Labour Relations

Labour Relations provides advice, guidance and training to managers regarding collective agreements and labour legislation and manages the grievance and arbitration process. The company is a party to twenty-four collective agreements and a number of mid-term agreements and letters of understanding. Labour Relations is responsible for negotiating and administering all such agreements and letters of understanding. In addition, the company must comply with legislation, such as the *Ontario Labour Relations Act*, the *Employment Standards Act* (Ontario), the *Human Rights Code* (Ontario), etc., all of which require interpretation to advise managers.

2.3.6 HR Productivity Initiatives

Continuous improvement is a core value at Hydro One Networks. Within the P&C function, there have been a number of initiatives to enhance productivity:

- The Human Resources/Payroll Transformation Project commenced in late 2013. This project will build further on the SAP platform and the SuccessFactors processes and technology to automate a number of talent management processes including, performance management, succession and career development, compensation management, recruitment management, and to update the company's current learning management system.

- The automation of Hydro One Networks' performance management process will improve the quality of the information available to managers regarding their staff, provide transparency and consistency in creating goals and assessing performance, provide the ability to calibrate performance, improve the ease of accessing this information, and provide reporting and trending information that currently does not exist because the process is manual.

- The Pension Administration Team is outsourcing additional transactional tasks that are currently completed by the pension analysts. This will allow the team to focus on more strategic pension issues and improve service and communication to plan members. The goal is to reduce costs to the pension plan, increase pension awareness and mitigate risk on the transactional items.

- HR Operations and Labour Relation have been merged under P&C, which creates an opportunity to leverage relationships throughout the organization to drive the desired cultural transformation and leverage natural synergies between these two groups.

- The creation of new reports will improve reporting, making information more accessible for managers as required. This will reduce the number of *ad hoc* requests, which will reduce the transactional work required by the P&C Reporting Group, permit them to focus on more strategic and analytical work, and improve their ability to respond to urgent requests (such as requests from the OEB or the Hydro One Board of Directors).

- A pensioner website is being developed that will provide external access to required information for pensioners. This will reduce the basic transactional work stemming from calls from pensioners. This will also reduce the cost of mailing printed materials to pensioners.

- P&C re-branded its existing internal website and launched a new “People Matters” internal website, with emphasis being placed on better and more up-to-date information, new tools and better search capabilities. Making this information available on the internal website will reduce basic transactional work for P&C staff and will provide more detailed and consistent information for the company’s staff members, generally.

- P&C will automate some master data transactions, using SAP technology, which will permit managers to complete HR transactions online, capturing data once at its source.

- The vacancy management process has moved from a paper-based format to an electronic format. Files that were once stored in paper hardcopy are now stored electronically, allowing for quick and easy management of the information.

- A new recruitment consultant was selected in 2013. The new consultant will assume many of the administrative duties currently done by P&C’s internal recruitment consultants. This will allow the internal recruitment consultants to focus on more strategic or relationship-building activities instead of simply processing paperwork. The goal is to improve customer service and decrease the administrative aspect of the job.

2.4 Corporate Communications

Table 6 provides a summary of Corporate Communications costs.

Table 6
Corporate Communications Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Total Cost	8.7	11.3	15.0	13.9	12.6	12.6	5.9	5.9

This function is performed by Corporate Communications, First Nations and Métis Relations and Outsourcing Services. The increase in costs over the historical years through the bridge year is reflective of the activities in the First Nations and Métis Relations, Corporate Communications and Outsourcing Services programs. First Nations and Métis Relations programs sustain long-term relationship building and negotiations with First Nations and Métis communities and are impacted by the growth of Hydro One core SDO work programs. Corporate Communications programs are targeting improvements in customer communications regarding power outages while increasing customer education and engagement efforts and research to support improved customer communication. The current outsourcing contract with Inergi LP expires in 2015. The re-tendering process currently underway which results in additional costs for the Outsourcing Services group. More details on the re-tendering process are available in Exhibit C1, Tab 3, Schedule 2.

2.4.1 <u>Corporate Communications</u>

Corporate Relations is comprised of Corporate Affairs, External Relations and the Executive Office. Corporate Relations is responsible for ensuring that Hydro One Networks builds the strategic relationships required to advance corporate objectives and present a single, positive brand internally and externally. Corporate Affairs is responsible for corporate reputation, executive support, customer and employee communications, media relations, community investment, web communications and corporate brand identity. External Relations is accountable for supporting the company's relationships with the government and its key stakeholders. External Relations also leads the Public Affairs Group which supports Hydro One Networks' public consultation obligations and community relations programs. The Executive Office supports the executive team. It advances key strategic initiatives and interfacing with lines of business to assist in the implementation of these initiatives, coordinating the development of processes to ensure alignment within Hydro One Networks and a unified focus on key priorities.

In 2013, Corporate Relations costs increased primarily due to Corporate Affairs incurring one-time expenses, such as costs to support the Mobile Customer Discovery Centre and an increased number of customer surveys in support of this Proposed Custom Application. The Executive Office also absorbed the costs of two rotational staff in 2013. For the 2015-2016 forecast, these additional costs have not been included.

2.4.2 First Nations and Métis Relations

Another important role that falls within the Corporate Relations function is First Nations and Métis Relations. First Nations and Métis Relations programs foster and maintain long-term relationship building and conduct engagement with First Nations and Métis communities that may be impacted by Hydro One Networks core SDO work programs.

Hydro One Networks owns and maintains assets on reserve lands and within the traditional territories of First Nations & Métis Peoples. Hydro One Networks recognizes that First Nations and Métis peoples and their lands are unique in Canada, with distinct legal, historical and cultural significance. Building relationships with First Nations and

Métis communities based upon trust, confidence, and accountability is vital to achieving our corporate objectives. The First Nations and Métis Relations group encompasses the following functions:

- Sustains long-term capability in the areas of First Nations and Métis relationship building, engagement and the successful development and implementation of initiatives to achieve Hydro One Networks' goals and objectives;
- Develops and maintains key relationships with government officials as well as representatives of key businesses including but not limited to other energy companies;
- Supports procurement opportunities for qualified First Nations & Métis businesses;
- Provides engagement services on projects and/or initiatives that potentially affect the First Nations & Métis peoples and communities;
- Provides leadership and advice within the company in the building of knowledge and awareness of First Nations and Métis historic and contemporary issues; and
- Develops, in conjunction with the Human Resources and Labour Relations departments, initiatives to enhance the level of aboriginal employment at Hydro One Network.

First Nations and Métis Relations costs are $3.1 million annually between 2015-2016. The portion allocated to Hydro One Transmission is $1.9 million annually for 2015 and 2016.

The increase in costs in the 2014 bridge year and 2015-2016 test years is required to sustain long-term relationship building and engagement processes with First Nations and Métis as a result of the growth of the Hydro One Networks core SDO work programs.

2.4.3 Outsourcing Services

The mandate of the Outsourcing Services Group is to govern and manage the contractual relationship with the company's outsourcing partner (currently, Inergi LP) in a manner that fosters collaboration and optimizes value and minimizes risk by ensuring that contracted services are delivered. The Outsourcing Services Group is responsible for managing the design, development, and implementation of new service delivery agreements with Hydro One Networks' suppliers.

The current outsourcing agreement with Inergi LP expires in 2015. Higher costs for the Outsourcing Services Group in the 2012 to 2014 period are primarily driven by: (a) fees for external support in preparing and issuing a request for proposals ("RFP") to replace the current outsourcing agreement, and (b) fees for a benchmarking study commissioned in 2013 to determine whether the costs under the current contract are market-comparable.

The Outsourcing Services Group's annual costs are $2.9 million in test years 2015 and 2016.The portion allocated to Hydro One Transmission is $1.7 million in 2015 and $1.7 million for 2016.

2.5 General Counsel and Secretariat

Table 7 provides a summary of the costs of the General Counsel and Secretariat function:

Table 7
General Counsel and Secretariat Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Total Cost	7.4	8.8	9.6	10.1	10.2	10.2	5.4	5.4

2.5.1 Overview

The offices of the General Counsel and Corporate Secretary ("GC&CS") provide legal advice and direction to Hydro One Networks and its affiliates, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. The GC&CS consists of two main functions: Law and the Corporate Secretariat. The Corporate Secretariat reports to the General Counsel.

The GC&CS functions in Hydro One Networks are set out below:

- Providing legal services to all business units including the company's major borrowing and financing initiatives, regulatory activities, transmission and distribution businesses (contracts, other commercial matters), employment, including pension and benefits, health, safety and environment, litigation, all Board of Directors-related activities, and arranging for the provision of legal services to the company. The volume of these services is driven by capital and OM&A activities, as well as increasing regulatory and legislative oversight functions;
- Overseeing the Law and Corporate Secretariat functions; and
- Ensuring compliance with legal and regulatory requirements.

Hydro One Networks does most of its legal work in-house, except when the in-house expertise is not available (for example, tax, labour) or when the workload exceeds the capacity of the internal legal group.

The increase in costs for GC&CS is driven mainly by increased work requirements related to the GEA, securities law matters including registration in the United States with the Securities and Exchange Commission (SEC), corporate finance matters and pension-related matters. Examples of the additional workload include procurement-related work due to large work programs, preparation of legal agreements associated with distributed generation, real estate-related legal work to obtain land and land rights for new development projects, and preparation of renewed securities-related documents for filing in Ontario and with the SEC.

2.5.2 Law

Law provides legal advice to all business units of the company, acting as an internal law firm. It advises on most aspects of law affecting Hydro One Networks, and relies on its experience and knowledge of the company's business in providing economic and timely advice. This function maintains core knowledge of the law and the company's business.

2.5.3 Corporate Secretariat

The Corporate Secretariat provides support to the Office of the Chair, the Board of Directors and its Committees, including the administrative aspects of the Board of Directors and its meetings. It provides advice and analysis with regard to a variety of board-related matters, including corporate governance best practices and emerging trends and issues. It provides advice and direction with regard to the business Code of Conduct, ensuring appropriate actions to resolve known or suspected violations.

2.6 Regulatory Affairs

Table 8 provides a summary of Regulatory Affairs costs:

Table 8
Regulatory Affairs Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Regulatory Affairs	9.1	7.4	7.6	8.3	8.0	7.9	3.7	3.7
OEB/NEB Costs	11.0	13.2	13.1	15.8	13.5	14.5	5.6	6.1
Total Cost	**20.1**	**20.6**	**20.6**	**24.1**	**21.5**	**22.4**	**9.3**	**9.8**

2.6.1 Overview

Regulatory Affairs consists of the Compliance, Applications and Regulatory Administration functions. The costs include Hydro One Networks' share of the Ontario Energy Board ("OEB") costs, including the OEB quarterly assessment costs, OEB proceeding-specific costs and OEB-ordered intervener cost awards.

2.6.2 Regulatory Affairs Activities

Regulatory Affairs is responsible for managing the company's relationships with the regulatory bodies with which it interacts, including the Ontario Energy Board, the IESO, the OPA, and the National Energy Board. Through this function, it is responsible for developing strategy and coordinating the company's submissions to these bodies as well participation in regulatory initiatives.

Regulatory Affairs is involved in the coordination, preparation and processing of applications, as well as providing support to witnesses and business support staff. Such proceeding-specific services are provided for a wide range of applications, including distribution and transmission rates, transmission leaves–to-construct, merger/ acquisition/ amalgamation/ divestiture applications and area and system supply planning. In addition to proceeding-specific work, Regulatory Affairs is responsible for a variety of ongoing reporting and other activities. The function prepares quarterly and annual reports required under OEB Reporting and Record-keeping Requirements. Work includes meeting, reporting on, and responding to regulatory compliance issues. Pricing and cost allocation analysis and support are also provided within Regulatory Affairs for rate applications. This includes the development of rate structures and rates for the regulated transmission and distribution tariffs applicable to Hydro One Networks and provides support in submitting and defending rate proposals. The function also assists with the implementation of approved transmission and distribution rates.

Load Forecasting and Load Data Management Units are included within the Regulatory Affairs group. Load forecasts are developed to enable system planning and financial planning which underlie Hydro One Networks ' financial forecasts. The load forecast function provides load forecast data including the capture of conservation and demand management impacts. Load forecast staff support the company’s business units and the OPA with forecasting analysis and evaluation covering time of use, bypass and embedded generation. The Load Data Management Unit provides analytical support for conservation and demand management projects and provides load research analysis.

Regulatory costs in 2014 through 2016 are being driven by an aggressive regulatory program. This includes a distribution rate application for 2015-2019 and a proposed transmission rate application for 2015-2016. Furthermore, the OEB is continuing a busy and challenging program of reviews and initiatives, most of which involve the company. At the present time, the OEB is conducting several generic proceedings on issues such as:

- Code amendments to the Transmission and Distribution System Codes;
- Consultation to Review the Framework Governing the Participation of Intervenors in Board Proceedings;
- Initiative to Develop Electricity Distribution System Reliability Standards;
- Regional Planning for Electricity Infrastructure; and
- Numerous other matters that arise from time to time.

2.6.3 Ontario Energy Board Costs

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered from the IESO, the OPA, Ontario Power Generation and from licensing fees and penalties. OEB costs that are subject to recovery include its staff costs, office space costs, administration costs and overheads. These costs are allocated to one of six categories – electricity distribution, electricity transmission, gas distribution, IESO, OPA and Ontario Power Generation. Hydro One Networks' allocation arises from OEB costs related to electricity distribution and transmission.

2.7 Security Management

Table 9 provides a summary of Security Management program costs.

Table 9
Security Management ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Total Cost	3.0	3.1	3.4	4.8	4.8	4.6	2.2	2.1

The Security Management function (formerly referred to as Corporate Security Services) exists to enable Hydro One Networks' success primarily in the protection of assets (assets include people, property and information), development and maintenance of Business Continuity and Emergency Preparedness & Response Plans and to assist in the reliable delivery of electricity. Security Management adds value by providing advice, coordination, guidance, investigative, technical and intelligence gathering expertise and services to company staff that support and optimize the reliable delivery of electricity, the protection of Hydro One Networks' assets, and the resumption of business in the event of an all hazards (natural, technological or human-caused) incident. Effective asset protection and recovery can be the primary differentiating factor between success and failure for a critical infrastructure organization such as Hydro One Networks. This is achieved by effective corporate security policies, directives, guidelines and services, which can significantly enhance employee and business productivity and safety.

The increase in costs is a result of an increased focus on a variety of mitigating strategies to reduce the impact of metal theft (primarily copper) that threaten the reliability of the transmission and distribution systems and the safety and security of staff, first responders and the general public.

Incidents of copper theft have dropped, in part, due to adding security protection systems at heavily targeted transmission sites. However, more organized criminal incidents have occurred in relation to metal thefts recently, primarily targeting stations that have not benefited from increased capital expenditures for protection systems. Although the total number of incidents has dropped, the average loss per incident is increasing due to the sophistication and organization of these crime groups. These crimes take longer to investigate, and prevention methods and strategies are often very complex and costly.

Total Security Management costs are $4.8 million in 2015 and $4.6 million in 2016. The amounts allocated to Hydro One Transmission are $2.2 million for 2015 and $2.1 million for 2016.

2.8 Internal Audit

Table 10 provides a summary of Internal Audit costs.

Table 10

Internal Audit Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Total Cost	3.1	3.5	3.4	3.6	3.6	3.6	2.4	2.4

Internal Audit reports to the CEO and the Audit and Finance Committee of the Board of Directors. It provides independent and objective assurance and consulting services designed to add value to and improve Hydro One Networks' operations. The mandate for Internal Audit is to provide independent assurance to the CEO and the Board of Directors that internal controls are adequate in areas of high-risk and to follow-up and report on management actions to address findings from past audits.

The department helps the company accomplish its objectives by bringing a systematic and disciplined approach to evaluating and improving the effectiveness of risk management, internal control and governance processes. The total costs for this function are $3.6 million annually for 2015 and 2016. The portion allocated to Hydro One Transmission is $2.4 million annually for 2015 and 2016.

2.9 Real Estate and Facilities

Table 11 provides a summary of Real Estate and Facilities costs.

Table 11

Real Estate and Facilities ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2011	2012	2013	2014	2015	2016	2015	2016
Real Estate	9.3	8.8	9.3	9.7	9.8	9.8	7.9	8.0
Facilities	42.3	45.8	44.8	50.5	51.6	51.5	28.7	28.6
Total Cost	51.6	54.6	54.1	60.2	61.4	61.3	36.6	36.6

2.9.1 Overview

The total cost for the Facilities and Real Estate function in 2015 is $61.4 million, with $36.6 million allocated to Hydro One Transmission. The 2016 cost is $61.3 million, with $36.6 million of that allocated to Hydro One Transmission.

The 2015-2016 funding is required for the expanded facilities work program that responds to current and future anticipated Hydro One Networks' work space accommodation needs. This includes new facilities in the field. The facilities work program accounts for approximately 84% of total funding in test years 2015 and 2016.

The increase in funding requirements is mainly driven by new facilities and building additions being put in-service. New facilities will be replacing existing facilities at the end of their useful lives, and new facilities are also needed to meet increased accommodation needs driven by Hydro One Networks' work program and operating requirements (which include housing specialized work equipment). The increase in funding requirements in bridge year 2014 and test years 2015 and 2016 is attributable to planned office improvements, which are expected to result in additional swing space and office moves costs. The funding requirements in the bridge and test years also reflect corporate health and safety initiatives and expected increases in fixed operating costs.

2.9.2 Real Estate Services ("RES")

Real Estate Services manages Hydro One Networks' land rights portfolio across the Province. This involves maintaining rights across over 200,000 acres of owned corridor, easement and "statutory right" properties and acquiring any new rights needed to ensure the safe and reliable operation of the transmission and distribution system. In addition, Real Estate Services oversees the management of Hydro One Networks' rights associated with distribution and transmission lands, stations and other property.

Real Estate Services' key work activities include:

- managing the acquisition of new real estate rights, which supports the company's distribution and transmission development and reinforcement project initiatives across the Province including those designed to accommodate renewable power sources on the grid;
- managing the Provincial secondary land use program on behalf of Ministry of Infrastructure/ Infrastructure Ontario (leasing transmission corridor lands to external parties);
- managing easement, other rights agreements on public/private sector, railway and other lands;
- managing First Nations land use permit settlements on reserve lands;
- managing about 500,000 unregistered, low-voltage, real estate rights agreements;
- providing specialized real estate service activities including managing property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services; and

- maintaining Geographic Information System (GIS) – property record database.

More specific support is provided on a selected project basis. This includes provision of land ownership information, damage claim settlement, road access and other rights acquisitions.

Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on lands/buildings, and employee relocation services as appropriate.

2.9.3 Facilities

The Facilities work program includes all aspects of company work space requirements which comprise not only company-owned facilities, but management of the portfolio of leased facilities and oversight of the construction of new facilities. The Facilities function manages all of the building and site facilities across the company. This includes leasing costs and contract management for head office. In addition, it includes costs for administrative facilities, service centres, and other work locations (for example, the London Call Centre). The Facilities organization is responsible to ensure program delivery in terms of service levels, planned capital improvements and providing for Hydro One Networks' accommodation needs.

The Facilities program focuses on providing employee workspace at sites across the province including head office, administrative and service centres, the OGCC, and other work locations (for example, the London Call Centre).

Providing adequate workspace, storage and garage facilities for employees and trades is critical to the effective undertaking of organizational work programs. Equally important is ensuring that new or existing employee workspaces are consistently maintained to a standard that meets current work requirements and complies with all corporate, legislative and other related health, safety and environmental standards. This program includes:

- providing accommodation strategies and acquiring new employee / trades workspace in line with operational requirements;
- managing 46 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses and taxes;
- co-ordinating activities related to the ongoing management, operation, maintenance and inspection of 91 Administrative/Service Centres and Ontario Grid Control Centre; and
- providing support services for head office space, such as provision of office supplies and equipment, coordination of office moves, records management and tenant services.

The facilities costs are largely driven by space needs (including workspace and housing space for material and work equipment) which is affected by company work programs and factors such as changing business and operating requirements and fixed cost contractual obligations. Also, the current regulatory environment (including health and safety requirements) ultimately impacts operating costs. Accommodation needs are influenced by the development and growth of the company's work programs and initiatives.

The majority of the Facilities work program costs are fixed. The Facilities work program is driven by fixed-cost contractual obligations, which arise primarily through relationships with external landlords. For example, rent, operating and tax costs are specified in formal lease agreements and opportunities to significantly amend these set costs typically do not materialize until the agreement expires. Other fixed costs are represented by negotiated contracts with internal and external service providers for base level facility maintenance (administrative/service centre building maintenance, janitorial and snow removal, minor repairs, building component inspections) and similar activities. These contracts focus on maintaining facilities in a condition that meets current employee work requirements and corporate/legislative requirements. Fixed facility cost components (for example, utilities, property taxes, operational costs) are expected to continue to rise. 2015-2016 test year funding also takes into consideration changing factors in the operating environment.

3.0 OTHER OM&A

Other OM&A expenses are comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs as listed in Table 12.

Table 12

Total Transmission Other OM&A ($ Millions)

Description	Test	
	2015	2016
Capitalized Overhead	(122.2)	(119.2)
Environmental Provision	(6.3)	(6.0)
Indirect Depreciation	(6.4)	(6.7)
Other	0.9	0.8
Total	**(134.0)**	**(131.1)**

3.1 Capitalized Overhead Credit

Table 13
Transmission Corporate Overhead Credit ($ Millions)

Description	Test	
	2015	2016
Transmission	(122.2)	(119.2)

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that support capital work. These costs are included in shared services and in the lines of businesses. OM&A expenses are thus reduced by the capitalized amounts.

Capitalized OM&A costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization studies performed by Black & Veatch.

3.2 Environmental Provision

Table 14
Transmission Environmental Provision ($ Millions)

Description	Test	
	2015	2016
Transmission	(6.3)	(6.0)

In 2001, Hydro One Networks first recognized a liability on its balance sheet for the present value of the future estimated environmental expenditures needed manage the risks associated with two legacy environmental issues inherited from Ontario Hydro. These risks pertained to polychlorinated biphenyls (PCBs) and two chemically contaminated lands. Future expenditures are required to inspect, test and remediate the contamination. Environmental work is initially recognized in the sustaining OM&A work program. The amount is then removed from OM&A as the costs are charged to the balance sheet provision. As well, the offsetting environmental regulatory asset is amortized based on the pattern of expenditure. The resultant impact on revenue requirement of this environmental work is nil, since the amortization expense is grouped with 'Depreciation and Amortization' on the operating statement.

3.3 Indirect Depreciation

Table 15
Transmission Indirect Depreciation ($ Millions)

Description	Test	
	2015	2016
Indirect Depreciation	(6.4)	(6.7)

Transportation and Work Equipment ("TWE") charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes, it is necessary to remove this depreciation amount from OM&A work programs and appropriately charge it as a depreciation expense. The credit increases in the test years due to the expanded use of T&WE in the larger SDO work program.

3.4 Other

Table 16
Transmission Other Costs ($ Millions)

Description	Test	
	2015	2016
Other Costs	0.9	0.8

These costs represent material unexpected or non-recurring expenses. For example, they include items such as adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments.

COMMON CORPORATE COSTS, COST ALLOCATION METHODOLOGY

Allocation of Common Corporate Costs to Hydro One's Distribution and Transmission businesses and to each Hydro One affiliate is based on clearly articulated shared functions and services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ("CCF&S"), Customer Service, Asset Management, Information Technology, and Operating Programs to support the Hydro One Networks' Distribution and Transmission businesses.

CCF&S include Corporate Management, Finance, Human Resources, Corporate Communications & Services, General Counsel & Secretariat, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate & Facilities.

A description of the CCF&S has been provided at Exhibit C1, Tab 3, Schedule 3.

Since 2004, in connection with each cost of service application, Hydro One has commissioned a study by Black and Veatch (B&V) to recommend a best practice methodology to allocate common corporate costs among the business entities using the common services. The adopted methodology represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The 2014 report on this study is provided as Attachment 1 to this exhibit.

As part of the 2014 study, the cost drivers used to allocate the common corporate costs in EB-2012-0031 were updated to incorporate current information. Updating the driver inputs resulted in a shift in allocated costs from Transmission to Distribution ($4.0 million or 1.0% of the total common corporate costs).

A time study was conducted within Hydro One's Planning & Operating and Customer Service groups. The time study for these groups spanned a four week period ending May 31, 2013 and represented approximately $115 million of labour costs. Incorporating the time study's results caused a shift in allocated costs from Distribution to Transmission ($4.2 million or 1.0% of the total common corporate costs).

Updating the time allocations of the functions and activities of all other groups that did not participate in the time study resulted in a shift from Distribution ($2.9 million or 0.7%) and Brampton ($0.2 million or 0.1%) to Transmission ($2.9 million or 0.7%) and Hydro One's shareholder ($0.2 million or 0.1%). (Percentages are based on total common corporate costs.)

Hydro One accepted the results of the 2014 B&V study as providing a reasonable and equitable approach to the assignment of common corporate costs among the business entities using the common services. This methodology was based on the R. J. Rudden Associates (Rudden) Study that the Board accepted in the Distribution rate decision RP-2005-0020/EB-2005-0378.

The following Tables 1 to 2 provide the annual allocation of 2015-2016 CCF&S costs, respectively to all business units.

Table 1
Allocation of 2015 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.4	2.8	2.4	0.1	0.1	0.0	0.1
Finance	44.6	25.3	18.0	0.8	0.2	0.3	0.0
Human Resources	13.0	6.9	5.7	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.6	5.9	6.6	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.2	5.4	4.1	0.1	0.2	0.3	0.1
Regulatory Affairs	21.5	9.3	12.0	0.0	0.0	0.1	0.2
Corporate Security	4.8	2.2	2.5	0.0	0.0	0.0	0.0
Internal Audit	3.6	2.4	1.1	0.1	0.0	0.0	0.0
Real Estate & Facilities	61.4	36.6	24.8	0.0	0.0	0.0	0.0
Total CCF&S Costs	**177.1**	**96.8**	**77.2**	**1.3**	**0.5**	**0.9**	**0.4**

Table 2
Allocation of 2016 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.4	2.8	2.4	0.1	0.1	0.0	0.1
Finance	43.8	24.9	17.6	0.7	0.2	0.3	0.0
Human Resources	12.2	6.5	5.4	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.6	5.9	6.6	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.2	5.4	4.1	0.1	0.2	0.3	0.1
Regulatory Affairs	22.4	9.8	12.4	0.0	0.0	0.1	0.2
Corporate Security	4.6	2.1	2.4	0.0	0.0	0.0	0.0
Internal Audit	3.6	2.4	1.1	0.1	0.0	0.0	0.0
Real Estate & Facilities	61.3	36.6	24.7	0.0	0.0	0.0	0.0
Total CCF&S Costs	**176.1**	**96.4**	**76.7**	**1.2**	**0.5**	**0.9**	**0.4**

OVERHEAD CAPITALIZATION RATE

This evidence describes the methodology used to allocate Common Corporate Costs (which includes Corporate Functions and Services, Asset Management and Operators) to capital projects.

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In its April 9, 2010 Decision on Hydro One's 2010 and 2011 distribution rates (EB-2009-0096), the Board accepted the methodology, recommendations and the allocation of costs from a study by Black & Veatch (B&V) (formerly RJ Rudden Associates). This study was commissioned to derive an overhead capitalization rate for Hydro One Distribution's common corporate costs. The accepted methodology was also used the previous distribution rate application EB-2007-0681 and the most recent transmission rate application EB-2012-0031.

Hydro One commissioned B&V to review and update its capital overhead methodology. The 2015-2016 overhead capitalization rates have been calculated consistent with the previously accepted B&V study methodology. The consistency in the use of this approach for the 2015-2016 test years has been reviewed by B&V in 2014, and is provided as Attachment 1 to this Exhibit.

Hydro One Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support and removes the need for an e-factor adjustment.

Hydro One proposes that the resulting overhead capitalization rate as calculated in the B&V study in 2013, continues to be a reasonable method of distributing common corporate costs to capital projects. Hydro One's submissions in this Proposed Application reflect the overhead capitalization rate as developed.

Table 1 summarizes the overhead capitalization rates as reviewed by B&V.

Table 1
Overhead Capitalization Rate
(%)

Overhead Cost Category	**Test Years**	
	2015	**2016**
Capitalized Administrative & General Costs	11%	11%
Capitalized Operating Costs	3%	4%
Total	14%	15%

Table 2
Overhead Capitalized Amount
($ millions)

Overhead Cost Category	**Test Years**	
	2015	**2016**
Capitalized Administrative & General Costs	92.8	90.4
Capitalized Operating Costs	29.5	28.8
Total	122.2	119.2

In its EB-2011-0268 decision, the Board granted Hydro One Transmission approval to adopt United States Generally Accepted Accounting Principles (US GAAP) in place of modified International Financial Reporting Standards (IFRS) as its approved basis for rate setting, regulatory accounting and regulatory reporting commencing January 1, 2012.

In its EB-2011-0268 decision, the Board also directed Hydro One Transmission to conduct a critical review of its then current and proposed capitalization practices. The Board stated that the review should not be a benchmarking study, but should include information, for comparison purposes, on what US transmitters typically capitalize and capitalization methodologies employed by other transmitters. (See page 13 of the decision.) A summary of the results of this review (which covered both transmission and distribution entities) was filed as part of Hydro One Transmission's last transmission rate application (EB-2012-0031). The methodologies used to allocate Common Corporate Costs and Other O&M costs to the transmission overhead capitalization rate was determined to be appropriate by the intervenors and Board Staff who participated in the Settlement Conference, and was accepted by the Board in its Decision.

As documented in the review report, Hydro One critically reviewed its cost capitalization policy with a particular focus on the capitalization of overhead and indirect costs. In its review, Hydro One found that its treatment of overhead capitalized is generally consistent with other major US and Canadian industry participants. Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One's industry research of other Canadian and US utilities. Hydro One also concluded that its overhead and indirect cost captilization methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with (a) legacy Canadian and existing US GAAP and (b) regulatory principles, including the key goals of achieving intergenerational equity and avoiding cross subsidization.

COMMON ASSET ALLOCATION

1.0 INTRODUCTION

This evidence will discuss the nature of Common Fixed Assets ("Shared Assets") and the method by which the costs of these assets are assigned to the Distribution and Transmission business units.

Similar to the corporate common costs discussed in Exhibit C1, Tab 6, Schedule 1, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment (“T&WE”).

2.0 SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (4% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this exhibit. Table 1 summarizes the total gross fixed assets and identifies the proportion of allocated shared assets.

Table 1

Summary of Gross Fixed Assets

as at December 31, 2012 ($ Million)

	Transmission	**Distribution**	**Total**
Total Fixed Assets	13,540.7	8,363.0	21,903.7
Shared Assets (in Total)	511.7	698.7	1,210.4
Shared Asset %	42.3%	57.7%	100%

Shared assets are sub-divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2 shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value as of December 31, 2012.

Table 2

Details of Shared Net Fixed Assets

as at December 31, 2012 ($ Million)

Asset	**Gross Asset Value**	**Accumulated Depreciation**	**Net Book Value**
Shared Major Assets	539.2	292.2	247.0
Shared Minor Assets	671.2	386.2	285.0
Total Shared Assets	**1,210.4**	**678.4**	**532.0**

3.0 ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, shared assets are not directly attributable to either the Transmission or Distribution business units. In addition, from year to year, the use of these shared assets may change, based upon changes in the underlying transmission and distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their use and that the costs are apportioned appropriately amongst the business units.

In 2008, Hydro One commissioned a study by Black & Veatch (B&V) (Formerly R.J. Rudden Associates) to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The B&V study resulted in the allocation of shared assets based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

Hydro One has accepted the approach of the B&V study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate Decision RP-2005-0020/EB-2005-0378/EB-2007-0681 and in the subsequent Transmission rate Decision EB-2006-0501/EB2008-0272/EB-2010-0002/EB-2012-0031, and was also used in Hydro One's latest application for Distribution Rates for 2015 to 2019 (EB-2013-0416).

The appropriate use of the common asset allocation methodology for the 2015 to 2016 test years has been reviewed and confirmed by B&V in 2014, and is provided as Attachment 1 to this Exhibit.

Due to the significance of Cornerstone as a Shared Asset, Hydro One has developed transfer price charge rates to allocate a portion of the revenue requirement related to certain Shared Assets to the Telecom and Remotes businesses. The methodology and impact of the transfer price charges are described in more detail in Attachment 1 to this Exhibit.

Hydro One has used the approved B&V Asset Allocation methodology in this proposed application and Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2012.

Table 3
Hydro One Common Asset Allocation
as at December 31, 2012 ($ Million)

Total Gross Value All Hydro One Transmission & Distribution Assets $21,903.7 million			
Transmission (Total)	$13,540.7	Distribution (Total)	$8,363.0
Transmission (Direct)	$13,029.0	Distribution (Direct)	$7,664.3
Transmission (Common)	$511.7	Distribution (Common)	$698.7

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and amount of Hydro One Transmission's depreciation and amortization expense for the 2015 and 2016 test years.

The depreciation and amortization expense for Hydro One's submission for 2007 and 2008 Electricity Transmission revenue requirements (EB-2006-0501) was supported by an independent study conducted by Foster Associates Inc. (Foster), completed in June, 2006. In EB-2008-0272, Hydro One submitted a 2008 Technical Update conducted by Foster completed in August 2008 that supported the 2009 and 2010 depreciation and amortization expense. No Depreciation Study or Technical Update was carried out for 2011 or 2012 rates and depreciation rates were not changed from those previously approved. The Board accepted the costs flowing from the previous Depreciation Study and Technical Updates for the purpose of supporting Transmission rates in those years. Foster Associates has completed a new Depreciation Study for Hydro One Transmission in support of its 2015 and 2016 proposed application. The new study can be found at Exhibit C1, Tab 7, Schedule 1, Attachment 1.

The depreciation and amortization expense for 2015 is $394.2 million and for 2016 is $404.0 million.

2.0 DEPRECIATION EXPENSE

In accordance with the Board's Decision (EB-2006-0501), Hydro One Transmission used the Foster methodology, updated to reflect the results from the new Depreciation Study completed in 2014, for determining the depreciation rates proposed to be used in the calculation of depreciation expenses for 2015 and 2016.

The depreciation expense for 2015 is $387.7 million and for 2016 is $397.9 million.

Detailed depreciation schedules are filed at Exhibit C2, Tab 4, Schedule 1.

Table 1

Transmission Depreciation Expense

$ Million

Description	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Depreciation On Fixed Assets	282.3	301.4	304.3	321.2	356.0	370.9
Less Capitalized Depreciation	(9.6)	(9.3)	(9.7)	(6.2)	(6.4)	(6.7)
Asset Removal Costs	19.7	22.1	25.4	44.9	38.1	33.7
Losses/(Gains) On Asset Disposition	(0.1)	(0.1)	0.2	-	-	-
Total	**292.3**	**314.1**	**320.3**	**360.0**	**387.7**	**397.9**

3.0 AMORTIZATION EXPENSE

Amortization expense addresses the recovery of amounts that the Board has required Hydro One Transmission to defer to a future date. The Board has, in past decisions, approved the deferred balance and prescribed the method and time period over which the balance in each regulatory deferral or variance account may be disposed.

Amortization schedules for test, bridge and historical years are filed at Exhibit C2, Tab 4, Schedule 1. Table 2, below, reproduces this summary.

Table 2

Transmission Amortization Expense ($ Million)

Description	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Environmental Assets and Other	8.9	5.9	6.1	11.2	6.5	6.1

3.1 Environmental Assets and Other

Hydro One Transmission provides for estimated future expenditures required to remediate past environmental contamination and to comply with current environmental legislation. Since these future expenditures are expected to be recovered in future rates, Hydro One Transmission has recognized the net present value of these estimated future expenditures as a regulatory asset on its Balance Sheet. This regulatory asset balance is amortized on a basis consistent with the pattern of current expenditures expected to be incurred up to the year 2018. Hydro One Distribution received concurrence from the Board for this accounting treatment as part of the RP-2000-0023 Decision. Hydro One Transmission's treatment of these costs in its Application for 2007-2008 Transmission Rates (EB-2006-0501) was consistent with that Decision and was accepted by the Board. The treatment of these costs in this Submission is consistent with both of these prior proceedings.

PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1.0 INTRODUCTION

Under the *Electricity Act, 1998*, Hydro One Networks Inc. (“Networks”) is required to make payments in lieu of corporate income taxes ("PILs") relating to taxable income earned by its transmission business. The Board has directed that the taxes payable method should also be used for regulatory purposes, according to its 2006 EDR Handbook, Section 7.1 “OEB 2006 Regulatory Taxes Expense Methodology”.

Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILs income tax payable being different from the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the Board and recovered from customers at that time.

PILS installments are remitted by Networks to the OEFC at the end of each month. Any balance owing at the end of the year is required to be paid by the end of February of the following year.

In the absence of an Electricity Transmission Handbook, the 2015 and 2016 Hydro One transmission regulatory tax calculations have been prepared consistent with the approach found in the 2006 EDR Handbook and the 2006 EDR Tax Model, as this approach reflects the tax payable relating to taxable income earned by the transmission business.

2.0 INCOME TAX RATE (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the test years 2015 and 2016, comprised of a Federal rate of 15% and an Ontario rate of 11.5% as a result of the Ontario budget bill enacted on June 20, 2012. Any variance between actual taxes payable and forecast taxes, as a result of rate changes for income tax or capital cost allowance will be captured in a deferral account for tax rate changes, described further in Exhibit F1, Tab 1, Schedules 1 and 2.

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between the regulatory net income before tax ("NIBT") and taxable income for the test years 2015 and 2016 is provided in Exhibit C2, Tab 5, Schedule 1, Attachments 1 & 2. This schedule contains the income tax component of the PILs computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and capital cost allowance (CCA).

Reconciliation between the accounting NIBT and taxable income for the historical years 2009 and 2010 is also provided in Exhibit C2, Tab 5, Schedule 1, Attachments 3 & 4**.** In order to make it easier to follow these reconciliations, Hydro One Transmission has placed these adjustments into the following five categories:

1) Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, depreciation versus CCA);
2) Deferral accounts not included in the revenue requirement;
3) Reversal of accounting adjustments not included in the revenue requirement;
4) Recurring items not in the revenue requirement; and

5) Items whose impact is immaterial in total, and as such, have not been included in the Company’s business plan (applicable to test years only).

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of Hydro One Transmission's taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Therefore, many adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes. This includes items such as depreciation, contingent liabilities, accounting losses, accounting provisions such as other post employment benefits ("OPEB") and revenue that has been received but not recognized for accounting purposes (for example, transmission export revenue). On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT. This includes items such as CCA, the deductible portion of capitalized overhead, accounting gains and OPEB payments. Such reductions also include expenses incurred for which a deferral account has been set up on the balance sheet, rather than shown as a deduction through the income statement.

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes.

5.0 TAX TREATMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities' balance sheets for foregone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the Board.

For example, as shown in Table 1, assuming that a 25% tax rate and a $100 expense is incurred, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the Board subsequently approves recovery of this expense over a 2-year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

Table 1

	Year 1	**Year 2**	**Year 3**	**CUM**
Income (deduction)	(100)	50	50	Nil
Tax Refund (payable)	25	(12.5)	(12.5)	Nil
Cash Inflow (outflow)	(75)	37.5	37.5	Nil

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with the "2006 EDR Handbook Report of the Board" issued May 11, 2005 (page 61) that stated as follows:

> "A PILS or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will

deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment."

6.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (such as obsolescence provisions, lawsuits, staff reductions), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based upon the information available at that time. The balance may be adjusted upward or downward, with NIBT either decreasing or increasing, respectively.

However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

It is not necessary to adjust the 2015 and 2016 NIBT for contingent liabilities in computing taxable income since no changes were forecasted in the contingent liability balances for 20135 and 20146. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

The combined (Federal and Ontario) enacted income tax rates are as follows:

	Historic			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Federal Tax Rate (%)	16.50	15.00	15.00	15.00	15.00	15.00
Provincial Rate (%)	11.75	11.50	11.50	11.50	11.50	11.50
Total Statutory Tax Rate (%)	**28.25**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**
Capital Tax Rate (%)[1]	nil	nil	nil	nil	nil	nil

(1) As of July 1, 2010, the Ontario capital tax is eliminated.

2.0

RATE BASE

1.0 INTRODUCTION

This Exhibit provides the forecast of Hydro One Transmission's rate base for the 2015 and 2016 test years and provides a detailed description of each of the rate base components. The composition of Hydro One Transmission's assets is described in Exhibit A, Tab 5, Schedule 1.

The rate base underlying the test year revenue requirement includes a forecast of net utility plant, calculated on a mid-year average basis, plus a working capital allowance. Net utility plant is gross plant in-service minus accumulated depreciation. Working capital includes an allowance for cash working capital and materials and supplies inventory.

2.0 UTILITY RATE BASE

Hydro One Transmission's utility rate base for the transmission system for the test years is filed in Exhibit D2, Tab 1, Schedule 1. The calculation of average balances to derive net utility plant for the historical, bridge and test years is filed in Exhibit D2, Tab 3, Schedule 1 and Exhibit D2, Tab 3, Schedule 2.

Hydro One Transmission's forecast rate base for the 2015 test year is $10,176.5 million and for the 2016 test year is $10,558.0 million. Table 1 provides a summary of the calculation of the Transmission rate base for the 2015 and 2016 test years.

Table 1.
Transmission Rate Base ($ Millions)[1]

Description	2015	2016
Gross Plant	15,665.6	16,353.0
Less: Accumulated Depreciation	(5,515.7)	(5,819.3)
Net plant in service	**10,149.9**	**10,533.7**
Working Capital	26.6	24.2
Total Rate Base	**10,176.5**	**10,558.0**

2.1 Derivation of Net Utility Plant

The mid-year gross plant balance reflects the in-service additions resulting from the capital expenditure program forecast for the test years. These programs are described in detail in the Company's written evidence at Exhibits D1, Tab 3 and in the supporting schedules filed at Exhibit D2, Tab 2, Schedules 1 and 2. The justifications for individual capital projects in excess of $3 million are filed in Exhibit D2, Tab 2, Schedule 3.

The 2015 Net Plant in-service of $10,149.9 million is $240.2 million or 2.4% higher than 2014 Board-approved Net Plant of $9,909.7 million approved in EB-2012-0031. The 2016 Net Plant in-service of $10,533.7 million is $383.9 million or 3.8% higher than 2015 Test Year. These increases reflect the Company's infrastructure investments to address asset replacement and refurbishment needs of our aging system, and to expand the system for the purposes of load growth, accommodating a modified generation mix,

[1] Gross plant and accumulated depreciation values are calculated using a mid-year approach. Capital contributions have been netted out. Contributed capital refers to amounts contributed by third parties to specific capital projects, such as, for example, Joint Use Assets.

and expanding access to interconnected electricity markets as described throughout Exhibit D1.

A continuity schedule for gross fixed assets for the test, bridge and historical years is shown in Exhibit D2, Tab 3, Schedule 1. In-service additions in that exhibit reflect the placing in-service of some of Hydro One Transmission's capital programs, shown in Exhibit D1, Tab 1, Schedule 2 and described in detail in Exhibit D1, Tab 3.

A continuity schedule for accumulated depreciation for the test, bridge and historical years is shown in Exhibit D2, Tab 3, Schedule 2. The accumulated depreciation balance for the test years incorporates the accepted Foster Associates' Inc. methodology. The depreciation expense is further discussed in Exhibit C1, Tab 7, Schedule 1.

2.2 Cash Working Capital

In 2012, Hydro One Transmission retained Navigant Consulting Inc. to undertake a lead-lag study. The provision for working capital in 2015 and 2016 incorporates the results of this new study.

The cash working capital requirement for the transmission system is based on the following factors:

- the forecast of revenues,
- the forecast of OM&A, taxes and other cash expenditures and the net lead lag days determined.

Applying the lead lag study methodology results in a net cash working capital requirement of $12.9 million for the 2015 test year and $10.3 million for the 2016 test year. The calculation of cash working capital is discussed in further detail in Exhibit D1, Tab 1, Schedule 3.

2.3 Materials and Supplies Inventory

The other component of working capital is materials and supplies inventory. The average annual materials and supplies inventory balances are $13.7 million for 2015 and $14.0 million for 2016. Materials and supplies inventory is discussed in further detail in Exhibit D1, Tab 5, Schedule 1.

3.0 COMPARISON OF RATE BASE TO BOARD APPROVED

Table 3 compares 2013 costs to the 2013 Rate Base approved by the Board in their Decision on Hydro One Transmission's previous application in EB-2012-0031.

Table 3
2013 Board Approved versus 2013 Rate Base
($M)

Rate Base Component	2013 Actual	2013 Board Approved	Variance
Gross Plant	14,148.8	14,309.0	(160.2)
Accumulated Depreciation	(4,964.3)	(4,981.0)	16.7
Net Utility Plant	**9,184.6**	**9,328.0**	**(143.5)**
Cash Working Capital[1]	11.7	11.7	0.0
Materials & Supplies Inventory	13.3	13.7	(0.4)
Total Rate Base	**9,209.3**	**9,353.4**	**(143.9)**

Notes:
1. Hydro OneTransmission does not calculate actual cash working capital, thus the 2013 approved amount was used for illustrative purposes.

Total rate base was $143.9 million below the Board approved amount; a variance of 1.5%.

Table 4 compares 2014 forecast costs to the 2014 Rate Base approved by the Board in their Decision on Hydro One Transmission's previous application EB-2012-0031.

Table 4
2014 Board Approved versus 2014 Bridge Year Rate Base
($M)

Rate Base Component	2014 Bridge Year (Forecast)	2014 Board Approved	Variance
Gross Plant	14,871.4	15,177.1	(305.8)
Accumulated Depreciation	(5225.2)	(5,267.4)	42.2
Net Utility Plant	**9,646.2**	**9,909.7**	**(263.6)**
Cash Working Capital[1]	11.1	11.1	0.0
Materials & Supplies Inventory	13.4	12.9	0.5
Total Rate Base	**9,670.7**	**9,933.8**	**(263.0)**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2014 approved amount was used for illustrative purposes.

Total rate base was $263.0 million below the Board approved amount, a variance of 2.6%.

IN-SERVICE CAPITAL ADDITIONS

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready for use by Hydro One Transmission's customers. However, the absolute amount of in-service additions and capital expenditures in any given year will typically be different. This difference arises from the multi-year nature of many capital projects and from the fact that some projects can come into service in stages.

Table 1

In-Service Capital Additions 2013 – 2016 ($ M)

	2013 ISA Actuals	2013 OEB Approved	2014 - Bridge Projected	2014 OEB Approved	Test Years 2015	Test Years 2016
Sustaining	403.8	443.3	588.4	701.1	572.2	480.9
Development	231.7	261.8	177.3	205.8	134.7	119.4
Operations	5.9	15.1	19.0	48.0	50.4	10.0
Common & Other	62.4	64.0	78.7	68.0	64.1	63.1
Total	**703.8**	**784.2**	**863.3**	**1023.1**	**821.3**	**673.3**

Hydro One Transmission is expecting to achieve this level of in-service capital additions by utilizing a mix of internal and external resources, including outsourcing. Please refer to our Work Execution Strategy in Exhibit A, Tab 16, Schedule 6 for how Hydro One Transmission intends to accomplish the work program.

Primary factors behind the 2013 in-service additions being $80 million lower than the OEB approved level of $784 million include:

- Sustainment in-service additions were lower than the approved amount by approximately $40 million due primarily to delays in the relocation of assets at

- Abitibi Canyon SS to Pinard TS and replacement of the Merivale Gas Insulated Switchgear (GIS) largely resulting from outage coordination issues.

- Development in-service additions were lower than the approved amount by roughly $30 million due primarily to delays in the Hearn TS and Hawthorne TS projects due to complications in obtaining outages.

- Operations in-service additions were lower than the approved amount by about $10 million primarily as a result of the cancellation of the Wide Area Network (WAN) project due to the lower demand for telecom network capacity.

The 2014 in-service additions are anticipated to be lower than the OEB approved level of $1,023 million by about $160 million primarily due to the following factors:

- Development in-service additions are forecast to be about $30 million lower primarily due to:
  - Delays in the Midtown Transmission Reinforcement project which suffered from flooding of an access shaft.

- Sustainment in-service additions are forecast to be roughly $100 million lower primarily due to:
  - The Riverside Junction by Strachan TS underground cable replacement project, which is expected to be completed for less than the previously approved amount partly due to lower material costs through procurement savings (approximately $35 million);

  - The replacement of the Bruce Special Protection Scheme being delayed due to functional requirement changes following a revised scope of work with the IESO (approximately $30 million); and
  - The execution of the Bruce A TS air blast breaker replacement project being delayed due to inclusion of additional work required at the site to address short circuit issues and additional end of life assets in an integrated manner to aide in outage coordination with the generators (approximately $35 million).

- Operations in-service additions are forecast to be lower by about $10 million due to the cancellation of the WAN project.

<u>In Service Additions in 2015 and 2016</u>

In-service capital additions will decrease in 2015 as compared to the 2014 projected amount and decrease more significantly in 2016 as compared to 2015. The significant decrease from 2015 to 2016 is mainly due to lower additions in Sustaining and Operations. The decrease in Sustaining reflects the completion of some major projects and the continuation of several large projects in the test years that will come into service in 2017 and beyond. The decrease in Operations is due to the large Network Management System (NMS) and other system upgrade projects coming in service in 2015.

For 2015 and 2016, Hydro One is continuing the shift towards completing more Sustaining capital work in an integrated manner in part to reduce the current problem of projects being delayed due to outage planning constraints. Going forward in the test years and beyond, Hydro One expects the in-service forecasts to be achievable with a greater focus on this integrated approach to planning and executing work to increase the probability of achieving required outages. In addition, a greater portion of the projects going in-service in 2015 and 2016 already have work in progress.

Capital Expenditures for 2015 and 2016 are described at the program and major project level in Exhibit D1, Tab 3 and Tab 4. All projects with spending greater than $3M in one of test years are described in more detail in Exhibit D2, Tab 2, Schedule 3.

A summary of the major in service additions in the Sustaining, Development and Operating areas is provided in Table 2:

Table 2

($M)	2015	2016
Sustaining		
Integrated DESN Replacements	113.9	60.7
EOL Station Reconfigurations	35.0	-
Power Transformer Replacements	38.1	53.5
BSPS Replacement	28.3	-
Integrated Station P&C Replacements	28.0	29.9
Transmission Line Reinvestments	37.2	29.6
Wood Pole Replacements	24.5	26.6
Development		
Midtown Transmission Reinforcement	61.6	-
Hawthorne TS Uprate Short Circuit	10.7	-
Guelph Area Transmission Reinforcement	-	94.3
Manby TS Uprate 115kV Switchyard	-	16.2
Operating		

NMS Upgrade	35.2	-

In the Common Corporate Costs area, there are in-service additions in 2015 and 2016 for IT systems, transport & work equipment and head office and field facility improvements.

TRANSMISSION ASSETS INVESTMENT OVERVIEW

1.0 INTRODUCTION

This exhibit provides a summary of the overriding requirements of the sustaining programs and the reliability statistics that are critical to understanding how performance of various assets impact the power system and customers. It also provides a longer term asset-centric view of the key transmission assets and their primary risk factors such as: demographic, performance, and condition information. These three dimensions together provide information to support the test-year Sustaining OM&A and Capital expenditures submitted in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively.

2.0 SUSTAINING OVERVIEW

Sustaining transmission assets is essential to the long term viability and performance of the transmission system. This is reinforced by the Transmission System Code that requires Hydro One Transmission to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments". Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One and its customers.

Hydro One Transmission's assets are reaching the end of their expected service life at a rate that exceeds the historic rate of replacement. This will result in cost pressures on both capital and maintenance programs to maintain the historic level of risk. In addition, the transmission system is in a continuing period of expansion that will present a need for increased maintenance expenditures as the asset base increases. The programs proposed to sustain the assets address current asset needs, and consider the trends of demographics, condition and reliability and the associated risk. It must be recognized that any reductions applied to the test years spending will have a compounding effect on system risks and cost pressures now and in the future.

The proposed test year Sustaining investment plan is directionally focused on maintaining equipment reliability and overall system reliability, through continued Sustaining Capital expenditures, while containing the test year Sustaining OM&A expenditures increases to less than inflation.

Sustaining programs strive to continuously innovate through adopting new technologies and approaches. Value will be derived by using innovative analytic tools and technologies. Efficient data collection and manipulation improves the effectiveness and consistency in investment plans. Value is also achieved through optimizing life cycle costs and targeting the right balance of capital and OM&A expenditures. In determining the appropriate maintenance strategies consideration is given to various approaches such as condition-based maintenance and time-based maintenance. Benchmarking against other utilities helps ensure that activities are in line with industry standards and practices.

Continued growth in the fleet replacement rates for key assets is imperative to manage the long-term reliability and lifecycle cost of the transmission fleet to the benefit of the ratepayer. Reducing Sustaining Capital funding will require increased Sustaining OM&A funding to maintain assets that are at end of life and should be replaced.

3.0 RELIABILITY OVERVIEW

Throughout the Sustaining exhibits, references are made to asset reliability and to system reliability. It is important to understand the difference between these two dimensions, as they are related, but need to be analysed separately to have a clear picture of trends and developing risk.

As a consequence of the redundancy often found in the transmission system, it's not unusual for an equipment defect or failure to have only a momentary impact on the power system, or in some cases no noticeable impact to end-use customers at all. For example, Hydro One Transmission typically has redundant transformers at load delivery stations, so that power can continue to be supplied to downstream customers during routine maintenance or in the event of a failure. In the event of a power system fault, depending on fault location and how the protections operate to clear the faulted zone, there may be no delivery interruption at all, or a very short interruption (fractions of a second to a few seconds), or the delivery points could be lost for an extended period of time (minutes to hours). These delivery point interruptions are tracked at the corporate level and benchmarked with peers.

Hydro One Transmission analyses equipment condition and defects as a leading indicator to major equipment performance (i.e. transformers, breakers, protections, circuits). As trends in major equipment performance begin to shift, there will be a lagging effect on broader system reliability. In managing the power system, specifically Sustaining investments, it is imperative to understand the leading-lagging spectrum of equipment condition, to major equipment performance, to system or delivery performance. By the time delivery impact begins to degrade, there would be significant underlying performance issues with major equipment that would take significant time and money to rebound from. Figure 1 represents the increasing impact to Customers as equipment defects evolve to major equipment outages that can impact delivery performance.

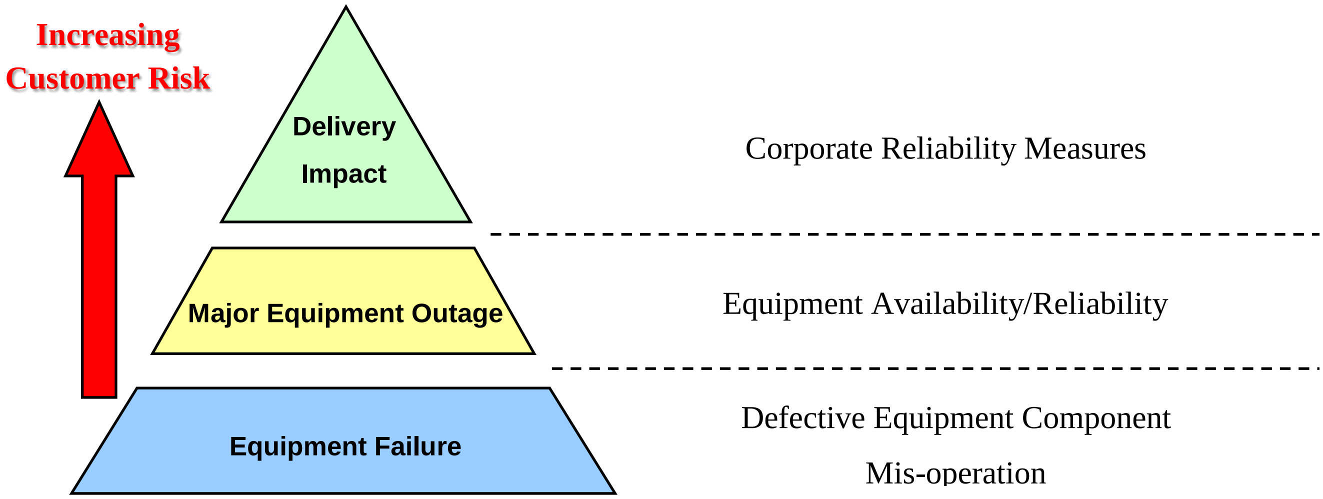


Figure 1: System Impact Hierarchy Model

Throughout the Sustaining exhibits, references are made to the impact of a particular asset to system reliability. This is most often expressed in terms of the frequency and duration of power interruptions. Figures 2 through 5 demonstrate the relative contribution between various assets to the system-wide delivery measures. Note that Lines assets that impact delivery performance are typically assessed against the entire system (radial single-point supplies and reinforced multi-circuit supplies), whereas Stations assets are expressed in terms of the multi-circuit delivery performance.

Figures 2 shows the 10-year history of the contribution of equipment failure to the frequency of delivery points interruptions for both delivery points; whereas Figure 3 focuses only on the frequency of the delivery point interruptions for only the reinforced or multi-circuit supplied delivery points.

There is an increasing trend of the number of equipment failures causing interruptions to customers, although there is some variability year over year. With the failure of Station equipment having a much more significant impact than Lines equipment. Sustaining capital and maintenance programs are largely focused on managing these reliability risks.

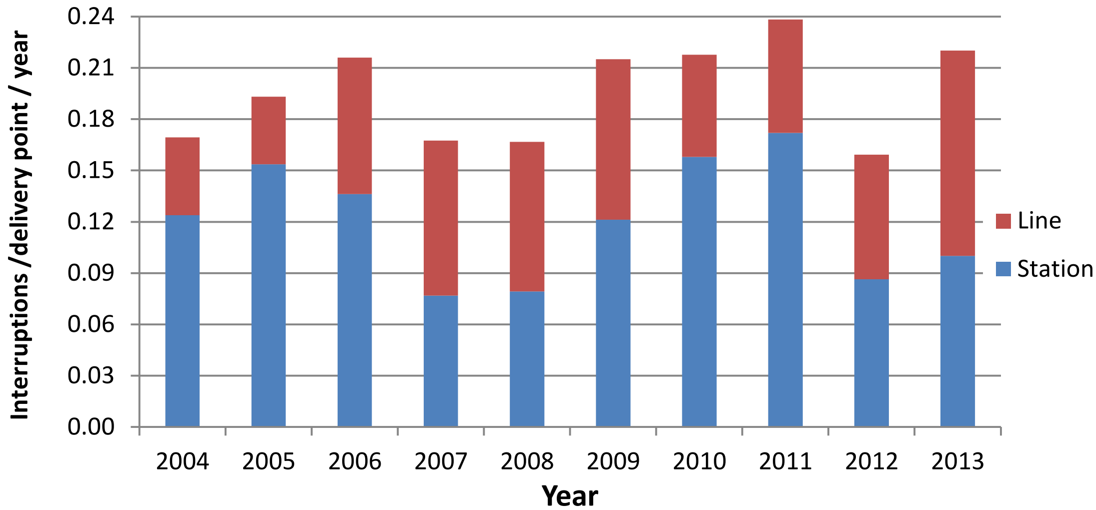


Figure 2: Equipment Failures Contributing to Frequency of Interruptions; All Delivery Points (Single & Multi-circuit Supplied)

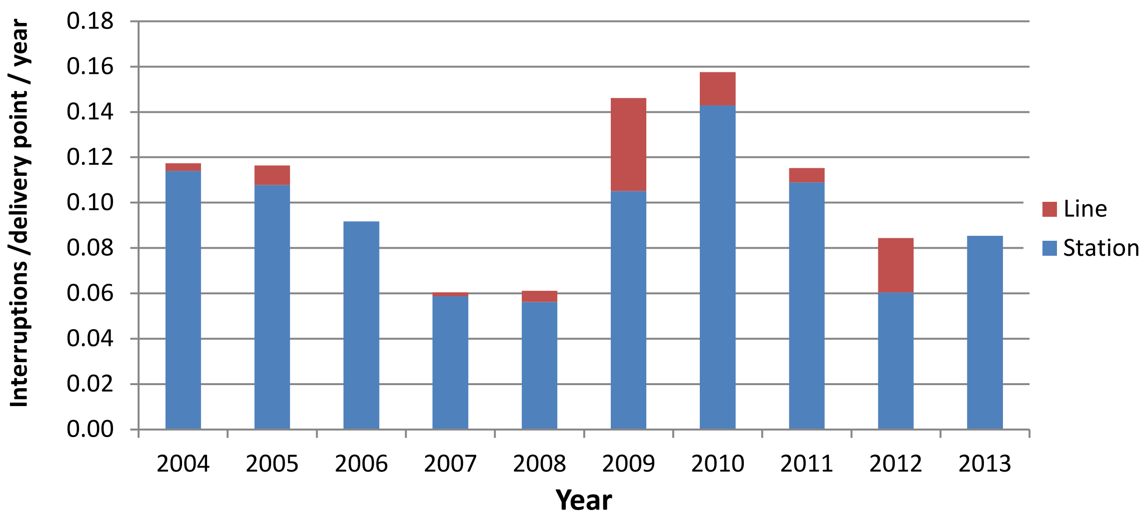


Figure 3: Equipment Failures Contributing to Frequency of Interruptions; Reinforced Delivery Points (Multi-Circuit Supplied Only)

Figures 4 show the 10-year history of the contribution of equipment failure to the duration of delivery points interruptions for all delivery points; whereas Figure 5 focuses only on the duration of delivery point interruptions for the reinforced or multi-circuit supplied delivery points.

There is a gradual worsening trend of the duration of interruptions across the entire system, with large variability year over year demonstrating that failures from equipment typically at the end of life can have major impacts on customer reliability measures.

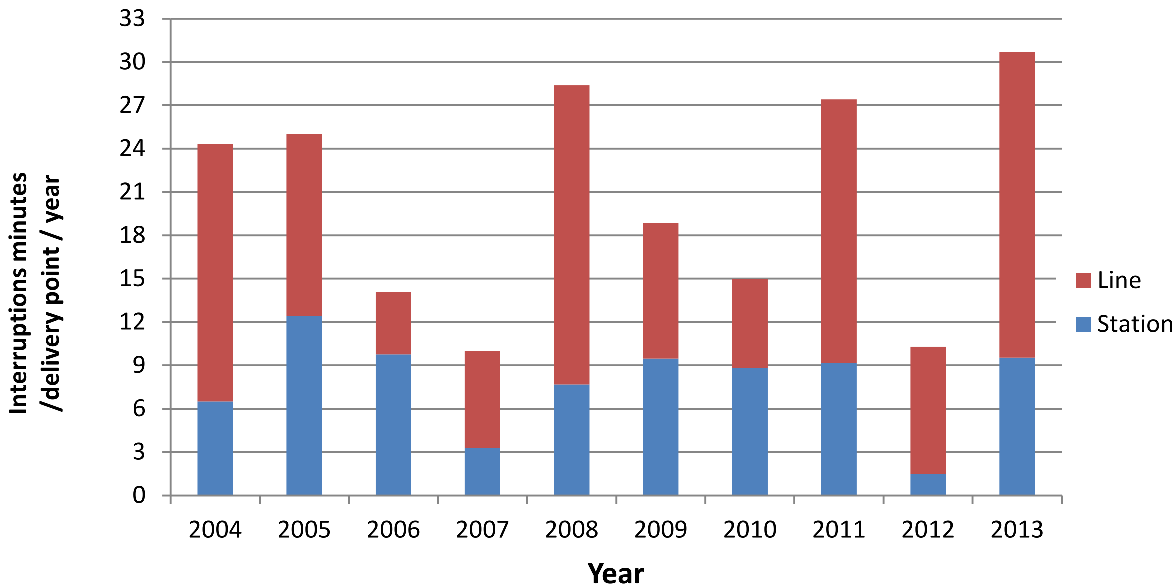


Figure 4: Equipment Failures Contributing to Duration of Interruptions; All Delivery Points (Single & Multi-circuit Supplied)

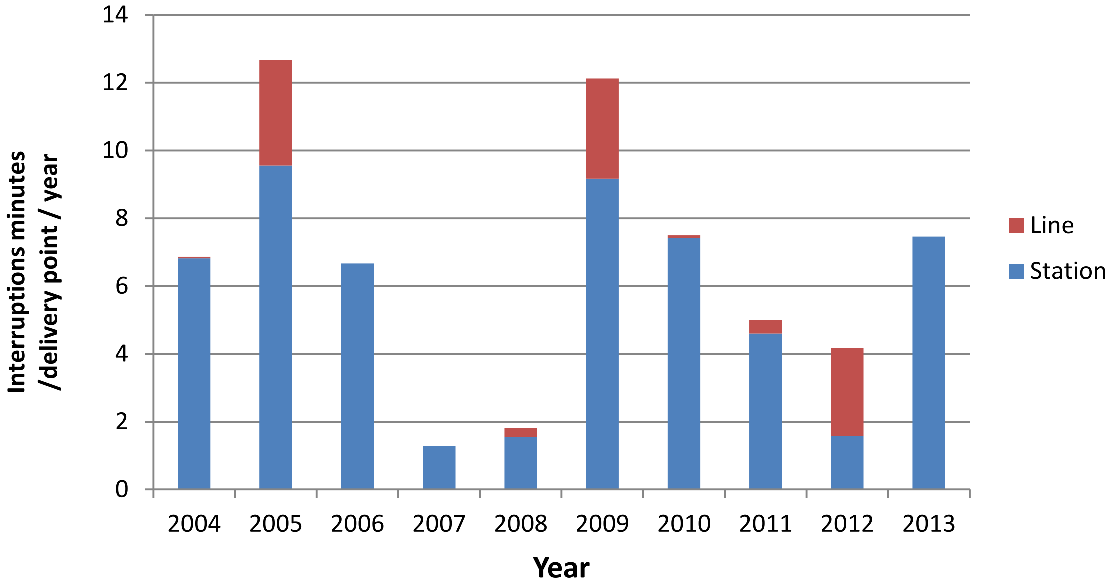


Figure 5: Equipment Failures Contributing to Duration of Interruptions; Reinforced Delivery Points (Multi-Circuit Supplied Only)

4.0 TRANSMISSION ASSET RISK ANALYSIS

The information presented below entails the asset risk analysis summaries for key transmission assets, based on the asset risk assessment process introduced in Exhibit A, Tab 16, Schedule 7. These summaries provide an overview of the strategy used to manage the asset, the forecasts of fleet demographics based on planned replacement rates, the condition and performance of the fleet, and the combined capital and OM&A cost impacts and relevant trends.

Various risk factors are considered for major transmission assets. Table 1 provides a summarized view of the primary asset risk factors for the key transmission assets impacting the majority of Sustaining Capital and OM&A expenditures as outlined in Exhibits D1, Tab 3, Schedule 2 and Exhibit C1, Tab 2, Schedule 2 respectively.

Table 1: Summary of Transmission Asset Risk

	Number of Assets	Assets Beyond Expected Service Life [% of Fleet]	Overall Asset Risk			Historic Renewal Rate 2011-2013 [% of Fleet]	Planned Renewal Rate 2014-2016 [% of Fleet]
			Demographics	Performance	Condition		
STATIONS							
Transformers	722 units	24%	High	Fair	Fair	2.0%	3.6%
Circuit Breakers	4,604 units	8%	Low	High	High	1.5%	3.0%
Protection Systems	12,135 systems	17%	Fair	Fair	High	3.1%	3.2%
LINES							
Overhead Conductor and Hardware	30,000 kms	19%	High	Fair	Fair	0.2%	0.3%
Wood Pole Structures	42,000 units	26%	Fair	Low	High	2.0%	2.0%
Steel Structures	50,000 units	21%	High	Low	Fair	0.3%	0.7%
Underground Cables	290 kms	16%	High	Fair	High	0.5%	1.3%

4.1 Transmission Station Assets

4.1.1 <u>Transformers</u>

Asset Overview

Hydro One Transmission has 722 large transmission class transformers in service, as outlined in Table 2.

Table 2: Transformer by Type

Transformer Type	***Number of Transformers***
Autotransformer – 500 kV	45
– 230 kV	89
Phase Shifter / Regulator / Reactor	5
Step Down Transformer – 230 kV	243
– 115 kV	340

The most common power transformer is the step-down transformer, which converts a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Another type is the autotransformer (as depicted in Figure 6) which connects to high voltage transmission systems such as 500/230 kV and 230/115 kV. Other transformers included in this group are phase shifting transformers, shunt reactors, and regulating transformers.

Figure 6: 500/230 kV Autotransformer

- Currently 24% of the transformer population is beyond its expected service life. Continuing at the historic rate of replacement, the number of transformers beyond their expected service life would increase to 35% by year 2024.
- The condition of the transformer fleet, determined through industry standard diagnostic testing, is such that 8% present high or very high condition risks that need to be mitigated.
- The forced outage frequency of transformers is relatively stable. However, transformers failures can have a significant impact to local and system reliability and continue to be one of the leading causes of delivery point interruptions. Transformers failures also have a negative impact on the environment in the event of oil spills.

Given the demographics of the transformer population, the condition trend and the risks associated with transformer failures, an increased rate of replacement over historic years is required to maintain an acceptable level of risk. Regulatory requirements related to oil leaks, noise levels and PCB contaminated oil in equipment also contribute to the need to replace some of the transformer fleet.

Asset Strategy

Hydro One Transmission's strategy for transformers is to manage the aging transformer fleet in a manner that preserves reliability while minimizing rate impacts. Hydro One Transmission continues to shift towards more condition based maintenance in order to maintain OM&A expenditures. Hydro One Transmission also proposes a replacement rate of approximately 3.6% per year to manage risks associated with operating an aged transformer population. This will result in continuation of the strategy to reduce the portion of the fleet operating with high risks associated with end of life issues.

Asset Assessment Details

<u>Demographics</u>

Hydro One Transmission uses a normal expected service life ("ESL") of between 40 years and 60 years depending on the type of transformer. Table 3 outlines Hydro One Transmission's ESL for various types of transformers. This is generally beyond the CEA-average transformer life expectancy of 40 years.

Table 3: Transformer Expected Service Life

Transformer Type	*Expected Service Life*
Autotransformer – 500 kV	40 years
– 230 kV	50 years
Phase Shifter / Regulator / Reactor	40 years
Stepdown Transformer – 230 kV two-winding	50 years
– 115 kV or 230 kV three-winding	40 years
– 115 kV two-winding	60 years

The average age of the transformer fleet is currently 35 years of age and 24% of the in-service transformers are currently beyond their expected service life. The demographics of the transformer population is outlined in Figure 7.

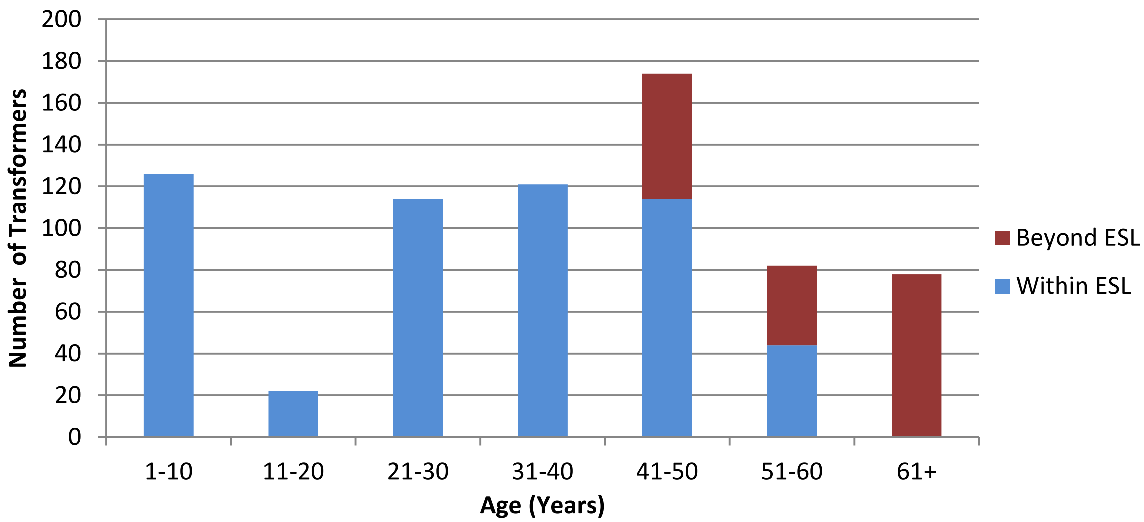


Figure 7: Demographics of the Transformer Fleet

The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through continued capital replacement programs. As can be seen in Figure 8, continuing at the historic rate of replacement would result in the percentage of transformers beyond their expected service life to increase to 35% by 2024. However at the proposed replacement rate of 26 transformers a year, the percentage of transformers beyond their expected service life will improve from 24% to 19% over the next 10 years.

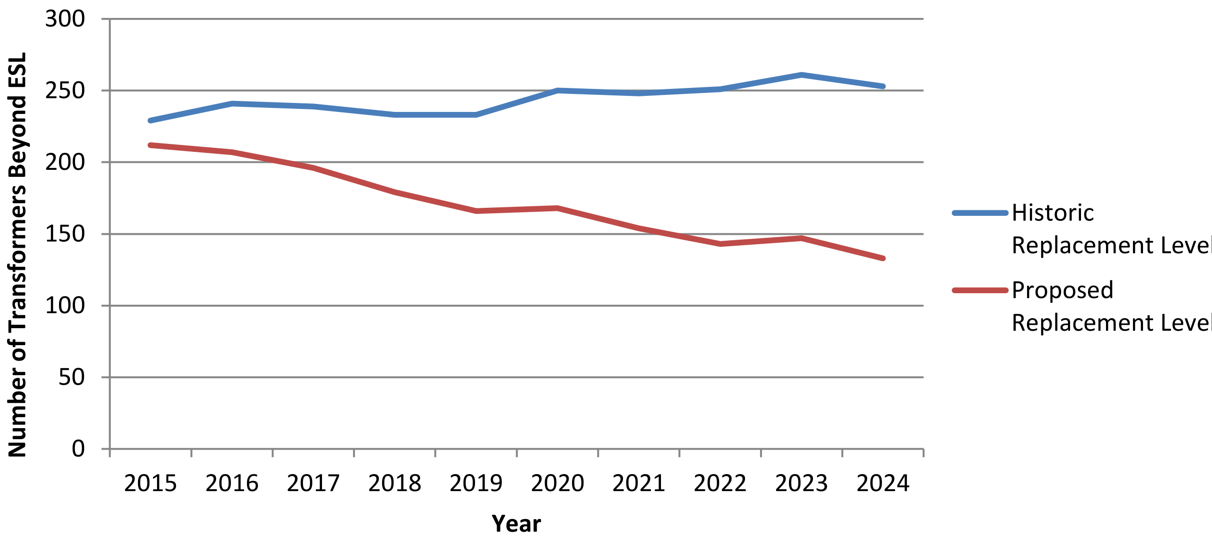


Figure 8: Projection of Transformers Beyond Expected Service Life

<u>Performance</u>

The forced outage frequency of transformers is relatively stable, as outlined in Figure 9. However, transformers failures can have a significant impact to local and system reliability. Transformer forced outages are one of the leading causes to customer delivery point interruptions, and represent 26% of the equipment-caused events impacting delivery point interruptions with multiple supplies over the past 10 years. To mitigate this risk the transformer replacements in the test years are focused on replacing transformers that are at the highest risk of causing delivery point interruptions and impacting the bulk electricity system.

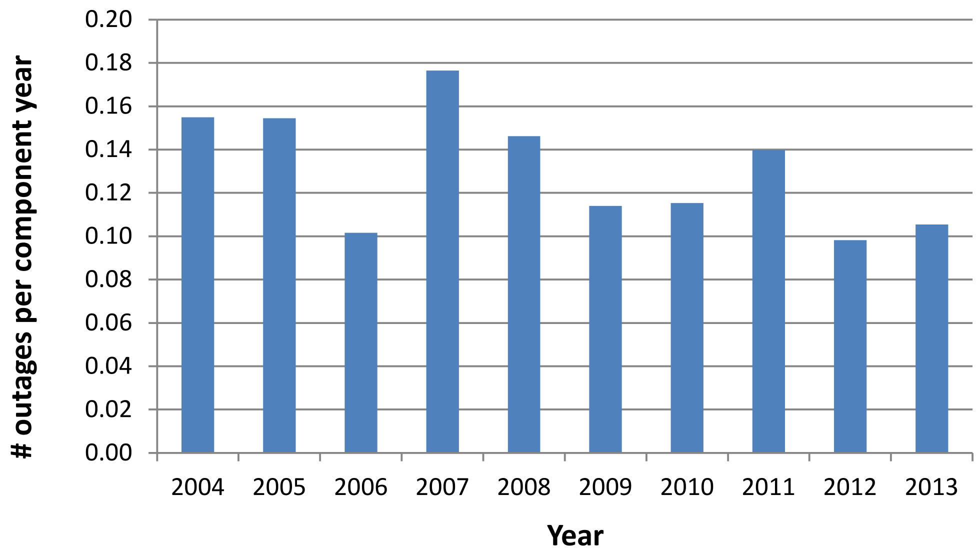


Figure 9: Forced Outage Frequency due to Transformer Failures

<u>Condition</u>

Transformer condition is a leading predictive indicator of equipment reliability. Condition is primarily based on transformer oil testing (dissolved gas analysis, furan, standard oil testing), power factor testing, and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, heat from transformer loading, exposure to oxygen, moisture contamination, and damaging acids in the insulating oil as a result of insulation aging. Degradation is irreversible and transformer replacement is the only economically viable solution.

Based on results gathered, currently 8% of Hydro One Transmission's transformer population has condition that puts it in high or very high risk, as outlined in Figure 10.

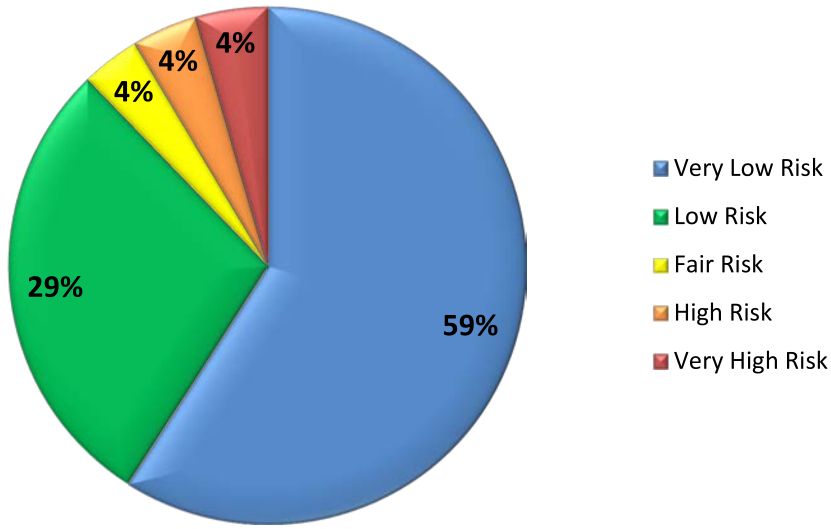


Figure 10: Transformer Fleet Condition Assessment

The transformers which tend to be in the worst condition are also those which are approaching or beyond their expected service life. Transformer condition is generally correlated to asset age, as well as how it has been operated and maintained throughout its service life. Sustaining capital and maintenance programs are targeted at transformers in degraded condition typically with high or very high risk of failure.

To date, the sustaining replacements have addressed many of the transformers with the highest probability of failure along with a number of maintenance activities have focused on remedial actions to mitigate the most significant risks. However to maintain the condition of the fleet, given the demographics and utilization, a continued replacement program beyond historic accomplishment rates is required to maintain or gradually improve the overall fleet condition.

<u>Other Influencing Factors</u>

Other factors driving the increase in transformer replacements are summarized below.

- Oil Leaks - Provincial regulations require that oil leaks are mitigated either through temporary measures such as absorbent materials and drip trays, through typically expensive refurbishment to re-gasket transformers, or replacement. Replacement is often the best technical and economical solution for aged transformers.

- Environmental Compliance Approval ("ECA") Commitments - (formerly CofA). Often ECA approvals come with a condition of bringing other aspects of the transmission station up to modern standards within a specified period of time, typically 3 years. Transformers are usually the influencing factor in ECA commitments for both spill containment and noise limits.

- Polychlorinated Biphenyl ("PCB") Contamination – Approximately 25% of bushings older than 1985 are forecast to contain oil with a PCB concentration of greater than 50 ppm. Environment Canada has a regulated end-of-use date of 2025 for oil volumes greater than 50 ppm. Replacements of this equipment will be required to maintain environmental compliance.

Cost Trends and Impacts

Transformer Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Replacements*	16	12	15	26	26	26
% of Fleet	2.2%	1.7%	2.1%	3.6%	3.6%	3.6%
Capital ($M)	81.1	100.5	120.7	162.9	105.7	120.1
OM&A ($M)	30.2	23.2	21.8	23.3	23.7	22.8

**Note that transformer replacements above are conducted under both the categories of Power Transformers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.*

The capital replacement rate in the test years is consistent with the bridge year forecast, which is an increase over historic level. Continued renewal of the fleet at this rate should be sufficient to maintain an acceptable level of risk through the test years. There is some variability in capital expenditures year over year, which is mostly a function of the type and size of transformers being planned for replacement.

OM&A expenditures are generally consistent year over year with some minor variation as accomplishment of targeted programs is completed.

Transformers are a major element in ensuring a reliable bulk electricity system. Transformer failures are directly impactive to load customers, either through loss of load or significant risk exposure of single supply until such time the transformer can be replaced. Maintaining the fleet in an adequate condition will help preserve reliability in line with good utility practice and regulatory obligations.

4.1.2 Circuit Breakers

Asset Overview

Hydro One Transmission has 4,604 circuit breakers in service, as outlined in Table 4. High voltage ("HV") breakers are installed in 500 kV, 230 kV or 115 kV positions, and medium voltage ("MV") breakers are installed at 44 kV, 27.6 kV, 13.8 kV or 12.5 kV positions.

Table 4: Circuit Breakers by Type

Circuit Breaker Type	***Number of Circuit Breakers***		
	HV	***MV***	***Total***
Oil	479	1339	1818
SF6	642	937	1579
Air Blast	182	27	209
GIS	91	21	112
Metalclad	0	845	845
Vacuum	0	41	41

A circuit breaker is a mechanical switching device that is capable of making, carrying and interrupting electrical current under normal and abnormal circuit conditions. Abnormal conditions occur during a short circuit such as a lightning strike or conductor contact to ground. During these conditions, very high electrical currents are generated that greatly exceed the normal operating levels. A circuit breaker is used to break the electrical circuit and interrupt the current to minimize the effect of the high currents on the rest of the system. Figures 11A through 11E illustrate the five primary types of circuit breakers used in Hydro One's transmission system.

Figure 11A: Oil Circuit Breaker

Figure 11B: SF6 Circuit Breaker

Figure 11C: Metalclad Circuit Breakers

Figure 11D: Air Blast Circuit Breakers

Figure 11E: 500kV GIS Circuit Breakers

- Currently 8% of the circuit breaker population is beyond its expected service life. Continuing at the historic rate of replacement, the number of circuit breakers beyond their expected service life would increase to 13% by year 2024.
- The condition of the circuit breaker fleet, determined through industry standard maintenance practices, is such that 16% present high or very high condition risks that need to be mitigated.
- The forced outage frequency of circuit breakers is relatively stable. However, circuit breaker failures can have a significant impact to local and system reliability and continue to be one of the leading causes of delivery point interruptions. Circuit breaker failures also have a negative impact on the environment in the event of SF6 release.

Given the demographics of the circuit breaker population, the condition trend and the risks associated with circuit breaker failures, increased rate of replacement over historic years is required to maintain an acceptable level of risk. Regulatory requirements related to oil leaks and PCB contamination in equipment also contribute to the need to replace some of the circuit breaker fleet.

Asset Strategy

Hydro One Transmission's strategy for circuit breakers is to manage the aging circuit breaker fleet in a manner that maintains system reliability while minimizing rate impacts. A targeted approach will focus on replacement of worst performing and/or obsolete breaker types. Hydro One Transmission is also shifting towards increasing the number of circuit breaker replacements completed in an integrated manner. At select stations, entire low voltage switchyards will be replaced with a pre-fabricated solutions consisting of metalclad or GIS, which will help manage the demographic pressures cost effectively and have several intangible benefits in areas of constructability and maintainability as well as reliability.

Asset Assessment Details

<u>Demographics</u>

Hydro One Transmission uses a normal expected service life ("ESL") of 40 years all circuit breakers with the exception of oil circuit breakers, where an ESL of 55 years is used.

The average age of the circuit breaker fleet is currently 27 years of age and 8 % of the in-service circuit breakers are currently beyond their expected service life. The demographics of the population is outlined in Figure 12.

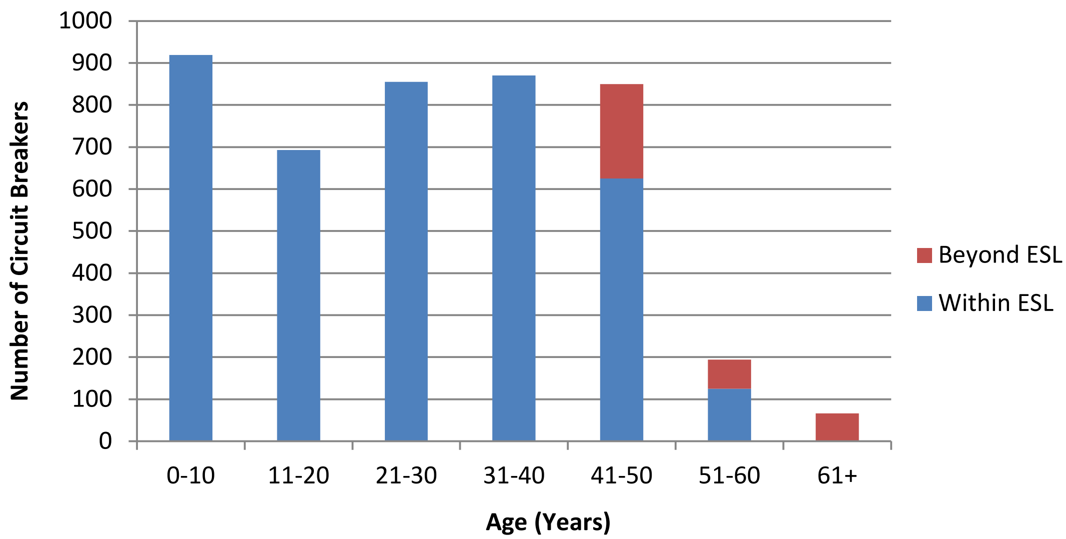


Figure 12: Demographics of the Circuit Breaker Fleet

Historic replacements have been generally sufficient to maintain a relatively small portion of the overall circuit breakers in operation beyond their ESL. Within the overall population, there are certain circuit breaker types which are operating at or beyond their ESLs.

- Approximately half of the air-blast breakers are beyond their ESL. These breakers are typically installed at system critical network stations;
- A large portion of the aged inventory is oil circuit breakers. The current replacement is focused on only the worst performing and/or technically obsolete models but an increased replacement rate will be required in the future;
- A significant portion of the metalclad breakers are operating well beyond their expected life. Legacy designs come with inherent safety risks that require mitigation.

Continued renewal of the fleet will be required to manage risks to system and customer reliability as a result of the long-term demographic pressures, as well as the more acute issues associated with air blast and metalclad circuit breakers.

As can be seen in Figure 13, continuing at the historic rate of replacement would result in the percentage of breakers beyond their expected service life to increase to 13% by 2024.

However at the proposed replacement rate, the percentage of breakers beyond their expected service life will have a more gradually increase from 8% to 10% over the next 10 years.

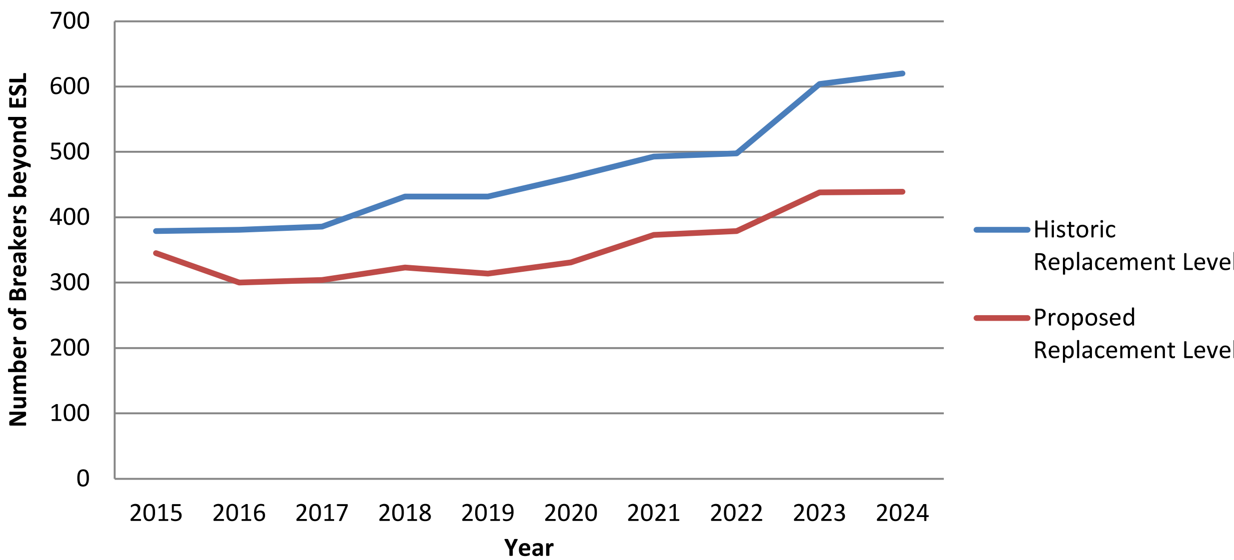


Figure 13: Projection of Circuit Breakers Beyond Expected Service Life

Performance

As displayed in Figure 14, Hydro One Transmission’s circuit breaker reliability for the entire circuit breaker population has been generally stable over the past five years.

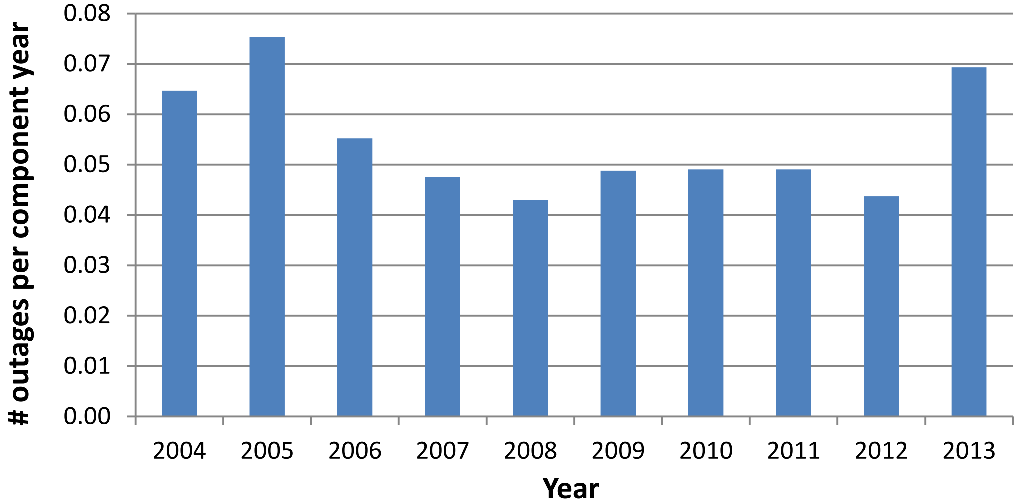


Figure 14: Forced Outages Frequency due to Circuit Breaker Failures

In 2013 there was a marked degradation in performance at the fleet population level which is primarily attributed to a much higher number of forced outages on air blast circuit breakers than previous years. This trend is notable in Figure 15, where the performance data for the different breaker interrupting mediums technologies is depicted.

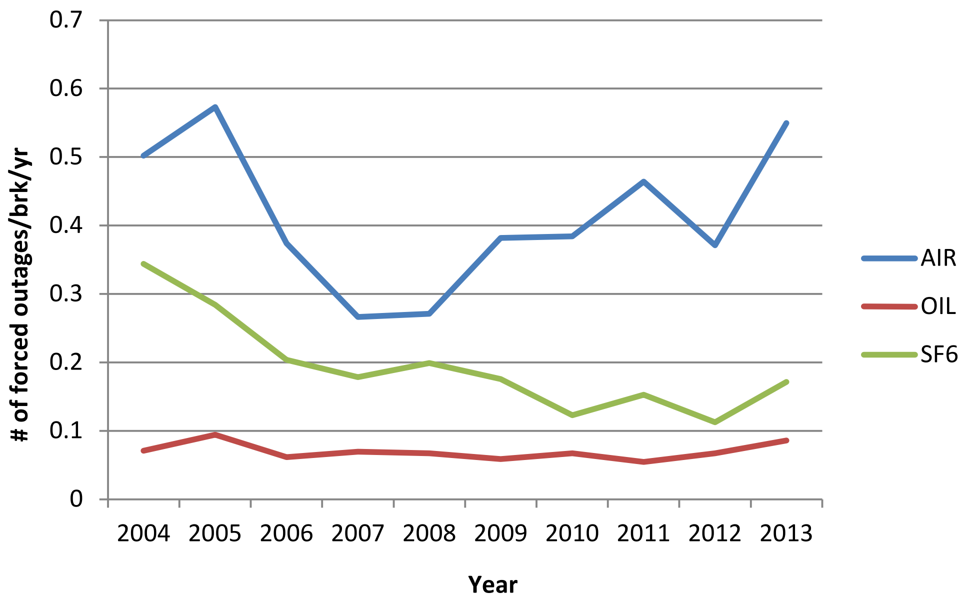


Figure 15: Forced Outage Frequency due to Circuit Breaker Failures by Type

Condition

Circuit breaker condition is a leading predictive indicator of equipment reliability. Condition is primarily based on feedback from preventive maintenance and corrective maintenance programs through diagnostic testing such as breaker timing, breaker oil analysis, history of deficiencies, etc. The components generally degrade as a function of time and usage. In some cases the degradation is reversible through replacement of wear components during maintenance but in many cases replacement is the only technical or economically viable solution.

Based on the results gathered, currently 16% of Hydro One Transmission's circuit breaker population has condition that puts it in high or very high risk, as outlined in Figure 16.

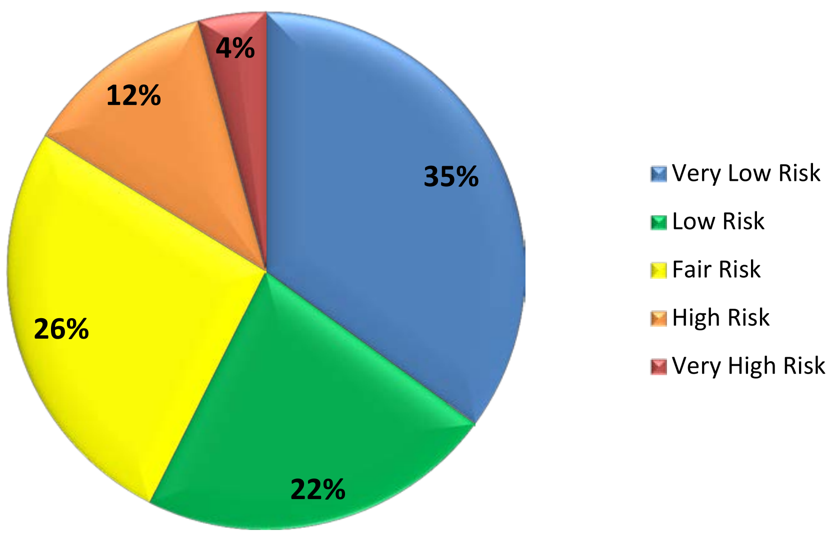


Figure 16: Circuit Breaker Fleet Condition Assessment

Other Influencing Factors

Other factors affecting circuit breakers that drive replacements requirements are summarized below.

- Safety - As the circuit breaker design has evolved over the past 50+ years, so has the safety standards and the requirement for safer work methods to protect utility workers. Early generation metalclad switchgear is most notable for having significant arc flash and electrical burn hazards in the event of equipment failure. These risks become more significant as the equipment ages.

- Technical Obsolescence - Many breakers are no longer supported by vendors and aftermarket parts are not available and/or cost effective. This is a significant factor for air blast circuit breakers, some first generation SF6 circuit breakers, and certain types of metalclad and oil circuit breakers.

- Equipment Operations - Breakers that have exceeded their expected service life in terms of number of operations are considered for replacement. Due to their frequent operation, this is most typical of capacitor and reactor breaker positions.

- Environmental Impact – Minimizing SF6 emissions and their resultant impact as a greenhouse gas to the environment is considered in the replacement or refurbishment plans for SF6 breakers.

Cost Trends and Impacts

Circuit Breaker Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Replacements*	100	55	57	125	150	147
% of Fleet	2.2	1.2	1.2	2.7	3.3	3.2
Capital ($M)	55.8	39.7	54.5	68.9	82.7	83.2
OM&A ($M)	19.3	18.5	20.7	17.3	19.4	19.8

** Note that circuit breaker replacements in the test years are a combination of both the categories Circuit Breakers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.*

The capital replacement rate in the test years is an increase over historic and bridge levels. Continued renewal of the fleet at an increased rate is required to maintain an acceptable level of risk through the test years. There is some variability in capital expenditures year over year, which is mostly a function of the type and size of circuit breakers being planned for replacement.

OM&A expenditures are generally consistent year over year with some minor variation as accomplishment of targeted programs is completed.

Circuit breakers are a major element in ensuring a reliable bulk electricity system. Breaker failures are directly impactive to load customers, either through loss of load or significant risk exposure of single supply until such time the station configuration can be returned to normal. Maintaining the fleet in an adequate condition will help preserve reliability in-line with good utility practice and regulatory obligations.

4.1.3 Protections

Asset Overview

Hydro One Transmission has over 12,135 protection systems in service. Protective relays and their associated systems are critical elements of the transmission system. They are connected throughout the transmission network to detect abnormal system conditions caused by natural events, physical accidents, or equipment failure. Upon detecting an abnormal condition, the systems immediately operate the necessary station equipment, such as circuit breakers and switches, to isolate faulted equipment, such as transmission lines, transformers, generators, or buswork, from sources of energy and the rest of the network. Failure to promptly isolate abnormal conditions can cause widespread outages, damage to equipment and injury to workers and the public.

Hydro One Transmission protection system fleet is comprised of three technological vintages; electromechanical, solid state, and microprocessor, as outlined in Table 5.

Table 5: Protection Systems by Technology

Protection System Technology	*Number of Protection Systems*
Electromechanical	4,775
Solid State	2,600
Microprocessor	4,760

By population, electromechanical and microprocessor protections are the most prevalent in Hydro One Transmission's fleet. Electromechanical relaying utilizes the principles of electromagnetic induction to convert electrical energy to mechanical movement to detect faults. In contrast, solid state systems rely on transistors using integrated circuit technology to detect fault conditions and microprocessor based systems provide advanced monitoring and fault detection capabilities. Figures 17A through 17C illustrate the three technology types of protection systems used in Hydro One's transmission system.

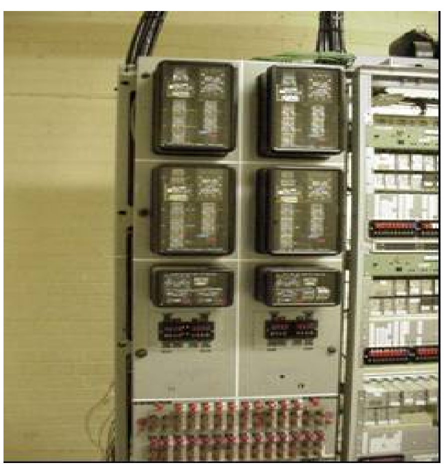


Figure 17A: Electromechanical Relay Panel

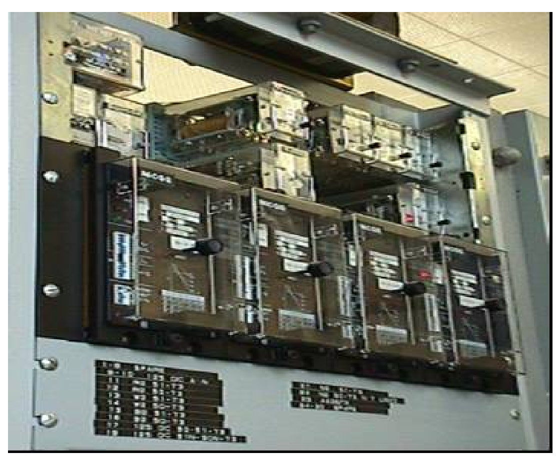


Figure 17B: Solid State Relay Panel

Figure 17C: Microprocessor Based Protection Scheme

- Currently 17% of the protection system population is beyond its expected service life. Continuing at the historic rate of replacement, the number of protection systems beyond their expected service life would increase to approximately 25% by year 2025.
- The condition of the protection system fleet is such that 26% present high or very high condition risks that need to be mitigated. There are specific concerns with Programmable Auxiliary Logic Controller ("PALC") relays, a solid state system, that have experienced an increase in defects over the last 10 years. An increase in the replacement rate is required to arrest this trend.
- Protection systems are composed of up to 100 individual components. With the vast number of protections, and complexity of replacement, there is significant risk if a common mode of failure for common manufacturer types/designs is experienced. Protection systems cannot be out of service for longer than several days without

incurring significant penalties in market inefficiency, disrupting planned outages, or impacting provincial or interconnected system reliability.

Given the demographics of the protection system population, the condition trend and risks associated with protection failures, an increased rate of replacement over historic years is required to maintain an acceptable level of risk. Protections are in the midst of a major technological change as old electromechanical and solid state relays are no longer available. A change in technology adds complexity to replacement activities; however the new microprocessor systems offer features not previously available in the older systems, including self-monitoring and alarming which allows for less frequent maintenance and remote data gathering to increase efficiency and ease of event analysis.

Asset Strategy

Hydro One Transmission's strategy for protection systems is to manage the aging protection systems fleet in a manner that maintains reliability while minimizing rate impact. Hydro One Transmission continues to contain OM&A expenditures through the replacement of electromechanical and solid state relays with microprocessor based systems which require less frequent maintenance while providing enhanced monitoring to ensure reliability. Hydro One Transmission proposes a replacement rate of approximately 3.7% per year in order to proactively replace protection systems before failure. This will be achieved by greater deployment of modular PCT installations at load stations where large numbers of protections are in need of replacement, continuing focused replacements of system critical protections, targeted replacement of failure prone relays such as PALC based systems, and bundling work opportunities with major refurbishment or re-investment projects.

Asset Assessment Details

Demographics

Hydro One Transmission uses technology-specific expected service lives ("ESL") for protection systems. Table 6 outlines Hydro One Transmission's ESL for the various technologies: electromechanical, solid state and microprocessor. The variation of ESL by technological vintage is based on generally accepted industry practice and internal experience.

Table 6: Protection Systems Expected Service Life

Protection Technology	***Expected Service Life***
Electromechanical	45 years
Solid State	25 years
Microprocessor	20 years

The average age of the protection system fleet is currently 23 years of age and 17% of the in-service protection systems are currently beyond their expected service life. Assessing the demographics of the individual technology types: 12% of electromechanical systems are operating beyond expected service life, 60% of solid state systems are operating beyond expected service life, and the first generation microprocessor systems have started to reach their ESL with 0.1% of these systems operating beyond expected service life. Furthermore, up to 8% of the current microprocessor system fleet will reach its expected service life within the next 5 years. The demographics of the protection system population is outlined in Figure 18.

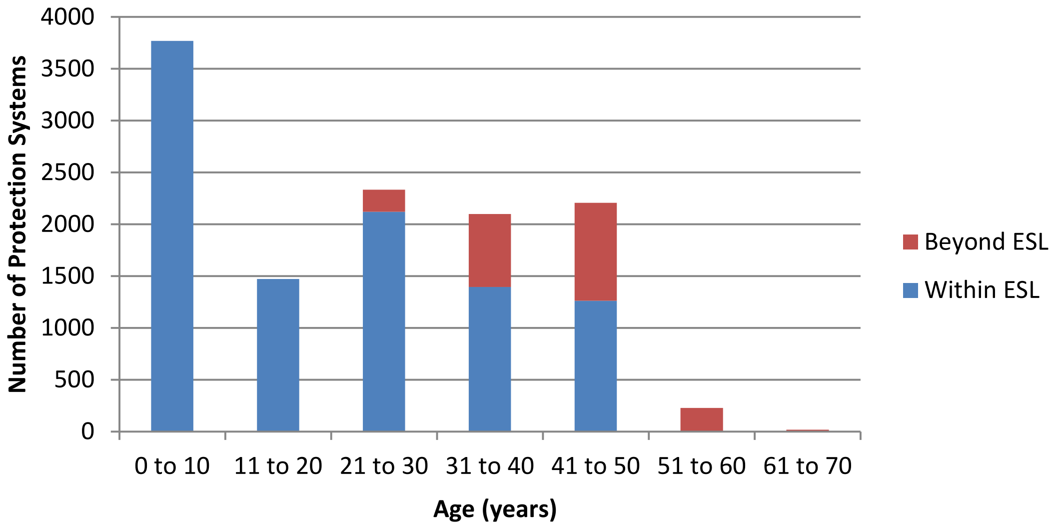


Figure 18: Demographics of Protection Systems Fleet

The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through increasing capital replacement programs. As can be seen in Figure 19, continuing at the historic rate of replacement would result in the percentage of protection systems beyond their expected service life increasing to 25% by 2025. However at the proposed replacement rate of 450 protection systems a year will allow the percentage of protection systems beyond expected service life to remain relatively constant over the next 10 years.

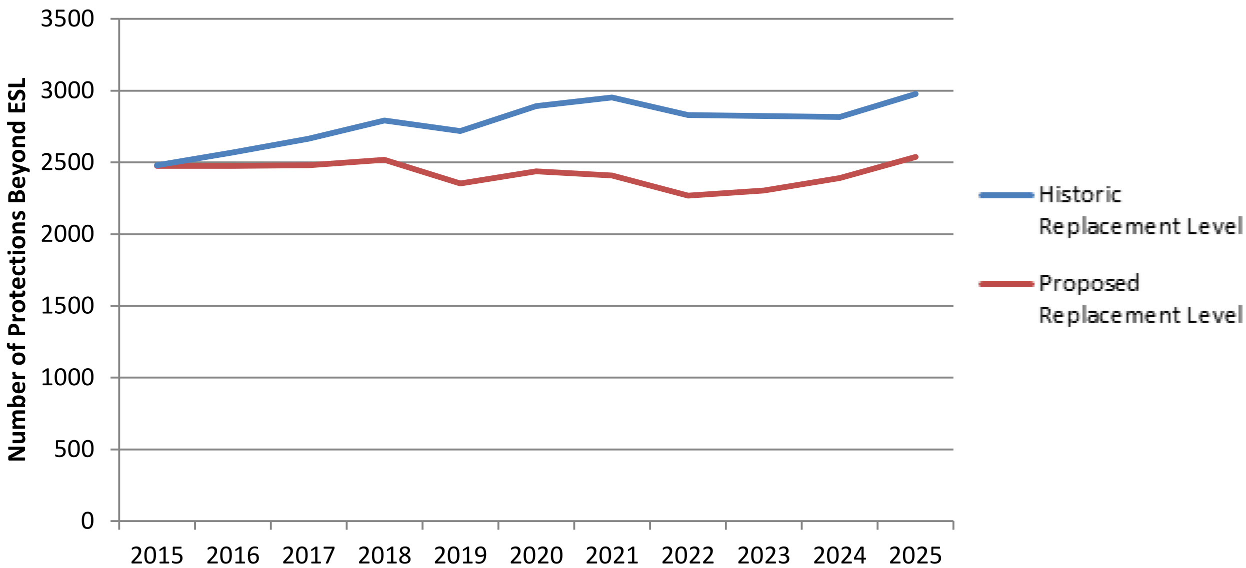


Figure 19: Projection of Protection Systems Beyond Expected Service Life

<u>Performance</u>

The forced outage frequency of equipment caused by protection systems has been a relatively declining trend for lines equipment and a relatively stable trend for station equipment over the past 10 years, as outlined in Figure 20. Protection systems play a critical role in ensuring the safe and reliable operation of the transmission system. The systems must be both dependable (operating when required) and secure (not operating on faults in adjacent protection zones) to ensure the reliability of supply. Protection systems cannot be out of service for longer than several days without incurring significant penalties in market inefficiency, disrupting planned outages, or impacting provincial or interconnected system reliability. To mitigate this risk the protection system replacements in the test years are focused on replacing protection systems that are at the highest risk of causing delivery point interruptions and impacting to the bulk electricity system.

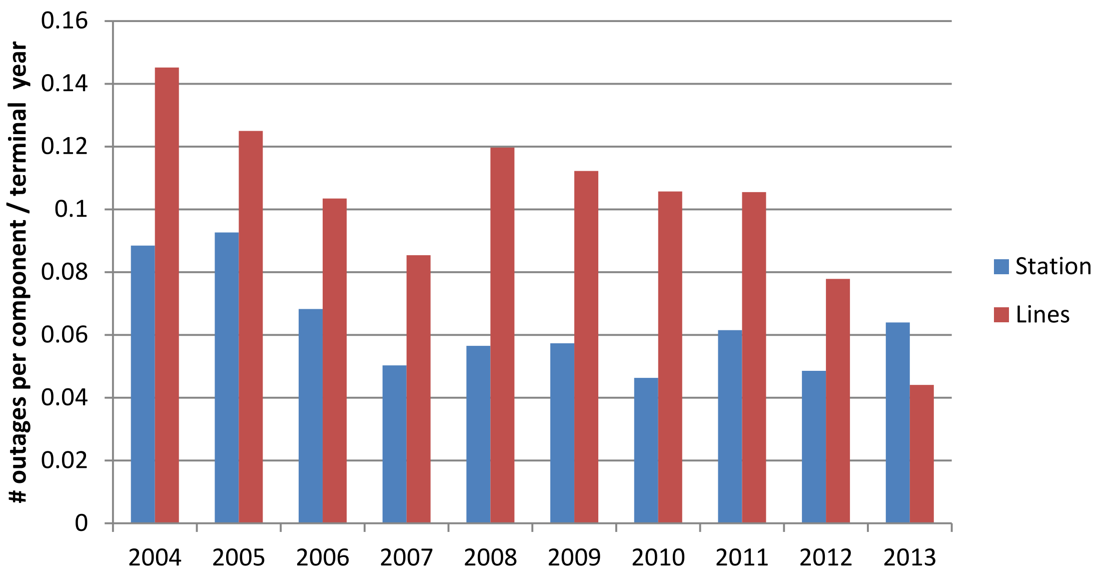


Figure 20: Station and Lines Equipment Direct Forced Outage Frequency Caused by Protection Equipment

PALC relays, one type of solid state protection system, have shown an increase in recorded defects and trouble calls over the last 10 years. Performance data shown in Figure 21 demonstrates an overall increasing trend in defects affecting PALC relays, with the moving 4 year average increasing 63% over the last the 6 years. Targeted investment to replace PALC relays is required to arrest the increasing trend and maintain reliability.

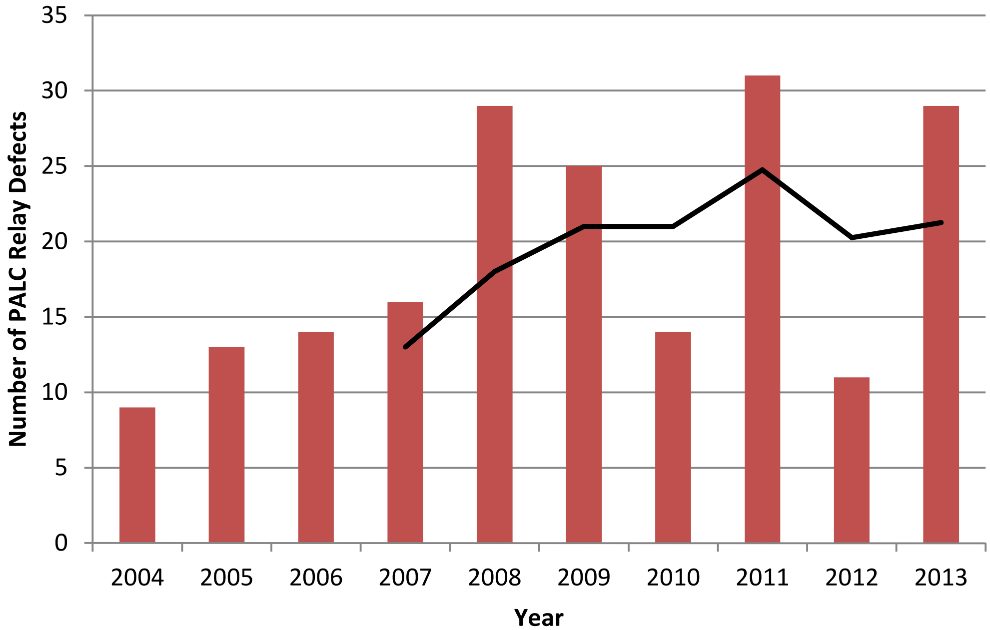


Figure 21: Historic Performance of PALC Relays

<u>Condition</u>

Protection system condition is an important indicator of equipment reliability. Condition is primarily based on age and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, which can alter the performance of the relay. This is primarily a concern with electromechanical systems, however component aging or defects and thermal cycling can also affect solid state and microprocessor based protection systems. However, as microprocessor based protections are a relatively new technology, detailed condition metrics and indicators are not as well established.

Based on results gathered, currently 26% of Hydro One Transmission's protection system population has a condition that puts it in high or very high risk, as outlined in Figure 22.

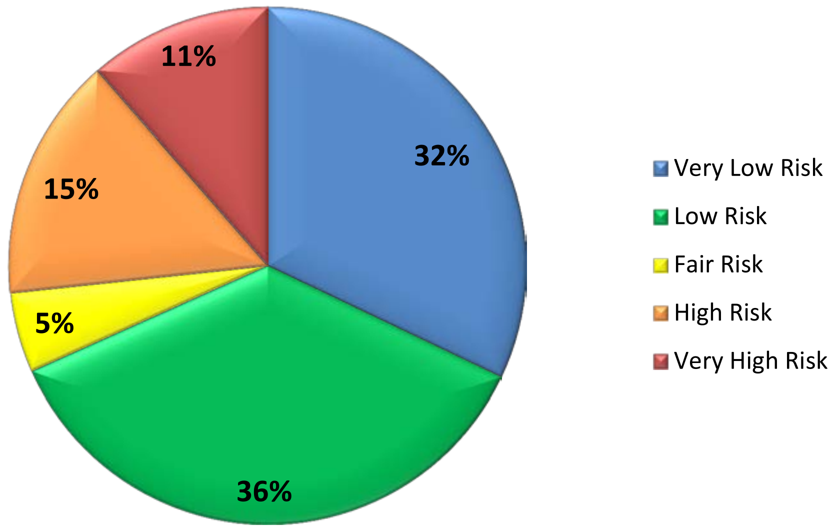


Figure 22: Protection Systems Fleet Condition Assessment

The protection systems which tend to be in the worst condition are also those operating beyond their expected service life or are identified as high risk such as PALC relays. Maintenance programs and re-verification intervals take into account the limitations and risks associated with each technological vintage to ensure continued and reliable operation. Electromechanical systems, as a result, require more frequent re-verification in contrast to microprocessor based systems to ensure reliable operation.

The sustaining capital replacement programs are targeted at replacing protections systems critical to system and customer reliability and with a high or very high risk of failure. However to maintain the condition of the fleet, given the demographics, a continued replacement program beyond historic replacement rates is required to maintain or gradually improve the overall fleet condition.

Other Influencing Factors

Other factors driving the increase in protection system replacements are summarized below.

- Safety – Operating protection systems beyond their expected service life increases the risk of systems failing to operate and potentially exposing workers and the public to the harm associated with uncontrolled flow of energy. Proactive replacements are required to mitigate this risk.

- Technical Obsolescence – Many protection systems are no longer available, limiting the availability of spares and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid state systems.

- Innovation – New microprocessor based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage. Modern microprocessor protection systems can be deployed with pre-tested configuration settings to facilitate fast and efficient system protection changes to accommodate dynamic changes to the configuration of the transmission system. Extended maintenance intervals for microprocessor based systems help contain OM&A expenditures and reduce life cycle costs.

Cost Trends and Impacts

Protection Systems Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Replacements*	389	350	340	350	365	450
% of Fleet	3.5%	2.9%	2.8%	2.9%	3.0%	3.7%
Capital ($M)	28.5**	53.5	53.8	56.3	57.9	70.5
OM&A ($M)	11.3	9.7	9.7	10.6	10.3	11.7

**Note that protection replacements above are conducted under both the categories of Protection and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.*
****Note: Excludes capital expenditures for protection replacements included under Station Re-Investment*

The capital replacement rate in the test years is increasing over the bridge and historic levels. Continued renewal of the fleet at an increased rate is required to maintain an acceptable level of risk over the test years and prevent an increase of protections operating beyond their expected service. This will be achieved by greater deployment of modular, prefabricated PCT buildings at load stations where a significant numbers of protections are in need of replacement; focused replacements of system critical protections; targeted replacements of failure prone relays such as PALC based systems; and bundling work opportunities with major refurbishment or re-investment projects.

OM&A expenditures are generally consistent year over year with minor variations attributed to time-based scheduling of preventative maintenance. Replacement of electromechanical and solid state protections with modern microprocessor based protection systems is expected to lower future maintenance costs as the new technology allows for extended maintenance intervals.

Protections are a critical component in ensuring a safe and reliable bulk electricity system, and maintaining a reliable supply to customers. Maintaining the fleet in an adequate condition will help preserve reliability in line with good utility practice and regulatory obligations.

4.2 Transmission Line Assets

4.2.1 Transmission Overhead Conductor and Hardware

Asset Overview

Hydro One's transmission system consists of approximately 30,000 circuit km of overhead transmission lines. Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One's transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV.

The bulk of Hydro One Transmission's overhead lines are constructed using aluminum conductors reinforced with a steel core ("ACSR"), as depicted in Figure 23. ACSR is the most prominent type of conductor used on transmission systems. The conductors are supported by steel structures, porcelain insulators and connecting hardware. The lines are protected from lightning strikes by shieldwire mounted above the conductors.

Figure 23: ACSR Conductor

- Currently 19% of conductor population is beyond their expected service life. The conductor kilometers beyond its expected service life will almost double over the next 10 years.
- The condition of the conductors is such that 8% present fair or high condition risks that need to be mitigated.
- The number and duration of forced outages for conductors has shown slight improvement of the last 10 years. However conductor failures can have very negative consequences both in terms of reliability and safety.

Given the current demographics of the conductor population, condition trend and the risks associated with conductor failures, an increased rate of conductor sampling, testing and replacements over historic years is required to maintain current levels of performance and risk.

Asset Strategy

Hydro One Transmission's strategy for conductors is to manage the aging conductor population in a manner that preserves reliability while minimizing rate impacts. Hydro One Transmission intends on continuing with a replacement rate of approximately 0.3% per year to manage risks associated with operating an aged conductor population. Hydro One Transmission considers condition assessment results, performance data, asset demographics and the consequence of failure to system and customer reliability when making replacement decisions related to conductors. When a conductor is deemed to have reached its end of service life all major components within that line section including the structures, shieldwire, u-bolts and insulators are assessed and refurbished to meet future system requirements. This work bundling of conductor replacement with refurbishment of other transmission line components at the same time is a cost effective approach that is taken in replacing all conductors.

Asset Assessment Details

<u>Demographics</u>

Hydro One Transmission uses an expected service life ("ESL") of approximately 70 years for conductors; although this can vary based on several factors, environmental conditions being the primary factor. The average age of transmission conductor fleet is currently 52 years of age and 19% of the conductors are currently beyond their expected service life. The demographics of the conductor population is outlined in Figure 24.

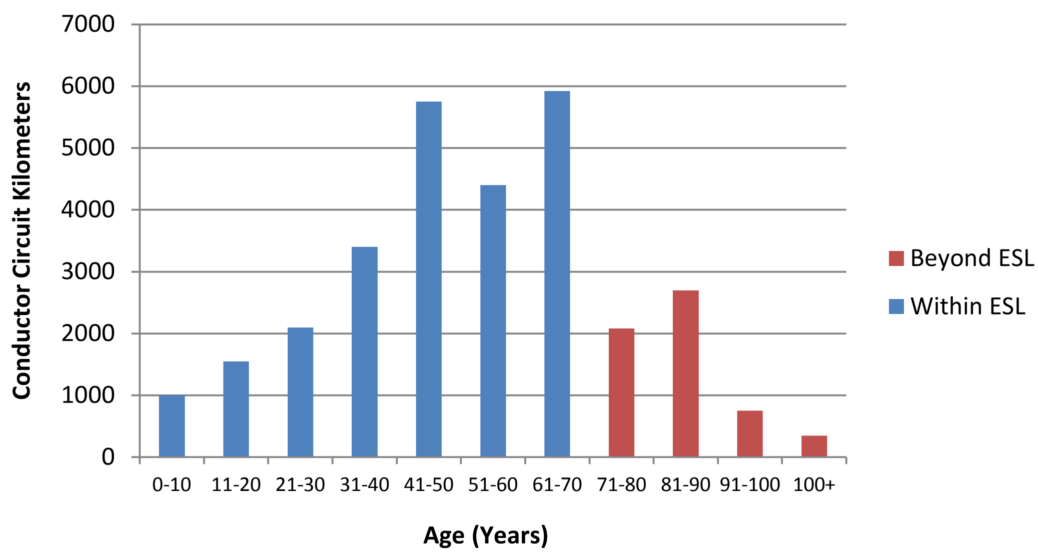


Figure 24: Demographics of Conductor Fleet

Although there have been recent increases in replacement rates to deal with immediate risks; as Figure 25 demonstrates by 2024 the number of conductors beyond their expected service life will nearly double. Hence a significant increase in future replacements will be required to maintain acceptable fleet demographics. If untended this would significantly increase the risk associated with system and customer reliability, as well as impacting exposure to public safety risks on populated areas, road crossings, public use of transmission corridors, etc.

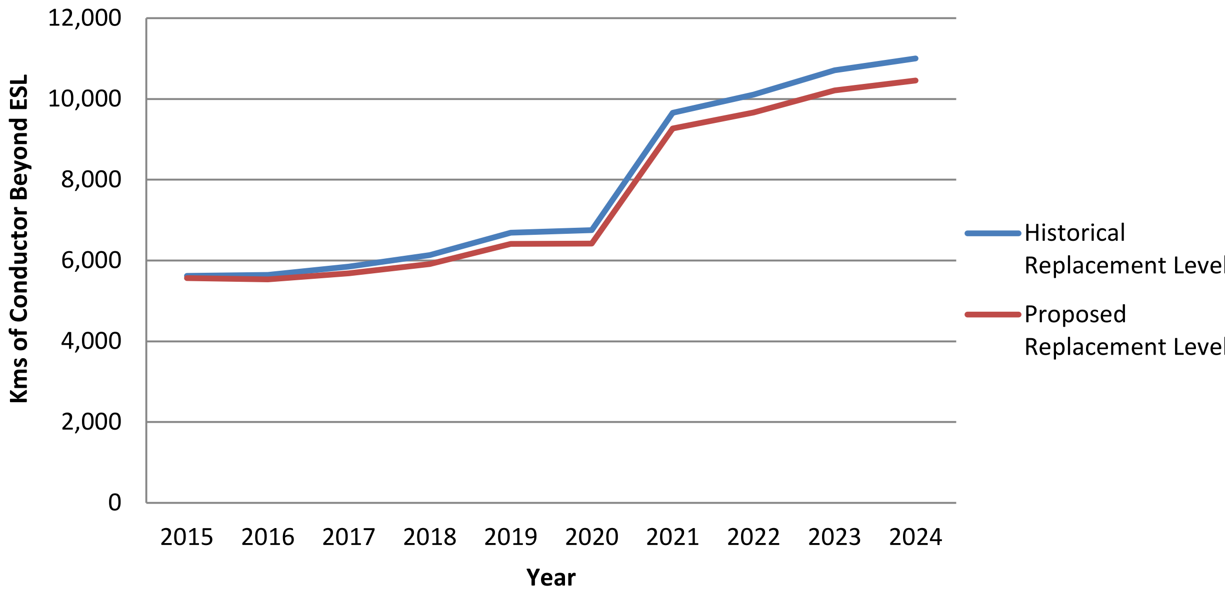


Figure 25: Projection of Conductor Beyond Expected Service Life

Performance

Conductor failure can have very negative consequences both in terms of reliability and safety. The number of forced outages due to conductor failures has shown slight improvement over the past 10 years, as outlined in Figure 26.

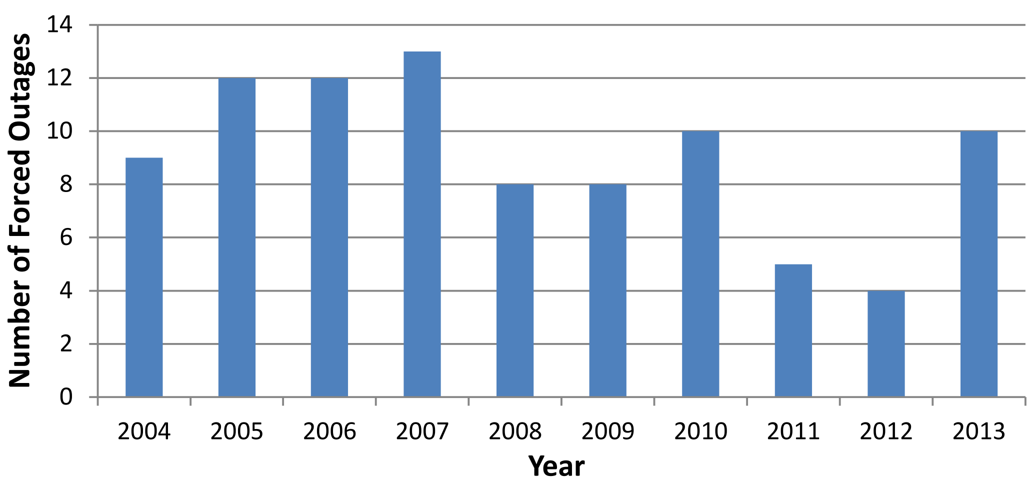
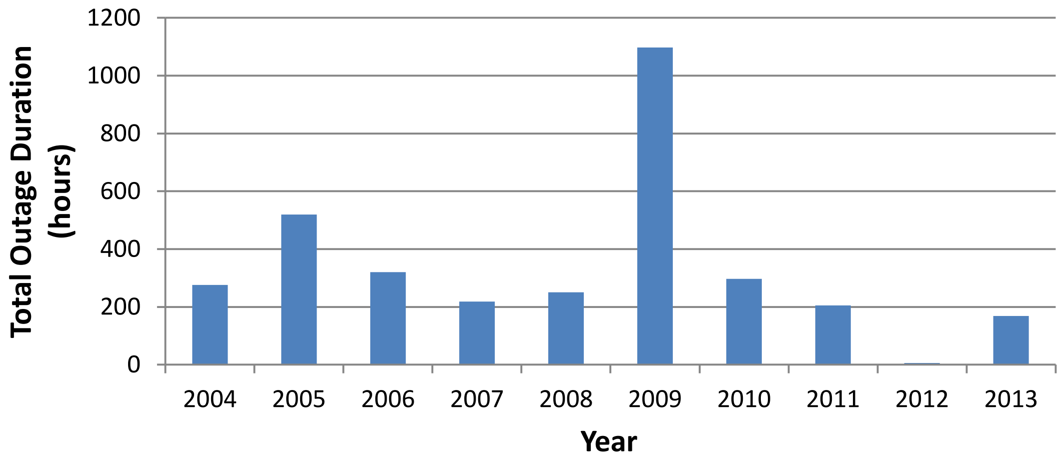


Figure 26: Forced Outage due to Conductor and related Hardware Failures

The forced outage duration due to conductor failure, displayed in Figure 27, demonstrates that conductor outage duration has been relatively stable over the last 10 years.



**Note: The extreme outage duration in 2009 was due to an emergency conductor replacement on B10H/B20H circuits.*

Figure 27: Forced Outage Duration due to Conductor and related Hardware Failures

It is expected that the outage frequency and duration performance will deteriorate given the demographics and condition of the fleet over the next 10 to 20 years if programs are not increased.

<u>Condition</u>

Hydro One Transmission has implemented a condition assessment program to assess condition of conductors after they reach 50 years of age. The corrosivity of the surrounding environment will have a significant impact on the condition of the conductor.

The results from these tests and previous studies carried out on life expectancy of conductors indicate that currently 8% of Hydro One Transmission's conductor population has condition that puts it in fair or high risk, as outlined in Figure 28.

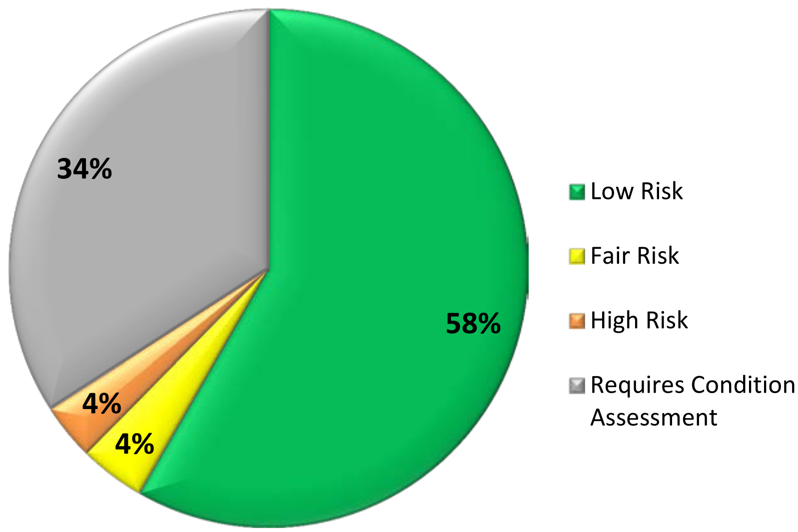


Figure 28: Conductor Fleet Condition Assessment

Hydro One Transmission continues to assess the merits of utilizing the use of a remote controlled conductor assessment device that can be used on energized lines and crawls along the conductor to non-destructively assess conductor condition.

Other Influencing Factors

- Aeolian Vibration - Geographical location, line orientation and more importantly conductor tension contribute to level of vibration each circuit experiences, which directly influences the useful lifespan of a conductor. Hydro One Transmission has experienced premature conductor failures due to a combination of conductor condition and conductor fatigue due to vibration.

- Safety – Given that transmission lines operate in the public domain, additional consideration must be given to the consequence of failure and potential impact on safety of the public. Factors as right-of-way use and proximity to road crossings are factors when assessing risk.

Cost Trends and Impacts

Conductor Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Kms of Circuit Replacements	37	22	75	113	99	60
% of Fleet	0.1%	0.1%	0.3%	0.4%	0.3%	0.2%
Capital ($M)	10.2	8.6	17.8	33.2	36.8	29.3
OM&A ($M)	10.6	10.6	9.4	13.1	14.2	14.5

The capital replacement rate has increased in recent years from a historic level of 0.1% to on average 0.3% of the fleet per year. Continued renewal of the fleet at this rate should be sufficient to continue to maintain the current level of risk through the test years. The circuits being addressed in the bridge and test years have all been identified as in poor condition through the testing and assessment process. The proposed OM&A expenditures level has increased slightly due to the need for more condition assessments to manage the risk of an aging fleet.

4.2.2 <u>Transmission Wood Pole Structures</u>

Asset Overview

Hydro One Transmission has approximately 42,000 wood pole structures. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. These wood pole structures are utilized on 230 kV and 115 kV circuits depending on the geographic location and security requirements of the line. The majority of transmission wood pole circuits support radial feed circuits, and as a result wood pole or cross-arm failure can often result in a direct customer outage.

The two basic transmission wood pole design types in use by Hydro One Transmission are "H Frame" design and "Single Pole" design. The H-Frame design consists of two poles and a cross-arm; whereas the "Single Pole" design uses a single pole with steel or wood cross-arms to suspend the conductors.

At the 230 kV circuit level a larger wood pole structure was traditionally used which utilized smaller wood poles as cross-arms to support the insulators and conductors. This structure type is known as the Gulfport type and approximately 5,800 of these where installed on the transmission system beginning in the mid 1960's. However, the small poles used as cross-arms were subsequently found to be defective and suffer from internal rot. Replacement programs over the past 10 years have been focused on eliminating these from the system.

Figures 29A through 29C illustrate these three different wood pole design types used in Hydro One's transmission system.

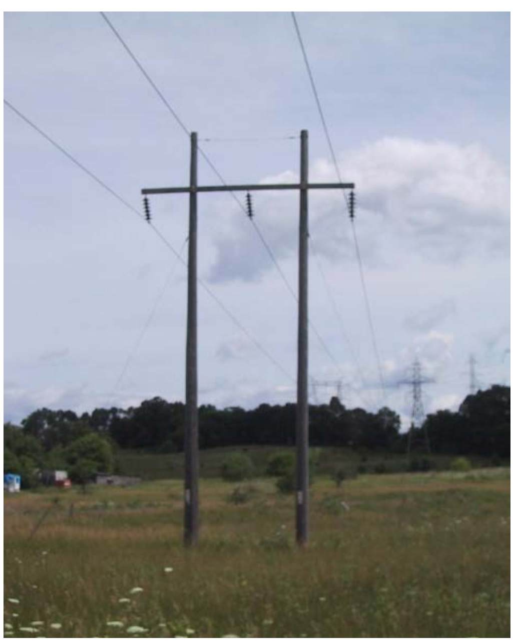


Figure 29A: Wood Pole H–Frame Structure

Figure 29B: Wishbone Structure

Figure 29C: 230 kV Gulfport Structure (with defective/failed cross-arm)

- Currently 26% of the wood pole population is beyond its expected service life.
- The condition of the wood pole fleet, determined through industry standard maintenance practices, is such that 16% present fair or high condition risks that need to be mitigated.
- The number and duration of forced outages for wood poles has shown slight improvement over the last 10 years. However wood poles failures can have very negative consequence to reliability due to the majority of transmission wood pole circuits supporting radial feed circuits.

Given the current demographics of the wood pole population, condition trend and the risks associated with wood pole failures, the continuation of a rate of replacement of 2% is required to maintain current levels of performance and risk.

Asset Strategy

Hydro One Transmission’s strategy for wood poles is to manage the aging wood pole population in a manner that preserves reliability while minimizing rate impacts. Hydro One Transmission intends on continuing with a replacement rate of approximately 2% per year to manage risks associated with operating an aged wood pole population and the defective 230 kV Gulfport type structures. Hydro One Transmission considers results of wood pole inspections and tests done in accordance with CSA guidelines, performance data, asset demographics and the consequence of failure to system and customer reliability when making replacement decisions related to wood poles. This will result in a continuation of the strategy to proactively replace wood poles to reduce wood pole failures that impact customer reliability, and minimize emergency response activities that have a higher risk of negatively impacting environmentally sensitive areas.

Asset Assessment Details

Demographics

Based on Hydro One Transmission’s experience, the normal expected service life (“ESL”) used for wood poles is about 50 years. Wood poles and cross-arms are normally treated with preservatives in order to prevent premature decay and extend their expected service life. The average age of the wood pole fleet is currently 32 years and 26% of the wood poles are currently beyond their expected service life. The demographics of the wood pole population is outlined in Figure 30.

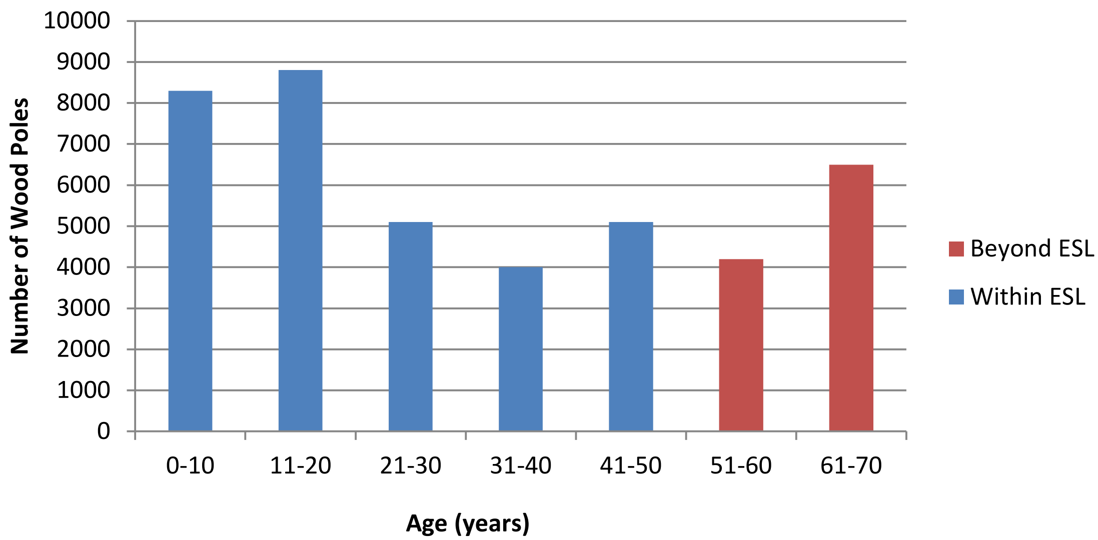


Figure 30: Demographics of the Wood Pole Fleet

Hydro One Transmission is proposing to maintain the current historic replacement rate of approximately 2% over the test years. As can be seen in Figure 31, at this rate of replacement the number of wood poles beyond their expected service life will improve from the present 26% to 18% by 2024.

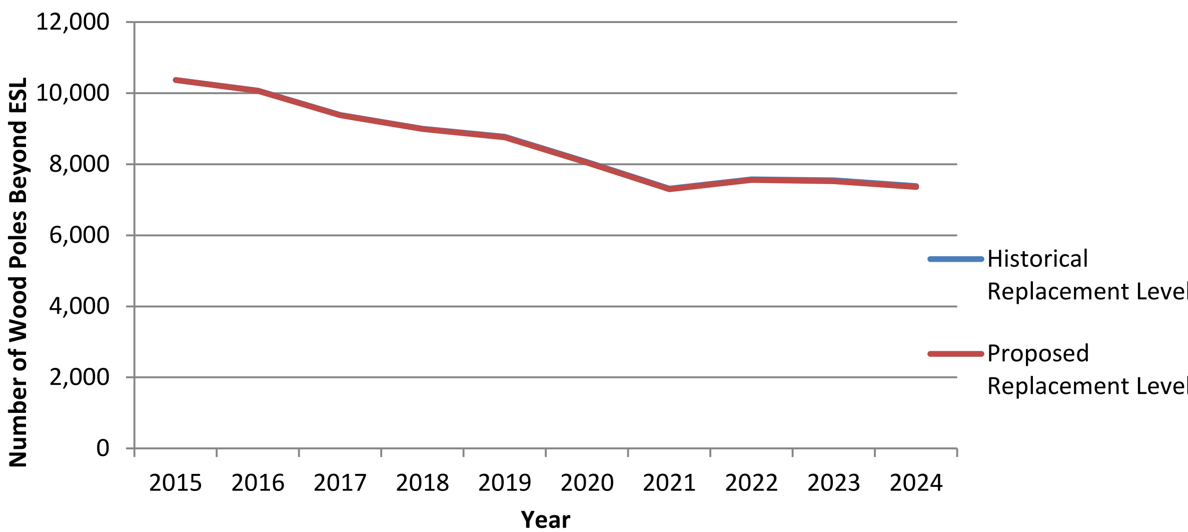


Figure 31: Projection of Wood Poles Beyond Expected Service Life

Performance

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm can often result in a direct customer outage. Many of these northern wood pole circuits feed major industrial customers and without an adequate supply of power, these customers are often forced to shut down until power is restored.

The number of forced outages due to wood pole structure failures has shown slight improvement over the past 10 years, as outlined in Figure 32, based on the current rate of replacement to address end of life wood poles and the defective Gulfport structures on the system.

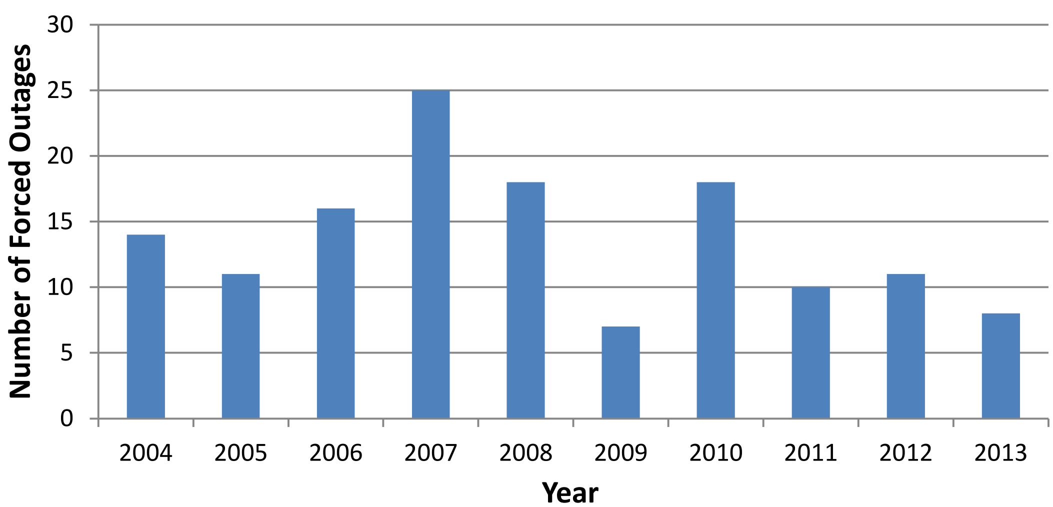


Figure 32: Forced Outages Due to Wood Pole Failures

The forced outage duration due to wood pole failures, displayed in Figure 33, demonstrates that wood pole outage duration has been stable over the last 10 years, except for the extreme spike in 2010. This type of year is not unexpected given many of these circuits are radial supplies and in remote locations, with difficult access.

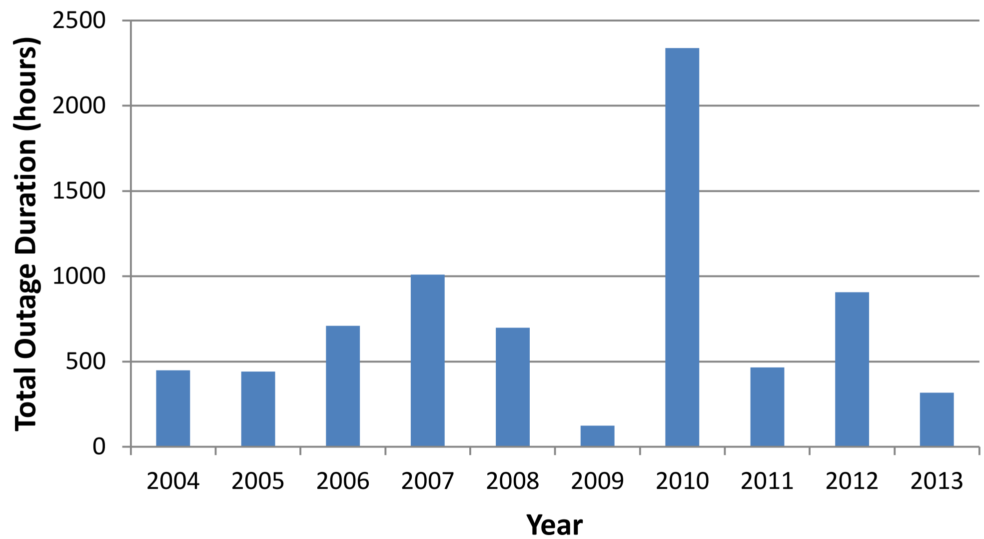


Figure 33: Forced Outage Duration due to Wood Pole Failures

At the current rate of replacement, this level of reliability is expected to remain consistent over the next 10 years hence maintaining current level of customer interruption performance.

<u>Condition</u>

Wood structures deteriorate over time; the rate of deterioration depends on location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Wood pole structures are comprised of either a single pole or multiple wood poles with a wood cross-arm which is bolted to the poles to support the insulator strings and conductors. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Wood pole assessments are undertaken to inspect the condition of cross-arms and pole tops, and to evaluate the soundness of the wood near the ground line. Based on the current condition assessment, 16% of Hydro One Transmission's wood pole population has condition that puts it in fair or high risk, as outlined in Figure 34. The assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Approximately 10% of the wood pole population needs to be assessed to determine their current condition risk.

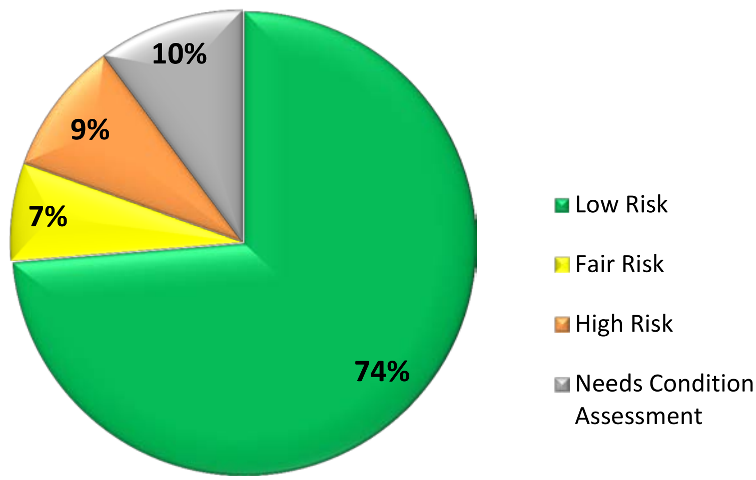


Figure 34: Wood Pole Fleet Condition Assessment

The number of poles reaching the end of life identified each year through condition assessments is in-line with the current replacement rate, and hence the number of wood poles in fair and high risk condition is expected to remain stable. As a result, reliability and safety risks will be in-line with past performance.

Cost Trends and Impacts

Wood Pole Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Replacements	862	763	830	850	850	850
% of Fleet	2.1%	1.8%	2.0%	2.0%	2.0%	2.0%
Capital ($M)	30.1	27.2	32.7	27.2	27.7	28.2
OM&A ($M)	2.9	4.4	3.1	4.4	4.1	4.2

The capital replacement rate in the test years remains consistent with the bridge year and historic levels. Continued renewal of the fleet at this rate has been very effective at keeping pace with the number of structures that reach their expected service life. Once the remaining defective Gulfport structures are eliminated from the transmission system within 4 years, the number of annual replacements is expected to be reduced.

OM&A expenditures are generally consistent year over year with some minor variation as accomplishment of targeted programs is completed.

Hydro One Transmission has also now begun to use composite poles to replace approximately 25% of its wood pole population that have reached their expected service life. This will allow for evaluation of this emerging technology product to determine if life cycle costs of these assets can be reduced. Any benefits realized would be on the longer term horizon.

4.2.3 <u>Transmission Steel Structures</u>

Asset Overview

Hydro One Transmission has approximately 50,000 steel structures, as depicted in Figure 35A, on the transmission system to support the transmission lines across the province. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 500 kV.

Steel structures are manufactured with a hot dipped galvanized zinc coating to protect the steel from corrosion. Based on Hydro One Transmission and industry experience, the expected service life of zinc coating can be anywhere from 30 to 60 years, and is the primary life-limiting factor for steel structures. Once a structure has lost its galvanizing and has begun to corrode, as depicted in Figure 35B, the bare steel underneath is exposed to the environment. If corrosion is allowed to continue, the steel structure will begin to lose mechanical strength. Recoating the structure with zinc-based paint, as depicted in Figure 35C, will provide on-going protection to the underlying steel.

Figure 35A: Steel Tower Structure

Figure 35B: Steel Tower with Corrosion

Figure 35C: Steel Tower Recoated

- Currently 21% of the steel structure population is beyond its expected service life. Continuing at the historic rate of replacement, the number of steel structures beyond their expected service life would increase to 24% by year 2024.

- The condition of the steel structure fleet, determined through industry standard maintenance practices, is such that 3% present fair or high condition risks that need to be mitigated.
- The number of forced outages for steel structure has shown slight deterioration over the last 10 years; although the duration of forced outages for steel structures has remained stable.

Given the current demographics of the steel structure population, condition trend and the risks associated with steel structure failures, an increase in the fleet renewal is required to maintain current levels of performance and risk.

Asset Strategy

Hydro One Transmission's strategy for steel structures is to manage the aging fleet of steel structures through a combination of planned replacements, component refurbishments and tower coating in order to maintain reliability of the system while minimizing rate impacts.

Effective tower coating can maintain a steel tower structure indefinitely by re-application of the coating approximately every 20 to 25 years depending on the installed environment of the structure. However tower replacement is a requirement once the structure has degraded to a point where recoating cannot stop the corrosion process. Hydro One Transmission strives to recoat before this point is reached; as the life cycle costs of regular coating programs are estimated to be less than half of a replacement strategy.

Asset Assessment Details

<u>Demographics</u>

Hydro One Transmission uses a normal expected service life ("ESL") of between 80 to 100 years for steel structures if the structures are not re-coated. The average age of the steel structure fleet is currently 56 years of age and 21% are currently beyond their ESL; for which 4% of these are beyond 100 years. The demographics of the steel structure population is outlined in Figure 36.

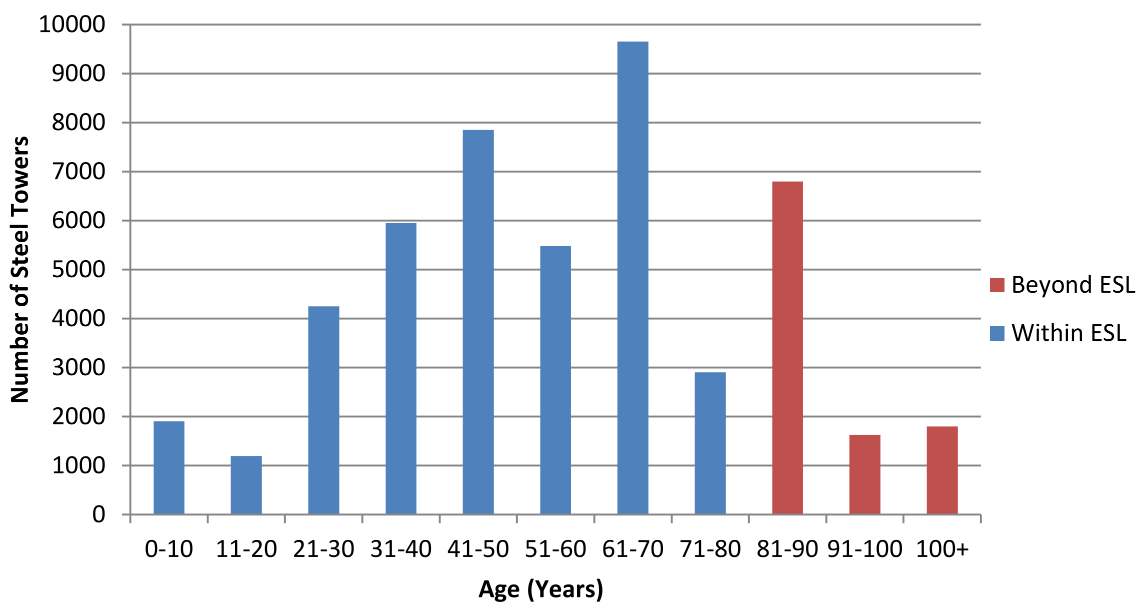


Figure 36: Demographics of Steel Structure Fleet

As can be seen in Figure 37, continuing at the historic fleet renewal rate would result in the percentage of steel structures beyond their expected service life increasing to 24% by 2024. However under the proposed plan, the percentage of steel structures beyond their expected service life will decrease from 21% to 18% over the next 10 years.

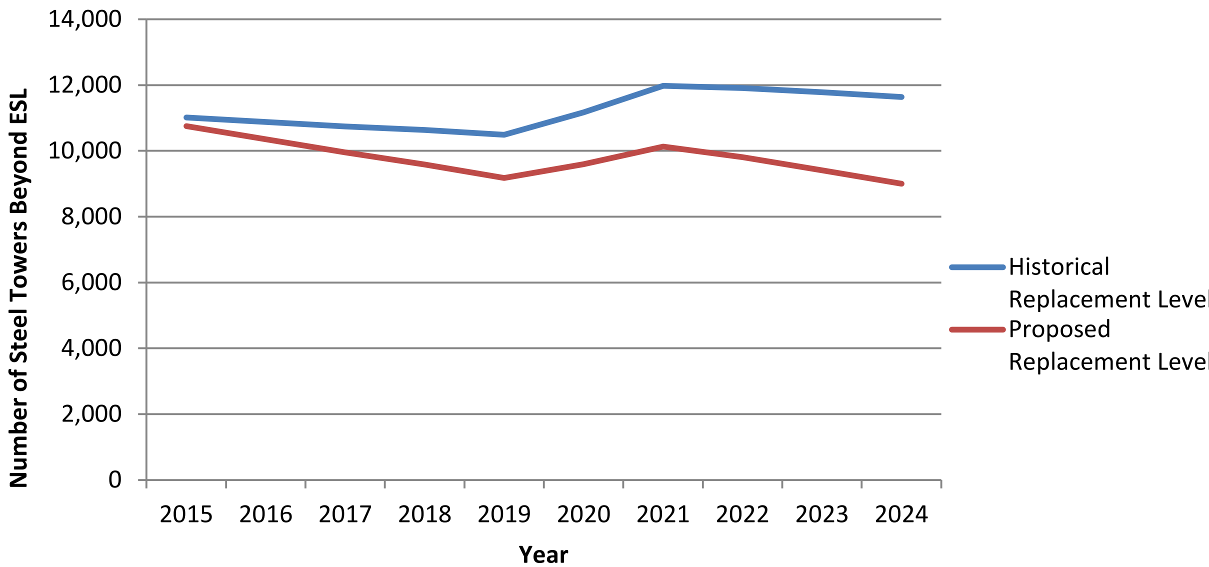


Figure 37: Projection of Steel Structures Beyond Expected Service Life

Performance

Forced outages for steel structures represents the number of times an outage is caused due to a steel structure failure such as failed, broken or bent tower member. It excludes forced outages caused by external interferences (animal contact, weather, etc.). Although single circuit tower outages typically do not result in delivery point interruptions, a multiple circuit tower failure can result in customer outages.

The number of forced outages due to steel structure failures has shown slight increase over the past 10 years, as outlined in Figure 38. With the current condition of the steel structures and the demographics of the fleet, it is expected that an increase in the capital programs will be required to prevent future increases in forced outages due to steel structures.

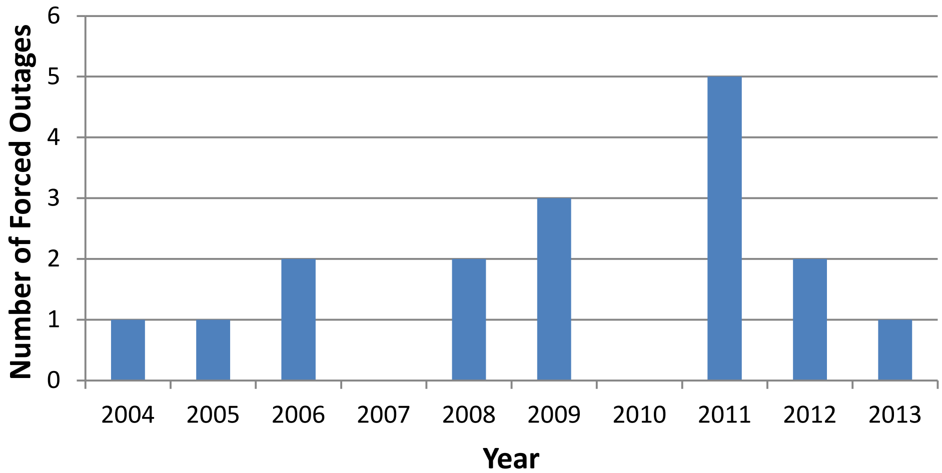


Figure 38: Forced Outages due to Steel Structure Failures

The forced outage duration due to steel structure failures, displayed in Figure 39, demonstrates a stable outage duration trend over the last 10 years, except for the extreme spikes in 2004 and 2005. These type of spikes are not unexpected given the very remote locations of some of the circuits, with difficult access. This can place considerable strain on the system as it may result in loss of supply to large customers including local distribution companies and generation connections.

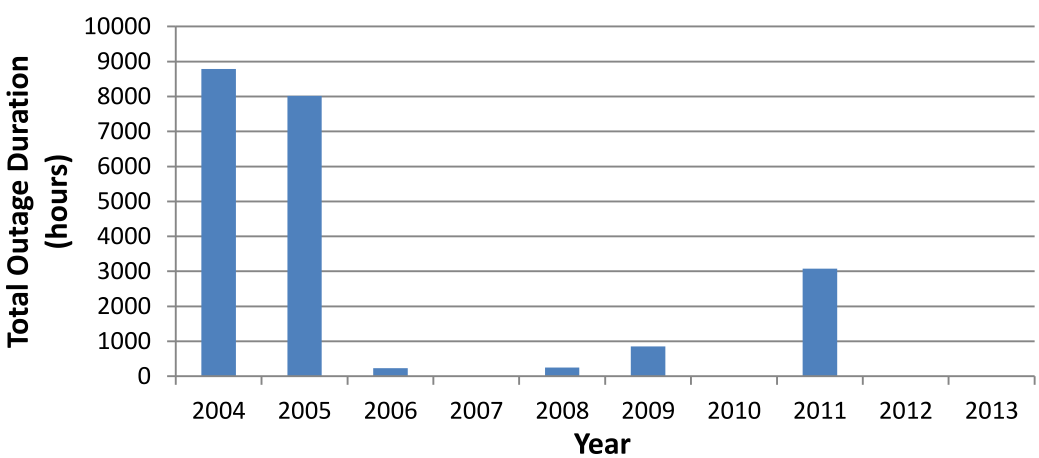


Figure 39: Forced Outage Duration due to Steel Structure Failures

<u>Condition</u>

The condition of the steel structures is determined through inspections, patrols and detailed corrosion assessment. Towers are visually inspected in accordance with NACE ("Nation Association of Corrosion Engineers") guidelines on the degree of corrosion. Detailed corrosion assessment includes climbing towers and measuring the remaining thickness of protective coating, loss of metal if any and assessment of bolts and fittings.

Based on the current assessment of condition, 3% of Hydro One Transmission steel structures have condition in the fair or high risk category, as outlined in Figure 40, and meet the current refurbishment/coating criteria. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. An additional 14% of steel structures need to be assessed in order to determine their condition.

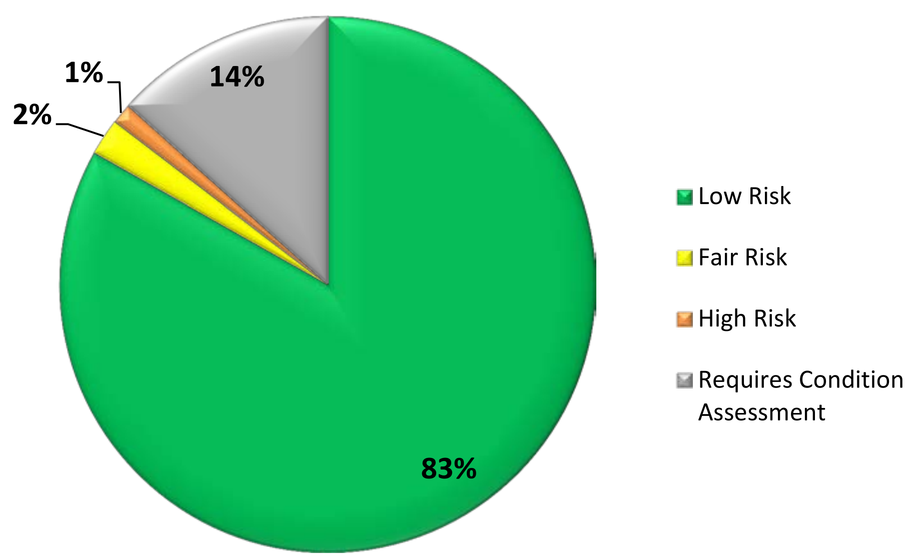


Figure 40: Steel Structure Fleet Condition Assessment

In order to maintain the condition of the fleet, the rate of refurbishment/coating will need to be increased. Towers in fair and high condition will require coating within the next 5 years. Should they exceed this optimum time to coat, the structures will eventually require either partial or full replacement.

Other Influencing Factors

- Innovation - Hydro One Transmission is continuing to investigate using alternative recoating products in order to reduce the amount of steel surface preparation and increase the drying process. This should reduce outage time and therefore permit a higher number of towers to be coated within the limited outage windows. Hydro One Transmission also continues to explore new steel tower coatings that are longer lasting than those that are currently commercially available.

Cost Trends and Impacts

Steel Structure Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Refurbishments	0	226	218	350	350	400
# of Replacements	0	0	17	4	4	12
% of Fleet	0%	0.5%	0.5%	0.7%	0.7%	0.8%
Capital ($M)	0.6	8.7	13.3	11.1	10.7	16.0
OM&A ($M)	4.7	4.8	3.1	4.4	4.1	4.2

The capital investment in the test years is an increase over historic levels. The strategy to manage the aging fleet of steel towers is a combination of planned replacements, component refurbishment and tower coating. The number of towers that have been refurbished, coated or replaced over the past 10 years has been very low. The result of recent condition inspections has pointed to rapid deterioration of steel structures in highly corrosive areas, which demonstrates a need to increase the fleet renewal. Hydro One Transmission plans to undertake an aggressive tower coating program to sustain these assets. Tower coating has been identified as the preferred alternative as it has a life cycle cost of roughly half that of tower replacement and is less impactive to the system as circuit outages required for coating are minimal.

OM&A expenditures are relatively stable with assessment activities performed frequently to assess zinc coating thickness and member condition.

4.2.4 Transmission Underground Cables

Asset Overview

Hydro One’s transmission system consists of approximately 290 km of underground cables that supply city centres in Toronto, Ottawa and Hamilton with short sections in London, Sarnia, Picton, Windsor and Thunder Bay. Transmission underground cables are typically extensions to, or links between, portions of the overhead transmission system operating at 230 kV and 115 kV. Underground cables are mainly used in urban areas where it is either impossible, or extremely difficult to build overhead transmission lines due to legal, environmental and safety reasons.

Depending on the cable design the three phase conductors may be contained together within a steel pipe or each phase conductor self-contained in its own sheath and installed separately underground. Transmission underground cables are systems, similar to transmission lines, made up of numerous components all of which need to integrate and function properly in order to deliver power with the reliability that is demanded.

There are three different types of high voltage underground cables in use on the transmission system: Low-Pressure Oil-Filled (“LPOF”) cables, High-Pressure Oil-Filled Pipe-Type (“HPOF”) cables, and Extruded Cross Linked Polyethylene (“XLPE”) cables.

Figures 41A through 41C illustrate the three types of underground cables used in Hydro One's transmission system.

Figure 41A: LPOF Cable

Figure 41B: HPOF Cable

Figure 41C: XLPE Cable

- Currently 16% of the underground cable population is beyond its expected service life. Continuing at the historic rate of replacement, the number of underground cables beyond their expected service life would increase to 30% by 2024.
- The condition of the underground cable fleet, determined through industry standard maintenance practices, is such that 14% present fair or high condition risks that need to be mitigated.
- The number of forced outages for underground cables has shown slight improvement over the last 10 years. However, the duration of forced outages for underground cables has been increasing. Due to the nature and construction of these assets, failures can result in significant reliability and environmental impacts.

Given the current aging demographics of the underground cable population, condition trend along with the nature of the problems recently experienced, and the risks associated with underground cables failures, are all indicative of the need to increase the historic level of replacement in order to preserve the current levels of performance and risk.

Asset Strategy

Hydro One Transmission’s strategy for underground cables is to manage the aging underground cables that supply city centres in Toronto, Ottawa and Hamilton in a matter that preserves reliability while minimizing rate impacts. Hydro One Transmission has employed and will continue with its rigorous maintenance program (involving inspections, analysis, and diagnostic testing of cables, vaults, jackets and potheads) that extends the life of these assets. Hydro One Transmission plans to continue forward with an average replacement rate consistent with the bridge year in order to manage the reliability and environmental risks associated with operating an aged underground cable population.

Asset Assessment Details

Demographics

Hydro One Transmission uses a normal expected service life ("ESL") of 50 years for underground transmission cables, which is based primarily on the original design expectations. However, due to the very rigorous maintenance program employed by Hydro One Transmission a number of cables beyond this age are still in satisfactory operating condition. The average age of the underground cable fleet is currently about 37 years and about 16% of cables are beyond their expected service life. The demographics of the underground cable population is outlined in Figure 42.

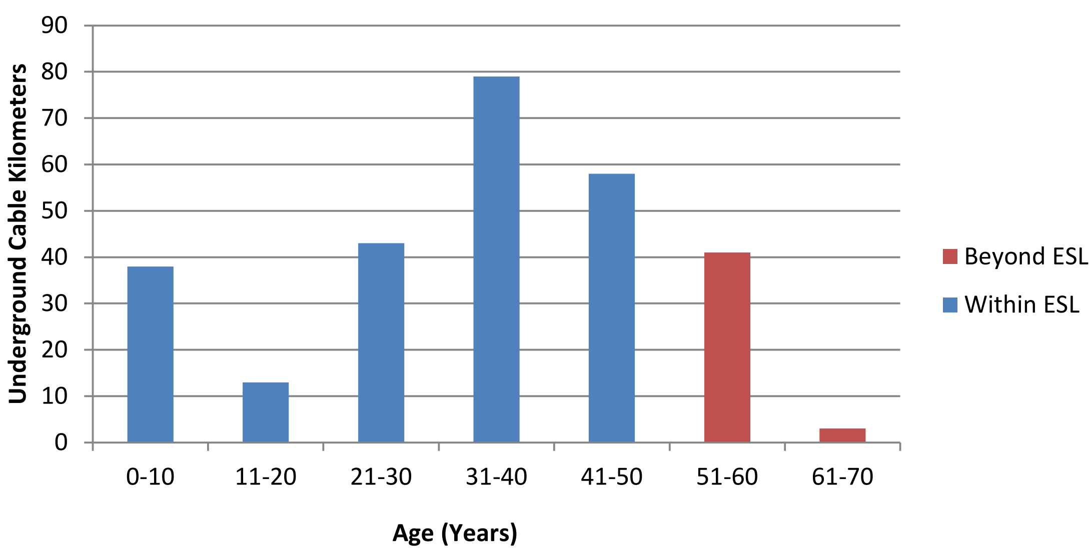


Figure 42: Demographics of Underground Cables Fleet

The potential risks to reliability and safety as a result of the aging demographics and deteriorating cable condition needs to be managed through a continued rigorous maintenance program to detect developing defects, as well as through capital replacement programs. As can be seen in Figure 43, continuing at the historic rate of replacement would result in the percentage of underground cables beyond their expected service life increasing to 30% by

2024. However at the proposed replacement rate, the percentage of underground cables beyond their expected service life will increase from 16% to 20% by 2024.

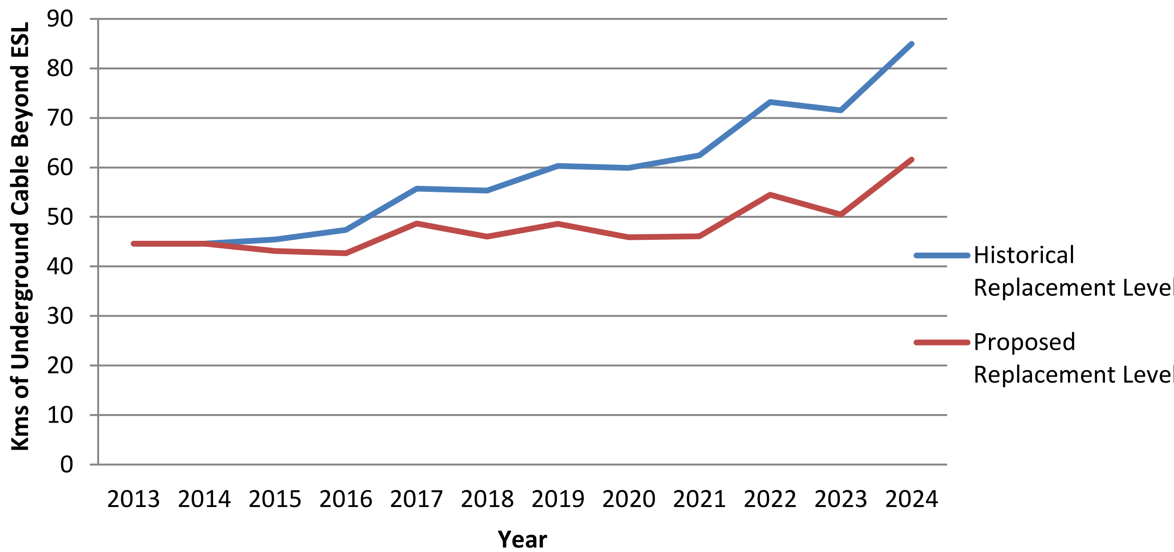


Figure 43: Projection of Underground Cables Beyond Expected Service Life

Performance

The underground transmission cables were first designed and installed with built-in redundancy and capacity so that failures would not immediately result in outages to customers. Many of these cables are still in service and are starting to experience the effects of aging and the increased loading due to the expansion in the downtown areas. There has been minimal impact in customer reliability due to underground cable failures over the last 10 years; however as the asset ages there is increased risk of failure with the underground system.

The number of forced outages due to a failure on part of the underground cable system has shown a slight improvement over the past 10 years, as outlined in Figure 44. There have been a number of major component replacement projects during the past 10 years including joint, termination, oil pressure system and bonding upgrades which have contributed to this reduction in the forced outages.

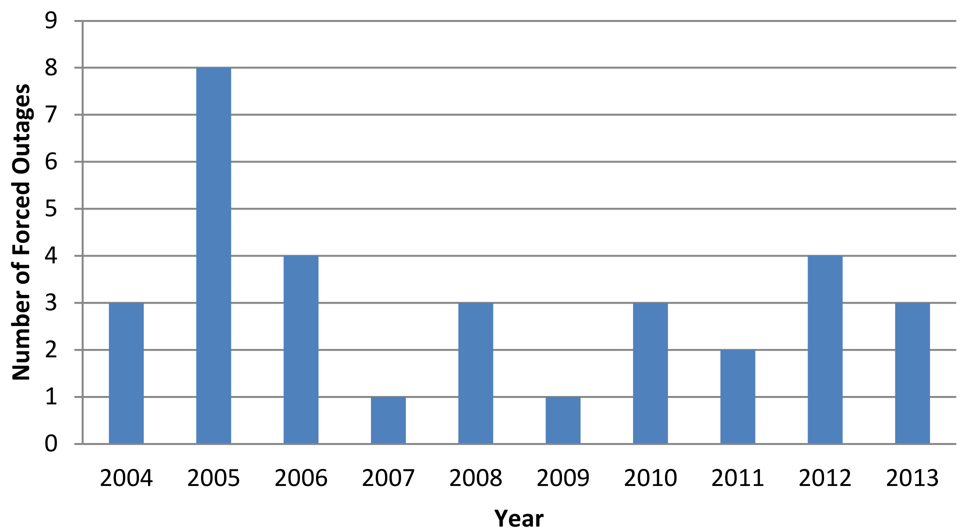


Figure 44: Forced Outages due to Underground Cable Failures

The forced outage duration of each occurrence was increasing significantly during the period from 2008 to 2011 but has been minimal during the last two years, as depicted in Figure 45. This recent decrease is mainly contributable to the replacement of two high risk end of life cable circuits H2JK and K6J. However, the increase in outage duration is representative of problems becoming more serious.

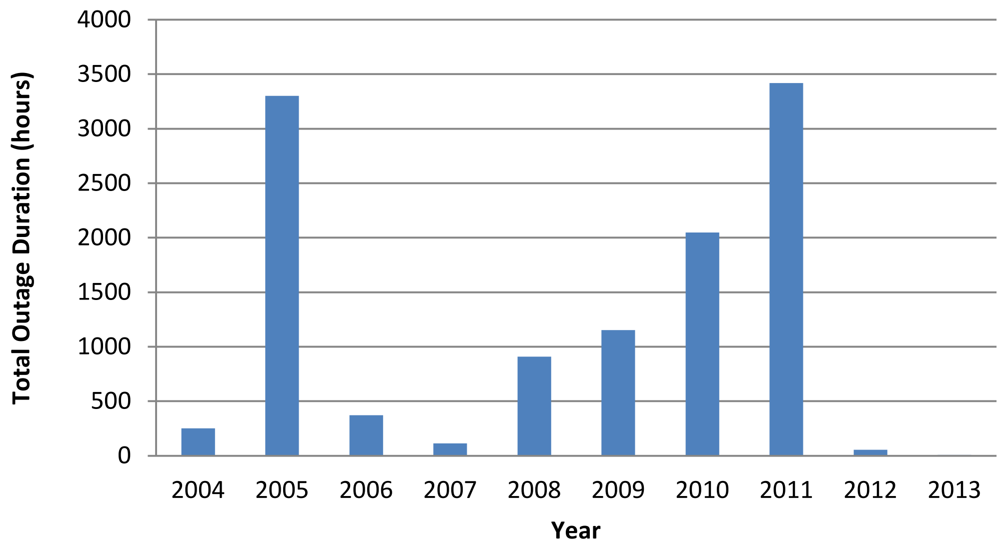


Figure 45: Duration of Forced Outages due to Underground Cable Failures

The forced outages depicted in Figure 44 and 45 are failures that were significant enough to require the circuit to be forced out of service. There are many other cases where equipment defects and cable leaks have occurred but were not severe enough to force the circuit from service but instead were addressed under a planned outage. Considering the deteriorating condition and demographics of the fleet, the continuation of a rate of replacement consistent with the bridge year is required to maintain the current forced outage frequency.

<u>Condition</u>

Hydro One Transmission assesses its underground cable fleet condition based on a variety of factors. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Not all sections of a buried cable are accessible for maintenance inspections and diagnostics, but the inspections are generally representative of the entire cable system.

Based on the current assessment of the underground cable fleet condition, 14% of Hydro One Transmission's underground cable population has condition that puts it in the fair or high risk, as outlined in Figure 46.

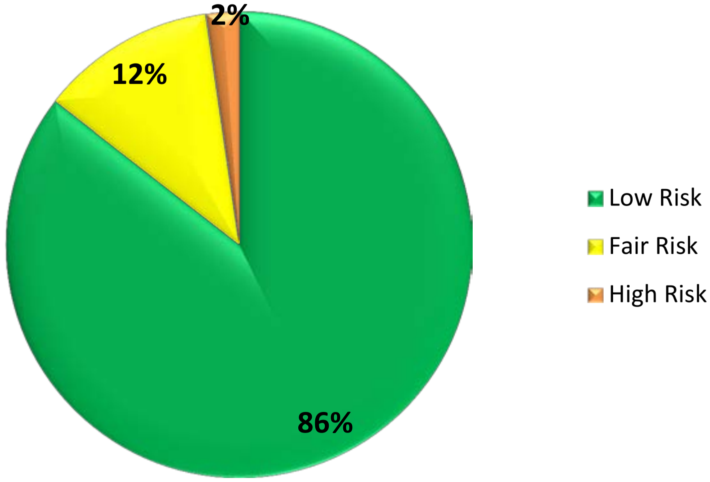


Figure 46: Underground Cable Fleet Condition Assessment

Underground cables located in major cities where loading has increased significantly since the original installation, impact the aging process and condition trend of these cables, as well as the likelihood of cable failures. In order to maintain the condition of the fleet, given the demographics and utilization, continued renewal of the fleet is required.

<u>Other Influencing Factors</u>

Other factors driving the increase in underground cable replacements are summarized below.

- Technical Obsolescence – There are some types of underground cables technology that are no longer available and supported by manufacturers. This is a significant factor for low pressure oil filled cables that rely on gravity feed oil reservoirs that are no longer available.

- Environmental Impacts – The failure of an underground cable can result in the leakage of oil into the surrounding area. In 2003, a downtown Toronto cable circuit

(H3L) failed which resulted in 5,500 litres of oil spilling into the Don River. The failure was located and repaired, which took over a month to complete. When the circuit was returned to service, it failed again after only 2 months at another location, indicating the need to replace.

- Equipment Loading – Cables are located in major cities where loading has increased significantly since original installation impacting the aging process as well as the number of cable failures.

- Criticality – Underground cables are used to supply the load of major cities, thus a failure of the cable can result in significant impact to customers. In 2010, a downtown Toronto cable circuit (H2JK) failed, since the other supply circuit (K6J) was on a planned outage at the time, the failure of the cable caused all of the five delivery points at Strachan TS to go out of service. The longer term major risk was if the condition of these two circuits deteriorated to a level that was impractical to repair, then both circuits would have to be removed from service resulting in considerable strain and risk to the system for a prolonged period of time.

Cost Trends and Impacts

Underground Cable Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Kms of Circuit Replacements	0	0	5.0	5.0	5.5	2.0
% of Fleet	0%	0%	1.7%	1.7%	1.9%	0.7%
Capital ($M)	0.6	2.6	32.8	19.4	28.1	15.1
OM&A ($M)	6.6	3.6	4.3	4.4	4.8	4.9

Hydro One is now entering into a period where the underground cable circuits are approaching their end of expected life and in order to effectively manage the underground cables continued renewal of the fleet must be maintained. There is some variability in capital expenditures year over year, which is mostly a function of the timing and magnitude of individual projects. The replacement of older oil filled cable systems with new XLPE cable systems, which have lower maintenance costs, will result in lower lifecycle costs.

OM&A expenditures are relatively stable year over year in order to carry out assessment activities to provide insight into cable condition.

Many factors drive cable replacement; the key factors include condition, performance, obsolescence, age, circuit criticality, and environmental impacts. Failure of underground cables can take significant time to repair or replace. This can place considerable strain on the system as it may restrict outages required for maintenance or repair of other equipment. Overloading other cables and related elements can place the system at risk of failure, loss of supply and blackout to the customer.

SUMMARY OF CAPITAL EXPENDITURES

1.0 SUMMARY OF CAPITAL BUDGET

The proposed capital expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision-making to ensure that the appropriate, cost-effective solutions are put into place to meet Hydro One Transmission objectives. These processes are described in detail in Exhibit A, Tab 16, Schedules 1 to 7.

The capital expenditures proposed in this filing represent investments that will ultimately become in-service capital assets supporting the Hydro One Transmission business. Specifically, these expenditures include:

a) design and development of specific assets providing future economic benefits;
b) purchase, construction and commissioning of specific assets providing future economic benefits;
c) additions to specific assets; and
d) betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific assets.

The proposed capital programs address Hydro One Transmission's integrated set of asset replacement and expansion needs to meet its objectives of: public and employee safety; maintenance of transmission reliability at targeted performance levels; meeting system growth requirements; compliance with regulatory requirements (such as specified within the Transmission System Code); environmental requirements; and Government direction. The development of these capital programs is based on comprehensive asset condition information, system loading versus capacity information and various studies.

Hydro One Transmission's capital budget is grouped into four different investment categories: Sustaining, Development, Operations, and Common Corporate Costs Capital. Table 1 provides a summary of Hydro One Transmission’s capital expenditures for the historical, bridge and test years.

Table 1
Summary of Transmission Capital Budget ($ Million)
Including Capitalized Overheads and Interest Capitalized*

Description	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Sustaining	333.2	389.3	480.0	579.3	581.9	548.6
Development	415.9	329.4	171.7	195.6	209.7	211.8
Operations	8.8	15.2	17.7	38.5	38.4	37.4
Common Corporate Costs Capital	52.3	42.1	49.1	85.8	69.4	68.5
TOTAL	**810.2**	**776.0**	**718.5**	**899.2**	**899.4**	**866.3**

*AFUDC for the period 2009 to 2011

The Transmission Capital requirements continue to grow over the 2014 to 2015 period to address asset replacement and refurbishment needs of Hydro One’s aging system, and to expand the system for the purposes of load growth, accommodating a modified generation mix, and expanding access to interconnected electricity markets. Overall spending requirements decline in 2016.

The increase in Sustaining expenditures is primarily due to the continued growth in the number of assets that are beyond their expected service life and have been identified as either at end of life, obsolete with no spare parts available, or requiring replacement in order to satisfy changes in the regulations that govern the transmission business. The increase in Development expenditures is primarily driven by large projects such as Clarington TS and Guelph Area Transmission Reinforcement. Operations spending increases mainly due to the NMS sustainment program, the WAN Outreach program and the Fault Locating program. Common Costs increases are primarily in the Facilities and Real Estate area for increased spending on building improvements in older field facilities and for head office improvements, and higher IT spending in the bridge year for the completion of the Cornerstone project.

Investment Summary Documents in support of capital projects with cash flows in excess of $3.0 million in either 2015 or 2016 are filed at Exhibit D2, Tab 2, Schedule 3.

2.0 SUSTAINING

The Sustaining capital program includes the costs for investments required to replace or refurbish components to ensure that existing transmission system facilities function as originally designed. Hydro One Transmission manages its sustaining program within two program categories, namely stations and lines. Details of the expenditures under this program are provided at Exhibit D1, Tab 3, Schedule 2.

3.0 DEVELOPMENT

The Development capital program consists of the investments required to upgrade or enhance transmission system capabilities to address load growth, generation connection requirements and transmission congestion, and to ensure that the system is designed and operated in a safe, secure and reliable manner. Details of the expenditures under this program are provided at Exhibit D1, Tab 3, Schedule 3.

4.0 OPERATIONS

The Operations capital program represents investments in infrastructure required to sustain the Central Transmission Operations function, which is operated from Hydro One's Ontario Grid Control Centre. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 4.

SUSTAINING CAPITAL

1.0 INTRODUCTION

Sustaining Capital consists of expenditures required to refurbish or replace transmission system components which are at end of life for technical or economic reasons to ensure the system will continue to function as originally designed. The expenditures covered under Sustaining Capital are intended to sustain existing transmission system facilities performance at required levels, thereby maintaining the overall reliability of the system while satisfying all legislative, regulatory, environmental and safety requirements.

Hydro One Transmission manages its Sustaining Capital program by dividing the expenditures into the following two categories:

- Stations, which funds the work required to refurbish or replace existing assets located within transmission stations, including existing protection, control, and telecommunication assets, and

- Lines, which funds the work required to refurbish or replace existing assets associated with overhead and underground transmission lines.

Sustaining Capital programs are driven by the asset needs and focus on managing the risks associated with the fleet of aging transmission assets. A summary of Hydro One Transmission's Sustaining Capital programs and proposed spending levels for the test years 2015 and 2016 are described herein.

2.0 SUSTAINING CAPITAL SUMMARY

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 16, Schedules 1 to 5, has been completed for all Sustaining Capital programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

The selection of planned Sustaining Capital investments is guided by the asset risk assessment process described in Exhibit A, Tab 16, Schedule 7. This process takes into account the condition, age, performance, criticality and utilization of specific assets. A summary of the asset risk assessment for key transmission assets is provided in Exhibit D1, Tab 2, Schedule 1.

Over the long term, an adequately maintained transmission system that performs to the level of its original design is in the best interest of Hydro One Transmission and its customers. As outlined in Exhibit D1, Tab 2, Schedule 1 a significant portion of Hydro One's transmission system is at an age where factors such as degraded condition and demographic pressures are contributing to operational risks. These risks must be managed in a cost-effective manner for the benefit of customers. Capital expenditures proposed in this exhibit address the needs identified in the test years as a result of the aging asset base. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future, and the ability to complete the required work, both in capital replacements and corrective maintenance as well as impact reliability and potentially safety.

The required funding for Sustaining Capital in the test years, along with the spending levels for the bridge and historic years is provided in Table 1 for each of the major sustaining categories.

Table 1
Sustaining Capital
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Stations	262.7	322.5	355.3	458.8	449.5	429.7
Lines	70.6	66.8	124.8	120.5	132.4	118.9
Total	**333.2**	**389.3**	**480.0**	**579.3**	**581.9**	**548.6**

The overall Sustaining Capital requirements for the test year 2015 have increased by less than 1% over projected spending in the bridge year 2014. The Sustaining Capital requirements for 2016 are approximately 6% less than the 2015 requirements. The proposed expenditures in 2015 and 2016 are felt to adequately maintain reliability to customers and the bulk electricity system, and manage the population of aging assets over this time period. Expenditures are focused on assets that are beyond their expected service life, have been identified as in degraded condition, are obsolete with no spare parts available, and/or require replacement in order to satisfy changes in the regulations that govern Hydro One Transmission's business.

As outlined in Exhibit D1, Tab 2, Schedule 1, asset demographics continue to create a challenge in managing the transmission system. The design of the Hydro One transmission system and effectiveness of Hydro One Transmission's maintenance programs have minimized the impact of aging assets on customers. However, equipment performance and condition trends reveal the necessity for continued investment to maintain the historic levels of risk.

One notable difference in the test year spending is the on-going focus on integrated projects in both the Stations and Lines asset categories. With many asset types beyond their expected service life and showing signs of the need for replacement, larger scale Station or Line refurbishment projects are an effective option to deal with the specific assets and in many cases make modifications that would not otherwise be practical. This may include upgrading load delivery stations to existing standards to eliminate safety risks, modifying the configuration at transmission stations, or removing oil filled cable systems. The air blast breaker replacement projects are one example with significant benefits. These breakers are typically installed at critical system stations, and once replaced, the equipment reliability is expected to improve by a factor of five and the replacement breakers will result in a 90% savings in maintenance costs.

Reduction in the Sustaining Capital funding would have impacts in a number of areas:

- A marked reduction in equipment and customer reliability at transmission stations as a result of increased transformer failures, inoperable breakers and switches, and potential misoperation of protection systems;
- Risk of non-compliance with Ministry of Environment regulations concerning adequate drainage and oil spills, and lack of progress against PCB phase out plans mandated by Environment Canada;
- Potential for wide spread power disruptions should the critical protection and control systems start to fail due to late response to aging infrastructure. A similar situation applies to several classes of breakers that are aging and do not have support for spare parts;
- Risk of non-compliance with NPCC and NERC regulations that require secure facilities for connection to the north east power grid. Protection and control systems are critical in this regard and if reliability cannot be maintained, Hydro One Transmission risks citations and fines; and
- An increase in power outages to lines facilities due to failure of structures, insulators and other components that make up the lines system. These facilities are located in the public domain and as such need to be kept in a state of good repair to adequately manage public safety and to maintain customer and system reliability.

3.0 STATIONS

Transmission Station facilities are used for the delivery of power, voltage transformation, switching, and serve as connection points for both load customers and generators. Station facilities contain many of the following major components: power transformers, circuit breakers, disconnect switches, bus work, insulators, potheads, power cables, surge arrestors, capacitor banks, reactors, instrument devices, protection and control systems, station service systems, grounding systems, site infrastructure and buildings.

Stations Sustaining Capital funding covers expenditures required to sustain existing assets located within transmission stations including protection, control and telecommunications facilities. Hydro One Transmission manages its Stations Sustaining Capital program by dividing the program into eight categories:

1. <u>Circuit Breakers</u>, which funds the capital investments to refurbish or replace circuit breakers;

2. <u>Station Re-investment</u>, which funds the capital investments to refurbish or replace several station components or systems in an integrated manner;

3. <u>Power Transformers</u>, which funds the capital investments to refurbish or replace power transformers;

4. <u>Other Power Equipment</u>, which funds the capital investments to refurbish or replace power equipment, other than power transformers and circuit breakers. This includes disconnect switches, capacitor banks, reactors, surge arrestors, low voltage cables and potheads, instrument devices and insulators. These components provide over-voltage protection, electrical insulation, metering and protection capability, electrical isolation, and voltage control;

5. Ancillary Systems, which funds the capital investments to refurbish or replace ancillary systems (such as station service systems, grounding systems, high pressure air ("HPA") systems etc.);

6. Station Environment, which funds the capital investments for the installation, replacement and refurbishment of transformer spill containment systems;

7. Protection, Control, Monitoring and Telecommunications, which funds the capital investments to refurbish or replace protection, control, monitoring and telecommunications equipment;

8. Site Facilities and Infrastructure, which funds capital investments to refurbish and replace station infrastructure (such as station buildings, heating ventilation and air conditioning ("HVAC") systems, water supplies, sewage, fences, fire protection, drainage, structural footings, etc.).

Required funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years are provided in Table 2 for each of these categories.

Table 2
Stations Sustaining Capital
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Circuit Breakers	29.2	11.2	23.4	23.0	13.5	24.5
Station Re-investment	36.4	62.1	89.0	157.6	241.0	159.7
Power Transformers	81.1	78.4	87.0	84.0	30.6	75.3
Other Power Equipment	16.2	28.3	26.5	24.8	23.7	25.9
Ancillary Systems	13.4	16.4	15.5	24.2	19.0	19.4
Station Environment	7.0	7.6	6.6	8.3	11.3	10.8
Protection, Control, Monitoring, and Telecommunications	61.6	95.0	84.4	116.9	92.2	95.6
Site Facilities and Infrastructure	17.8	23.4	22.9	20.0	18.1	18.5
Total	**262.7**	**322.5**	**355.3**	**458.8**	**449.5**	**429.7**

The overall Stations Sustaining Capital expenditures for the test year 2015 are approximately 2% less than the projected spending in 2014. The spending requirements for 2016 are also about 4% less the 2015 requirements. Though there is a declining trend, the planned expenditures for the test years represents on average a 40% increase compared to the historic years. These expenditures reflect the continuation of existing asset replacement rates to maintain reliability and risks levels on an on-going basis. Some variability can be observed year over year associated with the timing of specific projects. The primary driver for capital expenditures being higher when compared to historic years is due to the on-going focus within Station Re-investment on replacing air blast circuit breakers at critical system stations and executing integrated station rebuilds at load delivery stations.

3.1 Circuit Breakers

3.1.1 Introduction

Circuit breakers provide protection to the system under fault conditions, and provide a switching function under normal operating conditions. Hydro One Transmission has approximately 4,604 circuit breakers on the transmission system. Programs are developed to manage the risks associated with premature physical deterioration, decrease in reliability performance, and an aging asset base. Hydro One Transmission has over 120 unique circuit breakers types from approximately 30 different manufacturers currently operating on the system. The two main classification/interrupting type of circuit breakers that are addressed within this circuit breaker replacement program are Oil and Sulfur Hexafluoride ("SF6") circuit breakers. There are also some circuit breakers on the system that utilize vacuum interruption technology, and a small number of targeted replacements are planned within the test years. Generally this program does not include the replacement of air blast circuit breakers ("ABCB"), metalclad or gas insulated switchgear ("GIS"), as replacements of this type typically involve a broader scope than just a "one for one" replacement. This being the case, ABCB, metalclad and GIS are typically replaced on a project basis under the Station Re-investment, as discussed in Section 3.2 of this exhibit.

3.1.2 Investment Plan

In order to effectively manage the circuit breaker replacement programs, specific maintenance tests have been developed to obtain the data required to determine the condition and the likelihood of failure of circuit breakers. These tests, along with the operating history and application, individual breaker and breaker family performance, asset criticality and demographic data provide the basic information required to conduct asset assessments and determine asset replacement needs.

Table 3 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for the circuit breaker replacement programs.

Table 3
Circuit Breakers
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Oil Circuit Breaker Replacements	8.9	6.5	9.3	6.5	2.6	10.8
SF6 Circuit Breaker Replacements	15.4	11.2	10.8	10.7	8.0	11.2
Other Circuit Breaker Programs	4.9	(6.5)	3.4	5.8	2.9	2.5
Total	**29.2**	**11.2**	**23.4**	**23.0**	**13.5**	**24.5**

<u>Oil Circuit Breaker Replacements</u>

Hydro One Transmission owns and manages 1,818 oil circuit breakers. These breakers are no longer manufactured and replacement parts are becoming increasingly expensive and harder to source. In many cases the breakers cannot be economically repaired and if not replaced will impact on Hydro One Transmission's ability to supply reliable power. Many of these circuit breakers are at or approaching their expected service life. As the asset ages, the condition will further deteriorate, creating untenable conditions in keeping this class of equipment in service with reliable performance. This replacement program focuses primarily on technically obsolete and poor performing breakers.

Additional details for this program are provided in the Investment Summary Document S01 in Exhibit D2, Tab 2, Schedule 3.

SF6 Circuit Breaker Replacements

Hydro One Transmission manages 1,579 SF6 circuit breakers, the first of which were installed in the late 1960s. The newer SF6 circuit breaker designs remain as one of the utility standards for circuit breaker installations and are used to replace other circuit breaker types that have become obsolete. This replacement program focuses primarily on breakers in capacitor and reactor switching positions, which are subjected to the most severe application. These breakers have exceeded the number of design operations, are demonstrating poor performance, and require on-going costly corrective maintenance if not replaced. Another significant area of the replacement program is focused on the early generation SF6 breakers with poor design characteristics, high leak rates and that are now technically obsolete.

Additional details for this program are provided in the Investment Summary Document S02 in Exhibit D2, Tab 2, Schedule 3.

Other Circuit Breaker Programs

Hydro One Transmission also manages 41 vacuum breakers installed in 44 kV, 27.6 kV, and 13.8 kV positions. There is a targeted replacement program focused on breakers with design deficiencies, poor performance or breaker designs that are no longer supported by the manufacturer and where spare parts are not available, thus mitigating the risk of extended outage duration impacting customer reliability, should one of these breakers fail. Other investments under the other program category focus on the purchase of operating spare circuit breakers and the demand costs to replace failed units.

3.1.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $13.5 million and $24.5 million respectively. The 2015 expenditures are significantly less than the bridge year, whereas the 2016 expenditure is generally in line with the previous years spending in this program. This reduction in 2015 corresponds to an increase in 2015 spending in the Integrated DESN Investment category within the Station Re-investment program. The circuit breakers identified in need of replacement that would have otherwise been completed within the oil circuit breaker and SF6 circuit breaker replacement programs are being completed as part of integrated station-level refurbishments. Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

A reduction in this program will delay the replacement of aged and degraded equipment that is technically obsolete, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.

3.2 Station Re-investment

3.2.1 Introduction

Older stations typically contain a number of components that reach end of life at about the same time. Efficiency gains are achieved in many cases by replacing all such components within the station as part of the same project. This practice also contributes to greater customer satisfaction due to fewer planned outages, and reduced risk of unplanned outages that can occur when one or more system elements are removed from service. Station re-investment work complements other individual component replacement programs within Stations Sustaining Capital. Hydro One Transmission continues towards executing a greater portion of the planned work in this integrated fashion.

3.2.2 Investment Plan

In order to effectively manage a reliable transmission system, all critical components within a transmission station are assessed against required functionality, condition, performance, safety and environmental impacts. The required work is then combined in the most economical manner.

Hydro One Transmission manages its Station Re-investment program by grouping projects into similar types of work. Table 4 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each grouping.

Table 4
Station Re-Investment
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Metalclad Switchgear Replacements	6.0	(4.2)	(0.4)	5.4	4.8	8.3
Air Blast Circuit Breaker Replacements	16.4	22.4	17.9	35.5	73.7	59.4
End of Life Station Reconfigurations	7.6	27.0	39.7	28.0	40.0	26.9
Integrated DESN Replacements	0.1	1.0	30.4	79.2	107.1	64.2
Integrated Station Component Replacements	0	0	0.6	8.1	15.4	0.9
Other Historical Projects	6.3	16.0	0.8	1.4	0.0	0.0
Total	**36.4**	**62.1**	**89.0**	**157.6**	**241.0**	**159.7**

Metalclad Switchgear Replacements Projects

Hydro One Transmission has a number of metalclad switchgear lineups, typically at indoor stations in urban areas. Replacement programs are established to replace switchgear beyond its expected service life. Several installations are from the 1950s and have safety concerns, are technically obsolete, and are important to maintaining customer reliability in Toronto, Hamilton, and Ottawa. In the case of Toronto, a multiyear program is underway to replaced aged infrastructure in coordination with Toronto Hydro Electric System Limited ("THESL"). Prioritization has been done in coordination with THESL, allowing both utilities to leverage resources and construction outages. A portion of this work is recoverable from THESL. In 2012 and 2013, there were capital contributions from Toronto Hydro in the amount of $5.5 million and $0.6 million respectively for betterments made in coordination with replacement of the metalclad switchgear at Strachan TS, Glengrove TS and Carlaw TS.

Additional details for these projects are provided in the Investment Summary Document S03 in Exhibit D2, Tab 2, Schedule 3.

Air Blast Circuit Breaker Replacement Projects

Air blast circuit breakers are the poorest performing breakers in the Hydro One transmission system. Typically ABCBs were originally installed at critical transmission station during the 1970's build of the transmission system. ABCBs have the highest operating cost of any breaker technology, due to their high pressure air systems with sensitive components that need frequent maintenance. These circuit breakers are no longer produced and many models lack support for parts and technical expertise.

The transmission stations identified for ABCB replacements are outlined in Table 5. These breakers planned for replacement have been problematic and are in need of replacement due to performance, obsolescence, and system criticality. The work will entail replacement of the existing ABCB's with modern SF6 circuit breakers, as well as include the removal of the high pressure air systems and adjoining equipment determined to be at end of life.

Table 5
Air Blast Circuit Breaker Replacement Projects
($ Millions)

Ref#	Description	Test Years		Total Cost
		2015	2016	
S04	Richview TS	23.5	22.1	67.7
S05	Beck #2 TS	15.4	9.9	32.7
S06	Bruce A TS	22.1	26.4	74.6
S07	Burlington TS	11.3	0.0	18.5
	Other Projects <$3M	1.4	1.0	
	Total	**73.7**	**59.4**	

Additional details for these projects are provided in the Investment Summary Documents S04 to S07 in Exhibit D2, Tab 2, Schedule 3.

End of Life Station Reconfiguration Projects

Consistent with the integrated strategy of Station Re-investments, end of life station reconfiguration projects address many assets and components that are in need of replacement at a single station. These projects stem from typical end of life replacement needs, but the solutions employed also have a significant element of station reconfiguration. Synergies in design, construction and procurement can be best realized by executing an integrated project of this nature when all major station infrastructure is in need of replacement within the same general timeframe.

The transmission stations identified for end of life station reconfiguration are outlined in Table 6. The work will entail replacement of end of life assets as well as a substantial reconfiguration to the station’s topology to meet existing requirements.

Table 6
End of Life Station Reconfiguration Projects
($Millions)

Ref#	Description	Test Years		Total Cost
		2015	2016	
S08	Gage TS	26.9	26.9	72.4
S09	Timmins TS	5.2	0.0	10.7
S10	Hanmer TS	8.0	0.0	16.0
	Total	**40.0**	**26.9**	

Additional details for these projects are provided in the Investment Summary Documents S08 to S10 in Exhibit D2, Tab 2, Schedule 3.

Integrated DESN Replacement Projects

Projects within this grouping are targeted at replacing multiple assets within DESN (dual element spot network) stations, which facilitate power transformation from the bulk supply stations to load customers, typically at 44 kV, 27.6 kV, and 13.8 kV. The underlying force for the investment is typically multiple transformers that are in need of replacement, at which point opportunities are sought after to replace assets such as spill containment, protection and control systems, circuit breakers, disconnect switches and surge arresters at the same time in an integrated manner. Combining multiple elements into a single work package allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. The DESN stations identified for integrated replacements are outlined in Table 7.

Table 7
Integrated DESN Replacement Projects
($ Millions)

Ref#	Description	Test Years		Total Cost
		2015	2016	
S11	Dunnville TS	4.6	0.0	18.3
S12	National Research Council TS	15.5	0.0	22.1
S13	Espanola TS	0.9	17.9	18.8
S14	Strathroy TS	0.0	4.7	19.5

Ref#	Description	Test Years		Total Cost
		2015	2016	
S15	Elgin TS	18.8	11.3	33.0
S16	Gerrard TS	18.8	0.0	25.6
S17	Chenaux TS	14.0	5.9	20.1
S18	Overbrook TS	11.3	0.0	16.0
S19	Ear Falls TS	5.4	0.0	9.2
S20	Wiltshire TS	5.1	5.2	12.6
S21	Bridgman TS	4.5	0.0	9.4
S22	Dundas TS	3.4	0.0	15.6
S23	Goderich TS	0.9	6.6	14.1
S24	Leaside TS	1.9	9.7	17.0
	Other Projects <$3M	1.9	2.9	
	Total	**107.1**	**64.2**	

Additional details for these projects are provided in the Investment Summary Documents S11 to S24 in Exhibit D2, Tab 2, Schedule 3.

<u>Integrated Station Component Replacement Projects</u>

Projects within this grouping are to address multiple end of life components at a station which require replacement, but where the scope of work does not warrant a major rebuild of the station as would be the case in the Integrated DESN Replacement category. This category of expenditure was a started in 2013 on a pilot basis for nine transmission stations with work spanning over 2013 to 2016. The intention of the pilot was to work through a modified approach to planning and executing component replacement work to leverage efficiencies through better integration. Learnings from this pilot approach will be applied in future rate applications, as Hydro One Transmission continues towards executing a greater portion of planned work in an integrated fashion.

Additional details for these projects are provided in the Investment Summary Document S25 in Exhibit D2, Tab 2, Schedule 3.

3.2.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $241.0 million and $159.7 million respectively. Expenditures in Station Re-investment are highly dependent on the type and magnitude of specific projects carried out each year, as such there can be significant year over year variations. However the test year expenditures represent a significant increase over the historic spending, and are primarily a function of increased expenditures on air blast circuit breaker replacements and integrated DESN replacement projects. Although the expenditures within this category are higher than historic and bridge years, reductions in other categories of Stations Sustaining Capital have been implemented. This represents a general shift in planning approach to complete more sustaining capital investments using integrated approaches, as opposed to focusing primarily on component level replacements.

A reduction in this program will result in delays to address degrading performance of air blast circuit breakers at critical network stations, and the integrated rebuild of stations delivering load to customers. Negative impacts to both system reliability and customer reliability would be a result.

3.3 Power Transformers

3.3.1 Introduction

In total, Hydro One Transmission has 722 large transmission class transformers in service. The most common power transformer is the step-down transformer, which converts a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Another type is the autotransformer which connects to high voltage transmission systems such as 500/230 kV and 230/115 kV. Other transformers included in this group are phase shifting transformers, shunt reactors, regulating transformers. Grounding transformers and station service transformers are not included in this figure.

3.3.2 Investment Plan

Power Transformers are critical for the operation of the power system. In order to effectively manage the power transformer population, data is obtained from numerous sources which include inspections, diagnostic testing, planned maintenance activities, equipment performance reports, and feedback from real time operating systems that provide equipment loading.

The power transformer program addresses transformer replacements and purchases, as well as other transformer related activities. Table 8 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

Table 8
Power Transformers
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Power Transformer Replacements	56.3	71.8	74.4	69.3	20.7	60.1
Operating Spare Transformer Purchases	18.9	4.2	10.1	8.1	3.2	8.4
Other Transformer Programs	5.8	2.4	2.5	6.7	6.8	6.8
Total	**81.1**	**78.4**	**87.0**	**84.0**	**30.6**	**75.3**

Power Transformer Replacements

This program is in place to replace transformers that have reached end of life under planned conditions, as well as replacements under demand conditions following failures of in-service transformers. Specific maintenance tests have been developed to obtain the data required to determine condition and the likelihood of failure. The results from these tests, in combination with data on the operating history, individual transformer and transformer family performance, equipment criticality and demographic data provide the information required to determine if a unit is in need of replacement. The replacement of end of life power transformers are required to mitigate impacts to reliability, environment, customer, and safety.

Additional details for this program are provided in the Investment Summary Document S26 in Exhibit D2, Tab 2, Schedule 3.

Operating Spare Transformer Purchases

This program is in place to purchase operating spare transformers in line with Hydro One Transmission's probabilistic approach to determine the number of spare transformer requirements. The analysis considers performance trends and supply chain considerations of Hydro One Transmission's various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spare complement modeled requirement is intended to replenish inventory that is expected to be drawn down for future failures.

Additional details for this program are provided in the Investment Summary Document S27 in Exhibit D2, Tab 2, Schedule 3.

Other Transformer Programs

- Replacement of station service transformers that have reached end of life. Station service transformers step down primary voltages, i.e., 230 kV, 115 kV, 44 kV, 27.6 kV or 13.8 kV to secondary voltages of 600V or 120V AC to supply station auxiliary equipment such as battery chargers, transformer cooling and tap changers, and station heaters.
- Installation of online monitoring and diagnostic equipment to provide real-time condition data that impacts both the day-to-day operation of the transformers and the longer term sustaining capital replacements.

3.3.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $30.6 million and $75.3 million respectively. The 2015 expenditures are significantly less than previous years, whereas the 2016 expenditures are generally in line with historic spending in this program. This reduction in 2015 corresponds to an increase in 2015 spending in the Integrated DESN Investment category within the Station Re-investment program. Similar to the circuit breaker replacement program, the transformers identified in need of replacement that would have otherwise been completed within the power transformer replacement program are being completed as part of integrated station-level refurbishments. As demonstrated in Exhibit D1, Tab 2, Schedule 1, the total number of transformer replacements across the combination of all program categories is remaining generally consistent in the test years relative to bridge year.

A reduction in this program will delay the replacement of aged and degraded equipment as well as will result in maintaining a less than optimal spare inventory, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.

3.4 Other Power Equipment

3.4.1 Introduction

In addition to circuit breakers and power transformers, there are other components and system elements that are integral parts of transmission stations. These include disconnect switches, capacitor banks, reactors, surge arrestors, low voltage cables and potheads, instrument transformers and insulators. These components provide over-voltage protection, electrical insulation, metering and protection capability, electrical isolation, and voltage control.

3.4.2 Investment Plan

In order to effectively manage these other power equipment populations, data is obtained from numerous sources which include inspections, diagnostic testing, planned maintenance activities, along with operating history, historic load profile, individual equipment and family of equipment performance, asset criticality and demographic data.

Table 9 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for the investments that are included in Other Power Equipment category.

Table 9
Other Power Equipment
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Disconnect Switch Replacements	2.8	8.9	6.8	6.7	5.4	7.8
Capacitor Bank Replacements	3.7	4.8	4.1	6.2	6.3	6.5
Instrument Transformer Replacements	3.3	4.7	8.9	4.9	4.5	3.9
Insulator Replacements	4.7	3.9	3.5	4.3	4.4	4.5
Other Power Equipment Programs	1.8	6.0	3.2	2.7	3.1	3.2
Total	**16.2**	**28.3**	**26.5**	**24.8**	**23.7**	**25.9**

<u>Disconnect Switch Replacements</u>

Disconnect switches are used to provide an open connection in an electrical circuit. They can be manually or electrically driven and can be three phase or single phase. There are over 14,000 of these switches of various types and sizes and voltage levels within the transmission system. The replacement program is focused primarily on replacing disconnect switches in degraded condition. The condition of disconnect switches is obtained primarily from visual inspections of the current carrying parts, insulators, and mechanism and linkages as well as operational tests. The program also addresses problematic switches with a known safety issue, which has resulted in some switches failing and falling closed which is a considerable risk for the power system and staff relying on switches as guaranteed isolating point for work protection.

Additional details for this program are provided in the Investment Summary Document S28 in Exhibit D2, Tab 2, Schedule 3.

Capacitor Bank Replacements

Capacitor banks play a vital role in voltage regulation and power factor correction. There are over 360 capacitor banks positioned throughout the transmission system. The replacement program is focused on replacement of aged capacitor banks in degraded condition that are required to provide voltage support to maintain local reliability. Replacement information is mainly obtained through visual inspections during preventive maintenance and defects identified during corrective maintenance programs; which are generally correlated with asset age demographics.

Additional details for this program are provided in the Investment Summary Document S29 in Exhibit D2, Tab 2, Schedule 3.

Instrument Transformer Replacements

Instrument transformers play a vital role in the operation of the power system. Current and voltage transformers are instrument transformers whose role is to provide the measurements to drive protective relays to operate properly. They also provide the necessary measurements and metering information for system operators. The replacement program is focused on replacement of aged instrument transformers in degraded condition which pose a risk to system and customer reliability should they fail. Some replacements are required as part of Hydro One Transmission’s PCB removals program to meet regulatory deadlines set by Environment Canada. Replacement information is obtained from visual inspections of the instrument transformers including bushings, corrosion, and oil levels, as well as resistance tests, power factor and capacitance measurements, and dissolved gas in oil and oil moisture tests.

Additional details for this program are provided in the Investment Summary Document S30 in Exhibit D2, Tab 2, Schedule 3.

Insulator Replacements

Insulators are used in transmission stations for termination of conductors at structures and to support buses or equipment (e.g. disconnect switches, circuit breakers, instrument transformers, etc.). Station insulators are subject to both electrical and mechanical stresses at the installation point. There are over 220,000 insulators throughout Hydro One's transmission stations. Insulators are visually inspected to determine their condition and those that meet end of life criteria are replaced. Insulator replacements are performed under both planned and demand conditions and address a variety of insulator types across the numerous different pieces of equipment. Insulator failures cause equipment outages (potentially load interruptions), pose a safety risk to personnel, and can result in damage to other equipment that is exposed to the fault.

Additional details for this program are provided in the Investment Summary Document S31 in Exhibit D2, Tab 2, Schedule 3.

Other Power Equipment Programs

- Replacement of low voltage cable and pothead that have reached end of life. There are over 1,500 cable potheads within the transmission system. Cable potheads can leak over time, reducing their dielectric strength resulting in failures.
- Replacement of surge arrestors that have reached end of life. There are over 1,800 sets of surge arrestors within the transmission system. Surge arrestors are used to protect transformers from the effects of lightning strikes and therefore reduce equipment outages.

3.4.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $23.7 million and $25.9 million respectively. The average of the test-year expenditures is in line with the average historic and bridge year spending.

A reduction in this program will result in on-going operational risks associated with operating aged and degraded components and system elements that are integral parts of transmission stations, with likely impact to system and/or customer reliability.

3.5 Ancillary Systems

3.5.1 Introduction

Ancillary Systems are required at all of Hydro One’s transmission stations. These ancillary systems are comprised of station service systems, HPA systems, grounding systems, and battery and battery charger systems. These systems provide key services and operating support to all of the various station components (breakers, power transformers, protections, controls, and monitoring and infrastructure systems).

3.5.2 Investment Plan

Asset condition information is obtained for the various ancillary systems in order to effectively manage the replacement program. This information, plus asset demographic data and an understanding of the consequence to the system due to the failure, provides the basic information requirements to conduct equipment assessments and determine those assets in need of replacement.

Table 10 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for the investments that are included in Ancillary Systems category.

Table 10
Ancillary Systems
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Station Service Replacements	9.1	9.7	10.0	17.2	12.0	12.3
Station Battery and Charger Replacements	1.4	2.6	1.8	2.4	2.3	2.4
Station Grounding Replacements	2.6	3.8	3.6	2.8	2.9	2.9
Other Ancillary System Programs	0.3	0.3	0.1	1.8	1.8	1.8
Total	**13.4**	**16.4**	**15.5**	**24.2**	**19.0**	**19.4**

Station Service Replacements

Station service systems comprise all equipment necessary to distribute AC or DC power to station facilities from the battery and battery charger systems. The AC station service supplies power for transformer cooling, tap changer control, switchgear heating, battery chargers, HVAC, etc., all of which are essential to the provision of reliable power by the transmission stations and to connected loads. The DC station service supplies power for protection, control and communication systems, which protect and provide remote control of station equipment. In the event of a power supply failure, the station service system is designed to enable the transfer of loads over to the second station service supply. The replacement program is focused primarily on replacement of aged and degraded equipment which is required to perform adequately under normal and emergency conditions. Through installation of equipment built to modern standards mitigation of arc-flash safety risks associated with legacy installations is also achieved.

Additional details for this program are provided in the Investment Summary Document S32 in Exhibit D2, Tab 2, Schedule 3.

Station Battery and Charger Replacements

All of Hydro One's transmission stations contain at least one battery and battery charger system. Battery and battery charger systems designated as 'Station' supply all protection and control and other station ancillary DC services, while 'Telecom' designated systems supply the communication system DC requirements at selected stations.

Replacement information is obtained through visual inspections of the battery cells plate condition, connections, and seals, as well as functional testing such as: electrolyte level and specific gravity tests, impedance tests, voltage tests, equalize charge tests, battery load test, and battery discharge duration, charger volt and amp readings, and DC float and output test.

The replacement program is focused primarily on station battery and battery charger systems which can no longer be relied upon to perform their required back-up functionality, including sites which are NPCC regulated. The replacement program for telecom battery and battery charger systems are managed as part of the auxiliary telecommunication system as outlined in Section 3.7 of this exhibit.

Station Grounding System Replacements

Grounding systems are designed to ensure safety of personnel and equipment in and around transmission stations. Grounding systems provide a means of ensuring a common potential between metal structures and equipment accessible to personnel so that hazardous step, touch, mesh and transferred voltages do not occur. In addition, effective grounding systems limit the damage to equipment during faults or surges and they ensure proper operation of protective devices such as relays and surge arresters.

Replacement information for grounding systems is obtained from visual inspection, present and projected fault levels, history of faults, system configuration and technical details obtained through testing programs.

The replacement program is focused primarily on replacements and upgrades of grounding systems which are known to be in degraded condition and cannot be relied upon to adequately perform their critical safety function at stations where no other major refurbishments are planned.

<u>Other Ancillary System Replacements</u>

- Refurbishment of HPA system to address deficient HPA system components to maintain reliability of the ABCBs at critical network stations.
- Implementation of new AC station service system metering requirements mandated by the IESO.

3.5.3 <u>Summary of Expenditures</u>

The planned expenditure for 2015 and 2016 is $19.0 million and $19.4 million respectively. Overall the test year expenditures are approximately 25% higher than the average historic years spending. The increase in spending is required to continue to replace technically obsolete station service systems, as well as implement AC station service metering requirements mandated by the IESO.

A reduction in this program will result in on-going operational risks associated with operating aged and degraded components and system elements that are integral parts of transmission stations, with likely impact to system and/or customer reliability. Some of the programs are also intended to mitigate risks associated with regulatory compliance (i.e. battery and battery charger replacements for NPCC compliance), and safety (i.e. upgrade of grounding systems and replacement of station service systems), and reductions would limit Hydro One Transmission’s ability to manage these obligations.

3.6 Station Environment

3.6.1 Introduction

The stations environment program is driven by environmental requirements to install, replace and/or refurbish transformer spill containment systems. Spill containment systems are barriers designed to capture and control transformer oil spills, thus minimizing risk to the environment.

3.6.2 Investment Plan

Hydro One Transmission demonstrates effective environmental stewardship and corporate risk mitigation by proactively managing its transformer spill containment system infrastructure through replacements, refurbishments or installation of new systems. Table 11 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for spill containment systems.

Table 11
Stations Environment
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Spill Containment	7.0	7.6	6.6	8.3	11.3	10.8

Hydro One Transmission has approximately 75% of the transformer fleet equipped with spill containment systems. Of the spill containment systems installed there are 156 systems that are regulated by the Ministry of the Environment ("MOE") issued Environmental Compliance Approval ("ECA"), formerly known as Certificate of Approval, which mandates operational and maintenance requirements. The stations environment program will primarily be focused on addressing the older spill containment systems (i.e. pit liner systems installed in the 1970s) that have either significantly reduced functionality or are nearing end of life and do not meet Hydro One Transmission's current standards. Additionally there is an on-going requirement, set forth by the MOE, to install additional systems at stations to ensure the entire station is up to modern ECA standards any time that modifications are made to existing stations. Hydro One is typically granted a 3-year window by the MOE in which to make site-wide upgrades. These site-wide commitments account for roughly half of the program in the test years.

The prioritization and selection of a new installation and replacement or refurbishment of an existing spill containment system is based on asset condition information, site environmental and geotechnical data, drainage effluent quality, transformer leak records, and station-specific spill risk analysis.

Additional details for this program are provided in the Investment Summary Document S33 in Exhibit D2, Tab 2, Schedule 3.

3.6.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $11.3 million and $10.8 million respectively. This represents a significant increase over the historic and bridge spending. This increase is a result of an accelerated program required to mitigate environmental risks associated with aged and degraded containment systems as well as installation of new containment systems as required by the MOE.

A reduction in this program will increase the environmental risk exposure and constrain Hydro One Transmission’s ability to meet regulatory obligations established by the MOE.

3.7 Protection, Control, Monitoring and Telecommunications

3.7.1 Introduction

In order to protect, control and regulate the operation of the transmission system, there are four key systems: protective systems, control system, monitoring system and telecommunication systems.

Protection systems are devices connected throughout the transmission network for the purpose of sensing abnormal system conditions (e.g. as a result of natural events, physical accidents, equipment failure). Upon sensing an abnormal condition, protection systems immediately operate the appropriate circuit breakers to isolate the affected equipment (e.g. transmission line, transformer, generator, buswork) from sources of energy and the rest of the transmission system.

Control systems are used to perform control, monitoring, and alarming functions for each station remotely from the Ontario Grid Control Centre (“OGCC”), the back-up control centre, or locally at the station. Control systems also provide real time data to the IESO’s energy management system in accordance with the Market Rules.

Monitoring systems provide detailed, high speed records of normal and abnormal events that occur in stations or on transmission lines. These systems are required to meet NPCC and IESO requirements, and are used to analyze the performance of protective relays and schemes and to ensure due diligence. The information obtained from monitoring systems is also used for maintenance scheduling, diagnostic analysis and post-mortem event analysis, consistent with good utility practice.

Telecommunication systems provide high reliability and high-speed communication required for the protection, monitoring, and control of Hydro One's transmission system. These systems enable station-to-station communication, which helps minimize outage impact and equipment damage due to faults, and the remote monitoring and control of equipment throughout the system. Hydro One Transmission's telecommunication system consists of digital fiber-optic networks, Power Line Carrier ("PLC") systems, owned or leased metallic cables, digital microwave, and auxiliary telecommunication equipment associated with the primary systems.

3.7.2 Investment Plan

In order to effectively manage these systems investments are grouped into three categories according to the function of the asset or the compliance requirement. Table 12 outlines the proposed funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

Table 12
Protection, Control, Monitoring and Telecommunications
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Protection, Control and Monitoring	44.4	72.3	65.4	78.2	56.8	68.1
Auxiliary Telecommunication	14.7	16.7	14.1	20.3	21.8	20.0
Cyber Security	2.4	6.0	4.8	18.4	13.6	7.5
Total	**61.6**	**95.0**	**84.4**	**116.9**	**92.2**	**95.6**

<u>Protection, Control and Monitoring</u>

Protection, Control and Monitoring assets exist in very large numbers. This class of assets include: protective relays and their auxiliaries, remote terminal units ("RTU"), sequence of event recorders ("SER"), digital fault recorders, special protection schemes, local control systems and revenue metering systems; There are over 12,000 protection and control systems, each system consisting of up to 100 components. These systems cannot be out of service for longer than several days without incurring significant cost due to market inefficiency, disruption of planned outages, or impacting reliability. It is critical to ensure that end of life assets have well-defined replacement criteria and are replaced before the onset of failures or rapidly increasing maintenance. Should a large population of assets essential to the operation of the transmission system begin failing simultaneously, the results could be potentially disastrous. In order to avoid major disruption to the transmission system, it is essential to plan and execute the replacement programs for these assets in a proactive manner so that they are replaced before failure.

Replacement information is mainly obtained through actual defects and failure rates; inspection and testing results including calibration drift; obsolescence including lack of manufacturer support; demographic data; and/or NERC and NPCC reliability standards. The replacement program is focused primarily on the proactive replacement of systems approaching the end of their expected service life based on analysis of the demographics of population cohorts relative to the expected physical failure and end of life distributions for each; as well as addresses demand corrective to unplanned priority replacement of end of life protection and control equipment causing significant customer or system impact. Specific replacement programs are outlined in Table 13. Additional details for these programs are provided in the Investment Summary Documents S34 to S36 in Exhibit D2, Tab 2, Schedule 3.

Table 13
Protection, Control and Monitoring
($ Millions)

Ref#	Description	Test Years 2015	Test Years 2016	Total Cost
S34	Integrated Station P&C Replacements	28.7	31.4	60.1
S35	Protection Replacements	18.4	21.6	40.0
S36	RTU and SER Replacements	4.3	8.2	12.5
	Other Protection, Control and Monitoring Programs	5.3	6.9	12.3
	Total	**56.8**	**68.1**	

Other protection, control and monitoring programs include:

- Modification or upgrade to under frequency load shedding protection equipment in response to NPCC Directory 12 requirements to allow for load shedding at specified frequency thresholds. Full compliance is expected to be completed by 2017 in accordance with the implementation plan submitted to NPCC by the IESO.
- Upgrade of monitoring equipment to ensure compliance with NERC Reliability Standards, NPCC Regional Standards and IESO Market Rules with respect to disturbance monitoring.

Auxiliary Telecommunication

Telecommunication systems provide high reliability and high-speed communication required for the protection, control, and monitoring of Hydro One's transmission system. Hydro One Transmission's telecommunication system consists of digital fiber-optic networks, power line carrier systems, owned or leased metallic cables, digital microwave, and the associated auxiliary telecommunication equipment for each. Auxiliary telecommunication equipment includes such equipment as: DC remote trip systems, tone channels, fiber optic cable and telecom battery and battery charger systems.

The replacement program is primarily focused on replacing end of life auxiliary telecommunications equipment that supports protection and control equipment throughout the transmission system. Efficiencies in this program are realized through coordination with the replacement of protection and control equipment. Replacements are prioritized based on asset performance and the sustainment of protection and control system in compliance with NPCC and NERC reliability standards. Specific replacement programs are outlined in Table 14. Additional details for these programs are provided in the Investment Summary Documents S37 to S39 in Exhibit D2, Tab 2, Schedule 3.

Table 14
Auxiliary Telecommunication
($ Millions)

Ref#	**Description**	**Test Years**		**Total Cost**
		2015	**2016**	
S37	DC Signaling (Remote Trip) Replacements	6.7	4.6	11.3
S38	Protection Tone Channel Replacements	4.2	4.2	8.4
S39	PLC Device Replacements	4.6	4.7	9.3
	Other Auxiliary Telecommunication Programs	6.3	6.4	12.7
	Total	**21.8**	**20.0**	

Other auxiliary telecommunication programs include:

- Replacement of end of life battery and battery charger systems that power telecommunications equipment to ensure reliable operation during local or widespread outages.
- Replacement of end of life neutralizing transformers used to protect personnel, metallic communication circuits and telecommunications equipment from high voltages that can occur on telecommunications equipment in a transmission station.
- Enhancements of computer hardware and the operations support systems used by the Integrated Telecommunication Management Centre ("ITMC") for the monitoring and management of the power system telecommunications system.

Cyber Security

The cyber security program entails the implementation of systems and facilities required to achieve and sustain compliance with the NERC Critical Infrastructure Protection ("CIP") standards and address other cyber security vulnerabilities of equal or greater risk.

As outlined in proceeding EB-2012-0031, the energy sector is categorized as a critical infrastructure. This initiated the development of a set of ten NERC Critical Infrastructure Protection standards (CIP-002 to CIP-011), also referred to as the "Cyber Security" standards; to protect the reliability of the interconnected grid. In addition, NPCC Directory 4 instituted specific requirements for ensuring cyber security of grid protection systems. Hydro One Transmission must maintain compliance with the requirements of these standards. In addition, Hydro One Transmission follows good utility and IT Security practice to ensure that all cyber vulnerabilities are identified and secured.

On November 22, 2013 Version 5 of the NERC CIP standards were approved by the Federal Energy Regulatory Commission ("FERC"), extending the applicability of cyber security requirements to additional assets within Hydro One's transmission system. With the adoption of Version 5, the number of sites for evaluation and inclusion into the NERC CIP cyber security compliance program will increase. The new revision of this standard is expected to come into effect on April 1, 2016. Thus this cyber security program primarily focuses on ensuring compliance with the requirements of the new standards.

Other cyber security initiatives in 2015 and 2016 are required to address cyber vulnerabilities as they are uncovered and to implement improved security on the devices used by field staff to access and maintain Critical Cyber Assets. Additional details for this program are provided in the Investment Summary Documents S40 to S41 in Exhibit D2, Tab 2, Schedule 3.

3.7.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $92.2 million and $95.6 million respectively. This represents a decrease of about 20% over the bridge year 2014. This decrease is a result of the consolidation of the RTU and SER replacements into the Station Re-investment program to realize additional efficiencies during design, construction and commissioning. Investments in cyber security in 2014 are higher than historic to ensure compliance with the recently approved Version 5 of the NERC CIP Cyber Security standards and will ramp down over the test years once implemented in alignment with the mandated NPCC plan.

A reduction in this program will see a significant increase in the risk to the operation of the power system as reductions will limit the rate at which end of life protection, control, monitoring and telecommunications assets can be replaced, increasing the risk and frequency of failure. Failure of protection systems to immediately detect and isolate abnormal system conditions can cause widespread outages in local supply and the interconnected grid as well as equipment damage and injury to workers and the public. The failure of control and monitoring equipment can result in the complete loss of remote operating control of a station by system operators, requiring the dispatch of field personnel to locally control the station. Reductions will also jeopardize compliance with NERC cyber security requirements.

3.8 Site Facilities and Infrastructure

3.8.1 Introduction

Hydro One Transmission's site facilities and infrastructure systems are comprised of yard drainage, fire protection and detection, structural footings, station buildings, cranes, elevators, HVAC systems, access roads, water supplies, sewage management, and fences at transmission stations. These systems provide infrastructure and support services to all other station components, prevent unauthorized access, and make the station site functional for equipment and staff.

3.8.2 Investment Plan

The site facilities and infrastructure program is grouped into three categories to effectively manage the needs of these assets. Table 15 outlines the proposed funding for the test years 2015 and 2016, along with spending levels for the bridge and historic years for each category.

Table 15
Transmission Site Facilities and Infrastructure
($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Station Building Infrastructure	6.0	4.5	4.3	8.5	8.5	8.6
Station Civil Infrastructure	12.1	15.0	10.2	9.6	7.6	7.9
Station Perimeter Fences	(0.4)	3.8	8.4	1.9	2.0	2.0
Total	**17.8**	**23.4**	**22.9**	**20.0**	**18.1**	**18.5**

Station Building Infrastructure

This program targets the refurbishment or replacement of building components within transmission stations typically designed to house Hydro One staff, and in some cases electrical assets (i.e. protection, control, and telecom components). Types of work included are: replacement of the building roof, replacement of HVAC systems, upgrades to the water supply systems, or other refurbishments or enhancements to the station building.

Additional details for this program are provided in the Investment Summary Document S42 in Exhibit D2, Tab 2, Schedule 3.

Station Civil Infrastructure

This program targets the refurbishment or replacement of components and systems within the transmission stations that are designed to support or protect power system equipment. Types of work included are: refurbishment of support structures (concrete footings or steel/wood structures within the station), replacement of fire protection system/deluge systems, refurbishment of deteriorated cable trays that house control and power cables, replacement of drainage systems yard gravel, and repair to access roads in the station.

Additional details for this program are provided in the Investment Summary Document S43 in Exhibit D2, Tab 2, Schedule 3.

Station Perimeter Fences

The station perimeter fences program focuses on effectively deterring and delaying unauthorized individuals and animals from gaining access to transmission facility property. There has been a significant increase in criminal activity aimed at transmission stations. These incidents include copper theft, trespassing and major breaches of the perimeter fence.

The focus of this program is to enhance perimeter fences first before considering other areas within a station. Continued improvement of Hydro One Transmission's perimeter fences is imperative to ensure public and employee safety, and also reduce and combat instances of theft from Hydro One transmission stations. In addition, perimeter fences also help to keep wildlife out of stations, thereby mitigating the risk of animal contacts which are a significant contributor to delivery point interruptions.

3.8.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $18.1 million and $18.5 million respectively. While the test year expenditures for the overall Transmission Site Facilities and Infrastructure program represent a decrease from bridge year and average historic spending, there are year over year variations within each program category to address the needs of the specific infrastructure assets to maintain system and customer reliability; as well as combat instances of theft from Hydro One transmission stations that impact public and employee safety.

4.0 LINES

Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One's transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV. Hydro One's transmission system consists of approximately 30,000 circuit km of overhead transmission lines located on about 21,000 km of rights-of-way and 290 circuit km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shieldwire, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems and grounding systems. The underground transmission lines are generally located in large urban centres.

Lines Sustaining Capital funding covers expenditures required to replace or refurbish overhead and underground transmission lines or specific components that have reached the end of their service life. Hydro One Transmission manages its Lines Sustaining Capital programs by dividing the program into three categories:

1. Overhead Lines Refurbishment and Component Replacement, which funds the capital investments to refurbish or replace line components as well as funds tower refurbishment and coating and capital corrective work associated with clearance corrections and rights-of-way facilities;

2. Transmission Line Re-investment, which funds the capital investments to refurbish complete line sections on a project basis; as well as funds secondary land use projects, where Hydro One Transmission is required to relocate its facilities to accommodate new roads or other infrastructure changes;

3. Underground Cables Refurbishment and Replacement, which funds the capital investments to refurbish or replace cable sections and components.

Required funding for the test years, along with the spending levels for the bridge and historic years are provided in Table 16 for each of these categories.

Table 16
Lines Sustaining Capital
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	2012	2013	2014	2015	2016
Overhead Lines Refurbishment and Component Replacement	52.4	55.5	74.2	67.9	67.4	74.5
Transmission Lines Re-investment	17.1	9.7	17.8	33.2	36.8	29.3
Underground Cables Refurbishment and Replacement	1.0	1.6	32.8	19.4	28.1	15.1
Total	**70.6**	**66.8**	**124.8**	**120.5**	**132.4**	**118.9**

The overall Lines Sustaining Capital spending requirement for the 2015 test year is approximately 10% higher than the planned expenditures in the 2014 bridge year; whereas the spending requirement for 2016 is generally in line with the 2014 bridge year. These spending variations can be expected depending on the size and complexity of the underground or overhead line refurbishment projects undertaken at any point in time.

However the proposed spending for the test years represents an increase of 30% compared to the average spending over the historic and bridge years. These expenditures reflect the need for an increase in the line refurbishment and underground cable replacements to address the number of these assets that are approaching end of life. A significant increase is also required in the refurbishment of steel towers in order to extend the life of these assets.

4.1 Overhead Lines Refurbishment and Component Replacement

4.1.1 Introduction

Hydro One’s transmission system consists of approximately 30,000 circuit km of overhead transmission lines. In many cases, it is more cost-effective to replace one or more of the transmission line components that have reached their end of life rather than to rebuild the entire line. Transmission line components include: wood poles, insulators, shieldwire, switches, and steel structures. This program focuses on the replacement of individual overhead line components, as well as addresses electrical clearance corrections, right-of-way upgrades and emergency replacements.

It should be noted that in terms of component replacement, the focus of this program is on overhead line components other than conductors. When a conductor reaches the end of its life, the project takes on a much larger scope than individual component replacement with an emphasis to replace all components nearing end of life. Such conductor replacement projects are addressed under the Transmission Line Re-Investment Program, which is discussed in Section 4.2 of this exhibit.

4.1.2 Investment Plan

The overhead line refurbishment and component replacement program is grouped into categories to effectively manage the needs of the overhead line assets. Hydro One Transmission considers asset condition and performance, along with safety and regulatory compliance requirements when carrying out assessments on line components to determine which components are deemed to be at end of life and require refurbishment or replacement.

Table 17 outlines the proposed funding for the test years 2015 and 2016, along with spending levels for the bridge and historic years for each category.

Table 17
Overhead Lines Refurbishment and Component Replacement
($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Wood Pole Replacements	29.1	26.9	32.7	27.2	27.7	28.2
Steel Structure Coating	1.6	5.7	5.1	7.4	8.8	10.3
Steel Structure Replacements	0.1	0.5	8.3	3.7	1.9	5.7
Steel Structure Foundation Refurbishments	1.8	3.3	4.5	4.6	4.7	5.5
Shieldwire Replacements	3.0	4.4	2.9	5.3	4.4	4.4
Insulator Replacements	2.6	3.3	6.9	3.6	3.6	3.7
Transmission Lines Emergency Restoration	12.9	8.0	8.2	10.7	10.9	11.1
Other Line Component Replacements	0.0	3.4	5.6	5.4	5.5	5.6
Total	**52.4**	**55.5**	**74.2**	**67.9**	**67.4**	**74.5**

Wood Pole Replacements

Hydro One Transmission utilizes both wood poles and steel structures to support overhead transmission lines. Hydro One's transmission system contains approximately 42,000 wood pole structures. The replacement program is focused primarily on replacing wood poles that are at end of life. Wood poles are determined to be at end of life based on the results of wood pole tests and inspections, at which point they are scheduled for replacement. In addition to end of life replacements, Hydro One Transmission continues to address the defective 230 kV Gulfport type structures which are exhibiting pole deterioration on the inside.

Additional details for this program are provided in the Investment Summary Document S44 in Exhibit D2, Tab 2, Schedule 3.

Steel Structure Coating

Hydro One’s transmission system includes about 50,000 steel structures. Steel structures are manufactured with a zinc-based galvanized coating that protects the underlying steel against corrosion. The coating will generally last from 30 to 60 years, with the more corrosive environments depleting the galvanizing at a quicker rate. Assessment of the steel structure condition is carried out on an annual basis as part of the maintenance program, with a focus on transmission line sections that are greater than 30 years and are located in highly corrosive areas or in locations where known problems exist. The assessments determine the amount of galvanizing that remains on the structure, or in the case where the coating is depleted, the amount of metal loss that has occurred. This program focuses on coating steel tower structures that the assessment has deemed in need of corrosion protection due to loss of galvanized coating.

Additional details for this program are provided in the Investment Summary Document S45 in Exhibit D2, Tab 2, Schedule 3.

Steel Structure Replacements

Once the galvanized coating on a steel structure has been depleted, the bare steel becomes exposed to the environment and begins to corrode at a much faster rate. If the tower is not re-coated and corrosion is allowed to continue, components of the steel structures will begin to lose strength and eventually fall below Hydro One Transmission’s design standards. Once a structure is identified as being in poor condition through visual inspection and measurement of the zinc coating, a detailed corrosion assessment is conducted to determine whether it is possible to replace a portion of the steel structure and coat the remaining structure to protect it from corrosion or whether it is more economical to replace the entire structure. This program addresses the replacement of steel structures where the corrosion assessment has deemed the structure to be at end of life.

Additional details for this program are provided in the Investment Summary Document S46 in Exhibit D2, Tab 2, Schedule 3.

Steel Structure Foundation Refurbishments

The foundations of the transmission structures are integral to the strength of the steel structure. One of the earlier vintages of steel structures is the lattice steel structures which are constructed with a grillage (buried steel) foundation. These particular structure foundations are prone to deterioration of the protective zinc coating and/or corrosion at or below the groundline depending on the ground conditions. About 60% of lattice type steel towers on the Hydro One transmission system have grillage footings. The transmission lines foundation refurbishment program is focused on assessing the condition of the foundations and anchors and repairing or replacing foundations and anchors that have been deemed not to satisfy the original installed design requirements. The assessment of foundation uses a pre-specified rating system and the decision to coat, repair or replace depends on the severity of corrosion or metal loss found.

Additional details for this program are provided in the Investment Summary Document S47 in Exhibit D2, Tab 2, Schedule 3.

Shieldwire Replacements

The shieldwire in Hydro One's transmission system is primarily made up of galvanized steel wire that is positioned above the conductors to protect a circuit against lightning related outages and to provide continuity of the grounding system. When the zinc galvanizing has depleted, the underlying steel begins to corrode, resulting in pitting and loss of metal and eventual failure if not replaced in time. Hydro One Transmission maintains an on-going shieldwire testing program where a sample of wire is removed from a line section and tested in a laboratory to determine the condition of the wire and the need for replacement. This program focuses on the replacement of shieldwire that testing has deemed to not meet the required design requirement and is at risk of failing and dropping to the ground.

Additional details for this program are provided in the Investment Summary Document S48 in Exhibit D2, Tab 2, Schedule 3.

Insulator Replacements

Insulators are used in Hydro One Transmission's overhead lines to suspend energized conductor from supporting structures typically made of wood and steel. Insulator failures result in outages and at times allow energized conductor to fall to the ground creating safety hazards. Transmission line insulators' expected service life varies, depending on the type, design, manufacturer and their installed environment. Due to this large variation in the life expectancy some insulators require replacement well before the circuit reaches end of life. This program addresses the replacement of insulators that have reached end of life as well known insulator design or manufacturing issues for different insulator types.

Additional details for this program are provided in the Investment Summary Document S49 in Exhibit D2, Tab 2, Schedule 3.

Transmission Lines Emergency Restoration

A number of transmission line components fail each year due to adverse weather, component deterioration, vandalism, or through accidents caused by public activity. This demand driven program is needed to restore power following transmission line failures and to replace or repair those line components where there is an imminent danger of failure as identified through line patrols or asset assessment. The types of emergency work covered under this program includes the replacement of failed or defective transmission line components such as wood structures, cross-arms, towers, insulators, conductor, shieldwire and hardware.

Additional details for this program are provided in the Investment Summary Document S50 in Exhibit D2, Tab 2, Schedule 3.

<u>Other Component Replacements</u>

Other component replacements include replacement of switches, rights-of-way access components and aviation lights that have reached end of life. Replacements of these components are essential to maintain system reliability and to address public and employee safety risks. Transmission line clearance corrections are also part of this program and are required to reinstate electrical ratings for the circuit. This may involve raising a structure or installing an inter-space structure to increase clearances.

4.1.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $67.4 million and $74.5 million respectively. This is in line with expenditures in the 2014 bridge year but represents about a 15% increase over historic spending. This increase over historic spending is required to address an increase need for steel structure and foundation coating as well as steel structure replacement due to corrosion and a reduction of structural integrity.

A reduction in this program will lead to an increase of line component failures which can result in safety hazards to the public and could leave customers without power for lengthy periods of time, until repairs can be made. Furthermore, reductions to steel structure and foundation coating programs will result in increased costs in the future for costly steel structure replacements once structures exceed optimum time to coat and repair.

4.2 Transmission Lines Re-Investment

4.2.1 Introduction

Transmission line conductors are one of the most critical elements of a transmission line, both from an operational and safety perspective. When the conductor condition deteriorates to a critical level, failures are likely to occur in multiple locations anywhere on a line section. The overhead lines re-investment program addresses the need to re-build sections of transmission line based primarily on conductors reaching end of life, but will strategically also replace the other line components at or nearing end of life at the same time.

4.2.2 Investment Plan

Specific transmission line sections are selected for replacement from the assessment of condition based on the conductor testing results and the criticality of the line. Conductors are assessed by removing samples from a line section, and then testing the conductor strength, corrosion and serviceability characteristics (e.g. ductility and damage due to metal fatigue). Hydro One Transmission also considers asset demographics and performance as well as the ability to minimize safety and reliability risks.

Once selected, the entire transmission line section is then refurbished to meet present and future system requirements. The transmission lines identified for replacement are outlined in Table 18.

Table 18
Transmission Line Refurbishment Projects
($ Millions)

Ref #	Description	Test Years		Total Cost
		2015	2016	
S51	C25H Line Refurbishment	27.1	0.0	52.4
S52	H24C Line Refurbishment	4.9	12.0	21.7
S53	D10S/D9HS Line Refurbishment	4.8	0.0	4.8
S54	Q11S/Q12S Line Refurbishment	0.0	17.1	17.1
	Other Line Refurbishment Projects < $3M	0.0	0.2	
	Total	**36.8**	**29.3**	

In addition to the line refurbishment projects, the Line Re-investment program also funds the relocation, removal, or reinforcement of transmission assets in order to facilitate third-party projects such as roadwork, transit systems, and other major infrastructure or development work that may encroach upon or impact Hydro One Transmission assets and rights-of-ways. The projects planned for the test years are outlined in Table 19. The size and complexity of these projects vary from year to year, and are fully recoverable.

Table 19
Secondary Land Use and Recoverable Projects
($ Millions)

Ref #	Description	Test Years		Total Cost
		2015	2016	
S55	Keith TS Hwy 401 Expansion (Recoverable)	19.6	17.2	39.9
S55	Waterloo LRT (Recoverable)	17.1	0.0	26.1
S55	Mavers Aggregate Pit (Recoverable)	4.8	8.4	13.9
S55	Thunder Bay Hwy 11/17 Widening (Recoverable)	3.3	0.0	3.7
	Other Recoverable Projects < $3M	2.9	2.9	5.8
	Total Cost	**47.7**	**28.5**	
	Contribution	**47.7**	**28.5**	
	Net Capital Cost	**0.0**	**0.0**	

Additional details for these projects are provided in the Investment Summary Documents S51 to S55 in Exhibit D2, Tab 2, Schedule 3.

4.2.3. Summary of Expenditures

The planned expenditure for 2015 and 2016 is $36.8 million and $29.3 million respectively. The average spending in the test years is in line with the bridge year 2014, though year over year costs vary depending on the number and size of the line projects that require re-conductoring and refurbishment. However the test year expenditures represent a significant increase over the historic spending. This increase is required to address the increasing number of conductors that are being identified as reaching end of life through the conductor sample and testing program.

A reduction in this program will result in an increase in line failures, which could leave customers without power for lengthy periods of time until repairs are made or create safety hazards for the public.

4.3 Underground Cables Refurbishment and Replacement

4.3.1 Introduction

Hydro One's transmission system consists of approximately 290 circuit km of underground 115 kV and 230 kV transmission cables. The high voltage underground ("HVUG") cable systems are comprised of a number of sub-systems and components that need to function properly in an integrated manner to be able to deliver a reliable supply of electricity. The primary components and sub-systems are:

- Underground cable, that is made up of an inner core conductor of either copper or aluminum, insulation that is made of liquid impregnated paper or cross-linked polyethylene, and a protective sheath or steel pipe with a protective cover or coating;
- Cathodic protection systems, that protect the steel pipe against corrosion;
- Liquid pressurization systems, that include pumping plants to ensure oil or gas pressure is maintained at acceptable levels;

- Bonding and grounding systems, that address safety risks and control induction on the cable sheath; and
- Insulated cable terminations that connect a cable to an overhead line or connect a cable to a transformer station.

Hydro One Transmission's underground cable systems supply urban centres in Toronto, Ottawa and Hamilton, with short sections in London, Sarnia, Picton, Windsor and Thunder Bay. These underground cable systems are essential for electrical supply and as such require a very high degree of reliability. This program addresses the replacement or refurbishment of components and line sections of the HVUG cable system in order to maintain this reliability and mitigate safety concerns.

4.3.2 Investment Plan

Specific HVUG cable systems are selected for refurbishment or replacement once deemed at end of life. The decision to deem an underground cable and or cable components at end of life is driven predominantly by cable performance, condition, and component obsolescence. Of particular importance is condition data that is gathered from cable diagnostics and maintenance activities such as condition patrols, cable pipe corrosion surveys, oil tests, jacket tests, infrared scans and intrusive examination of insulation systems when afforded the opportunity. Based on assessment findings, entire cables or their subsystems are scheduled for replacement or refurbishment. Priority is given to assemblies and/or cables that are critical to the operation of the transmission system.

Planned capital investments in primary cable components and sub-systems vary from year to year depending on system needs. Table 20 outlines the planned projects for the test years. Additional details for these projects are provided in the Investment Summary Documents S56 and S57 in Exhibit D2, Tab 2, Schedule 3.

Table 20
Underground Cable Projects
($ Millions)

Ref #	**Description**	**Test Years**		**Total Cost**
		2015	**2016**	
S56	H2JK / K6J Cable Replacement	12.1	0.0	62.0
S57	H7L / H11L Cable Replacement	14.3	14.5	28.8
	Other Underground Cable Projects < $3M	1.8	0.6	
	Total	**28.1**	**15.1**	

Other underground cable projects include:

- Emergency repairs to the HVUG cable systems.
- Replacement of ring gaps associated with the cable bonding and grounding on the terminal ends of underground cables circuits. Studies have shown that due to rising fault currents at some stations the current devices are no longer adequate during system fault situations and could fail explosively.
- Replacement of sump pumps that control water levels in cable tunnels that accommodate underground cable circuits.
- Upgrades to the cathodic protection isolation devices on the underground pipe type cables which are critical to mitigate the risk of corrosion to the steel carrier pipes that contain the insulated conductors.

4.3.3 <u>Summary of Expenditures</u>

The planned expenditure for 2015 and 2016 is $28.1 million and $15.1 million respectively. The average spending in the test years is in line with the bridge year 2014, though year over year costs vary depending on the number and size of the underground cable replacement projects. However the test year expenditures represent a significant increase over the historic spending. This increase over historic years is required to replace a number of underground cable circuits that are in poor condition and are impacting the environment due to leakage of oil.

A reduction in this program will jeopardize the electrical supply reliability to the downtown areas of major centres in Ontario, as well as increase environmental risks associated with an increase in oil leaks from these aging cables.

DEVELOPMENT CAPITAL

1.0 INTRODUCTION

Transmission Development Capital covers funding for projects related to new or upgraded transmission facilities to:

- Provide inter-area network transfer capability to enable electricity to be delivered from areas with sources of supply to load centers.
- Provide adequate capacity to reliably deliver electricity to the local areas connected to Hydro One's Transmission system.
- Connect load customers (load connections) and generating stations (generation connections) to Hydro One Transmission's system.
- Carry out necessary mitigation measures to minimize high impact risk and ensure safe, secure and reliable operation of Hydro One Transmission's system in accordance with the Market Rules, TSC and other mandatory industry standards such as NERC and NPCC.
- Maintain the performance of Hydro One Transmission's system in accordance with Customer Delivery Point Performance ("CDPP") Standards.
- Develop and implement cost effective solutions to enable better use of existing infrastructure or for upgrading the infrastructure to address the impacts of the connection of renewable generation.

The projects take into consideration the need to plan and operate the interconnected Bulk Electric System in a safe, secure and reliable manner that meets Hydro One Transmission's license requirements and complies with criteria and standards based on good utility practice.

2.0 DEVELOPMENT CAPITAL PLANNING PROCESS

2.1 Summary of Guidelines and Criteria

Reliability is a key business value for Hydro One Transmission and thus, the Company focuses heavily on achieving its reliability objectives and on contributing to adequacy of electricity supply in the province. The importance of reliability is reinforced by obligations placed by various regulatory and reliability authorities on Hydro One Transmission to maintain acceptable voltages, keep equipment operating within established ratings, and maintain system stability during both normal operation and under recognized contingency conditions on the transmission system. These requirements of the Ontario Government and industry regulatory authorities include those of the North American Electric Reliability Council ("NERC"), the Northeast Power Coordinating Council ("NPCC"), the Ontario Energy Board ("OEB"), the Ontario Power Authority ("OPA"), and the Independent Electricity System Operator ("IESO") which utilizes its Ontario Resource and Transmission Assessment Criteria ("ORTAC") when conducting System Impact Assessments ("SIA") for new transmission facilities. In particular, Hydro One is required to comply with the Transmission System Code ("TSC") and its Transmission License requirements.

2.2 Development Capital Planning Process

An overview of the Development Capital Planning process is provided in Exhibit A, Tab 16, Schedule 3. More detailed explanation of the planning for each different type of investment (i.e. Network Upgrades, Local Area Supply, Load Connection, Generation Connection, Protection and Control for Enablement of Distribution Connected Generation, Protection and Control Modifications for Consequences of Connected Distribution Generation, Performance Enhancement, Risk Mitigation and Smart Grid) is provided in Sections 2.2.1 to 2.2.8 of this exhibit. The details on specific projects that are presently in various stages of conceptual or detailed planning, approval work and engineering and construction are outlined in Sections 3.1 to 3.8.

2.2.1 Planning for Network Upgrades

The planning for network upgrades is based on either increasing the inter-area transfer capability between generation and load centers within Ontario or increasing the interconnection capability with neighboring utilities. Constraints in the provincial transmission system can inhibit the efficient use of Ontario's own generation resources and the import and export of power through interconnection facilities. In order to maintain or enhance the transfer capability; new or upgraded facilities are required to ensure adequacy of electricity supply for the province.

There are several ways in which planning for network upgrades is triggered:

- Hydro One Transmission monitors the transmission system and identifies projects based on concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.
- Hydro One Transmission assesses significant and pervasive concerns expressed by load and/or generation customers, particularly when these concerns are in matters related to reliability or safety matters.
- Hydro One Transmission monitors the IESO's SIA reports for load and generation projects. If any SIA suggests that network upgrades may be required, Hydro One Transmission undertakes additional studies to assess alternatives for the upgrades and to identify recommended transmission solutions. In performing these assessments, Hydro One consults with the IESO, OPA, and the customers as appropriate.
- The OPA, through its initiatives related to procurement of additional supply resources for the province, recommends the need for inter-area transmission reinforcements. Typically, this recommendation is based on the Ontario Government's initiatives and

energy policies regarding renewable generation and/or phasing out of coal-fired generating stations in Ontario.

The solutions for improving transfer capability range from the installation of capacitor banks or static-var compensation to major transmission reinforcement or interconnection projects. The major network upgrades may involve long lead-times in the approval process (based on requirements under the EA Act and/or Section 92/95 of the OEB Act) and construction phase of the project.

2.2.2 Planning for Local Area Supply

The planning for local area supply is driven by load growth and local area reliability. New or upgraded facilities may be required in order to maintain acceptable voltages, equipment operating within the ratings, system stability, and/or operating flexibility. The term 'Local Area', for the purpose of this exhibit, refers to a confined subsystem or radial portion of the system supplying multiple transmission delivery points serving one or more customers. The geographic and electrical size of a local area varies based on the area system characteristics and connectivity to the bulk transmission system.

There are several ways in which planning for local area supply is triggered:

- Hydro One Transmission leads local area supply planning for the regions of the province where they are designated as the lead transmitter. Hydro One is the lead transmitter for 19 of the 21 regions. As part of the regional planning process, Hydro One will conduct regional planning studies on a regular basis in coordination with the OPA and the Local Distribution Companies (LDCs). The Board's current expectation is that all 21 regions will be reviewed on a cyclical basis of 5 years as a minimum.

- Hydro One Transmission monitors the transmission system and identifies concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.
- Hydro One Transmission may, on its own or in consultation with LDCs and other customers, carry out additional studies to identify needs and potential solutions to resolve constraints related to local area supply adequacy that may arise between regional plan review cycles In cases which require coordination of potential resources or pool funded facilities, Hydro One Transmission always consults with the OPA to confirm that the need and potential solutions are consistent with the OPA's plans.
- Hydro One Transmission monitors the IESO's SIA reports for Load Connections and other projects. If any SIA suggests that transmission reinforcements may be required in the local areas where the load connections or other projects are being contemplated, Hydro One Transmission undertakes additional studies to assess alternatives for Local Area Supply and to identify recommended transmission solutions. In performing these assessments, Hydro One consults with the LDCs and the OPA, where appropriate.

Solutions for local area supply range from the utilization of special protection systems or installation of capacitor banks to maximize the use of existing facilities (in order to defer the need for a major investment) to major transmission expansion projects to meet long-term needs. Major transmission expansion projects may include construction of new transmission lines into the area, and/or new or additional 230/115kV autotransformer capacity. These major projects typically require long lead-times, particularly if there are approval requirements under the Environmental Assessment ("EA") Act or Section 92/95 of the OEB Act.

2.2.3 Planning for Load Connections

The planning for new or modified load connections is driven primarily by customer requests but it can also arise from regional planning studies and the need to address end-of-life facilities. The connection needs may be satisfied through new and/or modified transmission connection facilities, including: new line connections, new feeder positions at existing Transformer Stations ("TSs"), increase of capacity at existing TSs, or construction of new TSs.

In accordance with the TSC, new load connections driven by customer requests may be self-provided by the transmission customer or, at the discretion of the transmission customer, they may be provided by Hydro One Transmission. If requested, Hydro One Transmission is required by the TSC and its Transmission Licence to provide a pool funded option for new line connections and transformation connection. The costs of these investments are the responsibility of the benefiting customer(s) and the costs are fully recovered from these customers via incremental connection revenues and/or capital contribution as per a Connection Cost Recovery Agreement ("CCRA"), the calculation of which is based on Hydro One Transmission's Connection Procedures approved by the OEB.

2.2.4 Planning for Transmission Connected Generation

The planning for transmission connected generation is based solely on customer requests and it is significantly impacted by external factors such as: the Ontario Government's initiatives, the OPA initiatives for procurement of renewable, clean and high efficiency energy, and private sector investments.

In accordance with Hydro One's Transmission License, Hydro One Transmission is required to connect new generators that meet the requirements of the Market Rules and all other applicable codes, standards and rules while maintaining system security and reliability for existing connected customers. In addition to the specific radial connection itself, modifications may be required to Hydro One Transmission’s network and up-stream connection facilities in order to incorporate the generation into the system. Examples of modifications that may be required include enhancements to protection systems, voltage or reactive power support, and/or breaker and station upgrades due to increased short circuit levels contributed by the generator. The customer capital contributions, as per a Capital Cost Recovery Agreement (CCRA), are determined in accordance with the TSC, with clarification provided by the Compliance Bulletin #200606, dated September 11, 2006.

2.2.5 Planning for Protection and Control for Enablement of Distribution Connected Generation

The connection of generation to the distribution system (“DG”) requires changes and additions to the protection and control facilities in transmission stations. These changes are required to ensure the reliability and capacity of the distribution system feeders and maintain protection of transmission assets. The need for them is determined as part of the Connection Impact Assessment process.

However, the required changes do not have a one-to-one correspondence with individual DG projects. Instead, specific changes will support different groupings of generators at the station. They become necessary at certain thresholds of aggregate DG capacity at a feeder, at a bus, and at the entire station. In accordance with the Transmission System Code the costs must be recovered from the generator whose actual connection requires the investment. Thus cost recovery is based on the sequence of actual connection and not, as with the Distribution System Code, the sequence in which the capacity was reserved.

When the Connection Impact Assessment is done, the actual connection sequence is not known and hence neither is the specific generator that will cross the threshold and be the target for cost recovery. Consequently, all generators connecting to the station, even those with very small capacity, must be allocated these full costs at time of Connection Impact Assessment. As these costs will be prohibitive to smaller generators, Hydro One is also implementing a system to rebate the first generator to actually cross the threshold, from the funds collected from other generators that connect after the threshold has been crossed. This rebating needs to be tracked at four grouping levels:

a. all generators connecting to an individual feeder beyond the point at which feeder protection directioning is required.
b. all generators connecting to a station bus after the bus protection needs to be directioned
c. all generators connecting to a station that require transfer trip
d. all generators connecting to a transmission line that require transfer trip

Databases and necessary staffing have been put into place to track the actual connection sequences and cost incurred for the protection modifications at these levels and to ensure the costs are allocated as fairly as possible to all generators.

2.2.6 <u>Planning for Protection and Control for Consequences of Distribution Connected Generation</u>

Hydro One tries to identify all costs associated with the connection of generators to the distribution system at the time of the connection impact assessment so that they can be recovered from the generators as a condition for obtaining the connection. However, there are two categories of costs for which this is not possible:

a. Occasionally some consequences of generation connection are not foreseen

b. Some costs can be anticipated but the exact timing of their need cannot be. These are cost associated with protection and control systems that span all, or large portions, of the grid network. The exact threshold when they will be required depends on factors which are less predictable such as changes in load patterns and real time generation patterns.

When unforeseen consequences arise, Hydro One experts analyze the problem to determine the underlying cause and then determine the scope of remedial program required. For the anticipated consequences, Hydro One monitors trends and tries to determine the most likely timing of need in order that resources and standards can be in place to achieve a planned and cost-effective implementation.

2.2.7 Planning for Smart Grid

The planning for smart grid system deployment in Transmission Stations (TS's) is oriented to offering value to Hydro One Transmission's LDC customers through improvements in protection and control systems at TS's to interface with, and support the objectives of an LDC's Smart Grid systems.

In developing its TS Smart Grid interface systems, Hydro One Transmission is learning from the strategies for smart grid being evaluated in Hydro One Distribution's Smart Zone pilot. These range from implementing and testing automatic fault isolation and restoration systems, managing reactive power with a DVAR controller at transformer stations with high DG penetration, enhancing monitoring and control of DG's at transformer stations, and installing new technologies and next generation intelligent electronic devices (IEDs) at transformer stations that employ the open standards best suited for interfacing with Distribution System Smart Grid equipment.

The plans for actual deployment of these systems will be driven by requests from LDC's for TS interfaces to their Smart Grid systems.

2.2.8 Planning for Performance Enhancement and Risk Mitigation

The planning for performance enhancements and risk mitigation projects is focused on upgrading transmission system assets to minimize high impact risk and address power quality issues to ensure safe, secure and reliable operation of Hydro One Trasmission's system in accordance with the Market Rules, TSC and other mandatory industry standards such as NERC and NPCC.

In accordance with the requirements of the TSC, Hydro One Transmission on January 17, 2008 filed its CDPP Standards proposal (EB-2004-0424) outlining the process to identify and address delivery points demonstrating poor performance and/or deteriorating trends in reliability performance. The proposal was approved by the Board in its Decision with Reasons of April 2, 2008.

3.0 DEVELOPMENT CAPITAL INVESTMENTS

Development Capital includes work on both network and connection facilities. The type of transmission development investments covered in this exhibit are: Inter-Area Network Transfer Capability, Local Area Supply Adequacy, Load Customer Connection, Generation Customer Connection, Protection and Control for Enablement of Distributed Generation, Protection and Control Modifications for Consequences of Connected Distribution Generation, Smart Grid, and Performance Enhancement and Risk Mitigation.

Hydro One Transmission's development capital programs and proposed spending levels under these investment types are summarized below.

Table 1
Development Capital

Investment Type	**($ Millions)**					
	Historical			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Inter Area Network Transfer Capability	**269.3**	**118.2**	**41.8**	**59.3**	**96.1**	**109.7**
Local Area Supply Adequacy	**64.0**	**98.0**	**63.1**	**83.7**	**94.4**	**67.4**
Load Customer Connection	**68.1**	**76.2**	**42.5**	**77.9**	**49.6**	**62.5**
Generation Customer Connection	**11.3**	**18.8**	**68.5**	**84.5**	**11.2**	**11.5**
Station Equipment Upgrades & Additions to Facilitate Renewables *(Government Instruction)*	**16.0**	**32.8**	**15.8**	**0.3**	**0.0**	**0.0**
Protection and Control Modifications for Enablement of Distribution Connected Generation	**14.1**	**22.5**	**22.6**	**20.0**	**21.1**	**20.1**
Protection and Control Modifications for Consequences of Connected Distribution Generation	**0.0**	**2.5**	**1.2**	**3.9**	**2.6**	**4.2**
Smart Grid	**5.8**	**10.7**	**8.8**	**5.6**	**3.1**	**0.0**
Performance Enhancement	**1.2**	**0.7**	**0.1**	**2.6**	**0.9**	**0.9**
Risk Mitigation	**17.9**	**18.1**	**28.4**	**23.8**	**8.1**	**4.8**
Gross Capital Total	**467.7**	**398.5**	**292.8**	**361.6**	**287.1**	**281.1**
Capital Contributions as per TSC	(51.8)	(69.1)	(121.1)	(166.0)	(77.4)	(69.3)
Net Capital Total	**415.9**	**329.4**	**171.7**	**195.6**	**209.7**	**211.8**

The overall gross spending on Development Capital work in the test years is below the historical levels. The net spending on Development Capital work in the test years is also largely below the historical levels. The primary reason for the lower capital expenditure levels is the reduction in number of generation connection projects, equipment upgrades to facilitate renewables and risk mitigation work. Further details for each Investment Type are provided in Sections 3.1 to 3.8 below which include explanations of changes in spending patterns compared to historical levels, a brief summary of major projects and, where appropriate, a summary of aspects related to prudency of cost for these projects.

As initiated in proceeding EB-2008-0272, based on input received during the previous Transmission Revenue Requirement proceeding EB-2006-0501, Hydro One Transmission has adopted the following Capital Project Category classification to provide an indication as to when specific projects would be considered approved for inclusion in rate base.

- *Category 1* - Development capital projects for which the OEB has already granted project-specific approval in another proceeding (for example, a proceeding for approval of the project under Section 92 of the OEB Act). For these projects, the actual in-service costs would be included in rate base when the project goes in-service.
- *Category 2* - Development capital projects that have an in-service date in one of the test years (2015 or 2016) and that do not require an approval under Section 92 of the OEB Act or any other such Board proceeding. Through the current proceeding, Hydro One Transmission is seeking approval for these projects to be included in the rate base when the projects are declared in-service (i.e. upon energization of the facilities).
- *Category 3* - Development capital projects that have significant spending within the test years (2015 or 2016), yet do not have an in-service date in any of the test years and do not require project-specific approvals from the OEB. For these projects, Hydro One Transmission is seeking guidance from the OEB on the appropriateness of the need, the proposed solution, and the recoverability of the project cost. The actual in-service costs would be included in rate base when the project goes in-service subject to Board approval at a future revenue requirement proceeding.
- *Category 4* - Development capital projects that have significant cash flows within the test years but they will require future project-specific approvals from the OEB in the form of Section 92 applications. Hydro One Transmission is not seeking approvals for these projects within this proposed application since the prudency review for these projects will be tested during the Section 92 process.

3.1 Inter-Area Network Transfer Capability

3.1.1 Description of Inter-Area Network Transfer Capability Investments

The integrated inter-area network, or bulk electric system, operates primarily at 500kV or 230kV over relatively long distances incorporating major generation resources and delivering their output to major load centers in the Province through interconnection points to major transmission stations. The network is also interconnected with the transmission systems in Manitoba, Québec, Michigan, Minnesota, and New York enabling imports and exports.

The investments in the Inter-Area Network Transfer Capability category provide new or upgraded transmission facilities to increase the transfer capability between generation areas and load centers within Ontario and/or with neighbouring utilities, on the basis of planned changes in generation sources and load patterns.

The consequences of not proceeding with these investments include increased risks to reliability and security of the interconnected system as a result of the lack of adequate transmission capacity to integrate supply sources and load demand. Constraints in the provincial transmission system can inhibit the use of Ontario's own generation resources, and imports and exports of power through interconnection facilities. These would result in negative economic or supply adequacy impacts, as well as potentially inhibiting the fulfillment of contractual provisions under agreements signed by the Ontario Government and the OPA.

Funding levels for 2015 and 2016 for Inter-Area Network Transfer Capability projects, along with the spending levels for the bridge and historic years are provided in Table 2 of Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 2.

Total capital expenditures for these projects have decreased significantly in years 2013 and 2014 compared to the respective values of $149M and $185M from the last rate filing. Also, overall spending in Inter-Area Network Transfer Capability projects in the Test Years is higher than the 2013 Historical and 2014 Bridge year. The main reasons for the changes are as follows:

- A deferral of the in-service date of Clarington TS from 2015 to 2017. The OPA had initially asked Hydro One to have Clarington in-service by summer 2015 in preparation of Pickering NGS retirement. However, with the extension of the Pickering NGS operating license to August 2018, the in-service date for the new station was moved to fall 2017. Expenditures previously forecast for 2013 and 2014 will now be incurred in 2015 and 2016.
- The cancellation of the Milton SVC project. The OPA advised Hydro One in August 2013 that the project was not required following the reduction in generation procurement announced by the Provincial Government in June 2013. There were significant expenditures of $30M and $40M previously forecasted for 2013 and 2014 respectively.

3.1.2 Summary of Inter-Area Network Transfer Capability Projects

The following summarizes the major inter-area network transfer capability projects separately identified in Table 2. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

All of the projects described below are non-discretionary (as defined in the OEB Filing Requirements for Transmission and Distribution Applications).

Project D1: ***New 500 kV Bruce to Milton Double Circuit Transmission Line***

This project comprises building a new 500kV double circuit transmission line between the Bruce Complex and Milton SS to securely incorporate the generation from all eight units from Bruce NGS and the committed renewable generation in the Bruce Area. The project was approved by the OEB under Section 92 of the OEB Act in its Decision and Order dated September 15, 2008 under Proceeding EB-2007-0050, and is classified as Category 1.

The current cost estimate of this project is $709.4M which is essentially the same amount outlined in Proceeding EB-2012-0031.

The project construction was completed in May 2012 with project closeout work including removal of temporary access roads and right-of-way environmental mitigation that continued into 2013. As well, expenditures (2014 - $6.9M, 2015 - $3.3M, 2016 - $3.2M, 2017 - $6.5M) will be incurred between 2014 and 2017 for real estate costs associated with the expropriation of lands that were approved by the OEB under Section 99 of the OEB Act in its Decision and Order dated March 15, 2011 under Proceeding EB-2010-0023.

Projects D2, D3: ***Clarington TS: Build new 500/230kV Station, and Installation of Shunt Capacitor Banks at Cherrywood TS***

These projects are required to reinforce the 230kV supply capability in the east GTA following the upcoming retirement of the Pickering Nuclear Generating Station (NGS). The need for this project was previously described by the OPA in their evidence provided in EB-2012-0031 entitled “OPA Information on the Description of Need and Rationale for Oshawa Area TS (Clarington TS)”.

The proposed plan covers building a new 500/230 kV station on Hydro One owned lands at the Clarington Junction Site. Hydro One has obtained all necessary approvals for building the new station and the project is now under construction. With the extension of the Pickering NGS operating license to 2018, the project in-service date was revised from Q2 2015 to Q3 2017. The OPA provided concurrence of this revised in-service date in the letter dated April 16, 2014 which is attached in Appendix B of this exhibit. The current cost projection for the Clarington TS project is $294.1M.

The OPA had also identified that additional reactive support at Cherrywood TS is required and recommended the installation of two 300 MVar capacitor banks coincident with Pickering NGS retirement. Hydro One has initiated preliminary engineering and project development work for the Cherrywood TS capacitor bank. The current cost projection for the Cherrywood project is $14M with an in-service date of 2018.

Projects D2 and D3 are classified as Category 3 since the in-service dates are beyond the test years although significant funding is required within the test years.

3.2 Local Area Supply Adequacy

3.2.1 Description of Local Area Supply Investments

The local area supply systems operate primarily at 230kV, 115kV, with a few pockets at 69kV, and they link the inter-area network to load centers, such as LDCs and large industrial customers, and, in some cases, to local generators.
Local Area Supply investments provide for new or upgraded facilities in order to provide for area supply adequacy, and to meet load forecast requirements in an area where the loading on existing transmission facilities reach capacity. These investments typically affect many customers over a significant period of time and the benefits cannot be allocated in a practical and fair manner to specific customers.

The consequences of not proceeding with these investments are dependent on the specific situation, for example:

- Curtailment of load in order to ensure that the power system operates in a reliable mode and within the equipment rating.
- Insufficient reactive support causing system and voltage instability that would lead to widespread adverse impact in the local area.
- System constraints that restrict the ability of new renewable or high efficiency generation to be connected.

Funding levels for 2015 and 2016 for Local Area Supply Adequacy projects, along with the spending levels for the bridge and historic years are provided in Table 3 in Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 3. Customer capital contributions, where applicable, were determined in accordance with the TSC and Hydro One Transmission's Connection Procedures approved by the Board.

The overall spending in Local area Supply projects in the test years is comparable to Historical spending. A conservative estimate of additional capital expenditures of $15 million in 2016 has been included to reflect potential projects that may arise from the regional plans and that may need to be started by 2016. The scope of such projects will be better understood once the regional plans have been developed. These projects are not planned to be in service in 2016 so they will not impact the calculation of rates for that year.

3.2.2 Summary of Local Area Supply Projects

The following summarizes the major local area supply adequacy projects identified in Table 3. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Project D4: ***Midtown Transmission Reinforcement Plan***

This project is planned to provide reliable supply capacity to the City of Toronto. This project is required to reliably accommodate existing load since the existing 115kV transmission supply is inadequate to meet the coincident summer peak loading under the contingency condition where there is a loss of one circuit. The project was approved by the OEB under Section 92 of the OEB Act in its Decision and Order dated June 17, 2010 under Proceeding EB-2009-0425, and is classified as Category 1.

The in-service date has been delayed from Q3-2014 reported in Proceeding EB-2012-0031 to Q4-2015 due to a tunnel shaft shoring failure and difficulty in obtaining outages. The project cost projection remains unchanged at $114.8M.

Projects D5, D6 ***Guelph Area Transmission Reinforcement, and Preston TS Transformation***

These projects are planned to provide reliable transmission supply capacity for load growth in the South-Central Guelph Area and the Kitchener/Cambridge Area. The projects are required as the transmission system is inadequate to meet the local area's existing demand and forecast load requirements.

The proposed plan consists of building a new 230/115 kV station at Cedar TS. The project will also provide new switches at the Guelph North Junction to address restoration performance requirements, reliability and operational issues. The project is currently underway following OEB approval for "Leave to Construct" under Proceeding EB-2013-0053 and the expected project in-service date is Q2 2016. The cost of the Guelph Area Transmission Refurbishment project is projected at $94.3 M. This is higher than the $88M cost estimate submitted in EB-2013-0053 and is mainly due to the increased cost based on vendor bids for the station work at Cedar TS, the increased scope of work identified during detailed engineering for protection and control at remote sites and for drainage work at Cedar TS.

The second project covers provision of an additional 230/115kV autotransformer and associated switching at the existing Preston TS. Project development and preliminary engineering studies are currently underway in accordance with the Regional Infrastructure Planning process led by Hydro One. The current cost projection for the Preston TS project is $24.9M and the earliest projected in-service date is Q2 2017.
Project D5 for Guelph Reinforcement is classified as Category 1 and has received Section 92 approval from the Board; and Project D6 at Preston TS is classified as Category 3 since the in-service date is beyond the test years but significant expenditures are required within the test years.

Project D7: ***Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate***

This project is planned to address both the aging infrastructure and under-rated equipment that limits the connection of renewable generation in the City of Toronto. The project consists of replacing the aging 115 kV breakers and associated 115kV switchyard facilities at Manby TS in order to improve short circuit ratings at these stations to comply with the Transmission System Code.

The project is classified as Category 1 and was previously reported in Proceeding EB-2012-0031 with an estimated cost of $17.5M and an in-service date of Q4 2014. However, additional deficiencies were identified during the execution phase – station service, new cable trenches and trays and more protection and control work. Significant delays were also introduced due to the necessity to coordinate outages with a number of other major projects in the area. The current project cost is estimated at $24.3M and the in-service date is Q2-2016. However, to facilitate renewable and high efficiency generation connections in the Toronto 115kV area, the breaker replacement work is targeted for completion by Q4 2014.

Project D8: ***Hawthorne TS: Replace 2 existing Transformers***

The preliminary results of the Ottawa Area Regional Planning Study have found that the load meeting capability of the Ottawa 230/115kV transmission system is limited due to the ratings of aging transformers. The study determined that more transformation capacity is needed in order to meet the forecasted load growth in the area. As a result, the most cost effective approach to meet the 230/115 kV autotransformer capacity need is to replace the older lower rated 225MVA transformers with standard 250MVA units.

The project cost is $12.5M and the planned in-service date for the new transformers is Q2 2017. It is classified as Category 3 since the in-service date is beyond the test years but significant expenditures are required within the test years. The risk in not proceeding with this project would result in increased risk of customer interruptions affecting supply reliability to customers and would not support future area growth.

Project D9: ***York Region – Increase Transmission Capability for B82V/B83V Circuits***

As a result of an Area Supply Study of the York Region, the OPA, in its letter dated June 14, 2013 (see Exhibit A, Tab 16, Schedule 9, Attachment 2) asked Hydro One to proceed with work to increase the load meeting capability of circuits B82V and B83V. The work requires the installation of new breakers, and the design and implementation of a new Load Rejection scheme for stations connected to these circuits. These measures will increase the circuits' load meeting capability to improve reliability for the near and medium term and allow the line to supply additional customer loads in northern Vaughan and northern York Region. It will also allow restoration of customer loads with York

Energy Centre as a local supply source, following a major outage on the main transmission line.

As this project provides for future load meeting capability and meeting restoration needs for the broader northern York Region area, the costs will be recovered from the network rate pool and no capital contribution is required from customers. The total cost of this project is $20M with an in-service date of Q2 2017, and it is classified as Category 3 since the in-service date is beyond the test years but significant expenditures are required within the test years.

3.3 Load Customer Connection

3.3.1 <u>Description of Load Customer Connection Investments</u>

Load customer connections can be addressed by new or modified transformation connection facilities including new feeder positions at existing transformer stations, increase of capacity at existing stations, or construction of new lines and stations. The projects are initiated based on the customers' requirements for capacity, reliability and/or power quality. The projects may also be initiated by regional planning or the need to address end-of-life facilities. Because these types of projects are primarily customer driven, the magnitude and volume of work can vary significantly year over year.

The consequences of not proceeding with these projects include: impairment of customers' ability to supply their current and expected loads, increased risk of rotating blackouts where existing facilities are overloaded, and/or violation of Hydro One Transmission's license, specifically, Section 8, "Obligation to Connect", and clause 5 which ensures that the company shall not refuse to make an offer to connect.

Funding levels for 2015 and 2016 for Load Customer Connection projects, along with the spending levels for the bridge and historic years are provided in Table 4 in Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million are separately identified in Table 4.

The overall spending in the test years is comparable to historical spending. A provision of $12 million in 2016 for additional projects has also been included. This provision is a conservative estimate intended to reflect a number of potential connection requests or load connection projects arising from regional planning for which there is limited scope definition and that may need to begin work in 2016.

3.3.2 Summary of Load Customer Connection Projects

The following is a summary listing of the load customer transformation connection projects by Category Type for which cash flow details are provided in Table 4. All of these projects are non-discretionary and customer driven.

Category 1 Projects	**Category 2 Projects**	**Category 3 Projects**	**Category 4 Projects**
	D10: Copeland MTS	D11: Seaton TS D12: Supply to Essex County Transmission Reinforcement	

These projects are funded by customers through a combination of future rate revenues and a capital contribution, where required, as determined in accordance with the TSC and Hydro One Transmission's Connection Procedures approved by the OEB. Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.4 Generation Customer Connection

3.4.1 Description of Generator Customer Connection Investments

Generation customer connections are typically addressed by radial connection facilities; however, in some cases other modifications may be required to Hydro One's local area connection or network facilities in order to incorporate the generation into the system.

Since mid-2004, there has been growing generation connection activity in direct response to the initiatives taken by the Ontario Government and the OPA. These initiatives include Renewables Request for Proposals ("RFPs"), Clean Generation RFPs, Combined Heat and Power RFPs, the FIT program, and other project procurements.

With the signing of the Green Energy Investment Agreement with the Korean Consortium in January 2010, and the release of 25 large-scale renewable energy projects under Ontario's Clean Energy Feed-In Tariff program in July 2011; there was significant generation connection activity in 2013 and 2014. This generation activity is expected to continue albeit at a slower pace as the OPA has initiated new generation procurement programs in 2014 for Large Renewable and Combined Heat and Power generation.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the Ontario Government or OPA or which have otherwise developed appropriately under the applicable codes and rules, many of which contribute to meeting the Ontario Government's targets for renewable electricity capacity
- Failure to meet Hydro One Transmission's obligation to connect new generators under its Transmission License and the TSC.

Funding levels for 2015 and 2016 for Generation Customer Connection projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 5 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 5.

The overall spending in the test years is significantly lower than historical spending. This reflects the fact that a significant number (19) of generation projects representing 2546 MW has been or will be connected in 2013/14. It also reflects approximately 10 projects that have OPA contract awards but continue to experience delays. Because the connection dates of these projects cannot be established, the cash flows cannot be projected with sufficient confidence. Given the status of these projects, it is unlikely there will be significant capital expenditures for these projects in the test years.

A provision of $2M and $5M in 2015 and 2016 respectively for additional generation connections has been included to account for unforeseen connections that may be required within the test years. Such connections could be merchant projects, delayed projects that are able to proceed sooner than anticipated or projects from the OPA's Large Renewable Program or Combined Heat and Power Program that are able to begin connection work in the test years.

Generation connection projects are categorized as "Customer Driven" because they are requested by the customer to accommodate new generation and these connection facilities are normally fully funded by the customer.

In some cases, network facilities may be triggered which would be the responsibility of Hydro One in accordance with the TSC, and in other cases, Hydro One Transmission takes the opportunity to upgrade or refurbish its equipment while providing a new or modified generation connection. In such cases, the project may include some net cash flow (to be funded by Hydro One Transmission) associated with the refurbishment work.

Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.4.2 <u>Summary of Generator Customer Connection Projects</u>

The following summarizes the major generation connection project identified in Table 5. Additional details for the project are provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

Project D13: *Napanee Gas Generation Connection*

This project covers the connection of the Napanee Generating Station. A contract has been awarded by the OPA to Trans Canada Inc. to build this 910MW gas turbine generation plant in the County of Lennox and Addington near the Town of Napanee. The new Napanee GS will connect to the Lennox TS 500kV switchyard.

The planned in-service date for Napanee GS is Q1 2017.

3.5 Protection and Control Modifications for Enablement of Distribution Connected Generation

3.5.1 <u>Description of Protection and Control Modification Investments for Enablement of Distribution Connected Generation</u>

The connection of generation to the Distribution Systems supplied from the Hydro One Transmission System requires a number of modifications and additions to the Protection and Control systems in the Transmission Stations. These modifications are required to preserve the reliability and loading capability of the feeders, to protect loads and generators from islanding, to preserve the proper function of station protections and to minimize disruption to the operation of the generators.

The consequences of not proceeding with these programs include:

- Severe restriction on the amount of generation that can be connected to distribution systems.
- Lost production periods for station generator customers as a result of planned or forced transmission conditions for which transfer trip protections are not valid

Funding levels for 2015 and 2016 for Protection and Control Modification projects, along with the spending levels for the bridge and historic years, are provided in Table 6 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 6.

Project D14: *Transmission Station P&C Upgrades for Distribution Connected Generation*

Certain upgrades to or replacements of the Protection and Control (P&C) systems at Transmission Stations are required in order to accommodate generation connected to distribution systems supplied from the TS. These costs are fully recovered through customer contributions.

Additional details on those Programs with annual gross capital spending in excess of $3 million in either of the test years as identified in Table 6 are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.6 Protection and Control Modifications for Consequences of Connected Distribution Generation

3.6.1 <u>Description of Protection and Control Modification Investments for Consequences of Connected Distribution Generation</u>

As the connection of generation to the Distribution Systems supplied from the Hydro One Transmission System accumulates, certain consequences can emerge that require further investment to address. Some of these are consequences that are unforeseen, others can be anticipated but the exact threshold when they will be required depends on factors which are less predictable such as load growth and changes to generation patterns.

The consequences of not proceeding with these programs include:

- Contravention of Hydro One's reliability compliance obligations, as they pertain to the NPCC's requirements for under frequency load shedding, and the reliability of Special Protection Schemes.
- Power quality problems for distribution load customers
- Deterioration in reliability and performance of system control functions
- Inability to manage operation during planned or forced outage conditions

Funding levels for 2015 and 2016 for Protection and Control Modification projects for the Consequences of Distributed Generation, along with the spending levels for the bridge and historic years, are provided in Table 7 in Appendix A to this exhibit.

The following sections summarize the investments identified under the Protection and Control for Consequences of Connected Distribution Generation program. All of these programs are non-discretionary.

3.6.1.1 Under Frequency Load Shedding and Load Rejection Modifications for DG

Some contingencies on the interconnected transmission system can cause a loss of generation. The resulting imbalance between generation and load will cause a downward trend in the system frequency. If this trend is not corrected, other generation will trip and a widespread blackout would result. To prevent this, NERC and NPCC mandate under frequency load shedding (UFLS) schemes which disconnect load from the system automatically until the generation load imbalance is corrected. Hydro One has about 130 Transmission Stations equipped for under frequency load shedding. The loads are shed by tripping feeder breakers. As generation connects to the feeders, the number of feeder breakers that trip only load is being reduced and alternate arrangements will need to be implemented to maintain required UFLS capability.

Special Protection Schemes (SPS's) initiate tripping of generation, load or both, in response to contingencies on the transmission system, to prevent overloads or system instability. As with UFLS, the tripping of load is accomplished by tripping of the feeder breakers at Transmission Stations. With generation connected to the feeders, the amount of load available for rejection is reduced and alternate arrangements will need to be implemented to maintain required SPS capability.

These are system driven schemes associated with the transmission network. They are not connection assets and are not for connection purposes. Consequently, these costs will be allocated to the network pool.

3.6.1.2 Transmission work to mitigate distance limitation

This encompasses the protection works required on transmission assets which are required to address the power-distance limitation problems observed at connected projects. This work was approved in the OEB proceeding EB-2010-0229 (Hydro One's exemption application). For example, in the case where a DG is relocated to a shorter feeder the cost of installing transfer trip and other protection modifications on the shorter feeder will be a Transmission cost incurred to mitigate power-distance limitations.

3.7 Smart Grid

3.7.1 Description of Smart Grid Investments

The major portion of Hydro One's Smart Grid investments are in Hydro One Distribution on the development of the Advanced Distribution System (ADS) Smart Zone Pilot which is located in the area around Owen Sound. However, Hydro One Transmission also requires investments for upgrading of the Protection and Control (P&C) systems in some Transmission Stations to make them capable of the necessary interactions with the intelligent devices on the distribution systems (Hydro One's or those of other LDC's) supplied from those stations.

The main objective of the Smart Grid transmission investments is to test the implementation and integration of new P&C technologies that are best suited to interfacing with, and supporting the functions planned for ADS implementations. Hydro One needs to establish standards that will support the ADS implementations of many distributors.

3.7.2 Summary of Smart Grid Investments

The smart grid capital expenditures in 2015 and 2016 for transmission related work represent the costs associated with the final commissioning of the new systems in Owen Sound TS that interface to the Smart Zone Pilot and costs to test wireless communication from TS sites to ADS devices. Based on the findings from this pilot work, new programs may be created in the future.

Funding levels for 2015 and 2016 for Smart Grid projects, along with the spending levels for the bridge and historic years are provided in Table 8 in Appendix A to this exhibit.

3.8 Performance Enhancement and Risk Mitigation Programs

The program investments in this category are grouped into two categories; Performance Enhancement and Risk Mitigation as outlined below:

3.8.1 Performance Enhancement

There are two types of Performance Enhancement programs: Delivery Point Performance and Power Quality.

a) Delivery Point Performance

Delivery Point Performance investments are initiated to improve the performance to customers at their delivery point. As per the Customer Delivery Point Performance Standard issued by the Board under Proceeding EB-2002-0424, a delivery point for a customer is defined as an outlier delivery point ("ODP") when the reliability performance of that delivery point is worse than its historical baseline performance over a defined period of time or when the reliability performance of the delivery point is worse than the historical baseline of a group of delivery points in the same load category (0-15MW, 15-40MW, 40-80MW and greater than 80 MW).

There are two types of investments undertaken to address ODPs. The first are investments associated with the regular maintenance program (eg. pole replacement program) and the second are investments to address a specific problem or to implement a corrective solution (eg. installation of fault indicators to target the location of phase spacers or surge arrestors).

b) Power Quality

Power Quality issues are complex and generally mitigation measures are unique to customer operations. The installation of Power Quality monitors are needed to collect and assess Power Quality data to understand the issues and then work with individual customers to address their issue.

The consequences of not proceeding with these Performance Enhancement investments include: non-compliance with the applicable regulatory requirements, increased customer complaints, and reliability issues.

Funding levels for 2015 and 2016 for Performance Enhancement projects, along with the spending levels for the bridge and historic years, are provided in Table 9 in Appendix A to this exhibit.

3.8.2 Risk Mitigation

Work to ensure compliance with mandatory standards (such as NERC, NPCC) is met, and high risk situations are mitigated, is funded through this development program.

With the exception of Force Majeure events such as the 1998 ice storm and the 2003 blackout, events presenting unacceptable risks to supply reliability are identified. Projects are identified to address needs on a priority basis considering legislative, regulatory, environmental and safety requirements. Accordingly, the funding levels under this program can vary based on the issues to be addressed and the required remedial actions.

The consequences of not proceeding with these investments include: non-compliance with the applicable regulatory requirements, increased customer complaints, and inability to mitigate high-risk safety, security and reliability issues.

There were four projects identified under this development program in EB-2012-0031. The two projects to address reliability were the 115kV breaker upgrades at Hawthorne TS and Allanburg TS. High short circuit levels have required interim operating measures to reduce the short circuit levels. These operating measures involve opening bus tie breakers and splitting the bus at the 115kV stations which substantially reduces the capability and the redundancy of these stations to supply their respective areas. Completing the breaker upgrades at Allanburg TS and Hawthorne TS will restore the reliability back to levels prior to the deployment of the interim measures. The Allanburg project is expected to be complete by Q4 2014. The Hawthorne project is expected to be complete by Q3 2015. However, to facilitate renewable and high efficiency generation connections in the Ottawa 115kV area, the 115kV breaker work is targeted for completion by Q2 2014 and remaining work covering bus conductor upgrade and insulator replacements will be done after the breaker work is complete.

Two other projects under this development program to address equipment and safety risk were the addition of reactors at Basin TS (in-service 2014) and the high voltage breakers at Main TS (in-service 2014). These investments were required to address risk of damage to cables due to excessive temporary over-voltages in the 115kV downtown Toronto system.

There are no additional projects identified under this program. Funding levels for 2015 and 2016 for Risk Mitigation projects are based on an allowance for unforeseen work and are provided in Table 10 of Appendix A of this exhibit along with the spending levels for the bridge and historic years.

3.9 Large Capital Projects with Limited Scope Definition

The purpose of this section is to highlight certain large capital projects which have not been included in the business plan or this proposed rate application due to limited scope definition and project information but could have significant capital expenditures in the test years.

There are currently four large capital projects which are in the study and scope definition phase. These projects are expected to be in-service beyond the test years so they will not impact the rates being sought in this proposed application. Unlike Category 3 projects, specific projection of yearly capital expenditures at a project level cannot be established at this time.

While these projects will not impact rates in the test years, there may be significant capital expenditures in the test years for project development work, including approvals work, and early ordering of major materials that require long delivery times. Should this work materialize significant planning, engineering, approvals, stakeholder consultation and real estate resources will be required to carry out the work.

Further descriptions of the four projects are provided below.

3.9.1 East West Tie Expansion – Station Work

Robust growth in the mining sector in the Northwest coupled with a changing supply mix in the region, including the shutdown of coal-fueled power plants at Thunder Bay and Atikokan, is driving a need to reinforce the supply in the Northwest in order to maintain an acceptable standard of reliability in the region. While this can be accomplished by either transmission or local resource solutions, the OPA has recommended the expansion of the East-West Tie as the preferred solution option based on technical, economic and other considerations. The proposed transmission solution is the construction of a second double-circuit 230 kV line between Wawa TS, Marathon TS and Lakehead TS, and the addition of switching and reactive support facilities at the three stations. The augmented East-West Tie will have a firm transfer capability of about 650 MW.

The OEB has designated Upper Canada Transmission (NextBridge trade name) to undertake the development of the proposed line, while Hydro One is the Incumbent Transmitter of the station facilities. Hydro One's project will provide the necessary station work and facilities, including the switchgear and reactive facilities to connect NextBridge's proposed 230 kV double-circuit line to Wawa TS, Marathon TS and Lakehead TS, with required facilities identified by the IESO.

The in-service date of the new facilities is currently expected to be between late 2017 and late 2018. Both the scope and timing of the required facilities will be better understood following the Leave to Construct application, expected in early 2015, for the construction of the new lines from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS.

3.9.2 TransCanada - Energy East

TransCanada Energy (TCE) plans to convert one of its existing Canadian pipelines from natural gas transmission to oil. The pipeline will transport crude oil from Western Canada to Eastern Canadian refineries, and the new pumping stations will require electric power supply from all provinces along the route.

In Ontario, 30 new pumping stations will be built in locations along the existing pipeline route, with 19 stations requiring electric supply from the Hydro One Transmission system. The remaining 11 stations will be supplied by entities other than Hydro One Transmission or via TransCanada's natural gas supply. The connections could involve lines, stations and protection and control work. Hydro One is currently working with TCE to scope the development and estimating work. Further scope development may be required following the outcome of the preliminary System Impact Assessment that the IESO is conducting.

The in-service date of the new facilities is currently expected to be between late 2017 and late 2018.

3.9.3 Northwest Bulk Transmission Line Project

The Northwest Bulk Transmission Line is a priority project identified in the 2013 Long-Term Energy Plan (LTEP). This project will provide additional supply capability to support growing load and new customers in the area west of Thunder Bay including the area north of Dryden. On November 17, 2013, the Minister of Energy issued a directive to the OEB to amend Hydro One's transmission license to proceed with the development of network transmission expansion in the area west of Thunder Bay subject to the scope and timing recommended by the OPA. At the time of this rate submission, Hydro One has not received scope and timing recommendations from the OPA. The OPA plans to provide Hydro One this information later in 2014, after it has updated the demand forecast for the Northwest. Subject to the ultimate scope for this project, it is expected that the earliest in-service date of the new transmission facilities may be in the 2020 timeframe, dependent on demand.

3.9.4 GTA Reactors

This project is to provide additional reactive power absorption capability to manage high voltages in the Greater Toronto Area (GTA) under light load conditions and/or generator/station equipment outage conditions. The IESO has observed, in the past year, a number of occasions of high voltages (ie. voltages exceeding 550 kV on the 500 kV system and 250 kV on the 230 kV system) across the transmission system in the GTA. The IESO System Operators dealt with these incidences by opening lightly loaded transmission circuits connected to the GTA system. However, the IESO does not consider this action an appropriate long term remedy to this problem and a more permanent solution involving facilities to better regulate voltages and absorb reactive power in the GTA is required.

Preliminary studies conducted by the IESO and the OPA have identified that the frequency and magnitude of the high voltage problem in the GTA will worsen with the retirement of the Pickering Nuclear Generating Station near the end of this decade (the Pickering generators provide reactive power control as part of its operation).

It is estimated that between four and six reactors may be required in the GTA. More detailed studies are underway to further refine the scope of work, including the number, type, size and location of reactors needed. As the high voltage problem already exists today, an in-service date of late 2017 is being planned, in consideration of the lead time required for this project.

OPERATIONS CAPITAL

1.0 INTRODUCTION

Operations Capital investments fund enhancements and replacements of facilities required to operate Hydro One's Transmission System and to meet requirements established by operating agreements, market rules and regulatory authorities as a transmission owner and operator. Planned investments will enable Hydro One to achieve its vision as a leading transmission company by employing "best in class" commercially available operations systems and equipment. These investments will provide monitoring and control functionality to maintain top-quartile system reliability, accurate up to date information, improved customer satisfaction, reduced outage restoration time and public and worker safety. The process to develop capital investments for Operations assets is discussed in Exhibit A, Tab 16, Schedule 3.

Operations capital investments are required to:

- sustain assets that are at or near end of life;
- perform major refurbishments; and
- implement, enhance and modify the physical infrastructure, systems and tools necessary for transmission operations.

Failure to sustain the Network Operating systems and tools will lead to increased business and operational risk as aging assets become less reliable, require more maintenance and lack vendor support. Network Operating system and/or tool failures negatively impact customer service, system reliability and regulatory compliance. It is important to our customers, the province of Ontario and our interconnected neighbours that Hydro One Transmission Operations prudently undertake investments necessary to operate the Transmission System to provide efficient, safe and reliable service.

The Operations Capital program for the test years is divided into two categories:

- **Grid Operations Control Facilities**; These investments fund enhancements and replacement of computer tools and systems that support the transmission operating functions at the Ontario Grid Control Centre ("OGCC") and the Back-up Control Centre ("BUCC").
- **Operating Infrastructure**; These investments fund enhancements and modifications to the physical infrastructure outside of the control centres, required for the effective operation of the Transmission System.

The required funding for the test years and the spending levels for the bridge and historic years is provided in Table 1.

Table 1

Operations Capital ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Grid Operations Control Facilities	3.7	3.4	11.3	18.1	14.2	12.5
Operating Infrastructure	5.0	11.9	6.4	20.5	24.1	24.9
Total	8.7	15.3	17.7	38.6	38.3	37.4

1.1 Grid Operations Control Facilities

The increased spend in Grid Operations Control Facilities from $3.4 million in 2012 to $11.3 million in 2013 was caused by significant unplanned expenditures related to flood restoration of the BUCC and costs associated with the Network Management System (NMS) Capital Sustainment project (formerly approved and named NMS Upgrade project in EB-2012-0031).

The planned spending in the bridge and test years, of $18.1 million in 2014, $14.2 million in 2015 and $12.5 million in 2016, is higher than the historic years due to the continuation of the NMS Capital Sustainment project and the commencement of the new BUCC facility development project. Both of these projects are discussed further in Section 3.3 and 3.4 of this exhibit.

Additional planned Capital projects include: Integrated Voice Communications & Telephony System Replacement, Network Outage Management System ("NOMS") Sustainment project and Control Room displays. These projects are discussed further in Section 3.5 and 3.6 of this exhibit.

1.2 Operating Infrastructure

The decreased spending in Operating Infrastructure from $11.9 million in 2012 to $6.4 million in 2013 can be mainly attributed to deferred implementation of the Wide Area Network (WAN) Project in order to re-assess the project scope in the context of other infrastructure and system needs.

The planned spending in the bridge and test years, of $20.4 million in 2014, $24.1 million in 2015 and $24.9 million in 2016, is higher than the historic years due to the WAN Outreach Program, funding of Grid Control Network Sustainment equipment and expansion of the Fault Location (Distance to Fault) Project. Implementation of Hubsite realignment was delayed in the historic years to allow for a detailed review of requirements to address adjacency and reliability concerns. Program spending continues on the deployment of the Station Local Area Networks (LAN) Infrastructure Program, as well as specific telecommunication network improvements and additional work related to the Frame Relay Replacement project. These projects are discussed further in Section 4.3 of this exhibit.

2.0 DESCRIPTION OF THE SYSTEMS AND TOOLS

Hydro One operates and controls the Hydro One Transmission System from the OGCC. Back-up facilities are provided at a separate location in the event that the OGCC or its computer systems are rendered unavailable. A suite of centralized systems and tools, supported by province wide telecommunication and station control infrastructure, is used to execute monitoring and control of transmission assets, the planning and scheduling of outages and the provision of Transmission System performance information. Hydro One continually assesses and implements technologies to improve the performance and efficiency of its transmission operating function. However, the operating function faces growing challenges:

- The efficient scheduling and real time management of an increasing number of equipment outages required to support the growing Sustainment and Development work programs.
- Challenges associated with aging assets that require closer monitoring and management of operating limits and equipment de-ratings resulting in increased workload.

- The Green Energy & Economy Act 2009 continues to drive the installation of renewable generation directly connected to transmission lines or the distribution systems. Many of these installations will necessitate enhancements to the suite of systems and tools for control and monitoring to effectively manage system impacts, performance and customer requirements. NMS functionality has been extended to allow monitoring of Distributed Generation facilities from the OGCC in the interim.

2.1 Grid Operation Control Facilities

The primary systems used in the monitoring and control of the Transmission System include:

- **The Network Management System ("NMS")** is the transmission network monitoring and control tool which performs the following functions: data acquisition, supervisory control, real-time and study mode network analysis, predictive assessment tools and training simulation. It provides the real time voltages, frequency, loading, equipment status and annunciates alarms for the change in status of equipment or if the equipment is in an abnormal condition in the Transmission System. The NMS also provides control of Hydro One Transmission assets in order to switch equipment in and out of service for outages, react to contingencies and change system configuration to provide reliable service to customers.

- **Operations Support Tools** enable the integration of outage management, and Utility Work Protection Code and electronic logging functions:

    - **Network Outage Management System ("NOMS")** is the transmission outage management tool used for planning, scheduling, assessing and executing transmission equipment outages and for transmitting outage approval requests, via a direct communication link, to the Independent Electricity System Operator ("IESO"). NOMS Version II was placed in production October 2010.

- The **Utility Work Protection** Code is used by Hydro One to establish conditions which, when combined with appropriate work practices, procedures and work methods will provide employees with a guaranteed safe work area. This electronic work permit forms system contains the necessary information to support the development of required Work Protection documentation.
- The **Electronic Log** is the records system for the daily control room activity. It has automated features to capture manual and automatic operations of transmission assets using the NMS. Other pertinent information including Utility Work Protection Code, asset condition and status and communications with customers and various entities are manually logged to create a chronological record of the daily activity. The electronic log provides system data for asset management and system planning.

- **Transmission and Station Operating Diagrams** provide detailed information on the normal operating configuration of the Transmission System and the electrical connection of the transmission system and station equipment. This information is essential for Work Protection applications and to ensure the safe and reliable operation of the Transmission System.

- The **Integrated Voice Communications & Telephony System ("IVCT")** is designed to allow OGCC Operations to effectively manage voice communications between the OGCC and IESO, interconnected utilities, transmission connected customers, emergency services and field staff. Satellite phone systems and Hydro One's provincial mobile radio system are also available for emergency use.

- The **Emergency Services Information System ("ESIS")** provides verified up-to-date contact numbers for all emergency response services (e.g. police, fire, ambulance, ministry of environment, gas utilities, etc.) across the Province. This system is designed to enable Hydro One staff to quickly and effectively contact emergency personnel.

2.2 Operating Infrastructure

Operating Infrastructure comprises the systems and telecommunications required to connect the OGCC and Back-up centre to transmission stations, to support real time field operations and to fulfill Hydro One's obligations for real time telemetry under the Market Rules and Transmission System Code. Specifically, the Operating Infrastructure includes:

- **Gateway Systems** that connect legacy station control systems at the approximately 460 transmission switchyards to modern systems used at the OGCC and Back-up Centres and to the systems at the IESO. There are 110 gateway systems located at 37 sites, referred to as Hub Sites, across the province. The station control systems themselves, also generally referred to as Remote Terminal Units (RTUs), are considered part of the station asset and not Operating Infrastructure.
- The **Wide Area Telecommunications Network** (WAN) that provides multiple independent paths, on Hydro One's Fibre Optic system, on third party leased telecom, and by various wireless media, to all stations that are of critical importance to the operation of the grid and its restoration following any major disturbance event. This network also carries real time data that Hydro One is obliged to provide to Transmission Connected Customers from the OGCC or Back-up Centre to local points of presence for these customers.

- The **Fault Locating Systems** which are new systems being deployed to promptly identify the location of failures on transmission circuits. This will save on costs and time for restoring circuits to service.

- The **Provincial Mobile Radio System** is the means by which both the OGCC and the field operations centres maintain continuous high reliability contact with field crews. It is designed to be reliable in the event of localized or widespread blackouts and capable of accessing all remote, and electrically noisy, locations where Hydro One field crews would be dispatched. For health, safety and operational reasons, it is essential to provide crews with an assured means of communication in case of emergency.

- **Underground Cable Monitors** which are probes that monitor the surface temperature of the cable jacket, soil temperature gradients and cathodic protection voltages in order to ensure the healthy and optimum operation of cables which are critical to the supply of large downtown load centres.

- **Geomagnetically Induced Current Monitors** which detect currents flowing through the Transmission System induced by the earth's magnetic field during solar disturbances. These currents can disrupt protection systems and cause outages.

- **Weather Stations** to acquire location specific weather data required for determining accurate operating limits on equipment, or other key condition information of vital importance to grid operation such as accumulation of insulator contamination and ice build-up.

3.0 GRID OPERATIONS CONTROL FACILITIES

3.1 Overview

Grid Operations Control Facilities provide critical capabilities to support transmission operations at the OGCC and BUCC. These investments fund enhancements and capital sustainment of computer tools and systems to maintain equipment performance, reliability and service quality of all critical systems, and to satisfying regulatory requirements.

Computer and network systems typically require renewal every five years due to advancing technology. Grid Operations Control Facilities requiring upgrades are at end of life and are subject to increased reliability risk and maintenance costs as a result of lack of vendor support.

The Capital projects for the Grid Operations Control Facilities are provided in Table 2.

Table 2

Grid Operations Control Facilities

Capital Projects ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
NMS Capital Sustainment project	0.0	0.0	7.0	15.6	12.6	0.0
BUCC New Facility Development	0.0	0.0	0.0	0.5	0.5	11.0
Integrated Voice Communications and Telephony System Replacement	0.0	0.0	0.0	1.1	1.1	0.0
Operations Support Tools (NOMS Sustainment project)	0.0	0.0	0.0	0.0	0.0	1.5
Miscellaneous	3.7	3.4	4.3	0.9	0.0	0.0
Total	**3.7**	**3.4**	**11.3**	**18.1**	**14.2**	**12.5**

3.2 Description of Investments

Table 3

Grid Operations Control Facilities

Capital Projects > $3 Million in Test Year 2015 or 2016 ($ Millions)

Ref #	Description	Cash Flow Test Years 2015	Cash Flow Test Years 2016	Total Cost	Removal Cost	Capital Cost
O01	NMS Capital Sustainment	12.6	0.0	12.6	0.0	12.6
O02	BUCC New Facility Development	0.5	11.0	11.5	0.0	11.5
	Other Projects/ Programs < $3M	1.1	1.5	2.6	0.0	2.6
	Total Cost	**14.2**	**12.5**	**26.7**	**0.0**	**26.7**
	Removal Cost	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	Capital Cost	**14.2**	**12.5**	**26.7**	**0.0**	**26.7**

3.3 Network Management System Capital Sustainment (ISD O01)

The NMS is the mission critical operating tool used for monitoring and control of the Hydro One Transmission System. The reliable operation of the Ontario Power System is dependent on the continued availability and high performance of the NMS.

The NMS Capital Sustainment project started in 2013 (approved in EB-2012-0031) and will continue into the bridge and test years, upgrading end of life components such as power system software, server operating system, database software and monitoring and control infrastructure hardware. This investment will maintain required levels of NMS performance, reliability, availability and regulatory compliance for continued sustainability. It also provides for additional capacity required for Transmission System growth, opportunity to leverage new baseline functionality and ensures the NMS remains a fully supported system at both the OGCC and BUCC.

The cost for the investment is $12.6 million in 2015.

The Investment Summary Document for the NMS Capital Sustainment project is filed under Exhibit D2, Tab 2, Schedule 3.

3.4 Network Operations BUCC New Facility Development Project (ISD O02)

The BUCC facility is required to manage and maintain control of the Hydro One Transmission System in the event the OGCC or its computer systems are rendered unavailable and to satisfy North American Electric Reliability Corporation (NERC) compliance standards.

The BUCC facilities consist of the building, computer tools, systems and infrastructure to support the Control Room and back office Operating functions. The existing BUCC facility is more than forty years old. The design and infrastructure are no longer capable of sustaining and meeting modern control centre requirements and standards. The existing BUCC computer rooms are at design limits in terms of physical space, power supplies and environmental controls. As a result, full redundancy of all systems is not currently available and the reliability of transmission operating facilities is reduced.

This investment will fund a new BUCC building at a new location and provides for growth and expansion to accommodate existing and future requirements of the Network Operating Division. Not proceeding with this investment will result in continued risk to the BUCC facility, systems and tools and may affect the reliability of the transmission system.

The costs for the investments are $0.5 million in 2015 and $11.0 million in 2016.

The Investment Summary Document for the BUCC New Facility Development is filed under Exhibit D2, Tab 2, Schedule 3.

3.5 Integrated Voice Communications and Telephony ("IVCT") System Replacement

The IVCT is used in 24-hour, seven day operations at the OGCC and the BUCC. This mission critical system provides effective voice communication management between the control centres and Hydro One field staff, connected customers, emergency services and the IESO. The current system was placed in-service with the inception of the OGCC in 2003. This investment is required to mitigate the risk of a system failure as it has reached end-of-life due to technological obsolescence and lack of vendor support.

The costs for this investment in the bridge and test years consist of $1.1 million in 2014 and $1.1 million in 2015.

3.6 Network Outage Management System ("NOMS") Sustainment

NOMS is an essential tool for planning, scheduling, assessing and executing transmission and distribution equipment outages. The current version of NOMS was placed in production in October 2010 and this investment is required in 2016 in order to ensure continued vendor support. This investment will review the viability of the tool and investigate the potential options including the implementation of a version upgrade or a total replacement of NOMS. Factors to be considered will be system growth, compatibility with other Operations systems and applications and the availability of new technologies.

This investment provides for the capital sustainment of the Network Outage Management System (NOMS). Planned investments include hardware refresh, operating system upgrade and the investigation of the refresh or replacement of the application, including but not limited to: software, system components, interfaces with corporate systems and other hardware as required.

The costs for this investment in the test years consist of $0.0 million in 2015 and $1.6 million in 2016.

4.0 OPERATING INFRASTRUCTURE

4.1 Overview

Operating Infrastructure provides support for transmission operations at the OGCC and BUCC. These investments fund enhancements, expansion and end of life replacement of the physical infrastructure, beyond the walls of the OGCC and BUCC, required for the operation of the Transmission System and to maintain equipment performance, reliability and service quality of all critical systems and to satisfy regulatory requirements.

Computer and Network systems typically require upgrades every five years due to technology advancements and increased demands on functionality. As these systems reach end of life, they are replaced and/or expanded to manage increased reliability risks and maintenance costs and to provide improved functionality.

The Capital projects/programs for Operating Infrastructure are provided in Table 4.

Table 4

Operating Infrastructure

Capital Projects ($ Millions)

Ref #	Description	Historic			Bridge	Test	
		2011	2012	2013	2014	2015	2016
O03	Wide Area Network Outreach Program	-	-	-	-	4.0	4.0
O04	Station LAN Infrastructure Program	0.9	4.0	4.0	4.0	4.0	4.9
O05	Fault Locating Program	0.5	0.0	0.0	3.0	3.0	3.0
O06	Grid Control Network Sustainment	-	-	-	2.0	3.0	2.0
O07	Hub Site Management Program	0.0	0.0	0.0	2.0	2.0	3.0
	Mobile Radio System Replacement	-	-	-	1.4	2.0	2.6
	Telemetry Expansion Program	-	-	-	-	1.0	1.0
	Underground Cable Monitoring Project	-	-	-	-	0.5	0.2
	Wireless Transformer Station Camera Installation Project	-	-	-	-	1.0	2.0
	Telecommunication Performance Improvement	-	-	-	-	0.4	0.5
	Miscellaneous	-	-	-	-	3.2	1.7
	Total	**-**	**-**	**-**	**-**	**24.1**	**24.9**

4.2 Description of Investments

Table 5

Operating Infrastructure

Capital Projects > $3 Million in Test Year 2015 or 2016 ($ Millions)

Ref #	Description	Cash Flow Test Years 2015	Cash Flow Test Years 2016	Total Cost	Removal Cost	Capital Cost
O03	Wide Area Network Outreach Program	4.0	4.0	8.0	0.0	8.0
O04	Station LAN Infrastructure Program	4.0	4.9	8.9	0.0	8.9
O05	Fault Locating Program	3.0	3.0	6.0	0.0	6.0
O06	Grid Control Network Sustainment	3.0	2.0	5.0	0.0	5.0
O07	Hub Site Management Program	2.0	3.0	5.0	0.0	5.0
	Other Projects/ Programs < $3M	8.1	8.0	16.3	0.0	16.3
	Total Cost	**24.1**	**24.9**	**49.0**	0.0	**49.0**
	Removal Cost	**0.0**	**0.0**	**0.0**	0.0	**0.0**
	Capital Cost	**24.1**	**24.9**	**49.0**	0.0	**49.0**

4.3 Wide Area Network (WAN) Outreach Program (ISD O03)

Hydro One requires expanded telecommunication capacity into many of its transmission stations to support: protection and control for transmission development, advanced distribution system, video surveillance for security and operating, cyber security and enterprise systems such as conferencing and mobile workforce enablement. If the capacity on Hydro One's network is not expanded, existing and future telecom services will be displaced onto leased telecom services.

The cost for this investment is $4.0 million in 2015 and $4.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.4 Station Local Area Network (LAN) Infrastructure Project (ISD O04)

Modern digital protection, control and monitoring devices located in a Transmission Station have the ability to be networked together. The networking of these devices provides many benefits in the form of reduced cabling costs, reduced cost for primary measuring devices or transducers, reduced design costs, and the ability to achieve business efficiencies by remote interrogation of the devices for fault locating, event analysis and asset utilization information.

This program installs a standardized LAN infrastructure, appropriate to the class of station, which incorporates Cyber Security, remote monitoring and has the capacity, or expandability, to meet all forecast needs.

The cost for this investment is $4.0 million in 2015 and $5.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.5 Fault Location (Distance to Fault) Project (ISD O05)

This program funds facilities required to accurately compute and promptly transmit the location of transmission line failures (faults) from the line terminal stations to the OGCC. Digital protection and monitoring devices are now in place in most stations which have the ability to collect raw information that can be used to compute the fault location on transmission lines emanating from the station. Presently, information regarding a fault's location is communicated verbally to the OGCC by protection and control staff once they have travelled to the station, interrogated the devices and performed the necessary calculations manually. This investment will allow for determination of the likely fault location in nearly real time, enable faster restoration and will result in improved efficiency and reduced cost and carbon footprint as the time spent in vehicle and helicopters searching for the fault will be greatly reduced.

The rollout of this program had to be delayed to reassess compliance with NERC Cyber Security Standards that came into effect in 2009. This resulted in changes to the functional and design requirements and the need to correct deficiencies at stations that were part of the first phase of the rollout.

The cost for this investment is $3.0 million in 2015 and $3.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.6 Grid Control Network Sustainment Program (ISD O06)

This is a new program to manage the end-of-life replacement of Grid Control Network elements. The program ensures the ongoing reliability and performance of control of the Grid by containing the rate of loss-of-control events to acceptable rates by replacement of network equipment just before end-of-life failure rates begin increasing. Additionally, the program avoids cost increases associated with maintenance of aging and obsolete equipment.

The cost for this investment is $3.0 million in 2015 and $2.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.7 Hub-Site Management Program (ISD O07)

This program is needed to continuously expand the gateway systems located at thirty-seven Hub-sites across the province to provide capacity for monitoring and control of new assets, stations and generators that are connected to the transmission system. As new assets are built, the additional telemetry required increases the utilization of the gateways. When a gateway approaches capacity, additional gateways and hub sites need to be added. After a period of approximately six years, the gateway boxes need to be replaced due to obsolescence. The Hub-site management program continually manages these factors to ensure the capacity and reliability of the grid control infrastructure is in place to meet the needs of the development, load connection and transmission generation connection programs.

This program was introduced in 2007; about four years after most of the gateways went into service for the creation of the OGCC. From 2007 to 2009 many gateway systems were upgraded to larger systems to address full capacity utilization problems of many systems. By 2011, grid expansion and generation connections had pushed six Hub-sites beyond design limits. The plan to begin addressing the need for hub site infrastructure improvements has been delayed due to:

- a review of the overall protection and control (P&C) architecture strategy and reliability requirements;
- to ensure alignment with evolving Cyber Security standards;
- to ensure compatibility with the Advanced Distribution System (“ADS”) interface requirements; and
- to negotiate a more optimum arrangement for telemetry provision to the IESO.

The cost for this investment is $2.0 million in 2015 and $3.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.8 Provincial Mobile Radio System Replacement

The Provincial Mobile Radio System (PMRS) is the communication medium used for the OGCC and field operations centre to maintain effective communication with field crews. This project will refresh end-of life PMRS base stations. The PMRS base station radio equipment is reaching end of life and needs to be replaced over the next five years. A study was underway in 2013 to examine possible replacement technologies and integration strategies. Rollout of replacement radios is planned to ramp up in 2015 and reach full project replacement rates in 2017. Completion is planned by 2018.

The cost for this investment is $4.5 million total for 2015 and 2016.

4.9 Telemetry Expansion Program

The key deliverables of this program are the splitting of critical bundled alarms and the addition of more detailed monitoring of transmission equipment. This will enable OGCC to make an immediate determination of the cause of an alarm and the appropriate response. This will eliminate the need for unnecessarily removing equipment from service and urgent costly field staff dispatches to investigate the cause of the alarms. This program is required to eliminate unnecessary equipment outages, make more efficient use of field staff, better manage aging assets and improve grid reliability. The removal of any piece of equipment from service can place load supply at risk and may result in the delay of other outages required to complete sustainment or development work. Delay or cancellation of outages can be very disruptive to the execution of work affecting both schedules and costs.

The total cost for this investment is $1.975 million total for 2015 and 2016.

5.0 UNDERGROUND CABLE MONITORING PROJECT

The Underground Cable Monitoring Project is the installation of probes to monitor the condition of the high voltage underground cables supplying downtown Toronto. These monitors will help ensure the health of the cables and cable jackets, detect and initiate an alarm annunciation at the OGCC in the event of a puncturing or deterioration of the cable insulation jacket. This will increase optimal operation of the Hydro One underground plants.

The cost for this investment is $0.7 million total for 2015 and 2016.

5.1 Wireless Transformer Station Camera Installation Project

This project will fund the development of a wireless camera standard to be used by OGCC to view remote transformer station status and provide operational awareness. In recent years Hydro One has seen a major increase in the security breach of transformer stations and theft of copper. Copper theft can result in high replacement costs, power quality issues, the removal of transmission equipment from service jeopardizing supply to customers and present a safety issue to electric utility staff and the public. The installation of wireless cameras will provide remote station security viewing capability prior to dispatching security staff.

The cost of this investment is $3.0 million total for 2015 and 2016.

5.2 Telecommunication Performance Improvement

This investment will fund improvements to resolve reliability and performance problems with third party telecommunications Hydro One uses to control and monitor some remote Transmission Stations. There are a number of stations where improvements to reliability is required due to recurring "last mile" telecom problems. Telecommunication failures can result in the removal from service of high voltage equipment due to the lack of protective relaying. This program addresses those issues by providing an alternate independent path or by addressing infrastructure problems which allow common mode failure issues.

The cost of this investment is $1 million total for 2015 and 2016.

SUMMARY OF COMMON CORPORATE COSTS CAPITAL

Capital expenditures under the Common Corporate Costs program support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such, they consist of assets that are largely shared by both the Transmission and Distribution businesses. Common Corporate Costs include information technology (IT) installations such as applications software and computer equipment, buildings, office equipment, transportation and work equipment ("T&WE"), tools, and service equipment.

Table 1 provides a summary of the Transmission portion of the Common Corporate Costs Capital over the Historic, Bridge and Test years.

Table 1
Common Corporate Costs & Other Capital Allocated to Transmission 2011-2016
($ Millions)

Description	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Information Technology	32.9	30.5	22.9	34.6	20.8	22.6
Facilities & Real Estate	7.8	11.6	7.4	28.3	28.9	24.7
Transport & Work, and Service Equipment	13.1	14.6	18.8	22.9	19.8	21.3
Other (including Distribution Line Loss and CDM)	(1.5)	(14.7)	0.0	0.0	0.0	0.0
Total	**52.3**	**42.1**	**49.1**	**85.8**	**69.4**	**68.5**

Exhibit C1, Tab 6, Schedule 3 outlines the appropriate cost drivers that have been utilized to derive the Transmission allocation of this capital.

The level of spending in Information Technology capital for the test years is consistent with the levels of spending in the historical and bridge years. Exhibit D1, Tab 4, Schedule 2 details the capital requirements for Information Technology.

The Cornerstone initiative has been a major business transformation initiative in the historical and bridge years; it deals with end of life replacement of enterprise systems and also provides a platform for further effectiveness and efficiency gains at Hydro One. The capital spending for the Cornerstone project will be completed in 2014, which includes the CIS system that was placed in service in 2013.

The primary driver for the spending in Facilities and Real Estate is the need to provide suitable space to accommodate staff and equipment required to handle the growth in Sustaining, Development and Operations work programs over the test years. Exhibit D1, Tab 4, Schedule 3 details the capital requirements for Facilities and Real Estate.

The decrease in Transportation & Work Equipment spending in 2015 from the bridge year is related to the stabilization in work programs for the Electro-Forestry Journey Person Program, the Forestry and Provincial Lines Apprenticeship Program and the helicopter replacement schedule. Overall spending in the test years rises slightly with a funding increase in 2016 driven by the helicopter replacement schedule. Service Equipment spending decreases from 2014 to 2016 as capital requirements for replacing specialized equipment decreases and Health, Safety and Environment costs for automated external defibrillators also decreases. Exhibit D1, Tab 4, Schedule 4 details the capital requirements for T&WE and Service Equipment.

STATEMENT OF UTILITY RATE BASE

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Utility Rate Base
Test Years (2015 and 2016)
Year Ending December 31
($ Millions)

Line No.	Particulars		2015		2016
	Electric Utility Plant				
1	Gross plant at cost	$	15,665.6	$	16,353.0
2	Less: accumulated depreciation		(5,515.7)		(5,819.3)
3	Net plant in service	$	10,149.9	$	10,533.7
4	Construction work in progress		0.0		0.0
5	Net utility plant	$	10,149.9	$	10,533.7
	Working Capital				
4	Cash working capital	$	12.9	$	10.3
5	Materials and Supplies Inventory		13.7		14.0
6	Total working capital	$	26.6	$	24.2
7	Total rate base	$	10,176.5	$	10,558.0

REVENUE REQUIREMENT

1.0 SUMMARY OF REVENUE REQUIREMENT

Hydro One Transmission has followed standard regulatory practice in the calculation of revenue requirement as follows:

Table 1
Revenue Requirement
($ Millions)

Particulars	2015	2016	Reference
OM&A	452.0	457.4	C1, Tab 2, Schedule 1
Depreciation	394.2	404.0	C1, Tab 7, Schedule 1
Income Taxes	71.8	82.8	C1, Tab 8, Schedule 1
Cost of Capital[1]	699.3	744.9	B1, Tab 1, Schedule 1
Total Revenue Requirement	**1,617.1**	**1,689.2**	E2, Tab 1, Schedule 1

[1] Includes Interest Capitalized recovery on the Niagara Reinforcement Project (2015 - $5.0 million and 2016 - $5.0 million).

The resultant revenue requirement of $1,617.1 million for 2015 and $1,689.2 million for 2016 are the amounts required by Hydro One Transmission to safely address customer service and system reliability needs at the lowest practical cost.

2.0 CALCULATION OF REVENUE REQUIREMENT

The details of the OM&A and Depreciation components of the revenue requirement are as follows:

2.1 OM&A Expense

($ Millions)

	2015	2016
Sustaining	238.7	241.1
Development	12.9	13.4
Operations	58.5	59.1
Customer Care	5.5	5.5
Shared Services and Other Costs	70.2	71.3
Taxes Other Than Income Tax	66.3	67.0
Total OM&A	**452.1**	**457.5**

2.2 Depreciation Expense

($ Millions)

	2015	2016
Depreciation	387.7	397.9
Amortization	6.5	6.1
Total Expense	**394.2**	**404.0**

3.0 RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2014 TO YEAR 2015

Table 2 compares, by element, the 2014 rates revenue requirement (as per EB-2012-0031) against the 2015 proposed rates revenue requirement.

Table 2

Comparison of Rates Revenue Requirements: Board Approved 2014 vs. 2015

($Millions)

Line no.	Description	Year 2014	Year 2015	Difference
1	OM&A	449.7	452.1	2.3
2	Depreciation	371.5	394.2	22.7
3	Capital Taxes	-	-	-
4	Income Taxes	54.5	71.8	17.2
5	Cost of Capital [1]	659.6	699.3	39.6
	Total Revenue Requirement	**1,535.3**	**1,617.1**	**81.8**
6	Deduct External Revenues [2]	(36.6)	(28.4)	8.2
	Revenue Requirement less External Revenues	**1,498.7**	**1,588.7**	**90.0**
7	Deduct Export Revenue Credit [3]	(34.1)	(33.4)	0.7
8	Deduct Regulatory Accounts Disposition [4]	(30.3)	(17.6)	12.6
9	Add Low Voltage Switch Gear [5]	12.1	13.2	1.2
	Rates Revenue Requirement	**1,446.4**	**1,550.9**	**104.5**

[1] Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.
[2] External revenues addressed in Exhibit E1, Tab 2, Schedule 1.
[3] Export revenue is addressed in Exhibit H1, Tab 5, Schedule 1.
[4] See Exhibit F1, Tab 1, Schedule 3 for further details.
[5] Low Voltage Switch Gear is addressed in Exhibit G1, Tab 4, Schedule 1.

There are a number of key operational and financial factors contributing to the increased rates revenue requirement that have an impact across the cost components in Table 2. The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in depreciation, as well as higher cost of debt and allowed ROE. Also contributing to the difference is higher income taxes, lower external revenues, and reduced regulatory account disposition.

Table 3 illustrates the value of the key impacts on the increase in the rates revenue requirement.

Table 3
Components of Change to Rates Revenue Requirement
2014[1] vs. 2015

Description	**Amount ($M)**
Increase in OM&A	2.3
Rate Base Growth	49.5
Increase in Cost of Debt	9.2
Increase in Cost of Equity	14.4
Tax - timing differences and other	6.4
External Revenue	8.2
Increase in Export Revenue Credit	0.7
Increase in Regulatory Accounts Disposition	12.6
Increase in Low Voltage Switch Gear	1.2
Other	0.1
Total Change	**104.5**

4.0 RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2015 TO YEAR 2016

Table 4 compares, by element, the 2015 rates revenue requirement against the 2016 rates revenue requirement.

[1] 2014 Amounts as per Hydro One Transmission's 2014 Revenue Requirement and Charge Determinants for EB-2012-0031 and EB-2011-0268.

Table 4

Comparison of Rates Revenue Requirements 2015 vs. 2016 ($ Millions)

Line no.	Description	Year 2015	Year 2016	Difference
1	OM&A	452.0	457.4	5.4
2	Depreciation	394.2	404.0	9.9
3	Income Taxes	71.8	82.8	11.1
4	Cost of Capital[1]	699.3	744.9	45.7
	Total Revenue Requirement	**1,617.1**	**1,689.2**	**72.1**
5	Deduct External Revenues[2]	(28.4)	(28.8)	(0.4)
	Revenue Requirement less External Revenues	**1,588.7**	**1,660.4**	**71.7**
6	Deduct Export Revenue Credit[3]	(33.4)	(34.3)	(0.9)
7	Deduct Regulatory Accounts Disposition[4]	(17.6)	(17.6)	-
8	Add Low Voltage Switch Gear[5]	13.2	13.9	0.6
	Rates Revenue Requirement	**1,550.9**	**1,622.0**	**71.4**

[1] Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.
[2] External revenues addressed in Exhibit E1, Tab 2, Schedule 1.
[3] Export revenue is addressed in Exhibit H1, Tab 5, Schedule 1.
[4] See Exhibit F1, Tab 1, Schedule 3 for further details.
[5] Low Voltage Switch Gear is addressed in Exhibit G1, Tab 4, Schedule 1.

The increase in 2016 rates revenue requirement is primarily due to the increase in core rate base as reflected in the increase in return on capital and depreciation. Other contributing factors include higher income taxes and slightly higher OM&A work program requirements.

Table 5 illustrates the value of the key impacts on the movement in the rates revenue requirement.

TABLE 5

COMPONENTS OF CHANGE TO RATES REVENUE REQUIREMENT:

2015 vs. 2016

Description	Amount ($M)
Increase in OM&A	5.4
Rate Base Growth	45.6
Increase in Cost of Debt	9.0
Increase in Cost of Equity	10.6
Tax - timing differences and other	1.4
External Revenue	(0.4)
Increase in Export Revenue Credit	(0.9)
Increase in Regulatory Accounts Disposition	-
Increase in Low Voltage Switch Gear	0.6
Other	0.1
Total change	**71.4**

[1] Net of External Revenue

Exhibit G1, Tab 1, Schedule 1 provides information on how the rates revenue requirements will be recovered through rates.

EXTERNAL REVENUES

1.0 STRATEGY

Hydro One Transmission's strategy is to focus on core work, while continuing to be responsive to external customer work requests where Hydro One Transmission has available resources and/or assets to accommodate the request.

External revenues earned through the provision of services to third parties are forecast to be $28.4 million in 2015 and $28.8 million in 2016 and account for approximately 1.8% of Hydro One Transmission revenues. These external revenues are used to offset the revenue requirement from Hydro One Transmission tariffs and thereby reduce the required revenue to be collected from transmission ratepayers.

2.0 COSTING AND PRICING

The costing of external work is determined on the basis of cost causality, with estimates calculated in the same way as internal work estimates, using the standard labour rates, equipment rates, material surcharge, and overhead rates (see Exhibit C1, Tab 5, Schedule 1 for a description of costing of work). An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit for the transmission ratepayers.

This exhibit identifies the revenues for external work. The associated costs for this work are described in Exhibit C1, Tab 3, Schedule 6.

3.0 DESCRIPTION

Table 1
External Revenues ($ Millions)

$M	2011 Historic	2012 Historic	2013 Historic	2014 Bridge	2015 Test	2016 Test
Secondary Land Use	20.8	22.0	21.1	14.1	14.3	14.5
Station Maintenance	11.4	13.9	12.6	7.1	7.2	7.3
Engineering & Project Delivery	4.8	2.3	2.2	0.2	0	0
Other External Revenues	4.6	3.8	10.7	6.9	6.9	7.0
Totals	**41.6**	**42.0**	**46.6**	**28.3**	**28.4**	**28.8**

3.1 Secondary Land Use

Hydro One Transmission manages the Provincial Secondary Land Use Program (“PSLUP”) on behalf of the Province, to whom Hydro One Transmission’s transmission corridor lands were transferred under Bill 58 on December 31, 2002. The program focuses on licensing and leasing the transmission corridor lands to external parties for “secondary” land use purposes that are compatible with Hydro One Transmission’s primary transmission business operations. Typical uses include parking lots, municipal roadways, parks and trails, agricultural areas, water mains and other municipal infrastructure occupations, as well as public transit parking lots and station operations. The PSLUP revenue stream is generated by charging land rentals to external parties for new license and lease occupations and subsequent agreement renewals, as well as lump sum consideration for easements granted (e.g., water mains) and operational land sales completed (e.g., roadway).

Under Bill 58 provisions (*An Act to amend certain statutes in relation to the energy sector*, c.1, S.O. 2002) and subsequently negotiated arrangements, all expiring corridor PSLUP agreements were transferred to the Province as of December 31, 2002. Remaining unexpired corridor agreements and associated revenue streams are retained by Hydro One until such time as these agreements expire. Upon expiration, the previously retained agreements and revenue streams by Hydro One are then also transferred to the province under the PSLUP.

Notwithstanding this transfer, Hydro One Transmission has provided front-line delivery services for the PSLUP on behalf of the Province since 2002. Under arrangements made on April 1, 2005, Hydro One Transmission was granted the right under agreement to continue delivery of the program through March 31, 2010. This agreement was extended for another five (5) years and is scheduled to expire on March 31, 2015. Hydro One Transmission anticipates that this agreement will be renewed or extended. The arrangements set out in the agreement include Hydro One Transmission's retention of PSLUP revenues for unexpired agreements until their expiry, as well as a results-based compensation model involving the sharing of revenues between Hydro One Transmission and the Province for new PSLUP agreements and for renewals of expired agreements which were previously transferred to the Province. Hydro One also manages a small portion of secondary land use revenue that does not fall under current PSLUP arrangements.

As a result, responsibility for the management and re-negotiation (as required) of all existing secondary land use agreements (including those previously transferred to the Province under the corridor land transfer arrangements) now rests with Hydro One Transmission. Hydro One Transmission will continue promoting and negotiating all new secondary land use business opportunities, where these are consistent with Hydro One Transmission's short and longer-term operational requirements.

The Secondary Land Use Revenue levels are forecasted to be $14.3 million in 2015 and $14.5 million in 2016. Historical figures in years 2011 to 2013 are higher due to unbudgeted one-time transactions involving easement grants (e.g. water mains) and operational land sales (e.g. roadways).

3.2 Station Maintenance

Revenues from external work in the Station Services segment include specialized activities similar to those performed internally for Hydro One Transmission. These activities include repairing electrical equipment (such as transformers, breakers and switches), specialty machining (spindles), protective relay installation, maintenance and calibration, coordinating services to reconnect modified systems to the network, as well as providing meter services and emergency services. Customers seek out station services skills resident within Hydro One Transmission, requiring highly specialized staff able to perform work on a variety of high voltage equipment in a variety of work settings (such as nuclear environments). Work is performed according to commercially negotiated contracts which reflect market level pricing.

Hydro One Transmission provides support to the external market place in areas which are related to the Company's transmission business. This work is primarily tied to support Ontario's key generation suppliers: Bruce Power LLP, Ontario Power Generation Inc. and Siemens Westinghouse Inc. in support of Ontario Power Generation Inc.

As can be seen in Table 1, this segment of external revenue is expected to decrease in 2014 through to 2016, primarily due to the expected shift in resources to Hydro One Transmission's growing work programs.

3.3 Engineering and Project Delivery

Hydro One Transmission's Engineering & Project Delivery activities continue to focus on internal work supporting the growing transmission work program, while striving to reduce external work to a minimal level. This segment of external revenue is derived from upgrading revenue meters at various sites per IESO requirements.

The 2014 amount of $0.2 million reflects the lower volume of activities related to revenue metering installations pursuant to the IESO requirements. This program will be completed in 2014.

3.4 Other External Revenues

Table 2
Other External Revenues

	2011 Historic	2012 Historic	2013 Historic	2014 Bridge	2015 Test	2016 Test
Other External Revenues	**4.6**	**3.8**	**10.7**	**6.9**	**6.9**	**7.0**

Other external revenues set out in Table 2 include royalties that Hydro One Transmission receives under the current outsourcing agreement with Inergi LP, details of which are provided in Exhibit C1, Tab 3, Schedule 2. They also include revenues from providing telecommunications services to Ontario Hydro successor companies (such as lease of fiber), revenues from special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous external revenues. These include a transfer price charge to Telecom and Remotes described in Exhibit C1, Tab 6, Schedule 3. In 2015 and 2016, forecasted revenues include $4.0 million each year for the lease of idle transmission lines.

REGULATORY ACCOUNTS

1.0 INTRODUCTION

The purpose of this evidence is to provide a description of Hydro One Transmission's Regulatory Accounts.

All of the Regulatory Accounts reported by Hydro One Transmission have been established consistent with the Board's requirements as set out in the Accounting Procedures Handbook, subsequent Board direction, or as per specific requests initiated by Hydro One Transmission.

Hydro One Transmission's outstanding deferral and variance accounts balances are summarized in Table 1 below:

Table 1
Summary of Transmission
Regulatory Accounts Balances For Approval ($ Millions)

Description	Balance as at Dec 31, 2012	Balance as at Dec. 31, 2013	Balance as at Dec. 31, 2014 (Forecast)
Total Regulatory Accounts	(52.8)	(67.4)	(36.1)

The forecast interest for 2014 is calculated by applying simple interest on the December 31, 2013 year-end principal balances using the forecast bankers' acceptance-3 month rate (1.20%) plus 0.25% spread as prescribed by the Board. Simple interest is applied to the monthly opening principal balance in this account according to the Board prescribed interest rate. Morevoer, the balance includes the disposition approved by the Board in EB-2012-0031.

Information on each account and its balance is described in Section 2.0 and Section 3.0 of this exhibit. Detail on regulatory accounts requests is discussed in Exhibit F1, Tab 1, Schedule 2. Detail on the disposition of the account balances is discussed in Exhibit F1, Tab 1, Schedule 3. Further details on deferral and variance accounts are provided in:

- Exhibit F2, Tab 1, Schedule 1: Regulatory Accounts for Approval
- Exhibit F2, Tab 1, Schedule 2: Planned Disposition of Regulatory Accounts - Schedule of Annual Recoveries
- Exhibit F2, Tab 1, Schedule 3: Continuity Schedule Regulatory Accounts

2.0 REGULATORY ACCOUNTS REQUESTED FOR APPROVAL

The Board's decision on Hydro One's Transmission Rates for 2013 and 2014 (EB-2012-0031) approved or required the establishment or continuance of certain regulatory accounts. Table 2 below, provides a list of the Transmission Regulatory Account balances requested for approval and disposition as part of 2015 and 2016 Transmission Rates.

Table 2
Transmission
Regulatory Accounts Requested for Approval ($ Millions)

Description	US of A Account Ref.	Balance as at Dec. 31, 2012	Balance as at Dec 31, 2013	Balance as at Dec 31, 2014 (Forecast)
Excess Export Service Revenue	2405	(31.8)	(41.9)	(23.5)
External Secondary Land Use Revenue	2405	(24.4)	(32.8)	(18.5)
External Station Maintenance, E&CS Revenue and Other External Revenue	2405	(5.0)	(6.4)	(1.3)
Tax Rate Changes	1592	(3.5)	(3.6)	0.8
Rights Payments	2405	2.7	(3.6)	(1.9)
Pension Costs Differential	2405	14.7	20.8	8.2
Long Term Future Corridor	1508	0.0	0.1	0.1
Total Regulatory Accounts for Disposition		**(52.8)**	**(67.4)**	**(36.1)**

2.1 Excess Export Service Revenue

This variance account was initially created as a result of the Board's decision of May 28, 2009 (EB-2008-0272). In its EB 2012-0031 decisions, the OEB approved continuance of this account. The Board requested that Hydro One Transmission continue to capture any differences between forecast export service revenue approved by the Board as part of 2013 and 2014 Transmission Rates and the actual export service revenue. As part of its decision, the Board ordered that the Export Transmission Services (ETS) rate be held at $2/MWh and approved the Hydro One Transmission forecast at $27.0 million and $34.1 million in revenue for both 2013 and 2014 respectively. The balance in this account is reported to the Board on a quarterly basis, consistent with the Board's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $19.0 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $23.5 million at the end of the bridge year 2014.

2.2 External Secondary Land Use Revenue

This variance account was created as a result of the Board's decision of May 28, 2009 (EB-2008-0272). The Board approved continuance of the account in its decision of EB-EB-2012-0031 requesting that Hydro One Transmission maintain a variance account to capture any difference between the $13.2 million of forecast external secondary land use revenues approved by the Board, for each test year, as part of 2013 and 2014 Transmission Rates, and the actual secondary land use revenues for each of these years.

As at December 31, 2013, Hydro One Transmission had an excess external secondary land use revenue balance of $32.8 million, inclusive of accrued interest. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $14.6 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $18.5 million at the end of the test year 2014.

2.3 External Station Maintenance, E&CS Revenue and Other External Revenue Account

This variance account was created as a result of the Board's decision of May 28, 2009 (EB-2008-0272). The Board approved continuance of the account in its decision of EB-EB-2012-0031. The Board requested that Hydro One Transmission continue to capture any differences between the Board approved and actual net external station maintenance, E&CS revenue and Other external revenue. As a result of the settlement agreement approved by the Board in EB-2013-0031, Hydro One expanded the scope of this account to capture the difference between forecast net other revenues and actual net other revenues received.

As at December 31, 2013, Hydro One Transmission had excess external station maintenance, engineering and construction services and other external net revenues of $6.4 million, inclusive of interest accrued. The balance in this account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $5.2 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $1.3 million at the end of the test year 2014.

2.4 Tax Rate Changes

This variance account was created as a result of the Board's decision of August 16, 2007 (EB-2006-0501). The Board approved continuance of the account in its decision of EB-

EB-2012-0031. The variance account captures the tax impact to Hydro One Transmission of:

- differences that result from a legislative or regulatory change to the tax rates or rules; and
- differences that result from a change in, or a disclosure of, a new assessment or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

Specifically, relative to this filing, in 2012, $0.8 million of under-collections from customers were recognized as a result of the difference between the actual effective tax rate (26.50%) and the rate incorporated in approved rates (26.25%). In 2013 the effective and Board-approved tax rates were equal.

This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

As at December 31, 2013, Hydro One Transmission has recognized a liability balance of $3.6 million, inclusive of interest accrued.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $4.3 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast asset account balance of $0.8 million at the end of the test year 2014.

2.5 Rights Payments

This account was established based on the Board’s decision on Hydro One’s Transmission Rates for 2011 and 2012 (EB-2010-0002) and the Board approved continuance of the account in its decision of EB-2012-0031. The Board requested that

Hydro One Transmission use a variance account to capture the difference between the forecast $4.5 million approved by the Board for both test years as part of 2013 and 2014 Transmission Rates and the actual Rights Payments. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

As at December 31, 2013, Hydro One Transmission has recorded a liability balance of $3.6 million, inclusive of interest accrued.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $1.8 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $1.9 million at the end of the test year 2014.

2.6 Pension Costs Differential

This account tracks the difference between the OM&A pension cost estimates based on actuarial assessments used for Hydro One’s Proposed Transmission Rate application and the actual OM&A pension contributions.

This account was established based on the Board’s decision on Hydro One Transmission’s Rates for 2011 and 2012 (EB-2010-0002) which accepted the continuation of the Pension Costs Differential account. The Board further approved continuance of the account in its decision of EB-2012-0031. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

As at December 31, 2013, Hydro One Transmission has recognized an asset balance of $20.8 million, inclusive of interest accrued.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $12.8 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast asset account balance of $8.2 million at the end of the test year 2014.

2.7 East West Tie Deferral Account

This account was approved by the Board on July 12, 2012 in Hydro One's application (EB-2012-0180) to establish a deferral account related to the East-West Tie Line proceeding (EB-2011-0140).

Hydro One was permitted to tracks costs in the EWTDA that relate to the following two categories:

1. costs incurred by Hydro One Transmission as incumbent transmitter to support the Board through the designation process and to eventually facilitate the line's connection; and
2. expenditures incurred relating to preliminary engineering and other station connection work required to accommodate the East West Tie line.

With the OEB having announced the successful bidder for the EWT project, Hydro One is seeking only to continue the second category of the prior approved account, that as the incumbent transmitter, will track costs for expenditures incurred relating to preliminary engineering and other station connection work required to accommodate the East West Tie line.

2.8 Long-Term Transmission Future Corridor Acquisition and Development Account

This deferral account, approved during EB-2012-0031, records transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure. In order to ensure land corridor availability in near-urban areas, long term investment planning is required. The costs recorded in the account will be associated with land assessment work such as environmental studies and assessments, preliminary engineering studies, public and First Nations/Métis consultations, etc. The outcome of this work will be helpful in making siting determinations for new corridors and in setting aside the required land for planning purposes, thus ensuring its availability and affordability when the project proceeds.

As at December 31, 2013, Hydro One Transmission has recognized an asset balance of $0.1 million, inclusive of interest accrued. This amount is expected to grow over the next few years.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date. This will result in a forecast asset account balance of $0.1 million at the end of the test year 2014.

2.9 External Revenue – Partnership Transmission Projects Account

This account was established based on the Board's decision on Hydro One Transmission's Rates for 2013 and 2014 in EB-2012-0031.
The deferral account records costs for services provided by Hydro One employees for work they are/will perform for partnership companies, whether partnered with Hydro One

Networks Inc. or Hydro One Inc., working on competitive or other partnership transmission projects.

Hydro One will identify specific employees to work with partnership companies in which the company has a vested interest. The company will track employee time and any expenses and the resulting costs will be invoiced to the appropriate partnered company. The amount of invoiced costs will be recorded in the External Revenue Partnership Transmission Project Account for reduction to future revenue requirements.

2.10 LDC CDM and Demand Response Variance Account

This account was established as a result of the settlement agreement which was approved by the Board for Hydro One Transmission's Rates for 2013 and 2014 in EB-2012-0031.

The account will track the impact of actual CDM and Demand Response results on the Load Forecast and the resulting impact on revenue requirement.

Hydro One Transmission proposes to record the following two elements in the CDM Variance account:

1) CDM Variance - Hydro One Transmission will track the difference between the forecast for 2013 and 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs.

2) Demand Response Variance - Hydro One Transmission will track the actual Demand Response results against the forecast for 2013 and 2014 in this variance account.

Hydro One will use the annual results reported by the OPA in September of each year for the verified results of the previous year in accordance with the CDM Guidelines issued by the Board in EB-2012-0003.

No balance has been recorded in this account as 2013 actual results will not be reported by the OPA until September 2014.

PLANNED DISPOSITION OF REGULATORY ACCOUNTS

1.0 INTRODUCTION

The purpose of this evidence is to outline the planned disposition of Hydro One Transmission's Regulatory Accounts.

2.0 PLANNED DISPOSITION OF REGULATORY ACCOUNTS

Hydro One Transmission is requesting disposition of the actual audited Regulatory Account values as at December 31, 2013, plus forecast interest for 2014 on the principal balances as at December 31, 2013, less any amounts approved for disposition in 2014 by the Board in the EB-2012-0031 rate filing for Transmission's rate years 2013 and 2014.

It is expected that new Transmission rates will be effective and implemented on January 1, 2015 and that disposition of the accounts requested will commence on that date. Hydro One Transmission's requested reduction to the Revenue Requirement of $36.1 million is detailed in Table 1:

TABLE 1

TRANSMISSION

DISPOSITION OF REGULATORY ACCOUNT BALANCES ($ MILLIONS)

Description	**Forecast Balance as at Dec 31, 2014**
(a) Excess Export Service Revenue	(23.5)
(b) External Secondary Land Use Revenue	(18.5)
(c) External Station Maintenance, E&CS Revenue and Other External Revenue	(1.3)
(d) Tax Rate Changes	0.8
(e) Rights Payments	(1.9)
(f) Pension Cost Differential	8.2
(g) Long Term Future Corridor	0.1
(h) Total Regulatory Accounts for Approval	**(36.1)**

With the setting of new uniform Transmission rates in 2015 and 2016, Hydro One Transmission is requesting an adjustment to the Revenue Requirement over the standard 24-month period, which is consistent with the test years of this proposed application. Refer to Exhibit F2, Tab 1, Schedule 2 for the proposed annual amounts.

For 2015 and 2016, this reduction will be factored into the Revenue Requirement per Exhibit E1, Tab 1, Schedule 1.

COST ALLOCATION AND CHARGE DETERMINANTS

1.0 PURPOSE

The purpose of Exhibit G1 is to describe the process followed by Hydro One Transmission to allocate the Transmission revenue requirement identified in Exhibit E1, Tab 1, Schedule 1 into the four rate pools.

This Exhibit sets the context for the Transmission Cost Allocation and Charge Determinants for this Proposed Application. This information will be Hydro One Transmission's input towards determining the Uniform Transmission Rates [UTR] applicable to all Ontario transmission customers.

2.0 SUMMARY

The rates revenue requirement outlined in Exhibit E1, Tab 1, Schedule 1, Table 4 is the starting point for the revenues to be allocated into the Rate Pools using the process described in this exhibit.

Table 1 summarizes the allocation of the 2015 and 2016 transmission rates revenue requirement to the four rate pools. The details of the cost allocation methodology are provided in Exhibit G1, Tab 2, Schedule 1. Also provided in Table 1 are the associated charge determinants per Rate Pool which will be used as Hydro One Transmission's inputs into the determination of the provincial UTRs. The Charge Determinants are discussed in Exhibit H1, Tab 3, Schedule 1.

Table 1

Summary of Rate Pool Revenue Requirement and Charge Determinants

	Network	Line Connection	Transformation Connection	Wholesale Meter	Total
2015 Revenue Requirement ($ Millions)	933.6	206.3	410.8	0.3	1,550.9
2015 Charge Determinants: Ave Monthly MWs	20,457	19,752	16,975		
Meter Points				35	
2016 Revenue Requirement ($ Millions)	972.0	218.0	432.1	0.2	1,622.3
2016 Charge Determinants: Ave Monthly MWs	20,676	20,050	17,231		
Meter Points				25	

3.0 COST ALLOCATION METHODOLOGY

The Cost Allocation and Charge Determinants methodologies remain unchanged from what was approved by the Board in the Decision and Rate Order in Proceeding EB-2012-0031.

The charges for transmission service are collected by the Independent Electricity System Operator (IESO) from Market Participants who are defined transmission customers, using Board-approved transmission rates. These rates are Uniform Transmission Rates that apply to the transmission customers of all transmitters in the Province of Ontario.

The remaining schedules of Exhibit G1 comprise the following:

- Exhibit G1, Tab 2, Schedule 1 details the cost allocation methodology used to determine the revenue requirement for the rate pools;
- Exhibit G1, Tab 3, Schedule 1 describes the Network, Line Connection and Transformation Connection rate pools, and the Low Voltage Switchgear Compensation;
- Exhibit G1, Tab 4, Schedule 1 describes the Wholesale Meter rate pool.

TRANSMISSION CUSTOMERS LOAD FORECAST

1.0 INTRODUCTION

This schedule summarizes the forecast customer demand by customer delivery point based on the load forecast methodology described in Exhibit A, Tab 15, Schedule 2. The forecast provides the information necessary for cost allocation, and to determine the charge determinants for the Network, Line Connection and Transformation Connection rate pools.

2.0 LOAD FORECAST FOR TRANSMISSION CUSTOMERS

2.1. Load Forecast Data for Cost Allocation

The load forecast data required to calculate the cost allocation of Dual Function Line Assets described in Exhibit G1, Tab 2, Schedule 1, Section 4.1.1 is the monthly coincident peak demand, adjusted for applicable losses, for each customer's transmission delivery point downstream of a Dual Function Line. The resulting allocation factors are listed in Exhibit G2, Tab 2, Schedule 1.

The sum of the forecasted monthly maximum non-coincident peak demand, adjusted for applicable losses for each customer's transmission delivery point downstream of Generation Connection Assets is required to calculate the allocation factors for Generation Connection Assets, as described in Exhibit G1, Tab 2, Schedule 1, Section 4.1.2. The resulting allocation factors are listed in Exhibit G2, Tab 3, Schedules 1 and 2.

2.2. Load Forecast Data for Charge Determinants

The load forecast data required to calculate the charge determinants for the rate pools is as follows:

- The monthly Coincident Peak demand values, adjusted for applicable losses, for each customer's transmission delivery point at the time of the monthly system peak demand.
- The monthly Non-Coincident Peak demand values, adjusted for applicable losses, for each customer's transmission delivery point, independent of the monthly system peak demand.
- The monthly demand values, adjusted for applicable losses, for each customer's transmission delivery point that is the higher of a) the monthly Coincident Peak demand or b) 85 % of the monthly Non-Coincident Peak demand between 7 AM and 7 PM on working weekdays for each customer delivery point.

The load forecast data shown in Table 1 and Table 2 at the end of this Schedule is for all transmission customer delivery points, irrespective of the transmission service charges they attract. The charge determinants for the Line Connection and Transformation Connection pools will be a subset of the non-coincident peak demand totals shown in Tables 1 and 2. The determination of which customer delivery points are included for the purpose of calculating the charge determinants for the Network, Line Connection and Transformation Connection pools is discussed in Exhibit H1, Tab 3, Schedule 1.

As Tables 1 and 2 illustrate, LDCs represent roughly 90% of the demand. The average monthly non-coincident peak demand for LDCs is forecast to be only about 10% higher than their average monthly coincident peak demand. For end-use transmission customers the non-coincident peak is about 53% higher than their coincident peak. This illustrates that LDC demand is largely what drives the overall system peak demand, and it also reflects the increased ability of end-use transmission customers to shift load away from the system peak, or have maximum demands at different times than LDCs.

Table 1
2015 Forecast Demand by Customer Category
(The forecast demand in this table is for all customers, irrespective of whether they pay Connection Service charges)

Category	# of Customer Delivery Points	Sum of Average Monthly Coincident Peak (CP) Demand		Sum of Average of [Higher of Monthly CP or 85 % of NCP from 7AM to 7PM]		Sum of Average Monthly Non-Coincident Peak (NCP) Demand	
		MW	% of Total	MW	% of Total	MW	% of Total
LDCs	445	18,127	92.8%	18,425	90.1%	19,889	88.7%
End-Use Customers	94	1,340	6.9%	1,719	8.4%	2,053	9.2%
Transmission-Connected Generators	103	59	0.3%	313	1.5%	480	2.1%
TOTAL TRANSMISSION	642	19,526	100.0%	20,457	100.0%	22,422	100.0%

Table 2
2016 Forecast Demand by Customer Category
(The forecast demand in this table is for all customers, irrespective of whether they pay Connection Service charges)

Category	# of Customer Delivery Points	Sum of Average Monthly Coincident Peak (CP) Demand		Sum of Average of [Higher of Monthly CP or 85 % of NCP from 7AM to 7PM]		Sum of Average Monthly Non-Coincident Peak (NCP) Demand	
		MW	% of Total	MW	% of Total	MW	% of Total
LDCs	445	18,393	93.0%	18,694	90.4%	20,158	89.1%
End-Use Customers	94	1,332	6.7%	1,705	8.2%	2,036	9.0%
Transmission-Connected Generators	103	53	0.3%	277	1.3%	426	1.9%
TOTAL TRANSMISSION	642	19,778	100.0%	20,676	100.0%	22,620	100.0%

CHARGE DETERMINANTS

1.0 INTRODUCTION

This exhibit provides the derivation of Hydro One Transmission's charge determinants for the approved rate pools, which when combined with the charge determinants of the other transmitters for the Network, Line Connection and Transformation Connection rate pools can be used by the Board to determine Uniform Transmission Rates (UTRs).

2.0 SUMMARY OF CHARGE DETERMINANTS

The rate pool charge determinants are summarized in Table 1 for the 2015 and 2016 Test Years. All charge determinants have been calculated per the methodology approved in the Board's EB-2012-0031 Decision.

Table 1
Summary of Rate Pool Charge Determinants

Charge Determinant [average monthly]	Network (MW)	Line Connection (MW)	Transformation Connection (MW)	Wholesale Meter (Meter Points at Mid-Year)
2015	20,457.1	19,751.9	16,975.0	35
2016	20,675.8	20,049.8	17,231.0	25

3.0 NETWORK CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Network Service charge determinant is the higher of a customer's demand coincident with the monthly system peak or 85% of the customer's non-coincident monthly peak demand between 7 AM to 7 PM as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1 (Attachment 1).

The Network charge determinant provides customers with time-of-use signals that encourage use of the transmission system outside the 7 AM to 7 PM period, for which no transmission Network charges apply. It also encourages customers to avoid the monthly system peak, with the potential for lowering their Network charges by up to 15% of their non-coincident peak demand between the hours of 7 AM to 7 PM multiplied by the Network rate.

All customers that are connected to Hydro One’s transmission system incur Network Service charges on a per Transmission Delivery Point basis. The 2015 and 2016 load forecast data for each customer’s Transmission Delivery Points, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Network Service charges.

4.0 LINE CONNECTION CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Line Connection Service charge determinant is the customer’s non-coincident monthly peak demand as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1.

All customers that utilize Line Connection assets owned by Hydro One Transmission incur Line Connection Service charges on a per Transmission Delivery Point basis. The customer demand supplied from a Transmission Delivery Point will not incur Line Connection Service charges if a customer fully owns, or has fully contributed toward the costs of, all Line Connection assets that connect the transmission delivery point to a Network station. Similarly, customers will not incur Line Connection Service charges for demand at a Transmission Delivery Point located at a Network station.

The Billing Demand for Line Connection Service is the customer's loss-adjusted demand supplied from the transmission system plus the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2 MW or more for renewable generation[1] and 1 MW or higher for non-renewable generation.

The 2015 and 2016 load forecast data for each customer's Transmission Delivery Points, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Line Connection Service charges.

5.0 TRANSFORMER CONNECTION CHARGE DETERMINANTS AND PAYMENT OBLIGATION

The Transformation Connection Service charge determinant is the customer's non-coincident monthly peak demand as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1.

All customers that utilize transformation connection assets owned by the Hydro One Transmission incur charges on a Transmission Delivery Point basis. The customer demand supplied from a Transmission Delivery Point will not incur Transformation Connection Service charges if a customer fully owns, or has fully contributed toward the costs of, all transformation connection assets associated with that Transmission Delivery Point.

The Billing Demand for Transformation Connection Service is the customer's loss-adjusted demand supplied from the transmission system plus the demand that is supplied by embedded generation for which the required government approvals were obtained

[1] This change was approved in the Transmission System Code Phase 1 Policy Decision with Reasons, Proceeding RP-2002-0120 and subsequently incorporated into the Rate Schedules issued as part of Proceeding EB-2005-0241.

after October 30, 1998 and which have installed capacity of 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation.

The 2015 and 2016 load forecast data for each customer's Transmission Delivery Point, adjusted for losses as appropriate, is then used to calculate the total charge determinants that attract Transformation Connection Service charges.

6.0 WHOLESALE METER POINTS

The forecasted number of Wholesale Meter Points is based on the 2013 year end Wholesale Meter Points and the meters anticipated to exit the wholesale meter pool based on the experience gained in the number of conversions completed to date, as well as knowledge of the conversion requirements for the remaining meter points.

The forecasted remaining Wholesale Meter Points are:

Table 2

	# of Meter Points			
	2013	2014	2015	2016
Year End	65	40	30	20
Mid Year			35	25

RATES FOR WHOLESALE METER SERVICE

1.0 INTRODUCTION

This Exhibit summarizes the derivation of rates applicable to the provision of Wholesale Meter Service. The Wholesale Meter Service rates are designed to recover the Wholesale Meter Pool revenue requirement identified in Exhibit G1, Tab 4, Schedule 1.

2.0 CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

Per the existing Rate Schedules approved by the Board in EB-2012-0031, the revenue requirement for the wholesale revenue meter function is collected from the meter service customers that are served by the Hydro One Transmission-owned wholesale revenue meters that form the Wholesale Meter Pool.

The revenue requirement for the Wholesale Meter Pool will continue to be collected using a uniform Wholesale Meter Service rate determined on a "per meter point" basis[1]. This is consistent with the approach used to set rates in Proceeding EB-2012-0031, and it is the same basis on which customers pay the exit fee when exiting the Wholesale Meter pool.

Table 1 below provides data for 2015 and 2016 on the forecast number of meter points, the revenue requirement to be recovered and the applicable rate (in $ / meter point / year) for Wholesale Meter service. An average rate of $8,000 per Meter Point per year for 2015 and 2016 is proposed.

[1] A unique meter point is deemed to exist with respect to each instrument transformer associated with a metering installation that is used for the purpose of billing and settlement by the IESO.

Table 1

Year	Annual Revenue Requirement ($ Million)	Forecast Number of Meter Points	Wholesale Meter Service Rate ($ / Meter Point / Year)
2015	0.28	35	7,990
2016	0.20	25	8,046

The increase in rates from the current level of $7,900 reflects the fact that the remaining metering installations on average are more complex and thus more expensive to service than those that comprised the pool of 140 wholesale meter points in 2011.

Regulated Wholesale Meter Service charges shall not apply to any metering installation(s), and associated meter points, that have exited from the Wholesale Meter pool. It is proposed that the Exit Fee for meter installations, which is based on the average Net Book Value of stranded wholesale revenue metering assets, remain at $5,200 per meter point as approved by the Board in EB-2012-0031.

The Rate Schedule for Wholesale Meter Service, including the Exit Fee, is provided in Exhibit H2, Tab 2, Schedule 1. As currently approved by the Board, the Wholesale Meter service charge is administered by Hydro One Transmission.

RATES FOR EXPORT TRANSMISSION SERVICE

1.0 INTRODUCTION

The Export Transmission Service (ETS) rate was increased to $2/MWh, effective January 1, 2011, as directed by the OEB in the EB-2010-0002 Decision with Reasons. The previous rate of $1/MWh had been in effect since market opening.

Hydro One Transmission proposes that the recommendation of the Elenchus report be adopted. A copy of the report is provided as Attachment 1 to this Exhibit.

2.0 BACKGROUND

The IESO collects ETS revenues and remits them on a monthly basis to Hydro One, whose transmission system is used to facilitate export and wheel-through transactions at the point of interconnection with the neighbouring markets. The ETS tariff was initially set at a rate of $1/MWh and remained at this level until December 31, 2010. When initially set, the tariff was considered by the Ontario Energy Board ("Board") to be a reasonable compromise between the many competing interests and proposals that were advanced by stakeholders in the course of Hydro One's transmission rate proceeding. Moreover, the tariff was considered by the Board to be an interim solution to a rather complex and contentious set of issues. Among other things, the contention emerged from what stakeholders believed should be the basis of, or purpose of, the tariff design and what ought to be an appropriate charge level to help defray the costs to domestic customers for the use of network transmission facilities to facilitate export and wheel-through transactions. As well, there were concerns about potential impacts of the tariff on international trade agreements and reciprocity obligations, the development of open and efficient regional markets, as well as the potential environmental consequences from higher exports that may be influenced by the tariff.[1]

In Hydro One's Transmission Rate Application EB-2006-0501, the Board approved a stakeholder settlement agreement which called for the ETS tariff of $1/MWh to be maintained for the time being; however, the IESO was identified as the entity responsible for undertaking a study of an appropriate ETS tariff and, through negotiation with neighbouring jurisdictions, to pursue acceptable reciprocal arrangements with the intention to jointly eliminate all ETS tariffs. It was understood that any proposed change to the tariff must be reviewed and approved by the Board as part of Hydro One's transmission rate review and approval process.

The IESO's initial ETS tariff study and recommendation was filed with the Board on August 28, 2009 and reviewed under proceeding EB-2010-0002.

In the EB-2010-0002 Decisions with Reasons the Board concluded that an additional study was required.

> *"The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake the study is the IESO."*

The OEB also directed Hydro One to increase the ETS rate to $2/MWh in the EB-2010-0002 Decision with Reasons.

---

[1] Decision with Reasons, Ontario Hydro Networks Company Inc. Transmission Rate Application, RP-1999-0044, Export and Wheel-through Transactions.

The IESO engaged Charles River Associates ("CRA") to perform a new ETS study, which was filed in May 2012 as a part of the evidence in proceeding EB-2012-0031. The Association of Power Producers of Ontario ("APPrO") and Hydro Quebec Energy Marketing Inc. ("HQEM") each filed expert evidence in response to the CRA Study. The Board considered their responses, and in the EB-2012-0031 Decision with Reasons, the Board directed Hydro One to:

> *"…prepare a cost allocation study involving the network assets utilized by export transmission customers and report the results of this study, including a proposal of the appropriate cost based ETS rate with supporting rationale, to the Board at its next transmission rates application."*

Hydro One engaged Elenchus Research Associates ("Elenchus") to perform this study.

3.0 EXPORT TRANSMISSION SERVICE STUDY

The Elenchus report proposes an ETS rate of $1.7/MWh for 2015 and 2016 using cost causality principles to allocate Hydro One's transmission costs between domestic and export customer groups. The Elenchus Report is be provided as Attachment 1 to this Exhibit.

Hydro One identified the Network asset value dedicated to interconnections which was provided to Elenchus for developing allocation factors between domestic and export demand. Hydro One also provided Elenchus information on the revenue requirement and rate base for the Network functional category.

Elenchus obtained provincial load forecast information from the IESO's website.

Elenchus performed a preliminary analysis, based on forecast data for 2013 consistent with what was submitted by Hydro One in Proceeding EB-2012-0031. Elenchus presented their methodology and preliminary results at a stakeholder session hosted by Hydro One on March 24, 2014. Details of the stakeholder session are provided at Exhibit A, Tab 19, Schedule 1.

Hydro One subsequently provided Elenchus with updated 2013 data and forecast data for 2015 and 2016 consistent with this proposed application, for inclusion in Elenchus' final report.

4.0 EXPORT TRANSMISSION SERVICE REVENUE

Hydro One's Export Transmission Service (ETS) revenues used for establishing the rates revenue requirement in this proposed application are determined based on the currently approved tariff of $2/MWh and the 3 year historical average volume of electricity exported from, or wheeled-through, Ontario over its transmission system.

For 2015 and 2016 the ETS revenue will continue to be disbursed through a decrease to the revenue requirement for the Network Pool, as per the cost allocation process approved by the Board in EB-2012-0031. The forecast for ETS revenue is $33.4 million and $34.3 million per year for 2015 and 2016, respectively.

Hydro One proposes to revise its rates revenue requirement to reflect the OEB's Decision and Order with respect to the ETS tariff as part of the Draft Rate Order to be submitted in connection with finalizing the 2015 Uniform Transmission Rates to be approved.

34 King Street East, Suite 600
Toronto, Ontario, M5C 2X8
elenchus.ca

Export Transmission Service Rate

Cost Allocation Methodology

Report Prepared by
Michael Roger
Elenchus Research Associates Inc.

On Behalf of HONI

May 7, 2014

Page Intentionally Blank

Table of Contents

Page Intentionally Blank

EXECUTIVE SUMMARY

This report presents Elenchus' recommendation on the cost allocation methodology that should be used to determine a cost-based Export Transmission Service rate in Ontario.

The recommended methodology should be based on:

- Using prior year actual hourly data for domestic and export customers,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared OM&A expenses,
- Only dedicated assets used to serve export customers and the related costs should be allocated to the export customer class,
- OM&A expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No external revenues should be allocated to the export customer class,
- The ETS rate should be based on HONI's OEB approved Network revenue requirement, as used in determining the Uniform Transmission Rates, marked-up to include other transmitters' approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology determines the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data in the proposed methodology and the related scenario sensitivity results, a value between \$1.7/MWh and \$1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of \$1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.

1 INTRODUCTION

Hydro One Networks Inc. ("HONI") retained Michael Roger of Elenchus Research Associates Inc. in order to develop a cost-based methodology to establish the Export Transmission Service ("ETS") rate.

In its Decision with Reasons dated June 6, 2013 on 2013 Export Transmission Service rates, (EB-2012-0031, Decision and Order, page 10), the Ontario Energy Board ("OEB") directed HONI to include a proposal of the appropriate cost-based ETS rate, with supporting rationale, to the OEB at its next transmission rates application.

More specifically the OEB stated on page 9 of its Decision with Reasons in Proceeding EB-2012-0031 that:

> *"The Board will require Hydro One to perform a cost allocation study to establish a cost basis for the ETS rate. Some parties have suggested that such a study would be prohibitively costly. However, the Board accepts the Elenchus testimony that a study could be properly scaled to address the magnitude of the issue and could be completed for a reasonable cost. The Board expects that this study will be completed in time for Hydro One's next cost of service transmission rate application. While Hydro One has the responsibility for completing this study, the Board expects that the IESO will assist Hydro One as required to fully address the ETS rate issue."*

This report presents the results of the cost-based methodology developed by Elenchus to establish the ETS rate.

This report is divided into 5 main sections. Section 2 provides a background on the evolution of the ETS rate from market opening in 2002 until now, section 3 presents the principles of cost allocation methodology, section 4 describes the proposed cost allocation methodology to determine the ETS rate, section 5 presents the results of applying the recommended methodology using 2013 proposed data and 2015 and 2016 proposed data and section 6 presents conclusions and recommendations to the OEB on the proposed cost allocation methodology and the ETS rate. Appendix A contains the CV for Michael Roger.

Michael Roger has been an expert dealing with cost allocation, rate design and rate regulation issues for over 35 years. Michael worked for over 32 years at Ontario Hydro, Ontario Power Generation and Hydro One and spent most of his career dealing with Cost Allocation and Rate Design issues for wholesale and retail electricity customers in Ontario. He has also testified on numerous occasions at OEB proceedings on behalf of utilities and other stakeholders and also has provided expert advice to the OEB in various task forces dealing with cost allocation and rate design issues. Michael's vast experience with Cost Allocation issues was applied in developing the cost-based cost allocation methodology to develop the ETS rate and forms the basis for Elenchus recommended methodology to the OEB.

2 BACKGROUND

In Proceeding RP-1999-0044 the OEB reviewed the issue of establishing an ETS rate to be implemented at market opening.

In its Decision with Reasons dated May 26, 2000, the OEB summarized the various arguments presented by stakeholders in this proceeding on what the ETS rate should be. The OEB decided that as an interim measure, the ETS rate should be fixed at $1/MWh. This was seen as a reasonable compromise between the competing interests and proposals presented by stakeholders in the proceeding on what was described as a complex and contentious issue. Among other things, the contention emerged from what stakeholders believed should be the basis of, or purpose of, the tariff design and what ought to be an appropriate charge level to help defray the costs to domestic customers for the use of the network transmission facilities to facilitate export and wheel-through transactions.

The OEB directed that HONI monitor and report at its next main rate submission how the export market was functioning and the developments in interconnected jurisdictions and whether the ETS rate should be reviewed.

HONI retained R. J. Rudden to do a "Jurisdictional Survey of Export and Wheel-through Service Rates". The survey was filed with the OEB on June 26, 2006 and was reviewed in proceeding EB-2006-0501.

As part of EB-2006-0501, the OEB approved a stakeholder settlement agreement which maintained the ETS rate of $1/MWh. In the agreement, the Independent Electricity System Operator ("IESO") was identified as the entity responsible for undertaking a study on the appropriate ETS rate. The settlement agreement stated that:

> *"...the IESO should now be identified as entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study."*[1]

The IESO retained Charles River Associates ("CRA") to do a quantitative analysis of the future effect of several export rate scenarios, with respect to exports and wheel-through volumes, ETS tariff revenue, and the Hourly Ontario Energy Price. The IESO's ETS study and recommendation was filed with the OEB on August 28, 2009 and was reviewed in proceeding EB-2010-0002. The IESO study reviewed four alternatives for setting the ETS rate:

1. Status Quo;
2. Equivalent average network charge;
3. Reciprocal treatment, and
4. Elimination.

[1] EB-2006-0501, Exhibit M, Tab I, Schedule 1, page 17, April 3, 2007

The IESO recommended the status quo alternative to the OEB.

In the Decision with Reasons in proceeding EB-2010-0002, page 75, the OEB concluded that an additional study was required. The OEB stated that:

> *"The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake this study is the IESO. In procuring the study, the IESO should circulate the terms of reference to the Applicant and the intervenors of record in this case with a view to ensuring that the resulting study will provide detailed analysis on the issues.*
>
> *This review of the terms of reference is not intended to be a strategic negotiation, but rather a technical exercise to ensure that the scope of the project is sufficiently broad and well-defined to ensure a useful and appropriate outcome. Work on this study should begin soon, to ensure completion well in advance of the time for the filing of the next transmission rates application by Hydro One."*

The OEB in the same proceeding increased the ETS rate to $2/MWh, providing the following rationale:

> *"Accordingly, the Board will direct that a change be made to the ETS rate for 2011 and 2012, increasing the rate to two dollars per MWh. In making this change the Board seeks to recognize the directional preference of the CRA study, and the absence of any particular analytical underpinning for the current rate. Subsequent panels assessing the level of this rate should not, however regard this new rate as having any particular precedential value. It is the Board's view that the new rate has more analytical support than the status quo, but that in order to arrive at a genuinely robust and valid rate, more study is required."*

In response to the OEB directive, the IESO engaged CRA to conduct a further review of the ETS rate. CRA reviewed the tariff and structures in neighbouring markets and assessed five proposed rate options against generally accepted rate making principles (consistency, simplicity, fairness and efficiency). The rate options considered were:

1. Status Quo
2. Elimination

3. Equivalent average network charge
4. Tiered rates (two alternatives)

The CRA study was filed and reviewed in proceeding EB-2012-0031.

In the IESO's submission to the OEB, the IESO indicated that none of the ETS tariff options materially impact reliability, but elimination of the tariff would best promote efficient operation of the wholesale electricity market.

As stated in the introduction in this report, the OEB directed HONI in proceeding EB-2012-0031 to develop a cost-based methodology to determine the ETS rate.

3 PRINCIPLES OF COST ALLOCATION

In order to determine cost-based rates, a cost allocation study is performed by a utility to fairly allocate shared assets and expenses to the customer groups served by the utility.

The cost allocation study is based on actual historical or forward looking test year data and reflects the operating circumstances of the utility at a particular point in time, either the last year for which actual historical information is available, or for the future test year for which rates are being established.

Traditionally three steps are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

Assets and expenses that are identified with a particular customer class and that are not shared with other customer classes are "Directly" allocated to that particular customer class.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, high voltage transmission, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, the function(s) served by the assets or expenses of the utility are identified so that costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as energy, demand and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of volume, system demand, or number of customers.

Allocation, which is the final step, is the process of attributing the energy, demand, and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to energy, demand, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class.

It is in this Allocation step that customers are grouped based on common characteristics, or utility asset utilization reflecting cost causality.

4 PROPOSED COST ALLOCATION METHODOLOGY

Elenchus proposes a cost allocation methodology to determine the ETS rate that is based on cost causality, is simple and follows the traditional three steps of a cost allocation methodology.

Elenchus looked at how transmission assets are being used to sell electricity, either to domestic customers of to neighbouring jurisdictions by exporters.

In Ontario generators do not pay for the use of the transmission system when they inject power into the grid in order to supply domestic electricity needs. Elenchus applied this same principle when evaluating the interconnected assets with neighbouring jurisdictions used by exporters. The interconnected assets are used to both export and import power and since generators in Ontario do not pay for the use of the transmission assets and the ETS rate is not applied to power imported into Ontario, Elenchus assumed that importers would also continue to not be charged for the use of the transmission system.

The proposed methodology considered the sale of electricity to domestic customers and neighbouring jurisdictions, not how the electricity was sourced and made available to satisfy sales.

HONI's 2013 transmission assets and revenue requirements were used in developing the recommended approach.

The proposed cost allocation methodology to determine the ETS rate reflects the interruptible nature of exports. The basis for treating exports as interruptible loads is found in the OEB's Decision with Reason in proceeding EB-2012-0031 that on page 5 states that:

> *"First, whether curtailments originate from generation issues or transmission issues, the Board agrees that export service does not receive the same priority access as domestic service. The Board accepts that the market rules treat exporters more as an interruptible load. This difference in treatment related to generation capacity has consequences for the overall service, even if export transmissions rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be* viewed as a separate class."

This has implications for how costs are allocated, as discussed in Section 4.3.

4.1 FUNCTIONALIZATION

In consultation with HONI, Elenchus determined that the assets and expenses associated with export activities can be found in the following HONI's transmission functions:

- Network (500 kV, 230 kV, and 115 kV lines)
- Dual Function lines (Network portion)
- Generation Line Connection
- Generation Transformation Connection
- Common (telecommunication equipment, control centre)
- Other (facilities not allocated to other functions under normal operating conditions)

These functions include dedicated and shared assets, and related expenses used by domestic and export customers.

The remaining functions used by Hydro One Transmission in determining its revenue requirement (e.g. transformation, line connection, line connection portion of dual function lines) are considered to be used only by domestic customers.

External revenues were also considered in the development of the cost allocation methodology. These revenues result mainly from secondary land use in right of ways and from providing maintenance services to other entities. These revenues are the result of using HONI's assets which have been designed to serve domestic customers only, therefore, no external revenues are proposed to be allocated to export customers.

4.2 CLASSIFICATION

Generally in costs allocation, transmission assets and expenses are classified as demand related. Transmission assets are designed to meet the maximum demand imposed by users of the system. Based on the functions evaluated, it was determined that the assets and expenses considered in the development of the ETS rate methodology are all demand related. There are no energy related or customer related assets and expenses.

4.3 ALLOCATION

In the cost allocation methodology developed to determine the ETS rate two customer groups are considered: domestic and export.

Assets dedicated to domestic customers are assets that only serve to connect Hydro One customer's load to the network.

Assets dedicated to interconnect (export) are assets that only serve to connect to another transmission utility.

Shared assets are those that serve both domestic and export customers, including assets associated with generation connection.

As export is considered to be interruptible service, no asset related costs associated with shared assets are proposed to be allocated to the export customer class.

This is considered appropriate because, as confirmed by Hydro One staff, HONI's planning of the Network transmission system does not take into consideration the capacity needed to supply export customers, transmission planning is only based on the capacity needs of domestic customers.

The assets dedicated to serve export customers have been directly allocated to the export customer class as well as the related expenses.

The OM&A expenses related to the use of shared assets have been allocated between domestic and export customers using the allocators described below.

4.3.1 COINCIDENT PEAK ALLOCATOR

In cost allocation, the allocation of demand related assets that are closest to the customer are allocated based on the non-coincident demand of the customer. The required assets are sized reflecting the maximum customer electricity demand.

Further away from the customer and closer to the generation system, it is the aggregate electricity demand of all customers, and not the sum of the individual customer demands, that determines the size of the facilities required to satisfy customers' electricity needs. In cost allocation, when apportioning assets and expenses further away from the customer (e.g. generation, transmission) and closer to the generation of electricity, it is the coincident demand that is used as an allocator, reflecting the criteria used to size the required assets.

Using 2010, 2011 and 2012 actual hourly load data for domestic and export customers from the IESO, coincident peak ("CP") allocators were developed.

Coincident peak is the hourly demand of domestic and export customers at the hour of maximum demand in the Ontario electricity system.

1 CP is the demand for each customer class at the hour of maximum system demand in a year. 12 CP is the average of the demand for each customer class at the hour of each month's maximum system demand.

1 CP or 12 CP are used by utilities in cost allocation studies to apportion generation and transmission costs amongst customer groups.

The following table includes the values developed for coincident peak.

Table 1

Coincident peak 2010 to 2012

	2010			2011			2012			Average		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,687	25,048	27,735	2,549	25,450	27,999	2,179	24,636	26,815	2,472	25,045	27,516
12CP	30,897	255,485	286,382	31,343	250,819	282,161	28,164	251,842	280,006	30,134	252,715	282,850

The 1 CP and 12 CP percentage allocators using 2010 to 2012 data are show in the table below

Table 2

Coincident peak %

	2012 Data			Average 2010 – 2012 Data		
Coincident Peak	Total	Domestic	Export	Total	Domestic	Export
1 cp	100.00	91.87	8.13	100.00	91.02	8.98
12 cp	100.00	89.94	10.06	100.00	89.35	10.65

The 1 CP and 12 CP values for the period 2011 to 2013 using actual hourly data are shown in the table below.

Table 3

Coincident peak 2011 to 2013

	2,011			2,012			2,013			Average		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,549	25,450	27,999	2,179	24,636	26,815	1,952	24,927	26,879	2,227	25,004	27,231
12CP	31,343	250,819	282,161	28,164	251,842	280,006	30,240	255,417	285,657	29,916	252,692	282,608

The 1 CP and 12 CP percentage allocators using 2011 to 2013 data are show in the table below

Table 4

Coincident peak %

	2013 Data			Average 2011 – 2013 Data		
Coincident Peak	Total	Domestic	Export	Total	Domestic	Export
1 cp	100.00	92.74	7.26	100.00	91.82	8.18
12 cp	100.00	89.41	10.59	100.00	89.41	10.59

Elenchus recommends that 12 CP should be used to allocate shared assets between domestic and export customers using the last year for which information is available.

When system loads are relatively flat and do not show a pronounced yearly peak, 12 CP is usually used by utilities to allocate demand related assets and expenses. In instances where there is a significant yearly peak compared to other peaks in the year, that is a very peaky load profile with low load factor, then 1 CP would be used to allocate demand related assets and expenses.

In Proceeding RP-1999-0044, the OEB reviewed allocators that could be used to recover Network assets and expenses and recommended against the use of non-coincident peak and settled on the use of coincident peak. With respect to using 1 CP, in paragraph 3.4.27 of the OEB Decision it states that:

> *"A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future."*

12 CP is used by HONI in apportioning assets and expenses when allocating Dual Function Line assets, (Proceeding EB-2012-0031, Exhibit G1, Tab 2, Schedule 1, pages 110-111).

4.3.2 COMPOSITE ALLOCATORS

The asset functions identified in section 4.1 were apportioned between domestic and export customers using the 12 CP allocator based on 2012 actual hourly data in order to develop composite allocators used to allocate shared OM&A expenses to domestic and export customer classes.

The OM&A expenses related to the identified shared functions were allocated in the cost allocation methodology to domestic and export customers using Net Shared Assets as composite allocators. Table 5 includes the percentage allocation of the composite allocators to the two customer classes based on 12 CP.

Table 5

Composite Allocators using 2012 actual hourly data

	Total	Domestic	Export
Net Shared Assets	**100.00%**	**92.89%**	**7.11%**
Dedicated to Domestic	**100.00%**	**100.00%**	**0.00%**
Dedicated to Interconnect	**100.00%**	**0.00%**	**100.00%**

Using 2013 actual domestic and export hourly data, the composite allocators are included in the following tables based on 12 CP and the 2015 and 2016 financial data.

Table 6

Composite Allocators using 2013 actual hourly data for 2015

	Total	Domestic	Export
Net Shared Assets	**100.00%**	**92.74%**	**7.26%**
Dedicated to Domestic	**100.00%**	**100.00%**	**0.00%**
Dedicated to Interconnect	**100.00%**	**0.00%**	**100.00%**

Table 7

Composite Allocators using 2013 actual hourly data for 2016

	Total	Domestic	Export
Net Shared Assets	**100.00%**	**92.79%**	**7.21%**
Dedicated to Domestic	**100.00%**	**100.00%**	**0.00%**
Dedicated to Interconnect	**100.00%**	**0.00%**	**100.00%**

5 ETS RATE RESULTS

The results of applying the proposed cost allocation methodology to develop a cost-based ETS rate are shown below.

The proposed cost allocation methodology was developed using 2012 actual hourly load data and 2013 proposed HONI financial data as submitted in proceeding EB-2012-0031.

The model was run again with 2013 actual hourly load data and the proposed 2015 and 2016 financial data being submitted by HONI at its rate submission.

5.1 Using 2012 Load data and 2013 HONI Proposed Financial Data

5.1.1 Base Case ETS rate

The base case result for developing the ETS rate using the proposed cost allocation methodology is based on the following assumptions:

- Shared Assets are apportioned using 2012 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop the composite allocators to be used to allocate shared expenses
- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers
- No asset related costs associated with shared assets are allocated to export customers
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets
- No External revenue credit is allocated to export customers
- HONI's proposed 2013 data, (Assets and Expenses), as submitted in proceeding EB-2012-0031 were used to develop the ETS rate based on the proposed cost allocation model.

Using HONI's export sales forecast for 2013, the resulting ETS rate is $1.77/MWh.

5.1.2 ETS Rate Including Other Transmitters' Revenue Requirement

The hourly data used from the IESO reflect all transmission electricity sales in Ontario, not just Hydro One's, while the financial assets and expense data used in developing the cost allocation methodology reflects only Hydro One's data. Marking-up the calculated ETS rate to reflect other transmitters approved Network revenue requirement would result in consistency between the sales data and the financial data, both of which would reflect all transmitters in Ontario.

As seen in the 2014 Uniform Transmission Rates, HONI's Network function revenue requirement is $882.9 million. The revenue requirement for all Ontario transmitters is $912.8 million, or 3.4% higher than HONI's revenue requirement.

Increasing the ETS rate of $1.77/MWh by 3.4%, results in an ETS rate of $1.83/MWh. This higher ETS rate would take into account the revenue requirement of all transmitters in Ontario.

5.1.3 Scenarios

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.

Table 8 Scenarios (2012 load data)

Scenario	Description	ETS rate ($/MWh)[2]
1	Same as Base case, but using 12 CP average of 3 years (2010 to 2012)	1.82
2	Same as Base case, but using 1 CP (2012)	1.59
3	Same as Base case, but using 1 CP average of 3 years (2010 to 2012)	1.67
4	Same as Base case, but allocation $0.16M External Revenue credit to Export customers	1.76
5	Allocating only shared OM&A costs to Export customers, no dedicated export assets allocated to Export[3]	1.22
6	Allocating to Export customers same Network function assets and expenses as Domestic customers, $1.43M External Revenue credit, using 12 CP (2012)[4]	4.73

5.2 USING 2013 LOAD DATA AND 2015 AND 2016 HONI PROPOSED FINANCIAL DATA

5.2.1 BASE CASE ETS RATE

The same assumptions described in section 5.1.2 are used in developing the ETS rate:

- Shared Assets are apportioned using 2013 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop

[2] Using HONI 2013 export sales forecast
[3] Assuming exporters do not pay for dedicated assets and related expenses
[4] Assuming export is treated as firm load, similar to domestic load

the composite allocators to be used to allocate shared expenses to domestic and export customer classes

- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers
- No asset related costs associated with shared assets are allocated to export customers
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets
- No External revenue credit is allocated to export customers
- HONI's proposed 2015 and 2016 data, (Assets and Expenses), as submitted in this proceeding are used to develop the ETS rate based on the proposed cost allocation model.

Using HONI's 2015 and 2016 export sales forecast, the resulting ETS rate is \$1.63/MWh for 2015 and \$1.62/MWh for 2016.

5.2.2 ETS Rate Including Other Transmitters' Revenue Requirement

In HONI's proposed 2015 and 2016 Uniform Transmission Rates, HONI's Network function revenue requirements are \$933.6 million and \$972.0 million respectively. The revenue requirements for all Ontario transmitters are \$963.0 million, and \$1,001.3 million for 2015 and 2016, or 3.2% and 3.0% higher than HONI's proposed revenue requirements.

Increasing the 2015 ETS rate of \$1.63/MWh by 3.2%, and the 2016 ETS rate of \$1.62/MWh by 3.0% results in ETS rate of \$1.68/MWh for 2015 and \$1.67/MWh for 2016. This higher ETS rates would take into account the revenue requirements of all transmitters in Ontario.

5.2.3 Scenarios

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.

Table 9 Scenarios (2013 load data)

Scenario	Description	ETS rate 2015 ($/MWh)[5]	ETS rate 2016 ($/MWh)[6]
1	Same as Base case, but using 12 CP average of 3 years (2011 to 2013)	1.63	1.62
2	Same as Base case, but using 1 CP (2013)	1.34	1.33
3	Same as Base case, but using 1 CP average of 3 years (2011 to 2013)	1.42	1.41
4	Same as Base case, but allocation $0.12M External Revenue credit to Export customers	1.62	1.61
5	Allocating only shared OM&A costs to Export customers, no dedicated assets allocated to Export [7]	1.15	1.13
6	Allocating to Export customers same Network function assets and expenses as Domestic customers, $1.3M External Revenue credit, using 12 CP (2013)[8]	4.84	4.88

6 CONCLUSIONS AND RECOMMENDED METHODOLOGY

The results of the proposed cost allocation methodology to develop a cost-based ETS rate and the sensitivity scenarios run using 2010 to 2012 load data show a Base Case result of $1.77/MWh and a range for the ETS rate between $1.22/MWh to $1.82/MWh

[5] Using HONI 2015 export sales forecast
[6] Using HONI 2016 export sales forecast
[7] Assuming exporters do not pay for dedicated assets and related expenses
[8] Assuming export is treated as firm load, similar to domestic load

for scenarios 1 to 5. The financial data is based on HONI's 2013 proposed data and excludes other transmitter's revenue requirement.

Using hourly load data for the period 2011 to 2013 and financial data for HONI as proposed for 2015 and 2016, the Base Case result for the ETS rate for 2015 is \$1.63/MWh and for 2016 is \$1.62/MWh. The range for the ETS rate is between \$1.13/MWh to \$1.63/MWh for scenarios1 to 5. The financial data excludes other transmitter's revenue requirement.

It is Elenchus' recommendation that the cost allocation methodology to be used to develop the ETS rate should be based on:

- Using the last year of actual hourly data for domestic and export customers. Forecast domestic and export hourly data is not available either from HONI or IESO,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared expenses.
- Only dedicated assets used to serve export customers and related expenses should be allocated to the export customer class,
- No asset related costs associated with shared assets should be allocated to export customers
- Expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No External revenues should be allocated to the export customer class, and
- The ETS rate should be based on HONI's OEB approved Network revenue requirement, as used in determining the Uniform Transmission rate, marked up to include other transmitters' approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology provides a supporting basis for determining the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data and the related scenario sensitivity results, a value between \$1.7/MWh and \$1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of \$1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.

APPENDIX A - CV MICHAEL ROGER

MICHAEL J. ROGER

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

---

ASSOCIATE, RATES AND REGULATION

Michael has over 35 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors, with particular emphasis in electricity rates in Ontario and the regulatory review and approval process for cost allocation and rate design. Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian, APPrO and Hydro 2000.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system. Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB). Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design. Keep up to date on Cost Allocation and Rate Design issues in the industry. Ensure deliverables are of high quality, defensible and meet all deadlines.

Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. 1999 - 2002

Manager, Management Reporting and Decision Support, Corporate Finance

- In charge of producing weekly, monthly, quarterly and annual internal financial reporting products. Input to and coordination of senior management reporting and performance assessment activities. Expert line of business knowledge in support of financial and business planning processes. Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature. Provide support to other units as necessary. Work as a team member of the Corporate Finance function.

Ontario Hydro 1998 - 1999

Acting Director, Financial Planning and Reporting, Corporate Finance

- In charge of the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company. Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting , Corporate Finance 1997

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy. Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company. Supervise professional staff supporting the function. Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing 1986 - 1997

- In charge of pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.

- The section was also responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head, (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers. Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro. Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates. Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant. Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity. Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System. Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board. Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecasting Analyst, Financial Forecasts **1980 - 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.

- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget. Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation¬.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 - 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

SECTION III

SUBSECTION iii

INTERROGATORY RESPONSES

Canadian Manufacturers & Exporters (CME) INTERROGATORY #1

Interrogatory

Hydro One indicates that it intends to file an Application in September 2014 with or without a settlement. The 2015-2016 Transmission Rate proposal Information Package table of contents at Exhibit A, Tab 1, Schedule 1 appears to list certain excerpts from Exhibits A to H of a traditional transmission rate application. In connection with the List of Contents in the Information Package, please provide the following information:

(a) Are the materials listed part of the material which will be filed in September 2014?

(b) Please provide a Table of Contents that lists all of the contents of the Application which Hydro One intends to file in September 2014 and indicate on that list what items of information listed are not yet available.

(c) Has Hydro One's Board of Directors approved the rates proposal outlined in the Information Package? If so, then please produce, in confidence if necessary, all documents relating to the presentations made to the Board of Directors with respect to this proposal and the Directors' approval thereof.

Response

(a) Hydro One expects that most of the listed Exhibits will be filed with the OEB in September 2014, as required by the OEB's "Filing Requirements for Electricity Transmission Applications".

(b) Hydro One currently does not have a complete Table of Contents for the "September 2014 Transmission Rate Application". In addition to satisfying the OEB's Filing Requirements for Electricity Transmission Applications, Hydro One may include/exclude specific material based on the discussions (current settlement process) in July and August of 2014.

(c) On February 13, 2014, the memo "Hydro One Application for the 2015-2016 Transmission Rates" was submitted to the Hydro One Board of Directors, which was approved. This will be provided in confidence to participants. Subsequently, this information was updated to reflect the revised load forecast and the incorporation of 2013 actuals.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #2

Interrogatory

The existing transmission rates are based on a Settlement Agreement reached in the EB-2012-0031 proceeding. Please distribute a copy of that Settlement Agreement.

Response

The EB-2012-0031 Settlement Agreement is included in Attachment 1.

EB-2012-0031 – Settlement Agreement

EB-2012-0031 – SETTLEMENT AGREEMENT

EB-2012-0031

SETTLEMENT AGREEMENT

Hydro One Networks Inc.
Test year 2013 and 2014 Transmission Rates

November 6, 2012

TABLE OF CONTENTS

	appropriate?	
15	Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?	27
16	Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the OM&A and Capital expenditures for 2013/14	27
Cost Of Capital/Capital Structure		
17	Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?	28
18	Is the forecast of long term debt for 2012-2014 appropriate?	29
Deferral/Variance Accounts		
19	Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?	30
20	Are the proposed new Deferral and Variance Accounts appropriate?	31
Cost Allocation		
21	Is the cost allocation proposed by Hydro One appropriate?	31
Green Energy Plan		
22	Are the OM&A and capital amounts in the Green Energy Plan (GEP) appropriate and based on appropriate planning criteria?	33
Export Transmission Service Rates		
23	What is the appropriate level for Export Transmission Rates in Ontario?	34
Connection Procedures		
24	Are the proposed modifications to the Hydro One connection procedures appropriate?	36
Accounting Standards		
25	Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified and reflected in the appropriate manner in the Application, the revenue requirement for the Test Years and the proposed rates.	37

Hydro One Networks Inc.
Test Year 2013 and 2014 Transmission Rates
EB-2012-0031

SETTLEMENT AGREEMENT

PREAMBLE:

This Settlement Agreement is filed with the Ontario Energy Board ("the Board") in connection with the application by Hydro One Networks Inc. ("Hydro One") for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity to be implemented January 1, 2013 and January 1, 2014.

Further to the Board's Procedural Order No. 3 dated and issued October 1, 2012, a Settlement Conference was held on October 23, 24, 25 and 26, 2012 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* ("Rules") and the Board's Settlement Conference Guidelines ("Guidelines").

Hydro One and the following intervenors ("the parties") participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO")
Association of Power Producers of Ontario ("APPrO")
Building Owners and Managers Association Toronto ("BOMA")
Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Energy Probe Research Foundation ("EP")
Goldcorp
London Property Management Association ("LPMA")
Pollution Probe ("PP") – participation subsequently withdrawn from proceeding
Power Workers' Union ("PWU")
School Energy Coalition ("SEC")
Vulnerable Energy Consumers Coalition ("VECC")

Ontario Energy Board staff also participated in the settlement conference, but are not a party to this settlement agreement.

Outlined below are the positions of the parties following the settlement conference. The settlement agreement follows the format of the Approved Issues List for ease of reference. The issues are characterized as follows:

Settled: If the settlement agreement is accepted by the Board, the parties will not adduce any evidence or argument during the oral hearing as the Applicant and those intervenors who take any position on the issue agree to the proposed settlement;

Partially Settled: If the settlement agreement is accepted by the Board, the parties will only adduce evidence and argument during the hearing on portions of the issues as the Applicant and those intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue; and

Not Settled: The Applicant and those intervenors who take a position on the issue will adduce evidence and argument at the hearing on the issue as the parties were unable to reach agreement.

For ease of reference, the following outlines the status of the issues as outlined in the Settlement Agreement:

Settled: Issue completely resolved. Parties will not adduce evidence or argument at the hearing.	**Partially Settled:** Issue partially resolved. Parties will adduce evidence and argument at hearing on certain portions of the issue.	**Not Settled:** Issue not resolved. Evidence to be adduced and argument presented on entirety of issue.
# issues settled: 23	# issues partially settled: 1	# issues not settled: 1

The positions taken by the various parties on each of the settled issues are identified throughout the Settlement Agreement. A party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue and takes no position on the settlement reached or on the sufficiency of the evidence filed to date.

The Settlement Agreement provides a brief description of each of the settled issues, together with references to the evidence filed. The supporting parties to each settled issue agree that the evidence in respect of that settled issue, as supplemented in some instances by additional information recorded in the proposal, supports the proposed settlement. In addition, the supporting parties agree that the evidence filed in support of each settled issue and the additional information as recorded herein contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

The Board's Settlement Conference Guidelines (p.3) require the parties to consider whether a settlement agreement should include an adjustment mechanism for any settled issue that may be affected by external factors. Hydro One and the other parties who participated in the Settlement Conference consider that no settled issues require such an adjustment mechanism other than those expressly set forth in this settlement agreement.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the Ontario Energy Board's *Rules of Practice and Procedure*. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the parties in this Proposal are without prejudice to the rights of parties to raise the same issue and/or to take any position thereon in any other proceedings, unless explicitly stated otherwise.

The parties agree that the remaining unsettled issue will be dealt with during the oral phase of this proceeding, subject to further direction from the Board. The outstanding issue relating to rate base is regarding the net book value (NBV) of Red Lake TS. Goldcorp is the only intervenor with concerns. Hydro One proposes that this issue be dealt with as directed by the Board.

The parties agree that all positions, negotiations and discussion of any kind whatsoever that took place during the Settlement Conference and all documents exchanged during the conference that were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Agreement.

It is fundamental to the agreement of the parties that none of the provisions of this Settlement Agreement are severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement Agreement in their entirety there is no Settlement Agreement unless the parties agree to the contrary.

For the Board's ease of reference, a List of Approvals Sought is attached as Appendix A.

OVERVIEW:

The parties were able to reach agreement on most issues, including Operations, Maintenance & Administration (OM&A) costs, Capital Expenditures and Rate Base, and all other Revenue Requirement related issues. The parties were unable to reach agreement on the appropriate Export Transmission rate for 2013 and 2014 and have therefore agreed that this issue should proceed to the oral hearing, subject to further direction from the Board

Overall rate impacts were a guiding principle that led to the Settlement Agreement. Hydro One filed a rate application seeking a 0.6% increase in 2013 transmission rates and a 9.1% increase in 2014 transmission rates. The parties efforts were focused on determining an appropriate Revenue Requirement and resulting rate levels for 2013 and 2014, while balancing Hydro One's need to continue to safely and reliably operate and to fund its expanding work program.

The overall financial impact of the Settlement Agreement is to reduce the revenue requirement from $1,464.5M to $1,445.7M in 2013 and $1,557.7M to $1,537.2M in 2014 or by $18.7M and $20.5M respectively. The resulting overall rate impact is a 0% rate increase in 2013 and 7.1% rate increase in 2014, down from 0.6% and 9.1% rate increases in the Application. The financial rate impact calculation is attached to this Settlement Agreement as Appendix B.

As noted above, all parties agree that the Settlement Agreement is a broad package proposal. Thus, individual components of the Settlement Agreement ought not be considered or reviewed in isolation. All parties agree the overall package of the Settlement Agreement represents a fair and reasonable agreement that balances the interests of all stakeholders including the ratepayers, the intervenors, concerns previously noted by the Board and Hydro One's needs in order to run a safe and reliable transmission system.

Only one issue remains outstanding – the Export Transmission Service (ETS) rate to be charged. Several parties have filed evidence regarding the appropriate ETS rate including the IESO, APPrO and Hydro-Québec Energy Marketing Inc. (HQ). Hydro One is neutral regarding this issue.

The particulars of the Settlement Agreement are detailed below by issue as set out in the Issues List.

GENERAL

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

   Settled. For the purposes of reaching a settlement, the parties accept that the Applicant has appropriately responded to all directives from prior proceedings. Particulars, where relevant, are discussed below in the context of other issues.

   Evidence: The evidence in relation to this issue includes the following:

A-15-2	Business Load Forecast and Methodology
A-15-2 Appendix A	Monthly Econometric Model
A-15-2 Appendix B	Annual Econometric Model
A-15-2 Appendix C	End-Use Model

A-15-2 Appendix D	Historical Ontario Demand and Charge Determinant Data
A-15-2 Appendix E	Consensus Forecast for Ontario GDP and Housing Starts
A-15-2 Appendix F	Forecast Accuracy
A-15-2 Attachment 1	Incorporating Conservation and Demand Management Impacts in the Load Forecast
A-19-1	Summary of Board Directives and Undertakings from Previous Proceedings
C1-3-3	Development OM&A
C1-3-3 Attachment 1	Smart Grid Development Report
C1-5-2	Compensation, Wages, Benefits
C1-5-2 Attachment 1	Mercer Compensation Cost Benchmarking Study
C1-5-2 Attachment 2	Payroll Table 2009 to 2012
C1-7-2	Overhead Capitalization Rate
C1-7-2 Attachment 1	Review of Overhead Capitalization Rates (Transmission) - 2013/2014
C1-7-2 Attachment 2	Review of Overhead Capitalization Policy
D1-3-3	Development Capital
D1-3-3 Appendix A	Summary of Development Capital Projects in Excess of $3 Million
D1-3-3 Appendix B	OPA Supporting Material for Oshawa TS
D1-3-3 Appendix C	OPA Document on Southwestern Ontario Reactive Compensation Milton SVC dated March 2012
D1-3-3 Appendix D	Letter from OPA dated June 30, 2011
D1-3-3 Appendix E	Letter from OPA dated March 8, 2012
D1-3-3 Appendix F	Letter from OPA dated August 7, 2012
D2-2-3	Investment Summary for Programs/Projects in excess of $3M
F1-1-1	Regulatory Accounts
H1-5-1	Rates for Export Transmission Service
I-1-1.01 Staff 1	OEB Interrogatory #1

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

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

   Settled. For the purposes of reaching a settlement, the parties agree that the settled revenue requirement before adjustment of $1,445.7M in 2013 and $1,537.2M in 2014 is reasonable. The parties are further in agreement that after adjusting for External Revenues, the Export Revenue Credit, transmission riders and low voltage switch gear items, the Rates Revenue Requirement resulting from this settlement agreement of $1,390.3M in 2013 and $1457.0M in 2014 is reasonable. This represents a decrease of $8.2M in 2013 and a decrease of $36.2M in 2014 from the application as originally filed. The resulting rate increase will be 0.0% in 2013 and 7.1% in 2014 versus 0.6% and 9.1% as proposed in the application.

   The parties agree that the revenue requirement will be adjusted to reflect the Board's latest cost of capital parameters for the 2013 and 2014 test years in the final rate order as described in Exhibit B1, Tab 1, Schedule 1.

   As of December 31, 2012, there will be a regulatory asset balance of ($30.3M). Hydro One initially proposed refunding that asset balance equally over each of the test years. In an effort to strive for a 0% increase in transmission rates for 2013, the parties agreed to utilize the regulatory asset balance as a balancing item to ensure that the increase in 2013 remains at 0.0% after other adjustments are made (such as for the latest cost of capital parameters). Any remaining balance will be refunded to customers in 2014. The precise amount to be refunded in the test years will be reflected in the final rate order.

The table below summarizes the proposal:

Hydro One Transmission Revenue Requirement Settlement Agreement

	2012	2013	2014
OM&A		440.3	449.7
Depreciation		345.0	371.5
Income tax		46.2	55.7
Cost of capital		614.2	660.4
Revenue requirement	**1,418.4**	**1,445.7**	**1,537.2**
	5.4%	1.9%	6.3%
Less: External revenues		-31.6	-36.6
Less: Export revenue credit		-31.0	-30.1
Less: "Tx Riders"		-4.5	-25.7
Add: LVSG		11.7	12.2
Rates Revenue Requirement	**1,385.1**	**1,390.3**	**1,457.0**
		0.4%	4.8%
Estimated impact of load reduction		0.4%	-2.3%
Assumed Rate Impact		**0.0%**	**7.1%**

Hydro One's application as filed assumes that the ETS rate would remain at $2/MWh. A number of alternative rates are being proposed. Should the Board approve a change in the ETS rate, the parties agree that the full impact of the change will be tracked in the existing Board approved Excess Export Services Revenue Account for disposition in a future rate application.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Revenue Requirement
E2-1-1	Calculation of Revenue Requirement
I-2-1.01 Staff 2	OEB Interrogatory #2
I-2-1.02 Staff 3	OEB Interrogatory #3

I-2-1.03 Staff 4	OEB Interrogatory #4
I-2-1.04 Staff 5	OEB Interrogatory #5
I-2-1.05 Staff 6	OEB Interrogatory #6
I-2-1.06 Staff 7	OEB Interrogatory #7
I-2-1.07 Staff 8	OEB Interrogatory #8
I-2-1.08 Staff 9	OEB Interrogatory #9
I-2-1.09 Staff 10	OEB Interrogatory #10
I-2-1.10 Staff 11	OEB Interrogatory #11
I-2-1.11 Staff 12	OEB Interrogatory #12
I-2-1.12 Staff 13	OEB Interrogatory #13
I-2-1.13 Staff 14	OEB Interrogatory #14
I-2-1.14 Staff 15	OEB Interrogatory #15
I-2-2.01 LPMA 1	LPMA Interrogatory #1
I-2-3.01 EP 1	Energy Probe Interrogatory #1
I-2-3.02 EP 2	Energy Probe Interrogatory #2
I-2-3.03 EP 3	Energy Probe Interrogatory #3
I-2-3.04 EP 4	Energy Probe Interrogatory #4
I-2-3.05 EP 5	Energy Probe Interrogatory #5
I-2-3.06 EP 6	Energy Probe Interrogatory #6
I-2-3.07 EP 7	Energy Probe Interrogatory #7
I-2-5.01 VECC 1	VECC Interrogatory #1
I-2-5.02 VECC 2	VECC Interrogatory #2
I-2-5.03 VECC 3	VECC Interrogatory #3
I-2-5.04 VECC 4	VECC Interrogatory #4
I-2-5.05 VECC 5	VECC Interrogatory #5
I-2-5.06 VECC 6	VECC Interrogatory #6
I-2-5.07 VECC 7	VECC Interrogatory #7
I-2-5.08 VECC 8	VECC Interrogatory #8
I-2-5.09 VECC 9	VECC Interrogatory #9
I-2-5.10 VECC 10	VECC Interrogatory #10
I-2-5.11 VECC 11	VECC Interrogatory #11
I-2-5.12 VECC 12	VECC Interrogatory #12
I-2-5.13 VECC 13	VECC Interrogatory #13
I-2-5.14 VECC 14	VECC Interrogatory #14
I-2-8.01 PWU 1	PWU Interrogatory #1
I-2-9.01 SEC 1	SEC Interrogatory #1
I-2-9.02 SEC 2	SEC Interrogatory #2
I-2-9.04 SEC 4	SEC Interrogatory #4
I-2-9.05 SEC 5	SEC Interrogatory #5
I-2-9.06 SEC 6	SEC Interrogatory #6
I-2-10.01 CCC 1	CCC Interrogatory #1
I-2-10.02 CCC 2	CCC Interrogatory #2

I-2-10.03 CCC 3	CCC Interrogatory #3
I-2-10.04 CCC 4	CCC Interrogatory #4
I-2-10.05 CCC 5	CCC Interrogatory #5
I-2-14.01 CME 1	CME Interrogatory #1
JT1.1 TCR Staff 4	OEB Technical Conference Response #4
KT1.12	Undertaking Response #12

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

LOAD FORECAST AND REVENUE FORECAST

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

   Settled. For the purposes of reaching a settlement, all parties accept Hydro One's load forecast as set out in Exhibit A, Tab 15, Schedule 2. Hydro One continues to apply the same forecasting methodology previously approved by the Board in EB-2010-0002 which the parties agree remains appropriate.

   The impacts of CDM and Demand Response and how they are reflected in the load forecast were the primary areas of concern for some intervenors. The Board had some concern in this area as well in prior proceedings. In EB-2010-0002, Hydro One's last Transmission Rates Application, the Board directed Hydro One to work with the OPA to devise a means of effectively and accurately measuring CDM impacts. Hydro One has done so and has relied upon the latest CDM and Demand Response forecasts in its load forecast for the test years.

   There remains some concern on the part of certain intervenors about the accuracy and reliability of the CDM and Demand Response forecasts prepared by the OPA. In order to address those concerns, Hydro One has agreed to establish a new variance account to track the impact of actual CDM and Demand Response results on the Load Forecast and the resulting impact on revenue requirement.

   Hydro One agrees to set up a variance account to track the difference between the forecast of 755MW for 2013 and 1158MWfor 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs. Hydro One will use the annual results reported by the OPA in September of each year for the verified results of the previous year in accordance with the CDM Guidelines issued by the Board in EB-2012-0003. T ime-of-use savings will not be included in this variance account because they are currently not included in the annual province-wide CDM program results reported by the OPA.

Hydro One also agreed to track the actual Demand Response results against the forecast as set out in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix A, Table 8 of 836MW in 2013 a nd 880MW2014 (net of 317MW and 410MW respectfully for 2013 a nd 2014 a lready included in CDM program results delivered by LDCs) in this variance account. Hydro One will use annual Demand Response results provided by the OPA each September for results of the previous year in a similar format as the province-wide CDM results delivered by the LDCs.

The disposition of the balance in the LDC CDM and Demand Response Variance Account will be part of a future Rate Application.

Evidence: The evidence in relation to this issue includes the following:

A-6-1	Compliance with OEB Filing Requirements for Electricity Transmitters
A-15-1	Economic Indicators
A-15-2	Business Load Forecast and Methodology
A-15-2 Appendix A	Monthly Econometric Model
A-15-2 Appendix B	Annual Econometric Model
A-15-2 Appendix C	End-Use Model
A-15-2 Appendix D	Historical Ontario Demand and Charge Determinant Data
A-15-2 Appendix E	Consensus Forecast for Ontario GDP and Housing Starts
A-15-2 Appendix F	Forecast Accuracy
A-15-2 Attachment 1	Incorporating Conservation and Demand Management Impacts in the Load Forecast
I-3-1.01 Staff 16	OEB Interrogatory #16
I-3-1.02 Staff 17	OEB Interrogatory #17
I-3-1.03 Staff 18	OEB Interrogatory #18
I-3-1.04 Staff 19	OEB Interrogatory #19
I-3-1.05 Staff 20	OEB Interrogatory #20
I-3-1.06 Staff 21	OEB Interrogatory #21
I-3-1.07 Staff 22	OEB Interrogatory #22
I-3-2.01 LPMA 2	LPMA Interrogatory #2
I-3-2.02 LPMA 3	LPMA Interrogatory #3
I-3-2.03 LPMA 4	LPMA Interrogatory #4
I-3-2.04 LPMA 5	LPMA Interrogatory #5
I-3-3.01 EP 8	Energy Probe Interrogatory #8
I-3-3.02 EP 9	Energy Probe Interrogatory #9
I-3-3.03 EP 10	Energy Probe Interrogatory #10
I-3-5.01 VECC 15	VECC Interrogatory #15
I-3-5.02 VECC 16	VECC Interrogatory #16
I-3-5.03 VECC 17	VECC Interrogatory #17
I-3-5.04 VECC 18	VECC Interrogatory #18
I-3-5.05 VECC 19	VECC Interrogatory #19

I-3-5.06 VECC 20	VECC Interrogatory #20
I-3-5.07 VECC 21	VECC Interrogatory #21
I-3-5.08 VECC 22	VECC Interrogatory #22
I-3-5.09 VECC 23	VECC Interrogatory #23
I-3-5.10 VECC 24	VECC Interrogatory #24
I-3-5.11 VECC 25	VECC Interrogatory #25
I-3-13.01 AMPCO 1	AMPCO Interrogatory #1
I-3-13.02 AMPCO 2	AMPCO Interrogatory #2
I-3-13.03 AMPCO 3	AMPCO Interrogatory #3
JT1.2 TCR EP1	Energy Probe Technical Conference Response #1
KT1.6	Undertaking Response #6
KT1.7	Undertaking Response #7
KT1.8	Undertaking Response #8

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

4. Are Other Revenue (including export revenue) forecasts appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the 2013 external revenue forecast of $31.6M is appropriate. Some intervenors were concerned that the forecast for external revenues in 2014 was too low based on historical average actual external revenues. A ccordingly, as part of the settlement, Hydro One agreed to increase the forecast for external revenues in 2014 by $4.8M to $36.6M from $31.8M in order to reflect the historical average of actual revenues in the previous three years. The table below summarizes the proposed change:

External Revenue ($M)	***2013***	***2014***
Filed Evidence	31.6	31.8
Settlement Agreement	31.6	36.6
Change Proposed	-	4.8

Three of the four inputs (Secondary Land Use, Station Maintenance and Engineering and Project Delivery) into the overall external revenue forecasts are currently tracked in symmetrical variance accounts. The parties agreed that all inputs into the external revenues should be tracked in a variance account. Thus, Hydro One agreed to create a new symmetrical variance account to track any differences in Other External Revenue.

As noted above, the parties have also agreed, that Hydro One will track any changes in ETS Revenue in the Excess Export Services Revenue Account should the Board approve a change to the current ETS rate of $2.00/MWh.

Evidence: The evidence in relation to this issue includes the following:

E1-2-1	External Revenues
I-4-2.01 LPMA 6	LPMA Interrogatory #6
I-4-2.02 LPMA 7	LPMA Interrogatory #7
I-4-2.03 LPMA 8	LPMA Interrogatory #8
I-4-2.04 LPMA 9	LPMA Interrogatory #9
I-4-2.05 LPMA 10	LPMA Interrogatory #10
I-4-2.06 LPMA 11	LPMA Interrogatory #11
I-4-5.01 VECC 26	VECC Interrogatory #26
I-4-5.02 VECC 27	VECC Interrogatory #27
I-4-5.03 VECC 28	VECC Interrogatory #28
I-4-5.04 VECC 29	VECC Interrogatory #29
I-4-9.01 SEC 7	SEC Interrogatory #7
I-4-10.01 CCC 6	CCC Interrogatory #6
I-4-10.02 CCC 7	CCC Interrogatory #7
KT1.23	Undertaking Response #23

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Overall OM&A Settlement and its Rationale

All issues relating to Operations, Maintenance and Administration costs have been settled. T he parties focused on ov erall spending levels for OM&A expenditures rather than focusing on any one particular aspect of those costs. The rationale for the settlement of Issues 5, 6 and 7 is outlined below.

Hydro One's application forecast OM&A expenditures of $453.3M and $459.7M in 2013 and 2014 respectively.

In order to address the concerns expressed by intervenors, balanced against Hydro One's needs to effectively operate the transmission business, combined with ongoing productivity initiatives being undertaken, Hydro One agreed to reduce 2013 spending levels by $13.0M from $453.3M to $440.3M. OM&A spending for 2014 will be reduced by $10M from $459.7M to $449.7M. The parties agree that these reduced proposed spending levels are appropriate.

The table below summarizes the proposed changes:

OM&A ($M)	***2013***	***2014***
Filed Evidence	453	460
Settlement Agreement	440	450
Change Proposed	-13	-10

5. Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?

Settled. See rationale above.

Evidence: The evidence in relation to this issue includes the following:

A-15-6	Work Execution Strategy
C1-1-1	Cost of Service Summary
C1-2-1	Sustaining Investment Structure
C1-2-2	Transmission Assets and Sustaining Investment Overview
C1-2-2 Appendix A	Hydro One Transmission Asset Descriptions
C1-3-1	Summary of OM&A Expenditures
C1-3-2	Sustaining OM&A
C1-3-3	Development OM&A
C1-3-3 Attachment 1	Smart Grid Development Report
C1-3-4	Operations OM&A
C1-3-5	Customer Care OM&A
C1-4-1	Summary of Shared Services – OM&A
C1-4-2	Common Corporate Functions & Services and Other OM&A
C1-4-3	Shared Services OM&A – Asset Management
C1-4-4	Shared Services OM&A – Information Technology
C1-4-4 Attachment 1	H1 Telecom Inc. Services Review and Benchmarking
C1-4-5	Shared Services OM&A – Cornerstone
C1-4-6	Shared Services OM&A – Cost of Sales - External Work
C1-4-7	Property Taxes
C2-1-1	Cost of Service

C2-2-1	Comparison of OM&A Expense by Major Category
I-5-1.01 Staff 23	OEB Interrogatory #23
I-5-1.02 Staff 24	OEB Interrogatory #24
I-5-1.03 Staff 25	OEB Interrogatory #25
I-5-1.04 Staff 26	OEB Interrogatory #26
I-5-1.05 Staff 27	OEB Interrogatory #27
I-5-1.06 Staff 28	OEB Interrogatory #28
I-5-1.07 Staff 29	OEB Interrogatory #29
I-5-1.08 Staff 30	OEB Interrogatory #30
I-5-1.09 Staff 31	OEB Interrogatory #31
I-5-1.10 Staff 32	OEB Interrogatory #32
I-5-1.11 Staff 33	OEB Interrogatory #33
I-5-1.12 Staff 34	OEB Interrogatory #34
I-5-1.13 Staff 35	OEB Interrogatory #35
I-5-2.01 LPMA 12	LPMA Interrogatory #12
I-5-3.01 EP 11	Energy Probe Interrogatory #11
I-5-3.02 EP 12	Energy Probe Interrogatory #12
I-5-3.03 EP 13	Energy Probe Interrogatory #13
I-5-3.04 EP 14	Energy Probe Interrogatory #14
I-5-3.05 EP 15	Energy Probe Interrogatory #15
I-5-3.06 EP 16	Energy Probe Interrogatory #16
I-5-3.07 EP 17	Energy Probe Interrogatory #17
I-5-3.08 EP 18	Energy Probe Interrogatory #18
I-5-3.09 EP 19	Energy Probe Interrogatory #19
I-5-3.10 EP 20	Energy Probe Interrogatory #20
I-5-3.11 EP 21	Energy Probe Interrogatory #21
I-5-8.01 PWU 2	PWU Interrogatory #2
I-5-8.02 PWU 3	PWU Interrogatory #3
I-5-8.03 PWU 4	PWU Interrogatory #4
I-5-8.04 PWU 5	PWU Interrogatory #5
I-5-8.05 PWU 6	PWU Interrogatory #6
I-5-8.06 PWU 7	PWU Interrogatory #7
I-5-8.07 PWU 8	PWU Interrogatory #8
I-5-8.08 PWU 9	PWU Interrogatory #9
I-5-8.09 PWU 10	PWU Interrogatory #10
I-5-8.10 PWU 11	PWU Interrogatory #11
I-5-8.11 PWU 12	PWU Interrogatory #12
I-5-8.12 PWU 13	PWU Interrogatory #13
I-5-8.13 PWU 14	PWU Interrogatory #14
I-5-8.14 PWU 15	PWU Interrogatory #15
I-5-8.15 PWU 16	PWU Interrogatory #16

I-5-9.01 SEC 8	SEC Interrogatory #8
I-5-9.02 SEC 9	SEC Interrogatory #9
I-5-9.03 SEC 10	SEC Interrogatory #10
I-5-9.04 SEC 11	SEC Interrogatory #11
I-5-9.05 SEC 12	SEC Interrogatory #12
I-5-9.06 SEC 13	SEC Interrogatory #13
I-5-9.07 SEC 14	SEC Interrogatory #14
I-5-9.08 SEC 15	SEC Interrogatory #15
I-5-9.09 SEC 16	SEC Interrogatory #16
I-5-9.10 SEC 17	SEC Interrogatory #17
I-5-10.01 CCC 8	CCC Interrogatory #8
I-5-10.02 CCC 9	CCC Interrogatory #9
I-5-10.03 CCC 10	CCC Interrogatory #10
I-5-10.04 CCC 11	CCC Interrogatory #11
I-5-10.05 CCC 12	CCC Interrogatory #12
I-5-10.06 CCC 13	CCC Interrogatory #13
I-5-10.07 CCC 14	CCC Interrogatory #14
I-5-10.08 CCC 15	CCC Interrogatory #15
I-5-12.01 THESL 1	THESL Interrogatory #1
JT1.1 TCR PWU 5	PWU Technical Conference Response #5
JTI.1 TCR Staff 8	OEB Technical Conference Response #8
JT1.1 TCR Staff 10	OEB Technical Conference Response #10
KT1.13	Undertaking Response #13
KT1.14	Undertaking Response #14
KT1.15	Undertaking Response #15
KT1.24	Undertaking Response #24
KT1.26	Undertaking Response #26
KT1.36	Undertaking Response #36

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

6. Are the proposed spending levels for Shared Services and Other O & M in 2013 and 2014 appropriate?

Settled. See rationale above.

Evidence: The evidence in relation to this issue includes the following:

C1-3-5	Customer Care OM&A
C1-4-1	Summary of Shared Services – OM&A

C1-4-2	Shared Services – Common Corporate Functions & Services and Other OM&A
C1-4-3	Shared Services OM&A– Asset Management
C1-4-4	Shared Services OM&A – Information Technology
C1-4-4 Attachment 1	H1 Telecom Inc. Services Review and Benchmarking
C1-4-5	Shared Services OM&A – Cornerstone
C1-4-6	Shared Services OM&A – Cost of Sales - External Work
C1-4-7	Property Taxes
I-6-1.01 Staff 36	OEB Interrogatory #36
I-6-1.02 Staff 37	OEB Interrogatory #37
I-6-1.03 Staff 38	OEB Interrogatory #38
I-6-3.01 EP 22	Energy Probe Interrogatory #22
I-6-3.02 EP 23	Energy Probe Interrogatory #23
I-6-3.03 EP 24	Energy Probe Interrogatory #24
I-6-3.04 EP 25	Energy Probe Interrogatory #25
I-6-3.05 EP 26	Energy Probe Interrogatory #26
I-6-5.01 VECC 30	VECC Interrogatory #30
I-6-5.02 VECC 31	VECC Interrogatory #31
I-6-9.01 SEC 19	SEC Interrogatory #19
I-6-10.01 CCC 16	CCC Interrogatory #16
I-6-10.02 CCC 17	CCC Interrogatory #17
I-6-10.03 CCC 18	CCC Interrogatory #18
I-6-10.04 CCC 19	CCC Interrogatory #19
I-6-10.05 CCC 20	CCC Interrogatory #20
I-6-10.06 CCC 21	CCC Interrogatory #21
I-6-10.07 CCC 22	CCC Interrogatory #22

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

7. Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Settled. See rationale above.

Evidence: The evidence in relation to this issue includes the following:

A-17-1	Cost Efficiencies/Productivity
A-17-2	Productivity Metrics

A-17-2 Attachment 1	Measuring Productivity at Hydro One
A-17-2 Attachment 2	OEB Expert Evidence Requirements
C1-5-1	Corporate Staffing
C1-5-2	Compensation, Wages, Benefits
C1-5-2 Attachment 1	Mercer Compensation Cost Benchmarking Study
C1-5-2 Attachment 2	Payroll Table 2009 to 2012
C1-5-3	Pension Costs
C2-3-1	Comparison of Wages and Salaries
I-7-1.01 Staff 39	OEB Interrogatory #39
I-7-1.02 Staff 40	OEB Interrogatory #40
I-7-1.03 Staff 41	OEB Interrogatory #41
I-7-1.04 Staff 42	OEB Interrogatory #42
I-7-1.05 Staff 43	OEB Interrogatory #43
I-7-1.06 Staff 44	OEB Interrogatory #44
I-7-1.07 Staff 45	OEB Interrogatory #45
I-7-1.08 Staff 46	OEB Interrogatory #46
I-7-2.01 LPMA 13	LPMA Interrogatory #13
I-7-2.02 LPMA 14	LPMA Interrogatory #14
I-7-3.01 EP 27	Energy Probe Interrogatory #27
I-7-3.02 EP 28	Energy Probe Interrogatory #28
I-7-3.03 EP 29	Energy Probe Interrogatory #29
I-7-3.04 EP 30	Energy Probe Interrogatory #30
I-7-3.05 EP 31	Energy Probe Interrogatory #31
I-7-3.06 EP 32	Energy Probe Interrogatory #32
I-7-3.07 EP 33	Energy Probe Interrogatory #33
I-7-3.09 EP 35	Energy Probe Interrogatory #35
I-7-3.10 EP 36	Energy Probe Interrogatory #36
I-7-3.11 EP 37	Energy Probe Interrogatory #37
I-7-3.13 EP 39	Energy Probe Interrogatory #39
I-7-3.14 EP 40	Energy Probe Interrogatory #40
I-7-3.15 EP 41	Energy Probe Interrogatory #41
I-7-3.16 EP 42	Energy Probe Interrogatory #42
I-7-3.17 EP 43	Energy Probe Interrogatory #43
I-7-3.18 EP 44	Energy Probe Interrogatory #44
I-7-3.19 EP 45	Energy Probe Interrogatory #45
I-7-3.20 EP 46	Energy Probe Interrogatory #46
I-7-3.21 EP 47	Energy Probe Interrogatory #47
I-7-3.22 EP 48	Energy Probe Interrogatory #48
I-7-3.23 EP 49	Energy Probe Interrogatory #49
I-7-5.01 VECC 32	VECC Interrogatory #32
I-7-8.01 PWU 17	PWU Interrogatory #17

I-7-9.01 SEC 20	SEC Interrogatory #20
I-7-9.02 SEC 21	SEC Interrogatory #21
I-7-9.03 SEC 22	SEC Interrogatory #22
I-7-10.01 CCC 23	CCC Interrogatory #23
I-7-10.02 CCC 24	CCC Interrogatory #24
I-7-10.03 CCC 25	CCC Interrogatory #25
I-7-10.04 CCC 26	CCC Interrogatory #26
I-7-13.01 AMPCO 4	AMPCO Interrogatory #4
I-7-13.02 AMPCO 5	AMPCO Interrogatory #5
I-7-13.03 AMPCO 6	AMPCO Interrogatory #6
I-7-13.04 AMPCO 7	AMPCO Interrogatory #7
JT1.1 TCR Staff 12	OEB Technical Conference Response #12
JT1.1 TCR Staff 13	OEB Technical Conference Response #13
JT1.1 TCR Staff 14	OEB Technical Conference Response #14
JT1.1 TCR Staff 15	OEB Technical Conference Response #15
JT1.1 TCR Staff 16	OEB Technical Conference Response #16
JT1.2 TCR EP3	Energy Probe Technical Conference Response #3
KT1.9	Undertaking Response #9
KT1.10	Undertaking Response #10
KT1.11	Undertaking Response #11
KT1.16	Undertaking Response #16
KT1.27	Undertaking Response #27
KT1.28	Undertaking Response #28
KT1.31	Undertaking Response #31
KT1.32	Undertaking Response #32
KT1.33	Undertaking Response #33
KT1.34	Undertaking Response #34

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

8. Are the methodologies used to allocate Shared Services and Other O & M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that Hydro One has used the Corporate Cost Allocation Methodology previously accepted by the Board in prior Hydro One Network Transmission and Distribution Rate Applications. Similarly, Hydro One has followed the overhead capitalization rate methodology previously accepted by the Board. Both of these have been updated for the current filing. The parties thus agree that the methodologies used to allocate Shared Services and Other O&M costs to the transmission overhead capitalization rate for 2013 and 2014 are appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-7-1	Common Corporate Costs, Cost Allocation Methodology
C1-7-1 Attachment 1	Review of Shared Services Cost Allocation (Transmisison) – 2012
C1-7-2	Overhead Capitalization Rate
C1-7-2 Attachment 1	Review of Overhead Capitalization Rates (Transmission) – 2013-2014
C1-7-2 Attachment 2	Review of Overhead Capitalization Policy
I-8-3.01 EP 50	Energy Probe Interrogatory #50
I-8-3.02 EP 51	Energy Probe Interrogatory #51
I-8-9.01 SEC 23	SEC Interrogatory #23
I-8-10.01 CCC 27	CCC Interrogatory #27
JT1.2 TCR EP5	Energy Probe Technical Conference Response #5
JT1.2 TCR EP6	Energy Probe Technical Conference Response #6

Supporting Parties: PWU, AMPCO, SEC, CCC, CME

Parties taking no position: EP, VECC, LPMA, BOMA, Goldcorp, APPrO

9. Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the amounts proposed to be included in the 2013 and 2014 revenue requirement for income and other taxes are appropriate, subject to an increase in the Apprenticeship Tax Credit by $1.3M in 2013 and $1.0M in 2014 (resulting in corresponding decreases in tax expenses included in rates).

Evidence: The evidence in relation to this issue includes the following:

C1-9-1	Payments in Lieu of Corporate Income Taxes
C2-5-1	Calculation of Utility Income Taxes
C2-5-1 Attachment 1	Calculation of Utility Income Taxes Test Years (2013, 2014)
C2-5-1 Attachment 2	Calculation of Capital Cost Allowance Test Years (2013, 2014)
C2-5-1 Attachment 3	Calculation of Utility Income Taxes Historic Years (2009, 2010)

C2-5-1 Attachment 4	Calculation of Capital Cost Allowance Historic Years (2009, 2010) and Forecast Years (2011, 2012)
C2-5-1 Attachment 5	Calculation of Apprenticeship and Education Tax Credit Test Years (2013, 2014)
C2-5-1 Attachment 6	Calculation of Apprenticeship and Education Tax Credit Historic Years (2009, 2010)
C2-5-2	2010 Hydro One Networks Income Tax Return
C2-5-2 Attachment 1	Federal and Ontario Income Tax Return
C2-5-2 Attachment 2	Calculation of Utility Income Taxes (Transmission and Distribution)
C2-5-2 Attachment 3	Calculation of Capital Cost Allowance (Transmission and Distribution)
C2-5-3	2011 Hydro One Networks Income Tax Return
C2-5-3 Attachment 1	Federal and Ontario Income Tax Return
C2-5-3 Attachment 2	Calculation of Utility Income Taxes (Transmission and Distribution)
C2-5-3 Attachment 3	Calculation of Capital Cost Allowance (Transmission and Distribution)
I-9-1.01 Staff 47	OEB Interrogatory #47
I-9-1.02 Staff 48	OEB Interrogatory #48
I-9-1.03 Staff 49	OEB Interrogatory #49
I-9-2.01 LPMA 15	LPMA Interrogatory #15
I-9-2.02 LPMA 16	LPMA Interrogatory #16
I-9-2.03 LPMA 17	LPMA Interrogatory #17
I-9-2.04 LPMA 18	LPMA Interrogatory #18
I-9-2.05 LPMA 19	LPMA Interrogatory #19
I-9-2.06 LPMA 20	LPMA Interrogatory #20
I-9-2.07 LPMA 21	LPMA Interrogatory #21
JT1.1 TCR Staff 17	OEB Technical Conference Response #17

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

10. Is Hydro One Networks' proposed depreciation expense for 2013 and 2014 appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the proposed depreciation expense for 2013 and 2014 which reflects the 2011

Depreciation Rate Review filed at Exhibit C1, Tab 8, Schedule 1, Attachment 1 is appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-8-1	Depreciation and Amortization Expenses
C1-8-1 Attachment 1	2011 Depreciation Rate Review
C2-4-1	Depreciation and Amortization Expenses
I-10-2.01 LPMA 22	LPMA Interrogatory #22

Supporting Parties: EP, LPMA, SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

CAPITAL EXPENDITURES AND RATE BASE

11. Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Partially Settled. The Applicant has proposed a rate base of $9,413.5M and $10,050.9M in the test years.

For the purposes of reaching a settlement, Hydro One has agreed to reduce its planned capital expenditures in 2013 as outlined below in Issue 12. This will result in reduced in-service additions in 2013, which has an associated reduction in rate base for both 2013 and 2014.

Taking into account those reductions, the parties other than Goldcorp agree that a rate base of $9,353.4M in 2013 and a rate base of $9,933.8M in 2014 are appropriate. This represents a reduction in rate base of $60.1M in 2013 and $117.1M in 2014 compared to that initially proposed, after reflecting depreciation.

Detailed calculations are provided in the table below.

Capital Expenditures ($M)	***2012***	***2013***	***2014***
Filed Evidence	850.0	1,102.4	1,121.5
Settlement Agreement	850.0	982.4	1,121.5
Change Proposed	-	- 120.0	-
In-Service ($M)			

Filed Evidence	1,294.7	904.1	1,023.0
Settlement Agreement	1,295.0	784.1	1,023.0
Change Proposed	-	- 120.0	-
Gross In-Service Impact on Rate Base ($M)			
Filed Evidence	8,628.5	9,413.5	10,050.9
Settlement Agreement	8,628.5	9,353.5	9,930.9
Change Proposed	-	- 60.0	- 120.0
Net Rate Base after Accumulated Depreciation ($M)			
Filed Evidence	8,628.5	9,413.5	10,050.9
Settlement Agreement	8,628.5	9,353.4	9,933.8
Change Proposed		- 60.1	- 117.1

The only aspect of this issue which remains unsettled is the net book value of Red Lake TS. Goldcorp is the only intervenor with concerns in this regard. Hydro One and Goldcorp have written separately to the Board regarding this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Rate Base
D1-1-2	In-Service Capital Additions
D1-2-1	Allowance for Funds Used During Construction
D1-5-1	Materials and Supplies Inventory
D2-1-1	Statement of Utility Rate Base
D2-3-1	Continuity of Property, Plant and Equipment
D2-3-2	Continuity of Accumulated Depreciation
D2-3-3	Continuity of Property, Plant and Equipment - Construction Work In Progress
I-11-1.01 Staff 50	OEB Interrogatory #50
I-11-1.02 Staff 51	OEB Interrogatory #51
I-11-1.03 Staff 52	OEB Interrogatory #52
I-11-1.04 Staff 53	OEB Interrogatory #53
I-11-2.01 LPMA 23	LPMA Interrogatory #23
I-11-2.02 LPMA 24	LPMA Interrogatory #24
I-11-2.03 LPMA 25	LPMA Interrogatory #25
I-11-4.01 PP 1	Pollution Probe Interrogatory #1
I-11-4.02 PP 2	Pollution Probe Interrogatory #2
I-11-4.03 PP 3	Pollution Probe Interrogatory #3
I-11-4.04 PP 4	Pollution Probe Interrogatory #4
I-11-4.05 PP 5	Pollution Probe Interrogatory #5
I-11-4.06 PP 6	Pollution Probe Interrogatory #6
I-11-4.07 PP7	Pollution Probe Interrogatory #7
I-11-4.08 PP 8	Pollution Probe Interrogatory #8

I-11-4.09 PP 9	Pollution Probe Interrogatory #9
I-11-4.10 PP 10	Pollution Probe Interrogatory #10
I-11-4.11 PP 11	Pollution Probe Interrogatory #11
I-11-4.12 PP 12	Pollution Probe Interrogatory #12
I-11-4.13 PP 13	Pollution Probe Interrogatory #13
I-11-4.14 PP 14	Pollution Probe Interrogatory #14
I-11-4.15 PP 15	Pollution Probe Interrogatory #15
I-11-4.16 PP 16	Pollution Probe Interrogatory #16
I-11-4.17 PP 17	Pollution Probe Interrogatory #17
I-11-4.18 PP 18	Pollution Probe Interrogatory #18
I-11-4.19 PP 19	Pollution Probe Interrogatory #19
I-11-4.20 PP 20	Pollution Probe Interrogatory #20
I-11-4.21 PP 21	Pollution Probe Interrogatory #21
I-11-4.22 PP 22	Pollution Probe Interrogatory #22
I-11-4.23 PP 23	Pollution Probe Interrogatory #23
I-11-4.24 PP 24	Pollution Probe Interrogatory #24
I-11-4.25 PP 25	Pollution Probe Interrogatory #25
I-11-4.26 PP 26	Pollution Probe Interrogatory #26
I-11-4.27 PP 27	Pollution Probe Interrogatory #27
I-11-4.28 PP 28	Pollution Probe Interrogatory #28
I-11-4.29 PP 29	Pollution Probe Interrogatory #29
I-11-5.01 VECC 33	VECC Interrogatory #33
I-11-7.01 Gold 1	Goldcorp Interrogatory #1
I-11-7.02 Gold 2	Goldcorp Interrogatory #2
I-11-7.03 Gold 3	Goldcorp Interrogatory #3
I-11-7.04 Gold 4	Goldcorp Interrogatory #4
I-11-7.05 Gold 5	Goldcorp Interrogatory #5
I-11-7.06 Gold 6	Goldcorp Interrogatory #6
I-11-9.01 SEC 24	SEC Interrogatory #24
I-11-12.01 THESL 2	THESL Interrogatory #2
I-11-12.02 THESL 3	THESL Interrogatory #3
I-11-12.03 THESL 4	THESL Interrogatory #4
I-11-12.04 THESL 5	THESL Interrogatory #5
I-11-13.01 AMPCO 8	AMPCO Interrogatory #8
I-11-13.02 AMPCO 9	AMPCO Interrogatory #9
JT1.1 TCR PP1	Pollution Probe Technical Conference Response #1
JT1.1 TCR PP2	Pollution Probe Technical Conference Response #2
JT1.1 TCR PP3	Pollution Probe Technical Conference Response #3
JT1.1 TCR PP4	Pollution Probe Technical Conference Response #4
KT1.5	Undertaking Response #5

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, APPrO

12. Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Settled.

For the purposes of reaching a settlement, the parties agreed to reduce 2013 capital expenditures and in service additions by $120.0 M from $1,102.4M to $982.4M. The reductions will be recognized through the re-prioritization of investments based on Hydro One's Investment Planning and Prioritization process to ensure the impact to risks and business values are minimized while reducing the overall rate impacts on customers. For the purposes of reaching a settlement, the parties agree that capital expenditures , for 2013 and 2014 are appropriate, with the agreed upon reduction in 2013.

The table below summarizes the proposed changes:

Capital Expenditures ($M)	***2012***	***2013***	***2014***
Filed Evidence	850	1102	1122
Settlement Agreement	850	982	1122
Change Proposed		-120	0

Evidence: The evidence in relation to this issue includes the following:

D1-3-1	Summary of Capital Expenditures
D1-3-2	Sustaining Capital
D1-3-3	Development Capital
D1-3-3 Appendix A	Summary of Development Capital Projects in Excess of $3 Million
D1-3-3 Appendix B	OPA Supporting Material for Oshawa TS
D1-3-3 Appendix C	OPA Document on Southwestern Ontario Reactive Compensation Milton SVC dated March 2012
D1-3-3 Appendix D	Letter from OPA dated June 30, 2011
D1-3-3 Appendix E	Letter from OPA dated March 8, 2012
D1-3-3 Appendix F	Letter from OPA dated August 7, 2012
D1-3-4	Operations Capital
D2-2-1	Comparison of Net Capital Expenditures by Major Category – Historic, Bridge Year and Test Year
D2-2-2	List of Capital Expenditure Programs or Projects Requiring in Excess of $3 Million in Test Year 2013 or 2014

D2-2-3	Investment Summary for Programs/Projects in Excess of $3 Million
I-12-1.01 Staff 54	OEB Interrogatory #54
I-12-1.02 Staff 55	OEB Interrogatory #55
I-12-1.03 Staff 56	OEB Interrogatory #56
I-12-1.04 Staff 57	OEB Interrogatory #57
I-12-1.05 Staff 58	OEB Interrogatory #58
I-12-1.06 Staff 59	OEB Interrogatory #59
I-12-1.07 Staff 60	OEB Interrogatory #60
I-12-1.08 Staff 61	OEB Interrogatory #61
I-12-1.09 Staff 62	OEB Interrogatory #62
I-12-1.10 Staff 63	OEB Interrogatory #63
I-12-1.11 Staff 64	OEB Interrogatory #64
I-12-1.12 Staff 65	OEB Interrogatory #65
I-12-1.13 Staff 66	OEB Interrogatory #66
I-12-1.14 Staff 67	OEB Interrogatory #67
I-12-1.15 Staff 68	OEB Interrogatory #68
I-12-1.16 Staff 69	OEB Interrogatory #69
I-12-1.17 Staff 70	OEB Interrogatory #70
I-12-1.18 Staff 71	OEB Interrogatory #71
I-12-1.19 Staff 72	OEB Interrogatory #72
I-12-3.01 EP 52	Energy Probe Interrogatory #52
I-12-3.02 EP 53	Energy Probe Interrogatory #53
I-12-3.03 EP 54	Energy Probe Interrogatory #54
I-12-3.04 EP 55	Energy Probe Interrogatory #55
I-12-9.01 SEC 25	SEC Interrogatory #25
I-12-9.02 SEC 26	SEC Interrogatory #26
I-12-9.03 SEC 27	SEC Interrogatory #27
I-12-9.04 SEC 28	SEC Interrogatory #28
I-12-9.05 SEC 29	SEC Interrogatory #29
I-12-9.06 SEC 30	SEC Interrogatory #30
I-12-9.07 SEC 31	SEC Interrogatory #31
I-12-9.08 SEC 32	SEC Interrogatory #32
I-12-9.09 SEC 33	SEC Interrogatory #33
I-12-9.10 SEC 34	SEC Interrogatory #34
I-12-10.01 CCC 28	CCC Interrogatory #28
I-12-10.02 CCC 29	CCC Interrogatory #29
I-12-10.03 CCC 30	CCC Interrogatory #30
I-12-10.04 CCC 31	CCC Interrogatory #31
I-12-10.05 CCC 32	CCC Interrogatory #32
I-12-12.01 THESL 6	THESL Interrogatory #6

I-12-12.02 THESL 7	THESL Interrogatory #7
I-12-12.03 THESL 8	THESL Interrogatory #8
I-12-12.04 THESL 9	THESL Interrogatory #9
I-12-12.05 THESL 10	THESL Interrogatory #10
I-12-13.01 AMPCO 10	AMPCO Interrogatory #10
JT1.1 TCR Staff 23	OEB Technical Conference Response #23
JT1.2 TCR EP8	Energy Probe Technical Conference Response #8
KT1.29	Undertaking Response #29
KT1.30	Undertaking Response #30

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

13. Are the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures appropriate?

Settled. Please see rationale for issue 12 above. For the purposes of reaching a settlement, the parties agree that the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures are appropriate.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Summary of Shared Services Capital
D1-4-2	Shared Services Capital – Information Technology
D1-4-3	Shared Services Capital – Cornerstone
D1-4-4	Shared Services Capital – Facilities & Real Estate
D1-4-5	Shared Services Capital – Transport, Work and Service Equipment
D2-2-1	Comparison of Net Capital Expenditures by Major Category – Historic, Bridge Year and Test Year
D2-2-2	List of Capital Expenditure Programs or Projects Requiring in Excess of $3 Million in Test Year 2013 or 2014
D2-2-3	Investment Summary for Programs/Projects in Excess of $3 Million
I-13-9.01 SEC 35	SEC Interrogatory #35
I-13-10.01 CCC 33	CCC Interrogatory #33
I-13-10.02 CCC 34	CCC Interrogatory #34
I-13-10.03 CCC 35	CCC Interrogatory #35

Supporting Parties: AMPCO, SEC, CCC, CME

Parties taking no position: EP, VECC, LPMA, BOMA, PWU, Goldcorp, APPrO

14. Are the methodologies used to allocate shared services and other capital expenditures to the transmission business appropriate?

Settled. Hydro One has used the Corporate Cost Allocation Methodology previously accepted by the Board in prior Hydro One Network Transmission and Distribution Rate Applications. F or the purposes of reaching a settlement, the parties accept that the methodologies used to allocate Shared Services and other capital costs to the transmission business are appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-7-3	Common Asset Allocation
C1-7-3 Attachment 1	Review of Shared Assets Allocation (Transmission) - 2012

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position. EP, LPMA, Goldcorp, APPrO

15. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

Settled. For the purposes of reaching a settlement the parties agree that the inputs and methodology used by the Applicant to determine the working capital component of the rate base are appropriate.

Evidence: The evidence in relation to this issue includes the following:

D1-1-3	Working Capital
D1-1-3 Attachment 1	A Determination of the Working Capital Requirements of Hydro One Networks' Transmission Business
D2-4-1	Statement of Working Capital
I-15-2.01 LPMA 26	LPMA Interrogatory #26
I-15-2.02 LPMA 27	LPMA Interrogatory #27
I-15-3.01 EP 56	Energy Probe Interrogatory #56

Supporting Parties: EP, VECC, LPMA, SEC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

16. Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14.

Settled. For the purposes of reaching a settlement**,** the parties accept that Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets in support of the OM&A and Capital expenditures for 2013 and 2014.

Evidence: The evidence in relation to this issue includes the following:

A-13-1	Planning Process
A-13-1 Appendix A	2012 Business Plan Assumptions
A-13-2	Transmission 10 Year Outlook
A-15-3	Investment Plan Development
A-15-4	Investment Prioritization Process
A-15-5	Project and Program Approval & Control
C1-2-1	Sustaining Investment Structure
C1-2-2	Transmission Assets and Sustaining Investment Overview
C1-2-2 Appendix A	Hydro One Transmission Asset Descriptions
I-16-1.01 Staff 73	OEB Interrogatory #73
I-16-1.02 Staff 74	OEB Interrogatory #74
I-16-1.03 Staff 75	OEB Interrogatory #75
I-16-1.04 Staff 76	OEB Interrogatory #76

Supporting Parties: SEC, VECC, LPMA, EP, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

COST OF CAPITAL/CAPITAL STRUCTURE

17. Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

Settled. For the purposes of reaching a settlement the parties agree that the proposed timing and methodology as outlined in Exhibit B1, Tab 1, Schedule 1 is appropriate for determining the return on equity and short-term debt prior to the effective date of the rates as reflected in the Board approved rate order for the test years.

The table below summarizes the revenue requirement impact of the proposed changes to the 2013 and 2014 rate base based on the applied for Cost of Capital parameters.

Cost of Capital ($M)*	***2013***	***2014***
Filed Evidence	618.1	668.1
Settlement Agreement*	614.2	660.4
Change Proposed	(3.9)	(7.7)

*Includes return on equity and cost of short and long term debt.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Cost of Capital
B2-1-1	Debt and Equity Summary
I-17-2.01 LPMA 28	LPMA Interrogatory #28
I-17-3.01 EP 57	Energy Probe Interrogatory #57
I-17-10.01 CCC 36	CCC Interrogatory #36
I-17-13.01 AMPCO 11	AMPCO Interrogatory #11

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

18. Is the forecast of long term debt for 2012-2014 appropriate?

Settled. For the purposes of reaching a settlement the parties agree the forecast of long term debt rates following the methodology outlined in Exhibit B1, Tab 2, Schedule 1 is appropriate. Please see the table above under Issue 17.

Evidence: The evidence in relation to this issue includes the following:

B1-2-1	Cost of Third Party Long-Term Debt
B2-1-2	Cost of Long-Term Debt Capital
I-18-2.01 LPMA 29	LPMA Interrogatory #29
I-18-2.02 LPMA 30	LPMA Interrogatory #30
I-18-2.03 LPMA 31	LPMA Interrogatory #31
I-18-3.01 EP 58	Energy Probe Interrogatory #58
I-18-3.02 EP 59	Energy Probe Interrogatory #59
I-18-3.03 EP 60	Energy Probe Interrogatory #60
I-18-9.01 SEC 36	SEC Interrogatory #36
I-18-9.02 SEC 37	SEC Interrogatory #37

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

DEFERRAL/VARIANCE ACCOUNTS

19. Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Settled. For the purposes of reaching a settlement, the parties accept Hydro One's account balances.

As noted in Issue 2 above, the parties agree that the amounts refunded to rate payers in 2013 associated with the ($30.3) million regulatory asset balance will be used as a balancing item to ensure a 0.0% increase for 2013. Any remaining balance will be refunded to customers in 2014. The precise amount to be refunded in each year will be reflected in the final rate order once the cost of capital has been established.

In addition, as noted above, the parties agreed that should the Board approve a change in the Export Transmission Services rate, the full impact of the approved rate will be tracked in the Board approved Excess Export Services Revenue Account for disposition in a future rate application.

As of December 31, 2012, both the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs had zero balances. For the purposes of reaching a settlement, Hydro One agreed to discontinue those two accounts. This is reflected in Appendix A.

Evidence: The evidence in relation to this issue includes the following:

F1-1-1	Regulatory Accounts
F1-1-3	Planned Disposition of Regulatory Accounts
F2-1-1	Regulatory Accounts for Approval
F2-1-2	Schedule of Annual Recoveries
F2-1-3	Continuity Schedules – Regulatory Accounts
I-19-1.01 Staff 77	OEB Interrogatory #77
I-19-1.02 Staff 78	OEB Interrogatory #78
I-19-1.03 Staff 79	OEB Interrogatory #79
I-19-1.04 Staff 80	OEB Interrogatory #80
I-19-3.01 EP 61	Energy Probe Interrogatory #61
I-19-9.01 SEC 38	SEC Interrogatory #38
I-19-9.02 SEC 39	SEC Interrogatory #39
I-19-10.01 CCC 37	CCC Interrogatory #37
I-19-10.02 CCC 38	CCC Interrogatory #38
I-19-10.03 CCC 39	CCC Interrogatory #39

JT1.1 TCR Staff 25	OEB Technical Conference Response #25
JT1.2 TCR EP9	Energy Probe Technical Conference Response #9
KT1.35	Undertaking Response #35

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: EP, LPMA, Goldcorp, APPrO

20. Are the proposed new Deferral and Variance Accounts appropriate?

Settled.

For the purposes of reaching a settlement and as previously described Hydro One has agreed to create two new variance accounts to track variances in

a) other external revenues and

b) the differences between the forecast and actual CDM savings related to the OPA funded LDC delivered programs and the actual Demand Response results against forecast. The CDM variance account is more fully described above in the context of Issue 3.

For the Other External Revenues Variance Account, Hydro One will establish a new variance account to record the differences between Other External Revenues embedded in rates and Actual Revenues.

These new proposed accounts have also been reflected in Appendix A.

Evidence: The evidence in relation to this issue includes the following:

F1-1-2	Regulatory Accounts Requested
I-20-1.01 Staff 81	OEB Interrogatory #81
I-20-10.01 CCC 40	CCC Interrogatory #40
I-20-10.02 CCC 41	CCC Interrogatory #41
JT1.1 TCR Staff 26	OEB Technical Conference Response #26

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

COST ALLOCATION

21. Is the cost allocation proposed by Hydro One appropriate?

Settled. Hydro One is proposing to continue to use the cost allocation methodology previously approved by the Board. For the purposes of reaching a settlement, the parties agree that the cost allocation proposed by Hydro One is appropriate.

Attached at Appendix C is an updated Draft Summary Uniform Transmission Rates and Revenue Disbursements Factors for 2013 and 2014.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation and Charge Determinants
G1-2-1	Description of Cost Allocation Methodology
G1-3-1	Network and Line Connection Pools
G1-4-1	Transformation Connection Pool
G1-5-1	Wholesale Meter Pool
G1-6-1	Low Voltage Switchgear Compensation
G2-1-1	List of Transmission Lines by Functional Category
G2-1-2	List of Transmission Stations by Functional Category
G2-2-1	Allocation Factors for Dual Function Lines
G2-3-1	Allocation Factors for Generator Line Connections
G2-3-2	Allocation Factors For Generator Station Connections
G2-4-1	Asset Value by Functional Category
G2-4-2	Depreciation by Functional Category
G2-4-3	Return on Capital and Income Taxes by Functional Category
G2-4-4	OM&A Costs by Functional Category
G2-5-1	Detailed Revenue Requirement by Rate Pool
H1-1-1	Overview of Uniform Transmission Rates
H1-2-1	Transmission Customers Load Forecast
H1-3-1	Charge Determinants
H1-4-1	Rates for Wholesale Meter Service
H2-1-1	Current Ontario Transmission Rate Schedules
H2-1-1 Attachment 1	Ontario Transmission Rates Schedules EB-2011-0268
H2-1-1 Attachment 2	Uniform Transmission Rates and Revenue Disbursement Allocators
H2-2-1	Current Wholesale Meter Service and Exit Fee Schedule
H2-2-2	Proposed Wholesale Meter Service and Exit Fee Schedule
I-21-5.01 VECC 34	VECC Interrogatory #34
I-21-5.02 VECC 35	VECC Interrogatory #35
I-21-5.03 VECC 36	VECC Interrogatory #36
I-21-5.04 VECC 37	VECC Interrogatory #37
I-21-5.05 VECC 38	VECC Interrogatory #38
I-21-5.06 VECC 39	VECC Interrogatory #39

I-21-5.07 VECC 40	VECC Interrogatory #40

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

GREEN ENERGY PLAN

22. Are the OM&A and capital amounts in the Green Energy Plan (GEP) appropriate and based on appropriate planning criteria?

Settled. For the purposes of reaching a settlement, the parties accept the filed GEP as appropriate for 2013 and 2014.

Hydro One clarified that the approvals for OM&A and capital sought in the GEP are the same projects included in the overall proposals for OM&A and capital. Given agreement regarding OM&A and capital, there is agreement for the GEP. Hydro One confirmed that it is not seeking Board approval of elements of the plan that go beyond the test years.

The 2013 and 2014 elements of Hydro One's GEP are covered by the settlement of Issues 2 to 18 inclusive. Intervenors have no questions in this proceeding on the elements of Hydro One's GEP that lie outside the ambit of the 2013 and 2014 test years.

Evidence: The evidence in relation to this issue includes the following:

A-14-1	Transmission Green Energy Plan
A-14-1 Appendix A	Letter from Ministry of Energy and Infrastructure – dated September 21, 2009
A-14-1 Appendix B	Letters from Ministry of Energy and Infrastructure – dated May 5, 2010 and May 7, 2010
A-14-1 Appendix C	Letter from Ontario Power Authority – dated April 7, 2011
A-14-1 Appendix D	Letter from Hydro One – dated December 29, 2009
I-22-1.01 Staff 82	OEB Interrogatory #82
I-22-1.02 Staff 83	OEB Interrogatory #83
I-22-3.01 EP 62	Energy Probe Interrogatory #62
I-22-3.02 EP 63	Energy Probe Interrogatory #63
I-22-3.03 EP 64	Energy Probe Interrogatory #64
I-22-3.04 EP 65	Energy Probe Interrogatory #65
I-22-3.05 EP 66	Energy Probe Interrogatory #66

I-22-9.01 SEC 40	SEC Interrogatory #40
I-22-13.01 AMPCO 12	AMPCO Interrogatory #12
I-22-13.02 AMPCO 13	AMPCO Interrogatory #13
I-22-13.03 AMPCO 14	AMPCO Interrogatory #14
I-22-13.04 AMPCO 15	AMPCO Interrogatory #15
I-22-13.05 AMPCO 16	AMPCO Interrogatory #16
I-22-13.06 AMPCO 17	AMPCO Interrogatory #17
I-22-13.07 AMPCO 18	AMPCO Interrogatory #18
I-22-13.08 AMPCO 19	AMPCO Interrogatory #19

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: EP, LPMA, Goldcorp, APPrO

EXPORT TRANSMISSION SERVICE RATES

23. What is the appropriate level for Export Transmission Rates in Ontario?

Not Settled. The parties agree that this issue should be determined in an oral hearing before the Board.

Evidence: The evidence in relation to this issue includes the following:

H1-5-1	Rates for Export Transmission Service
H1-5-2	IESO Export Transmission Service Study
H2-1-2	Proposed Uniform Transmission Rates
I-23-1.01 Staff 84	OEB Interrogatory #84
I-23-1.02 Staff 85	OEB Interrogatory #85
I-23-1.03 Staff 86	OEB Interrogatory #86
I-23-1.04 Staff 87	OEB Interrogatory #87
I-23-1.05 Staff 88	OEB Interrogatory #88
I-23-1.06 Staff 89	OEB Interrogatory #89
I-23-1.07 Staff 90	OEB Interrogatory #90
I-23-1.08 Staff 91	OEB Interrogatory #91
I-23-1.09 Staff 92	OEB Interrogatory #92
I-23-5.01 VECC 41	VECC Interrogatory #41
I-23-5.02 VECC 42	VECC Interrogatory #42
I-23-5.03 VECC 43	VECC Interrogatory #43
I-23-5.04 VECC 44	VECC Interrogatory #44
I-23-5.05 VECC 45	VECC Interrogatory #45
I-23-5.06 VECC 46	VECC Interrogatory #46

I-23-5.07 VECC 47	VECC Interrogatory #47
I-23-5.08 VECC 48	VECC Interrogatory #48
I-23-5.09 VECC 49	VECC Interrogatory #49
I-23-5.10 VECC 50	VECC Interrogatory #50
I-23-5.11 VECC 51	VECC Interrogatory #51
I-23-5.12 VECC 52	VECC Interrogatory #52
I-23-5.13 VECC 53	VECC Interrogatory #53
I-23-5.14 VECC 54	VECC Interrogatory #54
I-23-6.01 HQ 1	HQ Interrogatory #1
I-23-6.02 HQ 2	HQ Interrogatory #2
I-23-6.03 HQ 3	HQ Interrogatory #3
I-23-6.04 HQ 4	HQ Interrogatory #4
I-23-6.05 HQ 5	HQ Interrogatory #5
I-23-6.06 HQ 6	HQ Interrogatory #6
I-23-6.07 HQ 7	HQ Interrogatory #7
I-23-6.08 HQ 8	HQ Interrogatory #8
I-23-6.09 HQ 9	HQ Interrogatory #9
I-23-6.10 HQ 10	HQ Interrogatory #10
I-23-6.11 HQ 11	HQ Interrogatory #11
I-23-6.12 HQ 12	HQ Interrogatory #12
I-23-6.13 HQ 13	HQ Interrogatory #13
I-23-6.14 HQ 14	HQ Interrogatory #14
I-23-6.15 HQ 15	HQ Interrogatory #15
I-23-6.16 HQ 16	HQ Interrogatory #16
I-23-8.01 PWU 18	PWU Interrogatory #18
I-23-9.01 SEC 41	SEC Interrogatory #41
I-23-9.02 SEC 42	SEC Interrogatory #42
I-23-9.03 SEC 43	SEC Interrogatory #43
I-23-10.01 CCC 42	CCC Interrogatory #42
I-23-11.01 APPrO 1	APPrO Interrogatory #1
I-23-11.02 APPrO 2	APPrO Interrogatory #2
I-23-11.03 APPrO 3	APPrO Interrogatory #3
I-23-11.04 APPrO 4	APPrO Interrogatory #4
I-23-11.05 APPrO 5	APPrO Interrogatory #5
I-23-11.06 APPrO 6	APPrO Interrogatory #6
I-23-11.07 APPrO 7	APPrO Interrogatory #7
I-23-11.08 APPrO 8	APPrO Interrogatory #8
I-23-11.09 APPrO 9	APPrO Interrogatory #9
I-23-11.10 APPrO 10	APPrO Interrogatory #10
I-23-11.11 APPrO 11	APPrO Interrogatory #11
I-23-11.12 APPrO 12	APPrO Interrogatory #12

KT1.1	Undertaking Response #1
KT1.2	Undertaking Response #2
KT1.3	Undertaking Response #3
KT1.4	Undertaking Response #4

Supporting Parties: NOT REQUIRED

Parties taking no position:

CONNECTION PROCEDURES

24. Are the proposed modifications to the Hydro One connection procedures appropriate?

Settled. Hydro One proposed some modifications to the connection procedures currently in use. The modifications were intended to reflect the overall timelines required for load connections and generation connections based on Hydro One's experience over the last few years. The current Board approved Transmission Connection Procedures for Hydro One included timeframes which are ambitious given the current realities of the electricity market.

AMPCO had some concerns with the proposed modifications. Hydro One clarified that the changes were intended to simply reflect the true timeframes required to connect a load or generation customer based on Hydro One's experience. In addition, the changes are more transparent as they reflect the overall timeframes for each phase of the connection process rather than simply timelines for Hydro One to complete those items for which it is responsible within each phase. The proposed changes provide customers better information. With that clarification, AMPCO's concerns were addressed.

In Exhibit I, Tab 24, Schedule 1.03 Staff 95, Hydro One proposed two further revisions to the proposed new connection procedures in parts f) and j) of the response. Hydro One agreed to include the proposed revised connection procedures as part of the draft rate order, which will include the two changes outlined in the interrogatory response.

Accordingly, the parties are in agreement that the proposed changes to the connection procedures for Hydro One are appropriate.

Evidence: The evidence in relation to this issue includes the following:

A-12-1	Key Governing Legislation, Standards and Codes
I-24-1.01 Staff 93	OEB Interrogatory #93
I-24-1.02 Staff 94	OEB Interrogatory #94
I-24-1.03 Staff 95	OEB Interrogatory #95

I-24-1.04 Staff 96	OEB Interrogatory #96
I-24-1.05 Staff 97	OEB Interrogatory #97
I-24-3.01 EP 67	Energy Probe Interrogatory #67
I-24-10.01 CCC 43	CCC Interrogatory #43
I-24-13.01 AMPCO 20	AMPCO Interrogatory #20
I-24-13.02 AMPCO 21	AMPCO Interrogatory #21
I-24-13.03 AMPCO 22	AMPCO Interrogatory #22
I-24-13.04 AMPCO 23	AMPCO Interrogatory #23
I-24-13.05 AMPCO 24	AMPCO Interrogatory #24

Supporting Parties: PWU, AMPCO

Parties taking no position: EP, SEC, VECC, LPMA, BOMA, CCC, CME, APPrO

ACCOUNTING STANDARDS

25. Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified and reflected in the appropriate manner in the Application, the revenue requirement for the Test Years and the proposed rates.

Settled. For the purposes of reaching a settlement the parties agree that all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP have been identified and reflected in the appropriate manner in the Application, the revenue requirement for the test years and the proposed rates.

Evidence: The evidence in relation to this issue includes the following:

A-12-2	Summary of Hydro One Transmission Policies
I-25-1.01 Staff 98	OEB Interrogatory #98

Supporting Parties: SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO, PWU

Parties taking no position: EP, APPrO

APPENDIX A

LIST OF APPROVALS SOUGHT

1. An Order pursuant to Section 78 of the *Ontario Energy Board Act* approving 2013 and 2014 Revenue Requirement and rates for the transmission of electricity to be implemented January 1, 2013 and January 1, 2014.

2. As a result of the Settlement Proposal, Hydro One Networks seeks approval of a revenue requirement of $1,446 million and $1,537 million for the test years 2013 and 2014, respectively. This results in an increase in Hydro One Transmission's Rates Revenue Requirement of 0% and 7.1%, respectively, reflecting an estimated increase on the average customer's total bill of 0.0% in 2013 and 0.6% in 2014. The estimate of the impact on a customer's total bill assumes commodity costs of 7.2¢/kWh and that transmission represents 7.9% of an average distribution connected customer's total bill.

3. Hydro One Networks seeks approval of regulatory assets totaling ($30.3) million as at December 31, 2012. Hydro One seeks approval to refund this balance over a two year period and to reduce the annual revenue requirement accordingly. Hydro One proposes to refund an amount that will ensure the overall rate increase in 2013 will be 0.0% and to refund any remaining balance to customers in 2014.

4. Hydro One Networks seeks approval to continue the following deferral accounts including, the Excess Export Service Revenue Account, the External Secondary Land Use Revenue Variance Account, the External Station Maintenance and E&CS Revenue Variance Account, the Tax Rate Changes Account, the Rights Payments Variance Account, the Pension Cost Differential Account, and the East-West Tie account.

5. For 2013 and 2014, Hydro One Transmission is requesting that the Board approve the establishment of four new deferral accounts, the External Revenue – Partnership Transmission Projects Account, the Long-Term Transmission Future Corridor

Acquisition and Development Account, the Other External Revenues Variance Account, the LDC CDM and Demand Response Variance Account.

6. Hydro One Transmission is also requesting the discontinuance effective January 1, 2013 of the Deferred Export Service Credit Revenue Account, the Long Term Project Development Costs Account, the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs Account.

7. Hydro One Networks also requests the Board approve several proposed modifications to the current Transmission Connection Procedures, which were approved by the Board in EB-2006-0189 to reflect the current electricity market conditions with respect to the connection of renewable generation. The proposed changes relate to a number of sections in Hydro One Transmission's Connection Procedures including: 1) the Customer Connection Process, 2) Security Deposit Procedure, 3) Customer Impact Assessment Procedure, 4) Schedule of Charges and Fees, and 5) Connection Process Timelines. Hydro One will also incorporate further revisions to the proposed connection procedures as outlined in parts f) and j) of the interrogatory response to in Exhibit I, Tab 24, Schedule 1.03, Staff 95.

8. Approval of Hydro One's Green Energy Plan for 2013 and 2014.

	Filing (Blue Page)			Reduce 2013 capex/in-service by $120M; decrease OM&A by $13M & $10M; increase 2014 ext. revenue by $4.8M; increase tax credit by $1.3M & $1M; adjust rider refund timing; updated LVSG			Updated Cost of Capital (DRAFT RATE ORDER VIEW)			Updated Export Credit to get to 0% in 2013		
Draft Rate Increases	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE
October 29, 2012	9.42%	9.16%	9.44%	9.42%	9.16%	9.44%	9.42%	8.93%	9.28%	9.42%	8.93%	9.28%
	2012	2013	2014	2012	2013	2014	2012	2013	2014	2012	2013	2014
Revenue requirement												
OM&A		453.3	459.7		440.3	449.7		440.3	449.7		440.3	449.7
Depreciation on fixed assets		315.1	335.8		313.4	332.5		313.4	332.5		313.4	332.5
Capitalized depreciation		(9.8)	(9.8)		(9.8)	(9.8)		(9.8)	(9.8)		(9.8)	(9.8)
Asset removal costs		35.3	41.9		35.3	41.9		35.3	41.9		35.3	41.9
Other amortization		6.1	6.9		6.1	6.9		6.1	6.9		6.1	6.9
Return on debt		268.3	283.8		266.5	280.5		270.2	280.3		270.2	280.3
Return on equity		344.9	379.5		342.7	375.1		334.1	368.7		334.1	368.7
Income tax		46.4	55.2		46.2	55.7		43.1	53.4		43.1	53.4
AFUDC		4.9	4.8		4.9	4.8		5.0	4.8		5.0	4.8
Revenue requirement	1,418.4	1,464.5	1,557.7	1,418.4	1,445.7	1,537.2	1,418.4	1,437.7	1,528.4	1,418.4	1,437.7	1,528.4
	5.4%	3.2%	6.4%	5.4%	1.9%	6.3%	5.4%	1.4%	6.3%	5.4%	1.4%	6.3%
Less: Non-rate revenues	(28.7)	(31.6)	(31.8)	(28.7)	(31.6)	(36.6)	(28.7)	(31.6)	(36.6)	(28.7)	(31.6)	(36.6)
	1,389.7	1,432.9	1,525.9	1,389.7	1,414.1	1,500.6	1,389.7	1,406.1	1,491.8	1,389.7	1,406.1	1,491.8
	5.9%	3.1%	6.5%	5.9%	1.8%	6.1%	5.9%	1.2%	6.1%	5.9%	1.2%	6.1%
Less: Export revenue credit	(16.0)	(31.0)	(30.1)	(16.0)	(31.0)	(30.1)	(16.0)	(31.0)	(30.1)	(16.0)	(27.0)	(34.1)
	1,373.6	1,401.9	1,495.8	1,373.6	1,383.1	1,470.5	1,373.6	1,375.2	1,461.7	1,373.6	1,379.2	1,457.7
	6.0%	2.1%	6.7%	6.0%	0.7%	6.3%	6.0%	0.1%	6.3%	6.0%	0.4%	5.7%
Less: "Tx Riders"	-	(15.1)	(15.1)	-	(4.5)	(25.7)	-	-	(30.3)	-	-	(30.3)
	1,373.6	1,386.8	1,480.6	1,373.6	1,378.6	1,444.8	1,373.6	1,375.2	1,431.5	1,373.6	1,379.2	1,427.5
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%	6.6%	0.1%	4.1%	6.6%	0.4%	3.5%
Add: LVSG	11.5	11.7	12.5	11.5	11.7	12.2	11.5	11.7	12.2	11.5	11.6	12.1
Rates Revenue Requirement	1,385.1	1,398.5	1,493.1	1,385.1	1,390.3	1,457.0	1,385.1	1,386.8	1,443.6	1,385.1	1,390.8	1,439.5
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%	6.6%	0.1%	4.1%	6.6%	0.4%	3.5%
Estimated impact of load reduction	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**
Assumed Rate Impact	**7.8%**	**0.6%**	**9.1%**	**7.8%**	**0.0%**	**7.1%**	**7.8%**	**-0.3%**	**6.4%**	**7.8%**	**0.0%**	**5.8%**
Rate Base		9413.5	10050.9		9353.4	9933.8		9353.4	9933.8		9353.4	9933.8

APPENDIX C

DRAFT

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2013

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI (Note 3)	$3,897,095	$779,431	$1,650,564	$6,327,089
CNPI (Note 4)	$2,840,979	$568,204	$1,203,260	$4,612,443
GLPT (Note 5)	$21,710,466	$4,342,158	$9,195,184	$35,247,808
H1N (Note 1)	$855,746,155	$171,151,779	$362,440,102	$1,389,338,036
All Transmitters	$884,194,694	$176,841,572	$374,489,109	$1,435,525,376

Transmitter	Total Annual Charge Determinants (MW)			
	Network	**Line Connection**	**Transformation Connection**	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	4,019.8	2,939.4	1,057.6	
H1N (Note 2)	240,274.0	232,874.3	201,107.9	
All Transmitters	245,064.3	236,695.8	202,910.3	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.61**	**0.75**	**1.85**	
FNEI Allocation Factor	**0.00441**	**0.00441**	**0.00441**	
CNPI Allocation Factor	**0.00321**	**0.00321**	**0.00321**	
GLPT Allocation Factor	**0.02455**	**0.02455**	**0.02455**	
H1N Alocation Factor	**0.96783**	**0.96783**	**0.96783**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2013 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2013 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2010-0291 dated on December 19, 2011.
Note 6: Calculated data in shaded cells.

APPENDIX C

DRAFT

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2014

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI (Note 3)	$3,870,865	$799,421	$1,656,804	$6,327,089
CNPI (Note 4)	$2,821,857	$582,777	$1,207,808	$4,612,443
GLPT (Note 5)	$21,564,340	$4,453,521	$9,229,946	$35,247,808
H1N (Note 1)	$890,953,721	$184,001,982	$381,345,079	$1,456,300,783
All Transmitters	$919,210,784	$189,837,701	$393,439,638	$1,502,488,123

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	4,019.8	2,939.4	1,057.6	
H1N (Note 2)	234,635.3	227,880.9	196,795.3	
All Transmitters	239,425.6	231,702.4	198,597.7	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.84**	**0.82**	**1.98**	
FNEI Allocation Factor	**0.00421**	**0.00421**	**0.00421**	
CNPI Allocation Factor	**0.00307**	**0.00307**	**0.00307**	
GLPT Allocation Factor	**0.02346**	**0.02346**	**0.02346**	
H1N Alocation Factor	**0.96926**	**0.96926**	**0.96926**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2014 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2014 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2010-0291 dated on December 19, 2011.
Note 6: Calculated data in shaded cells.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #3

Interrogatory

(a) Slide 7 shows proposed transmission rate increases of 3.2% and 3.3% for 2015 and 2016 respectively. Are these percentages equivalent to the price cap escalator which Hydro One would require for application to the Ontario Energy Board ("OEB" or the "Board") approved 2014 Base Rates to produce the revenues Hydro One says it needs to produce reasonable transmission rates for 2015 and 2016?

(b) Slide 9 presents OM&A productivity savings for 2014, 2015 and 2016. For 2015 and 2016, the savings are $46M and $49M. What is the approximate X-factor percentage that would need to be applied to 2014 Board approved Base Rates to produce OM&A savings in each of the years 2015 and 2016 which are, on average, $47.5M/year?

Response

(a) The proposed transmission rate increases of 3.2% and 3.3% for 2015 and 2016 are not based on any price cap escalator. The proposed rate increase is a result of revenue requirement calculated in a "cost-of-service" rate application.

(b) Hydro One has not calculated nor used the X-factor percentage in this proposed transmission rate application. As mentioned above, this is a "cost-of-service" rate application and the proposed OM&A expeditures are "need-based".

Canadian Manufacturers & Exporters (CME) INTERROGATORY #4

Interrogatory

Exhibit A, Tab 15, Schedule 1, page 4 of the Information Package refers to historical and forecast debt rates at Exhibit B2, Tab 1, Schedule 2. Please provide a copy of that Exhibit.

Response

The historical and forecast debt rates at Exhibit B2, Tab 1, Schedule 2 can be found in Attachment 1 of this interrogatory response.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Debt and Equity Summary
Historical Years (2011, 2012, 2013) and Bridge Year (2014)
As at December 31
($ Millions)

Updated

Line No.	Particulars	Amount Outstanding 2011 Actual (a)	Amount Outstanding 2012 Actual (b)	Amount Outstanding 2013 Actual (c)	Amount Outstanding 2014 Projection (d)
I	Long-term debt *	4,329.1	4,634.3	4,916.1	4,946.6
2	Short-term debt	511.4	373.3	34.6	286.2
3	Preference shares	239.0	239.0	239.0	239.0
4	Common equity	3,583.8	3,879.5	4,290.3	4,364.0

* Includes debt payable within one year; excludes variable rate debt, unamortized debt premiums/discount, hedging gains/losses market

HYDRO ONE NETWORKS INC.
TRANSMISSION
Summary of Cost of Capital
Test Years (2015 and 2016)
Utility Capital Structure
Year Ending December 31

		2015				2016			
Line No.	Particulars	($M)	%	Cost Rate (%)	Return ($M)	($M)	%	Cost Rate (%)	Return ($M)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
I	Long-term debt	5,157.9	50.7%	5.02%	258.9	5,385.9	51.0%	5.08%	273.7
2	Short-term debt	407.1	4.0%	3.19%	13.0	422.3	4.0%	4.45%	18.8
3	Deemed long-term debt	541.0	5.3%	5.02%	27.2	526.5	5.0%	5.08%	26.8
4	Total debt	6,105.9	60.0%	4.90%	299.0	6,334.8	60.0%	5.04%	319.3
5	Common equity	4,070.6	40.0%	9.71%	395.3	4,223.2	40.0%	9.96%	420.6
6	Total rate base	10,176.5	100.0%	6.82%	694.3	10,558.0	100.0%	7.01%	739.9

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Historical Year (2011)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/10 ($Millions)	Total Amount Outstanding at 12/31/11 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	0.0	160.6	10.2	
3	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
4	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	87.0	87.0	5.1	
5	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
6	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	189.0	189.0	10.8	
7	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
8	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
9	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
10	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
11	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
12	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.9	
13	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
14	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
15	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
16	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
17	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
18	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.66	5.22%	225.0	225.0	225.0	11.8	
19	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
20	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
21	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.87	4.33%	130.0	130.0	130.0	5.6	
22	3-Mar-09	6.030%	3-Mar-39	195.0	1.1	193.9	99.43	6.07%	195.0	195.0	195.0	11.8	
23	16-Jul-09	5.490%	16-Jul-40	210.0	1.3	208.7	99.37	5.53%	210.0	210.0	210.0	11.6	
24	19-Nov-09	3.130%	19-Nov-14	175.0	0.6	174.4	99.64	3.21%	175.0	175.0	175.0	5.6	
25	15-Mar-10	5.490%	16-Jul-40	120.0	(0.7)	120.7	100.59	5.45%	120.0	120.0	120.0	6.5	
26	15-Mar-10	4.400%	1-Jun-20	180.0	0.8	179.2	99.56	4.45%	180.0	180.0	180.0	8.0	
27	13-Sep-10	2.950%	11-Sep-15	150.0	0.5	149.5	99.64	3.03%	150.0	150.0	150.0	4.5	
28	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.27	4.98%	150.0	150.0	150.0	7.5	
29	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	0.0	205.0	63.1	2.8	
30	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	0.0	70.0	5.4	0.2	
31		**Subtotal**							4228.1	4329.1	4283.1	231.8	
32		Treasury OM&A costs										1.2	
33		Other financing-related fees										5.4	
34		**Total**							4228.1	4329.1	4283.1	238.4	5.57%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Historical Year (2012)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/11 ($Millions)	Total Amount Outstanding: at 12/31/12 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	0.0	73.6	4.3	
4	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
5	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	0.0	159.9	9.1	
6	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
7	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
8	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
9	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
10	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
11	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
12	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
13	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
14	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
15	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
16	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
17	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
18	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
19	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
20	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.85	4.34%	130.0	130.0	130.0	5.6	
21	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
22	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
23	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	175.0	175.0	5.6	
24	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
25	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
26	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
27	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
28	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
29	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
30	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	0.0	154.0	142.2	4.6	
31	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	0.0	165.0	101.5	3.1	
32	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	0.0	68.8	42.3	1.7	
33	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	0.0	52.5	24.2	0.9	
34	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	0.0	141.0	54.2	2.1	
35		**Subtotal**							4329.1	4634.3	4651.1	240.5	
36		Treasury OM&A costs										1.6	
37		Other financing-related fees										3.9	
38		**Total**							4329.1	4634.3	4651.1	246.0	5.29%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Historical Year (2013)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/12 ($Millions)	Total Amount Outstanding: at 12/31/13 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	0.0	203.1	10.4	
18	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.85	4.34%	130.0	0.0	110.0	4.8	
19	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
20	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
21	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	175.0	175.0	5.6	
22	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
23	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
24	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
25	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
26	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
27	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
28	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	142.2	4.6	
29	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	101.5	3.1	
30	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	42.3	1.7	
31	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	24.2	0.9	
32	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	54.2	2.1	
33	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	0.0	239.3	55.2	2.6	
34	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	0.0	412.5	95.2	2.7	
35		**Subtotal**							4634.3	4916.1	4511.0	229.7	
36		Treasury OM&A costs										1.6	
37		Other financing-related fees										3.6	
38		**Total**							4634.3	4916.1	4511.0	234.9	5.21%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Bridge Year (2014)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/13 ($Millions)	Total Amount Outstanding at 12/31/14 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	0.0	148.1	4.8	
20	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
21	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
22	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
23	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
24	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
25	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
26	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
27	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
28	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
29	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
30	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
31	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
32	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	
33	15-Mar-14	4.928%	15-Mar-44	68.5	0.3	68.2	99.50	4.96%	0.0	68.5	52.7	2.6	
34	15-Jun-14	4.091%	15-Jun-24	68.5	0.3	68.2	99.50	4.15%	0.0	68.5	36.9	1.5	
35	15-Sep-14	3.101%	15-Sep-19	68.5	0.3	68.2	99.50	3.21%	0.0	68.5	21.1	0.7	
36		**Subtotal**							4916.1	4946.6	4999.8	243.9	
37		Treasury OM&A costs										1.5	
38		Other financing-related fees										3.2	
39		**Total**							4916.1	4946.6	4999.8	248.7	4.97%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2015)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/14 ($Millions)	Total Amount Outstanding: at 12/31/15 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
20	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
21	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	0.0	103.8	3.1	
22	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
23	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
24	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
25	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
26	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
27	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
28	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
29	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
30	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
31	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	
32	15-Mar-14	4.928%	15-Mar-44	68.5	0.3	68.2	99.50	4.96%	68.5	68.5	68.5	3.4	
33	15-Jun-14	4.091%	15-Jun-24	68.5	0.3	68.2	99.50	4.15%	68.5	68.5	68.5	2.8	
34	15-Sep-14	3.101%	15-Sep-19	68.5	0.3	68.2	99.50	3.21%	68.5	68.5	68.5	2.2	
35	15-Mar-15	5.628%	15-Mar-45	159.3	0.8	158.6	99.50	5.66%	0.0	159.3	122.6	6.9	
36	15-Jun-15	4.791%	15-Jun-25	159.3	0.8	158.6	99.50	4.86%	0.0	159.3	85.8	4.2	
37	15-Sep-15	3.801%	15-Sep-20	159.3	0.8	158.6	99.50	3.91%	0.0	159.3	49.0	1.9	
38		**Subtotal**							4946.6	5274.7	5157.9	254.4	
39		Treasury OM&A costs										1.6	
40		Other financing-related fees										2.9	
41		**Total**							4946.6	5274.7	5157.9	258.9	5.02%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2016)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/15 ($Millions)	Total Amount Outstanding at 12/31/16 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	0.0	48.5	2.3	
11	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	0.0	13.8	0.7	
13	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
14	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
18	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
19	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
20	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
21	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
22	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
23	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
24	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
25	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
26	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
27	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
28	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
29	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
30	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	412.5	412.5	11.8	
31	15-Mar-14	4.928%	15-Mar-44	68.5	0.3	68.2	99.50	4.96%	68.5	68.5	68.5	3.4	
32	15-Jun-14	4.091%	15-Jun-24	68.5	0.3	68.2	99.50	4.15%	68.5	68.5	68.5	2.8	
33	15-Sep-14	3.101%	15-Sep-19	68.5	0.3	68.2	99.50	3.21%	68.5	68.5	68.5	2.2	
34	15-Mar-15	5.628%	15-Mar-45	159.3	0.8	158.6	99.50	5.66%	159.3	159.3	159.3	9.0	
35	15-Jun-15	4.791%	15-Jun-25	159.3	0.8	158.6	99.50	4.86%	159.3	159.3	159.3	7.7	
36	15-Sep-15	3.801%	15-Sep-20	159.3	0.8	158.6	99.50	3.91%	159.3	159.3	159.3	6.2	
37	15-Mar-16	6.128%	15-Mar-46	197.5	1.0	196.5	99.50	6.17%	0.0	197.5	151.9	9.4	
38	15-Jun-16	5.291%	15-Jun-26	197.5	1.0	196.5	99.50	5.36%	0.0	197.5	106.3	5.7	
39	15-Sep-16	4.301%	15-Sep-21	197.5	1.0	196.5	99.50	4.41%	0.0	197.5	60.8	2.7	
40		**Subtotal**							5274.7	5597.0	5385.9	269.2	
41		Treasury OM&A costs										1.6	
42		Other financing-related fees										3.0	
43		**Total**							5274.7	5597.0	5385.9	273.7	5.08%

Canadian Manufacturers & Exporters (CME) INTERROGATORY #5

Interrogatory

Please provide copies of all documents in Hydro One's possession provided by Mercer Consulting Inc. and Great-West Life pertaining to Hydro One's salaries and benefits in the period 2013 to 2016 inclusive. Documents of this nature are referenced at Exhibit A, Tab 15, Schedule 1, page 8.

Response

Mercer Consulting Inc, provided information on a consolidated basis. Networks allocated portion is based on the ratio of earnings. Please see attachment 1 for the following:

- Non-pension post-retirement benefits: refer to Mercer Consulting Inc. document Appendix B.3.
- Non-pension post-employment benefits: refer to Mercer Consulting Inc. document Appendix B.4.
- Supplemental Pension Plan: refer to Mercer Consulting Inc. document Appendix A.
- Pension benefits are reported under cash basis thus Mercer Consulting Inc. accrual basis forecasts are not used.

For active employee benefits: Health and Dental escalation information comes from our actuary based on information from Great West Life and Hydro One. Life insurance is based on review of the last 3 years, per information sourced from Great West Life, and escalated using CPI. Health tax refund for PWU is escalated using labour rate.

Hydro One Inc. Non-Pension Post Retirement Benefits - Hydro One + Inergi — **Appendix B.3**

Projected 2013 Accounting Under US GAAP

Figures in $thousands	Projections 2013	2014	2015	2016	2017	2018	2019
A. Change in benefit obligation							
1. Benefit obligation at beginning of year	1,321,517	1,367,343	1,355,418	1,136,302	1,004,827	1,040,676	1,012,696
2. Current service cost	34,644	34,592	33,768	24,457	21,336	21,801	21,426
3. Interest cost	56,761	62,094	64,869	68,147	67,478	69,829	70,326
4. Plan participants' contributions	0	0	0	0	0	0	0
5. Amendments	0	0	0	0	0	0	0
6. Actuarial (gains) / losses	(4,331)	(64,490)	(270,744)	(174,133)	(0)	(63,666)	(94,083)
7. Benefits paid from plan/company	(41,249)	(44,120)	(47,009)	(49,946)	(52,965)	(55,944)	(58,935)
8. Expenses paid	0	0	0	0	0	0	0
9. Net transfer in/(out) (including acquisitions/divestitures)	0	0	0	0	0	0	0
10. Plan curtailments	0	0	0	0	0	0	0
11. Plan settlements	0	0	0	0	0	0	0
12. Benefit obligation at end of year	1,367,343	1,355,418	1,136,302	1,004,827	1,040,676	1,012,696	951,430
B. Change in plan assets							
1. Fair value of plan assets at beginning of year	0	0	0	0	0	0	0
2. Expected return on plan assets	0	0	0	0	0	0	0
3. Actuarial gains/(losses) on plan assets	0	0	0	0	0	0	0
4. Employer contributions	41,249	44,120	47,009	49,946	52,965	55,944	58,935
5. Member contributions	0	0	0	0	0	0	0
6. Benefits paid from plan/company	(41,249)	(44,120)	(47,009)	(49,946)	(52,965)	(55,944)	(58,935)
7. Expenses paid	0	0	0	0	0	0	0
8. Plan settlements	0	0	0	0	0	0	0
9. Net transfer in/(out) (including acquisitions/divestitures)	0	0	0	0	0	0	0
10. Fair value of plan assets at end of year	0	0	0	0	0	0	0
C. Amounts recognized in the balance sheet							
1. Present value of obligations	1,367,343	1,355,418	1,136,302	1,004,827	1,040,676	1,012,696	951,430
2. Fair value of plan assets	0	0	0	0	0	0	0
3. Surplus (deficit) for funded plans	(1,367,343)	(1,355,418)	(1,136,302)	(1,004,827)	(1,040,676)	(1,012,696)	(951,430)
4. Unrecognized net actuarial losses (gains)	305,395	226,850	(51,503)	(225,636)	(215,206)	(269,611)	(349,665)
5. Unrecognized past service cost (benefit)	1,319	0	0	0	0	0	0
6. Cumulative employer contributions in excess of net periodic cost	(1,060,629)	(1,128,568)	(1,187,805)	(1,230,464)	(1,255,883)	(1,282,307)	(1,301,095)
Annual charges to OCI							
- Net actuarial gains (losses) incurred in year	4,331	64,490	270,744	174,133	0	63,666	94,083
- Past service credits (costs) incurred in year	0	0	0	0	0	0	0
Sub-total	4,331	64,490	270,744	174,133	0	63,666	94,083
LESS							
- Net actuarial gains (losses) amortized in year	(16,143)	(14,055)	(7,609)	0	10,430	9,262	14,028
- Past service credits (costs) amortized in year	(2,632)	(1,319)	0	0	0	0	0
Sub-total	(18,775)	(15,374)	(7,609)	0	10,430	9,262	14,028
Credit (charge) to OCI in year	23,106	79,864	278,353	174,133	(10,430)	54,404	80,055
Amounts recognized in Accumulated Comprehensive Income (Loss)							
- AOCI(L)	(306,714)	(226,850)	51,503	225,636	215,206	269,611	349,665
- Accumulated contributions in excess of net periodic benefit cost	(1,060,629)	(1,128,568)	(1,187,805)	(1,230,464)	(1,255,883)	(1,282,307)	(1,301,095)
- Net amount recognized in statement of financial position	(1,367,343)	(1,355,418)	(1,136,302)	(1,004,827)	(1,040,676)	(1,012,696)	(951,429)
D. Components of pension cost							
Amounts recognized in profit and loss statement							
1. Current service cost	34,644	34,592	33,768	24,457	21,336	21,801	21,426
2. Interest cost	56,761	62,094	64,869	68,147	67,478	69,829	70,326
3. Expected return on plan assets	0	0	0	0	0	0	0
4. Amortization of past service cost	2,632	1,319	0	0	0	0	0
5. Amortization of net (gain) loss	16,143	14,055	7,609	0	(10,430)	(9,262)	(14,028)
6. Curtailment (gain) / loss recognized	0	0	0	0	0	0	0
7. Settlement (gain) / loss recognized	0	0	0	0	0	0	0
8. Total net periodic benefit cost recognized in the P&L account	110,180	112,060	106,246	92,604	78,384	82,368	77,724
E. Gain/loss Amortization							
MV assets (BOY)	0	0	0	0	0	0	0
PBO (BOY)	1,321,517	1,367,343	1,355,418	1,136,302	1,004,827	1,040,676	1,012,696
Corridor	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cumulative (gains)/losses (BOY)	325,869	305,395	226,850	(51,503)	(225,636)	(215,206)	(269,611)
(Gains)/losses subject to amortization	325,869	305,395	226,850	(51,503)	(225,636)	(215,206)	(269,611)
EARSL	24.00	24.00	24.00	24.00	24.00	24.00	24.00
Amortization of (gains)/losses	16,143	14,055	7,609	0	(10,430)	(9,262)	(14,028)
F. Net Asset/Liability Reconciliation							
1. Net asset (liability) (BOY)	(991,698)	(1,060,629)	(1,128,568)	(1,187,805)	(1,230,464)	(1,255,883)	(1,282,307)
2. Pension expense recognised in P&L in the financial year	110,180	112,060	106,246	92,604	78,384	82,368	77,724
3. Employer contributions made in the financial year	41,249	44,120	47,009	49,946	52,965	55,944	58,935
4. Benefits paid directly by company in the financial year	0	0	0	0	0	0	0
5. Net transfer in/(out) (including the effect of any acquisitions/divestitures)	0	0	0	0	0	0	0
6. Net asset (liability) as of end of year (1)-(2)+(3)+(4)+(5)	(1,060,629)	(1,128,568)	(1,187,805)	(1,230,464)	(1,255,883)	(1,282,307)	(1,301,095)
G. Assumptions							
Discount rate (beginning of year)	4.25%	4.50%	4.75%	6.00%	6.75%	6.75%	7.00%
Salary scale (beginning of year)	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Discount rate (end of year)	4.50%	4.75%	6.00%	6.75%	6.75%	7.00%	7.25%
Salary scale (end of year)	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%

Hydro One Inc. Non-Pension Post Employment Benefits

Appendix B.4

Projected 2013 Accounting Under US GAAP

Figures in $thousands	Projections 2013	2014	2015	2016	2017	2018	2019
A. Change in benefit obligation							
1. Benefit obligation at beginning of year	40,876	38,799	36,530	32,296	28,923	26,352	23,733
2. Current service cost	3,332	3,325	3,320	3,145	3,056	3,092	3,145
3. Interest cost	1,668	1,668	1,648	1,816	1,805	1,625	1,495
4. Plan participants' contributions	0	0	0	0	0	0	0
5. Amendments	0	0	0	0	0	0	0
6. Actuarial (gains) / losses	(491)	(475)	(2,208)	(1,124)	0	325	218
7. Benefits paid from plan/company	(6,586)	(6,787)	(6,994)	(7,210)	(7,432)	(7,661)	(7,898)
8. Expenses paid	0	0	0	0	0	0	0
9. Net transfer in/(out) (including acquisitions/divestitures)	0	0	0	0	0	0	0
10. Plan curtailments	0	0	0	0	0	0	0
11. Plan settlements	0	0	0	0	0	0	0
12. Benefit obligation at end of year	38,799	36,530	32,296	28,923	26,352	23,733	20,693
B. Change in plan assets							
1. Fair value of plan assets at beginning of year	0	0	0	0	0	0	0
2. Expected return on plan assets	0	0	0	0	0	0	0
3. Actuarial gains/(losses) on plan assets	0	0	0	0	0	0	0
4. Employer contributions	6,586	6,787	6,994	7,210	7,432	7,661	7,898
5. Member contributions	0	0	0	0	0	0	0
6. Benefits paid from plan/company	(6,586)	(6,787)	(6,994)	(7,210)	(7,432)	(7,661)	(7,898)
7. Expenses paid	0	0	0	0	0	0	0
8. Plan settlements	0	0	0	0	0	0	0
9. Net transfer in/(out) (including acquisitions/divestitures)	0	0	0	0	0	0	0
10. Fair value of plan assets at end of year	0	0	0	0	0	0	0
C. Amounts recognized in the balance sheet							
1. Present value of obligations	38,799	36,530	32,296	28,923	26,352	23,733	20,693
2. Fair value of plan assets	0	0	0	0	0	0	0
3. Surplus (deficit) for funded plans	(38,799)	(36,530)	(32,296)	(28,923)	(26,352)	(23,733)	(20,693)
4. Unrecognized net actuarial losses (gains)	0	0	0	0	0	0	0
5. Unrecognized past service cost (benefit)	0	0	0	0	0	0	0
6. Cumulative employer contributions in excess of net periodic cost	(38,799)	(36,530)	(32,296)	(28,923)	(26,352)	(23,733)	(20,693)
Annual charges to OCI							
- Net actuarial gains (losses) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
- Past service credits (costs) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
LESS							
- Net actuarial gains (losses) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
- Past service credits (costs) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Credit (charge) to OCI in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Amounts recognized in Accumulated Comprehensive Income (Loss)							
- AOCI(L)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
- Accumulated contributions in excess of net periodic benefit cost	(38,799)	(36,530)	(32,296)	(28,923)	(26,352)	(23,733)	(20,693)
- Net amount recognized in statement of financial position	(38,799)	(36,530)	(32,296)	(28,923)	(26,352)	(23,733)	(20,693)
D. Components of pension cost							
Amounts recognized in profit and loss statement							
1. Current service cost	3,332	3,325	3,320	3,145	3,056	3,092	3,145
2. Interest cost	1,668	1,668	1,648	1,816	1,805	1,625	1,495
3. Expected return on plan assets	0	0	0	0	0	0	0
4. Amortization of past service cost	0	0	0	0	0	0	0
5. Amortization of net (gain) loss	(491)	(475)	(2,208)	(1,124)	0	325	218
6. Curtailment (gain) / loss recognized	0	0	0	0	0	0	0
7. Settlement (gain) / loss recognized	0	0	0	0	0	0	0
8. Total net periodic benefit cost recognized in the P&L account	4,509	4,518	2,760	3,837	4,861	5,042	4,858
E. Gain/loss Amortization							
MV assets (BOY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PBO (BOY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Corridor	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cumulative (gains)/losses (BOY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
(Gains)/losses subject to amortization	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EARSL	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Amortization of (gains)/losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A
F. Net Asset/Liability Reconciliation							
1. Net asset (liability) (BOY)	(40,876)	(38,799)	(36,530)	(32,296)	(28,923)	(26,352)	(23,733)
2. Pension expense recognised in P&L in the financial year	4,509	4,518	2,760	3,837	4,861	5,042	4,858
3. Employer contributions made in the financial year	6,586	6,787	6,994	7,210	7,432	7,661	7,898
4. Benefits paid directly by company in the financial year	0	0	0	0	0	0	0
5. Net transfer in/(out) (including the effect of any acquisitions/divestitures)	0	0	0	0	0	0	0
6. Net asset (liability) as of end of year (1)-(2)+(3)+(4)+(5)	(38,799)	(36,530)	(32,296)	(28,923)	(26,352)	(23,733)	(20,693)
G. Assumptions							
Discount rate (beginning of year)	4.25%	4.50%	4.75%	6.00%	6.75%	6.75%	7.00%
Salary scale (beginning of year)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Discount rate (end of year)	4.50%	4.75%	6.00%	6.75%	6.75%	7.00%	7.25%
Salary scale (end of year)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Prepared by Mercer (Canada) Limited

Hydro One Inc. Supplemental Pension Plan (SPS / DSPS)

APPENDIX A

Projected 2013 to 2019 Accounting Under US GAAP

Figures in $thousands	Projections						
	2013	2014	2015	2016	2017	2018	2019
A. Change in benefit obligation							
1. Benefit obligation at beginning of year	90,637	89,362	88,995	79,008	73,002	72,752	75,191
2. Current service cost	1,931	1,816	1,726	1,413	1,216	1,155	1,178
3. Interest cost	3,875	4,260	4,455	4,723	4,889	5,042	5,193
4. Plan participants' contributions	0	0	0	0	0	0	0
5. Amendments	0	0	0	0	0	0	0
6. Actuarial (gains) / losses	(4,300)	(3,460)	(12,939)	(8,718)	(2,774)	0	(2,829)
7. Benefits paid from plan/company	(2,781)	(2,983)	(3,229)	(3,424)	(3,581)	(3,758)	(4,362)
8. Expenses paid	0	0	0	0	0	0	0
9. Net transfer in/(out) (including acquisitions/divestitures)	0	0	0	0	0	0	0
10. Plan curtailments	0	0	0	0	0	0	0
11. Special Termination Benefits	0	0	0	0	0	0	0
12. Benefit obligation at end of year	89,362	88,995	79,008	73,002	72,752	75,191	74,371
B. Change in plan assets							
1. Fair value of plan assets at beginning of year	3,597	3,938	4,277	4,578	4,856	5,133	5,419
2. Expected return on plan assets	0	0	0	0	0	0	0
3. Actuarial gains/(losses) on plan assets	0	0	0	0	0	0	0
4. Employer contributions - benefits paid	2,781	2,983	3,229	3,424	3,581	3,758	4,362
5. Employer contributions - letter of credit fee	682	679	603	557	555	574	568
6. Member contributions	0	0	0	0	0	0	0
7. Benefits paid from plan/company	(2,781)	(2,983)	(3,229)	(3,424)	(3,581)	(3,758)	(4,362)
8. Expenses paid	(341)	(340)	(302)	(279)	(278)	(288)	(285)
9. Plan settlements	0	0	0	0	0	0	0
10. One -time adjustment	0	0	0	0	0	0	0
11. Fair value of plan assets at end of year	3,938	4,277	4,578	4,856	5,133	5,419	5,702
C. Amounts recognized in the balance sheet							
1. Present value of obligations	89,362	88,995	79,008	73,002	72,752	75,191	74,371
2. Fair value of plan assets	3,938	4,277	4,578	4,856	5,133	5,419	5,702
3. Surplus (deficit) for funded plans	(85,424)	(84,718)	(74,430)	(68,146)	(67,619)	(69,772)	(68,669)
4. Unrecognized net actuarial losses (gains)	5,530	1,567	(11,514)	(19,185)	(20,215)	(18,377)	(19,535)
5. Unrecognized past service cost (benefit)	499	214	20	0	0	0	0
6. Cumulative employer contributions in excess of net periodic cost	(79,395)	(82,937)	(85,924)	(87,331)	(87,834)	(88,149)	(88,204)
Annual charges to OCI							
- Net actuarial gains (losses) incurred in year	4,300	3,460	12,939	8,718	2,774	0	2,829
- Past service credits (costs) incurred in year	0	0	0	0	0	0	0
Sub-total	4,300	3,460	12,939	8,718	2,774	0	2,829
LESS							
- Net actuarial gains (losses) amortized in year	(983)	(503)	(142)	1,047	1,744	1,838	1,671
- Past service credits (costs) amortized in year	(285)	(285)	(194)	(20)	0	0	0
Sub-total	(1,268)	(788)	(336)	1,027	1,744	1,838	1,671
Credit (charge) to OCI in year	5,568	4,248	13,275	7,691	1,030	(1,838)	1,158
Amounts recognized in Accumulated Comprehensive Income (Loss)							
- AOCI(L)	(6,029)	(1,781)	11,494	19,185	20,215	18,377	19,535
- Accumulated contributions in excess of net periodic benefit cost	(79,395)	(82,937)	(85,924)	(87,331)	(87,834)	(88,149)	(88,204)
- Net amount recognized in statement of financial position	(85,424)	(84,718)	(74,430)	(68,146)	(67,619)	(69,772)	(68,669)
D. Components of pension cost							
Amounts recognized in profit and loss statement							
1. Current service cost	1,931	1,816	1,726	1,413	1,216	1,155	1,178
2. Expected letter of credit fee	341	340	302	279	278	288	285
3. Interest cost	3,875	4,260	4,455	4,723	4,889	5,042	5,193
4. Expected return on plan assets	0	0	0	0	0	0	0
5. Amortization of past service cost	285	285	194	20	0	0	0
6. Amortization of net (gain) loss	983	503	142	(1,047)	(1,744)	(1,838)	(1,671)
7. Curtailment (gain) / loss recognized	0	0	0	0	0	0	0
8. One -time adjustment	0	0	0	0	0	0	0
9. Special Termination Benefit	0	0	0	0	0	0	0
10. Total net periodic benefit cost recognized in the P&L account	7,415	7,204	6,819	5,388	4,639	4,647	4,985
E. Gain/loss Amortization							
Cumulative (gains)/losses (BOY)	10,813	5,530	1,567	(11,514)	(19,185)	(20,215)	(18,377)
EARSL	11.00	11.00	11.00	11.00	11.00	11.00	11.00
Amortization of (gains)/losses	983	503	142	(1,047)	(1,744)	(1,838)	(1,671)
F. Net Asset/Liability Reconciliation							
1. Net asset (liability) (BOY)	(75,443)	(79,395)	(82,937)	(85,924)	(87,331)	(87,834)	(88,149)
2. Pension expense recognised in P&L in the financial year	7,415	7,204	6,819	5,388	4,639	4,647	4,985
3. Employer contributions made in the financial year	682	679	603	557	555	574	568
4. Benefits paid directly by company in the financial year	2,781	2,983	3,229	3,424	3,581	3,758	4,362
5. Net transfer in/(out) (including the effect of any acquisitions/divestitures)	0	0	0	0	0	0	0
6. Net liability (asset) as of end of year (1)-(2)+(3)+(4)+(5)	(79,395)	(82,937)	(85,924)	(87,331)	(87,834)	(88,149)	(88,204)
G. Gain/loss Amortization							
Discount rate (beginning of year)	4.25%	4.75%	5.00%	6.00%	6.75%	7.00%	7.00%
Salary scale (beginning of year)	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Expected return on assets in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Discount rate (end of year)	4.75%	5.00%	6.00%	6.75%	7.00%	7.00%	7.25%
Salary scale (end of year)	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%

Canadian Manufacturers & Exporters (CME) INTERROGATORY #6

Interrogatory

At Exhibit A, Tab 16, Schedule 8, pages 3 and 4 of the Information Package, there is a Table showing Actual and Budget Capital Expenditures covering the period 2010 to 2019. Further details of Capital Expenditures are found at Exhibit D1, Tab 3, Schedules 1 to 4. These numbers include capitalized overheads and capitalized interest. Please provide the following additional information:

(a) A revised spreadsheet in the format of Exhibit A, Tab 16, Schedule 8 which will include for the years 2010, 2011, 2012 and 2013 two (2) additional columns for each year which will show:
    (i) Hydro One's initial budget for each line item;
    (ii) The Board approved amount; and
    (iii)The actual amount for each year.

(b) For 2014, show Hydro One's initial budget, the Board approved amount and the projected actual based on six (6) months actual and six (6) months forecast.

(c) Using the spreadsheet to be provided in response to sub-paragraphs (a) and (b), please present the numbers shown therein with the capitalized overheads and capitalized interest amounts unbundled from the other numbers.

Response

(a) Please see table below for the Board approved amount and the actual amount for the years 2010 to 2013. For historical years, the original budget amount was the same as the proposed amount filed in the applications prior to the Boards' decisions.

	Proposed 2010	Approved 2010	Actual 2010	Proposed 2011	Approved 2011	Actual 2011	Proposed 2012	Approved 2012	Actual 2012	Proposed 2013	Approved 2013	Actual 2013
Transmission Capital ($ millions)												
Sustaining Capital												
Transmission Stations												
Circuit Breakers	21.1	21.1	29.6	23.6	23.0	29.2	24.9	24.3	11.2	25.0	29.7	23.4
Station Reinvestment	43.5	43.5	17.9	84.0	81.1	36.4	84.7	81.8	62.1	172.9	124.0	89.0
Power Transformers *(including Strategic Transformers)*	62.5	62.5	106.8	63.5	60.6	81.1	65.7	62.7	78.4	93.8	111.4	87.0
Other Power Equipment	21.6	21.6	13.9	19.6	19.0	16.2	21.2	20.5	28.3	22.3	22.3	26.5
Ancillary Systems	64.9	17.2	13.3	18.0	17.5	13.5	18.1	17.7	16.4	19.9	22.6	15.6
Stations Environment	17.2	3.7	4.0	8.4	8.3	7.0	8.5	8.4	7.6	11.6	10.9	6.6
Protection, Control, Monitoring, and Telecommunications	13.1	64.9	66.8	93.8	91.8	61.6	107.5	105.4	95.0	118.8	117.8	84.4
Transmission Site Facilities	3.7	4.4	32.3	26.5	17.9	17.8	26.4	17.7	23.4	30.0	23.6	22.9
Total Transmission Stations Capital	247.6	238.9	284.7	337.3	319.4	262.7	357.0	338.5	322.5	494.2	462.4	355.3
Transmission Lines												
Overhead Lines Refurbishment and Component Replacement	53.4	53.4	54.0	55.6	54.0	52.4	57.6	56.0	55.5	70.6	71.1	74.2
Transmission Lines Reinvestment	16.1	16.1	16.2	8.9	8.7	17.1	7.3	7.1	9.7	37.9	18.3	17.8
Underground Lines Cable Refurbishment & Replacement	4.4	4.4	1.4	22.2	22.1	1.0	21.6	21.5	1.6	32.2	32.6	32.8
Total Transmission Lines Capital	74.0	74.0	71.6	86.7	84.8	70.6	86.5	84.6	66.8	140.7	122.0	124.8
Total Sustaining Capital	**321.6**	**312.9**	**356.3**	**424.0**	**404.2**	**333.2**	**443.4**	**423.1**	**389.3**	**634.9**	**584.3**	**480.0**

	Proposed 2010	Approved 2010	Actual 2010	Proposed 2011	Approved 2011	Actual 2011	Proposed 2012	Approved 2012	Actual 2012	Proposed 2013	Approved 2013	Actual 2013
Development Capital												
Inter Area Network Transfer Capability	509.6	497.1	392.8	307.9	319.8	269.1	139.3	169.4	117.8	148.6	102.0	41.7
Local Area Supply Adequacy	50.4	50.4	58.5	150.5	145.8	57.5	101.4	98.3	86.4	97.2	87.9	54.0
Load Customer Connection	58.1	54.1	33.8	81.8	78.0	51.1	84.7	80.7	60.6	45.2	24.1	24.7
Generator Customer Connection	23.1	23.1	3.9	0.0	0.0	0.1	0.0	0.0	-0.2	0.5	5.7	-0.3
Performance Enhancement & Risk Mitigation	14.2	14.2	19.6	24.0	23.0	19.0	7.2	6.9	18.3	32.5	34.2	27.7
TS Upgrades to Facilities Distribution Generation	0.0	0.0	12.5	33.8	33.8	10.3	81.4	81.4	33.1	19.2	17.1	13.9
P&C Enablement for Generation Connections	0.0	0.0	2.1	11.4	1.2	3.1	36.0	5.3	2.5	2.8	0.5	1.2
Smart Grid	3.4	3.4	0.0	7.8	7.8	5.8	6.8	6.8	10.7	2.0	6.2	8.8
Total Development Capital	**658.8**	**642.3**	**523.1**	**617.2**	**609.4**	**415.9**	**456.8**	**448.8**	**329.4**	**348.0**	**277.8**	**171.7**

Operations Capital												
Grid Operating and Control Facilities	9.8	9.8	3.6	22.6	22.2	3.7	18.5	18.1	3.4	15.1	12.9	11.3
Operating Infrastructure	19.1	19.1	4.0	21.7	21.3	5.0	38.9	38.2	11.9	32.4	25.6	6.4
Total Operations Capital	**28.9**	**28.9**	**7.6**	**44.3**	**43.5**	**8.8**	**57.4**	**56.4**	**15.2**	**47.5**	**38.5**	**17.7**
Capital Common Corporate Costs and Other Costs												
Transport, Work & Service Equipment	16.2	16.2	17.1	21.6	20.0	13.1	17.0	15.7	14.6	16.7	20.7	18.8
Information Technology (including Cornerstone)	40.6	40.6	24.7	20.9	17.9	32.9	14.6	12.5	30.5	30.1	30.8	22.9
Facilities & Real Estate*	7.9	16.6	7.6	23.9	30.0	7.8	19.1	25.9	11.6	25.0	29.2	7.4
Other (including CDM)	0.1	0.1	-0.2	0.0	-3.2	-1.5	0.0	-2.1	-14.7	0.3	0.0	0.0
Total Capital Common Corporate Costs and Other Costs	**64.9**	**73.5**	**49.1**	**66.3**	**66.7**	**52.3**	**50.6**	**53.1**	**42.1**	**72.1**	**80.6**	**49.1**
Total Transmission Capital	**1074.1**	**1,057.6**	**936.1**	**1,151.8**	**1,123.5**	**810.2**	**1,008.3**	**981.3**	**776.0**	**1,102.4**	**981.3**	**718.5**

*Security and Infrastructure investments had been included in Sustaining Capital in the proposed amount, instead of in Facilities & Real Estate as in the Approved and Actual amounts.

(b) Please see the table below for the 2014 data. The current forecast based on the most recent actual results is the same as what has been provided in the information package in May.

Transmission Capital ($ millions)

	Forecast	Initial Budget/ Approved
Sustaining Capital		
Transmission Stations		
Circuit Breakers	23.0	23.1
Station Reinvestment	157.6	179.8
Power Transformers *(including Strategic Transformers)*	84.0	104.6
Other Power Equipment	24.8	22.7
Ancillary Systems	24.2	25.7
Stations Environment	8.3	6.4
Protection, Control, Monitoring, and Telecommunications	116.9	113.0
Transmission Site Facilities	20.1	19.6
Total Transmission Stations Capital	458.8	494.9
Transmission Lines		
Overhead Lines Refurbishment and Component Replacement	67.9	65.4
Transmission Lines Reinvestment	33.2	43.8
Underground Lines Cable Refurbishment & Replacement	19.4	47.9
Total Transmission Lines Capital	120.5	157.2
Total Sustaining Capital	**579.3**	**652.1**
Development Capital		
Inter Area Network Transfer Capability	59.3	201.8
Local Area Supply Adequacy	70.9	95.4
Load Customer Connection	22.2	36.8
Generator Customer Connection	9.7	3.3
Performance Enhancement & Risk Mitigation	23.7	8.1
TS Upgrades to Facilities Distribution Generation	0.3	0.0
P&C Enablement for Generation Connections	3.9	3.5
Smart Grid	5.6	5.5
Total Development Capital	**195.6**	**354.4**
Operations Capital		
Grid Operating and Control Facilities	18.1	13.7
Operating Infrastructure	20.5	29.0

Total Operations Capital	**38.5**	**42.7**
Capital Common Corporate Costs and Other Costs		
Transport, Work & Service Equipment	22.9	20.3
Information Technology (including Cornerstone)	34.6	20.9
Facilities & Real Estate	28.3	29.8
Other (including CDM)	0.0	0.0
Total Capital Common Corporate Costs and Other Costs	**85.8**	**71.0**
Total Transmission Capital	**899.2**	**1,120.4**

(c) The capitalized overhead rates are developed with the support of Black & Veatch using OEB-approved methodology. Capitalized interest rates are also developed according to OEB-approved methodology. Both interest and overhead capitalization rates are applied on a monthly basis to capital expenditures. Unbundling of these amounts would be very difficult.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #7

Interrogatory

Table 1 in Exhibit D1, Tab 1, Schedule 2, page 1 presents Actual and Projected Actual In-Service Capital Additions for 2013 and 2014 compared to the OEB approved amounts. Please provide the following additional information:

(a) Please broaden this Table to include the years 2010, 2011 and 2012 to show for each of the years 2010 to 2014 inclusive the following information:
   (i) Hydro One's initially budgeted In-Service Capital Additions;
   (ii) OEB approved amounts; and
   (iii)ISA Actuals

Response

a) Please see the table on the next page for the requested information.

In-Service Capital Additions 2010 - 2016 ($ M)

	2010			2011			2012			2013			2014			Test Years	
	Proposed	OEB Approved	ISA Actuals	Proposed	OEB Approved	ISA Actuals	Proposed	OEB Approved	ISA Actuals	Proposed	OEB Approved	ISA Actuals	Proposed	OEB Approved	Bridge Forecast	2015	2016
Sustaining	319.5	319.5	318.7	366.8	363.0	350.6	399.4	394.5	351.6	497.3	443.3	403.8	701.1	701.1	588.4	572.2	480.9
Development	527.6	527.6	425.7	397.8	378.2	374.6	1,083.4	1,074.8	793.8	301.8	261.8	231.7	205.8	205.8	177.3	134.7	119.4
Operations	24.2	24.2	18.0	42.3	41.0	6.8	54.7	52.7	10.6	45.1	15.1	5.9	48.0	48.0	19.0	50.4	10.0
Common & Other	90.5	90.5	71.6	63.7	52.3	61.8	81.3	69.9	43.5	59.8	64.0	62.4	68.0	68.0	78.7	64.1	63.1
Total	**961.8**	**961.8**	**834.1**	**870.6**	**834.4**	**793.7**	**1,618.8**	**1,591.9**	**1,199.4**	**904.1**	**784.2**	**703.8**	**1,023.1**	**1,023.1**	**863.3**	**821.3**	**673.3**

Canadian Manufacturers & Exporters (CME) INTERROGATORY #8

Interrogatory

Slide 8 in the June 25, 2014 Presentation and Table 1 at Exhibit C1, Tab 2, Schedule 1 presents OM&A information in summary form. Please provide the following additional information:

(a) Please broaden the Presentation in Table 1 to include the year 2010 and to include for each of the years 2010 to 2014 inclusive the following information:
   (i) Hydro One's initial budget;
   (ii) OEB approved amounts; and
   (iii) Actuals for 2010 to 2013 inclusive and projected Actuals for 2014.

(b) Please explain the circumstances which gave rise to the $43M property tax credit in 2013 and provide the facts upon which the characterization of this amount as a "one-time" credit are based.

(c) When did Hydro One first become aware of this potential tax credit and when was the tax credit claim first asserted?

Response

(a) Please see table below for the Board approved amount and the actual amount for the years 2010 to 2013, as well as forecast amount for 2014. For historical years, the Board approved amount became the budgeted amount for Hydro One once the Board issued its decisions. Proposed amount prior to the Board's approval has been included in the table below for each of the years.

	2010			2011			2012			2013			2014		
	Proposed	Approved	Actual	Proposed	Approved	Actual	Proposed	Approved	Actual	Proposed	Approved	Actual	Proposed	Approved	Forecast
Sustaining	240.1	225.1	204.2	233	227.7	227.6	243.1	237.5	204.7	233.5	235.7	221	237.6	246.5	236.2
Development	16.3	13.1	15.7	18.2	18.1	12.6	18.9	18.8	8.5	13.4	13.7	8.6	14.4	14.7	12.9
Operations	53.7	17.5	58.1	66.3	61.2	57.3	68.2	62.4	54.8	64.3	57.7	56.7	66.4	58	57.4
Customer Care	-	1.5	1.5	46.9	6.4	5.2	46.4	6.7	4.4	1.3	4.9	5.3	1.4	4.7	5.8
Common Corporate and Other OM&A	66.4	97.1	74.8	1.1	34.5	44.2	1.2	29.4	80.7	69.5	61.9	75.8	67.6	59	70.6
Property Taxes & Rights Payments	73.1	71.8	66.5	70.8	70.8	67.5	72.2	72.2	62.1	71.5	66	21.2	72.3	66.8	65.6
Total	449.7	426.2	420.8	436.3	418.8	414.5	450	427.1	415.2	453.3	440	388.6	459.7	449.8	448.6

(b) Under the Electricity Act, 1998, Hydro One Networks Inc. is required to make annual payments in lieu of property taxes on its transformer and distribution stations throughout the province. For over ten years, the Company has been working with the Municipal Property Assessment Corporation (MPAC) and the Ministry of Finance (MoF) to correct assessment valuations associated with the properties.

A legislative regulation (Ontario Regulation 423/11 made under the Electricity Act, 1998) was filed by the MoF on August 31, 2011, to reflect the assessment valuations for property tax years (1999-2011) on Hydro One Networks Inc.'s transformer station properties.

As a result of the amendment to the above regulation, Hydro One Networks Inc. filed a return for property tax year 2011 with the MoF before the required date of October 16, 2012. In January 2012, the Company filed returns for property tax years 1999 – 2010 with the MoF before the required date of January 31, 2012. The MoF accepted as filed Hydro One Networks Inc.'s proxy property tax returns for 1999-2010 property tax years as indicated in a letter dated March 8, 2013, in which the MoF also stated that the returns are still subject to audit.

Based on the MoF acceptance of Hydro One Networks Inc.'s property tax filing regarding outstanding liability for property tax years 1999-2012, total credit entries of approximately $43 million were recorded to OM&A in 2013.

(c) Hydro One became aware of this potential property tax credit in 2011. The property tax credit claim was first asserted in 2012.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #9

Interrogatory

(a) Please list and provide copies of all documents in Hydro One's possession pertaining to the benchmarking of any of the components of Transmission Capital and OM&A Expenditures.

(b) What weight, if any, did Hydro One place on benchmark information when budgeting its Capital and OM&A Expenditures for 2015 and 2016?

Response

(a) Hydro One did not benchmark any of the components of Capital and OM&A Expenditures in this proposed Transmission Rate Application.

(b) See above response for (a).

Canadian Manufacturers & Exporters (CME) INTERROGATORY #10

Interrogatory

(a) Please provide a copy of the Depreciation Study described in Exhibit C1, Tab 7, Schedule 1.

(b) The information at Exhibit C1, Tab 7, Schedule 1, page 2 indicates that depreciation expenses in 2015 will increase by about $17.7M, followed by a further $10.2M increase in 2016. In connection with this information, please advise whether the composite depreciation rate being claimed by Hydro One is increasing or decreasing and provide information in the format of Table 1 at Exhibit C1, Tab 7, Schedule 1, page 2 which will show the depreciation expenses based on an assumption that the Board's consideration of requests for changes in depreciation expenses will be deferred to Hydro One's 2017 Transmission Rates case.

Response

(a) The study requested has been provided as Attachment 1 to this interrogatory response.

(b) The depreciation expense between 2014 to 2015 increases by $27.7M and not $17.7M (from $360M to $387.7M as per Exhibit C1, Tab 7, Schedule 1.)

The depreciation rates have increased. The table below provides the new depreciation expense assuming that changes in depreciation rates are deferred to Hydro One's 2017 Transmission Rate case.

Description	Test	
	2015	**2016**
Depreciation On Fixed Assets	338.5	351.7
Less Capitalized Depreciation	-6.4	-6.7
Asset Removal Costs	38.1	33.7
Losses/(Gains) On Asset Disposition		
Total	**370.1**	**378.7**

2013 Depreciation Rate Review

hydro one

— Transmission Operations
— Common Operations

foster associates

CONTENTS

SECTION I

Executive Summary

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for Transmission and Common plant owned and operated by Hydro One Networks Inc. (Company or Hydro One Networks). Work on this review, conducted by Foster Associates, Inc. (Foster Associates), commenced in April 2013 and progressed through mid–August, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Rockville, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer applications for conducting depreciation and valuation studies.

PLANT ACCOUNT STRUCTURE

The hierarchical structure of the plant accounting records maintained by Hydro One Networks for major asset categories provides: a) Uniform System of Account (USoA) categories; b) cost of asset components (Category ID); and c) vintage identification (Asset ID).

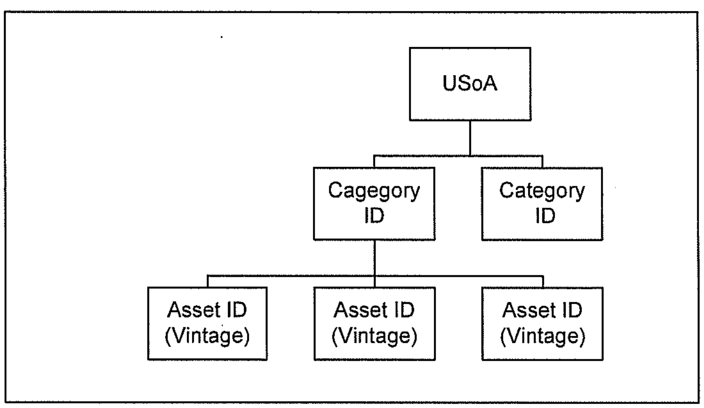


Fig. 1 Account Structure

The lowest level at which the installed cost of a property unit (*e.g.*, a single pole or transformer) can be estimated is by vintage year of placement within a Category ID. (The cost of a property unit within a vintage can be estimated by dividing the vintage cost by the recorded number of installed property units). A Category ID is an aggregation of vintage costs sharing common physical or functional attributes. All vintages of power transformers larger than 230 kV, for example, or all vintages of underground cable are classified in unique Category IDs. It is neither practical nor feasible, however, to estimate service lives and maintain accumulated depreciation reserves for each property unit.

CURRENT DEPRECIATION RATES

Depreciation rates currently used by Hydro One Networks for Transmission and Common operations were developed in a 2011 depreciation review conducted by Foster Associates. In EB–2010–0002 (Decision dated December 23, 2010), the Ontario Energy Board (OEB) accepted the depreciation expense flowing from the depreciation review for purposes of setting rates in the test year.

Life tables were constructed in the 2011 review for each USoA plant account for which retirements were recorded over the period 2000–2010. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

Absent the availability of sufficient retirement activity to conduct statistical service life studies, depreciation rates developed in the 2011 review were derived from a composite of parameters *(i.e.*, projection lives and projection curves) recommended by the former Ontario Hydro internal Depreciation Review Committee (DRC) for asset categories within a USoA category. The dominant projection curve and dollar–weighted average projection life (rounded to the nearest integer) of the constituent asset categories were selected to describe the forces of retirement acting upon a USoA plant account.[1]

2013 DEPRECIATION RATE REVIEW

The principal findings and recommendations of the Hydro One Networks 2013 Depreciation Rate Review are summarized in the Statements section of this re-

[1]In 1954, by joint agreement of the Engineering, Operations and Comptroller's Division of Ontario Hydro, average service lives were estimated for each of the Company's various plant accounts. The estimated lives were based on engineering/financial judgment and information gathered regarding service lives used by other utilities. Statistical studies based on survivor curves were introduced in 1959 to further improve the estimation of life expectancies. The DRC was established in 1973 to provide formal engineering review for various classes of assets. The role of the committee was expanded in 1975 to include responsibility for recommending service lives and service costs (*i.e.*, provisions for fixed asset removal costs) of all assets. The DRC annually reviewed the service lives of all major facilities and a selection of plant components, with the objective of reviewing all plant components at least once every five years. DRC recommendations were based on factors such as operating experience, retirement history, engineering judgment, expected regular maintenance and system requirements. The DRC review process was discontinued by Hydro One Networks in 1998.

port. Statement A provides a comparative summary of current and proposed annual depreciation rates for each USoA rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, and average remaining life. Statement E provides the computation of proposed USoA projection lives derived from an analysis of component category lives. A set of statements is included in this report for both Transmission (BU 210) and Common (BU 300) Operations.

Scope of Review

Principal activities undertaken in the 2013 review included:

- Collection of plant and reserve data;
- Reconciliation of assembled database to Company records;
- Discussions with Hydro One Networks plant accounting and operations personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

Depreciation System

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that produces acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for a group plant account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been adopted, Hydro One Networks is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the general plant amortization categories summarized in Table 1 below.

Account Number	Description	Amortization Period
A	B	C
1610	Computer Software	10 yrs.
1915	Office Furniture and Equipment	7 yrs.
1920	Computer Hardware - Minor	5 yrs.
1925	Computer Software - Major	6 yrs.
1935	Stores Equipment	8 yrs.
1940	Tools, Shop and Garage Equipment	6 yrs.
1945	Measuring and Testing Equipment	5 yrs.
1960	Miscellaneous Equipment	5 yrs.

Table 1. Amortization Accounts

With the exception of USoA Accounts 1610 and 1925, general plant amortization categories are only recorded in BU 300. Additionally, with the exception of Account 1925, currently approved amortization periods are retained for all amortization categories. The proposed amortization period for Account 1925 (Computer Software – Major) has been adjusted from ten to six years to more nearly align the amortization period with the Company's hardware/software refresh policy.

Recommended Depreciation Rates

Table 2 provides a summary of the changes in annual rates and accruals resulting from the 2013 review of Hydro One Networks' Transmission Operations (BU 210).

Function	Accrual Rate			2013 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	1.17%	1.17%	0.00%	$ 165,420	$ 165,420	$ -
Transmission	1.76%	1.80%	0.04%	203,680,864	207,507,776	3,826,912
General Plant	4.53%	5.25%	0.72%	39,046,484	45,209,101	6,162,617
Total	1.95%	2.03%	0.08%	$ 242,892,768	$ 252,882,297	$ 9,989,529

Table 2. Transmission Operations

The composite accrual rate recommended for Transmission Operations is 2.03 percent. The current equivalent rate is 1.95 percent. The recommended change in the composite rate is an increase of 0.08 percentage points.

A continued application of current rates would provide annualized depreciation expense of $242,892,768 compared with an annualized expense of $252,882,297 using the proposed rates. The resulting 2013 expense increase is $9,989,529.

Table 3 provides a summary of the changes in annual depreciation rates and accruals derived for the Company's Common Operations (BU 300).

	Accrual Rate			2013 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	9.28%	9.28%	0.00%	$33,865,737	$33,865,737	$0
General	6.28%	8.41%	2.13%	19,064,453	25,542,054	6,477,601
Total	7.91%	8.88%	0.97%	$52,930,190	$59,407,791	$6,477,601

Table 3. Common Operations

Adjustments recommended in the 2013 review produce a composite depreciation rate of 8.88 percent. Depreciation expense is currently accrued at an equivalent composite rate of 7.91 percent. The proposed change in the composite depreciation rate is, therefore, an increase of 0.97 percentage points.

A continued application of current rates would provide annualized depreciation expense of $52,930,190 compared with an annualized expense of $59,407,791 using the rates developed in the review. The increase for Common Operations proposed in the 2013 review is $6,477,601.

SECTION II

Study Procedure

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. The 2013 review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Networks for Transmission and Common Operations. The proposed rates are subject to approval by the Ontario Energy Board.

SCOPE

The steps involved in conducting the 2013 depreciation review can be grouped into four major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2013 review included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by Hydro One Networks provides aged transactions for all plant accounts.

Prior to 1998, plant accounting records were maintained in a legacy Fixed Asset Management System (FAMS) developed by Ontario Hydro. FAMS was replaced with an SAP system in 1998. The SAP system was replaced with a PeopleSoft asset accounting system in 2000. The PeopleSoft system was configured with the asset categories maintained in the SAP system and uploaded with age distributions of surviving plant at December 31, 1999.[2] The PeopleSoft system was replaced in August 2009 by an updated version of the SAP system.

Plant and reserve data used in conducting the 2013 depreciation review were assembled by Hydro One Networks personnel and coded by Foster Associates. Plant accounting transactions recorded between January 1, 2011 and December 31, 2012 were extracted from the SAP system, coded and appended to the database used in conducting the 2011 review. An additional dataset of category plant balances at December 31, 2012 was assembled and reconciled to aggregate USoA balances. (See Statement E).

Age distributions of surviving plant (*i.e.*, plant surviving by vintage year of placement) at December 31, 2012 were derived by Foster Associates from the vintaged plant transactions and reconciled to age distributions provided by Hydro One Networks. The complexity of the process through which the database was compiled and mapped to USoA plant categories prevented Foster Associates from reconciling the database to any public reports of Hydro One Networks. The integrity of the assembled database, however, was confirmed by the Company.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the ex-

[2]In 2003, Hydro One undertook a two–phase project to a) map asset categories maintained in PeopleSoft to USoA plant classifications; and b) align quantities maintained in a Power System Data Base (PSDB) to the re–mapped USoA account classifications. The PSDB provides property unit identification and quantities associated with investments maintained in PeopleSoft. Asset categories maintained in SAP were not mapped to USoA plant account classifications. This limitation prohibited using pre–2000 plant accounting activity in the 2011 and 2013 depreciation reviews.

pected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered predictive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each retirement unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was employed in this review. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this review. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

As noted above, the database for Hydro One Networks contains plant accounting transactions for activity years 2000–2012. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[3] A similar limitation applies to the database of Hydro One Networks which contains minimal retirement activity during the available activity years. Retirements must be sufficiently distributed across vintages within these years in order to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each USoA plant account for which retirements were recorded over the period 2000–2012. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and inde-

[3]Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

terminate measurements of service life. These results were directly attributable to an insufficient distribution of retirements over the available band of activity years.

As was noted in the 2011 review, limitations in conducting life analyses were also imposed by vintage years "banded" by the Company in 1992 and again in 1998 when age distributions from a Fixed Asset Management System (FAMS) were uploaded to SAP. All pre–1950 vintages were assigned a vintage year of 1950. Plant installed between 1951 and 1955 was assigned a vintage year of 1955. Similarly, plant installed during the intervals 1956–1960, 1961–1965 and 1966–1970 were assigned vintage years 1960, 1965 and 1970, respectively. Although discontinued in 1971, the banding of pre–1970 vintages will continue to produce unreliable life indications until most of the earlier vintages have been retired from service.

Pending the availability of sufficient retirement activity to conduct service life studies, it is the opinion of Foster Associates that a composite of the parameters estimated for the asset categories recorded in a USoA account provides the best available estimate of service life statistics for the current depreciation review.

CLASS/CATEGORY SERVICE LIVES

Class categories used in the 2013 review are those established in 2008 in preparation for implementation of International Financial Reporting Standards (IFRS). While Hydro One Networks has received an exemption from an otherwise mandatory adoption of IFRS for rate regulated entities, the Company intends to continue maintaining category classifications for engineering operations and business planning purposes.

The review of category lives undertaken in the current study included onsite meetings with Company engineers, accountants and other subject matter experts having managerial responsibilities for the assets under review. Meetings of the project team were facilitated by Foster Associates. Discussions were held with representatives from planning, operations, maintenance, information technology and facilities to assess the reasonableness of proposed category lives within their respective areas of expertise. Consideration was also given to the range of service lives recommended in the Asset Amortization Study prepared for the Ontario Energy Board by Kinectrics Inc.

USOA SERVICE LIVES

Proposed projection lives for USoA categories were derived from harmonic weighting of the constituent category lives recommended by the project team. Iowa survivor curves considered descriptive of the forces of retirement acting upon each USoA category were selected by Foster Associates based on experience and an understanding of the parametric form of the associated probability density functions. Projection lives and projection curves recommended for all depreciable

USoA categories are summarized in Statement E.

Depreciation Reserve Analysis

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

Survivor curves used in the calculation of a theoretical depreciation reserve are intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measurement of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has not been considered in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for Hydro One Networks at this time. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current review) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

With the exception of amortizable categories in which theoretical or computed reserves replace recorded reserves, all remaining reserves were redistributed by multiplying the calculated reserve for each USoA primary account by the ratio of the sum of recorded reserves to the sum of calculated reserves. The sum of redistributed reserves is, therefore, equal to the sum of recorded depreciation reserves before the redistribution.

Statement C provides a comparison of recorded, computed and rebalanced reserves for Transmission Operations (BU 210) at December 31, 2012. The recorded reserve was $4,549,856,174 or 36.6 percent of the depreciable plant investment. The corresponding computed reserve is $4,066,335,584 or 32.7 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $483,520,590 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

Statement C also provides a comparison of recorded, computed and rebalanced reserves for Common Operations (BU 300) at December 31, 2012. The recorded reserve was $339,476,788, or 50.8 percent of the depreciable plant investment. The corresponding computed reserve is $308,958,980 or 46.2 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $30,517,808 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will provide or the amount of potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. Broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2013 review were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. It is the opinion of Foster Associates that this system will remain appropriate for Hydro One Networks, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting for these rate categories relieves Hydro One Networks of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

SECTION III

Statements

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life statistics recommended for Hydro One Networks Transmission and Common Operations. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2013 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2012.
- Statement D provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, and average remaining life.
- Statement E displays the computation of proposed USoA projection lives derived from recommended Category ID lives.

Current depreciation accruals shown on Statements B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by Hydro One Networks for the mix of investments recorded on December 31, 2012. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio}}{\text{Remaining Life}}.$$

Statements A through E

HYDRO ONE NETWORKS INC. (BU 210)
Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
1610 Computer Software	7.19		1.17%	← 10 Year Amortization →			1.17%
Total Intangible Plant			1.17%	7.19		91.60%	1.17%
TRANSMISSION PLANT							
1705D Land - Depreciable	75.60		0.96%	75.60		27.43%	0.96%
1706 Land Rights	81.69		0.95%	74.50		28.65%	0.96%
1708 Buildings and Fixtures	29.81		1.80%	29.81		45.78%	1.82%
1715 Station Equipment	31.16		2.04%	31.16		35.53%	2.07%
1720 Towers and Fixtures	57.56		1.26%	55.36		29.63%	1.27%
1730 Overhead Conductors and Devices	44.92		1.43%	43.16		37.95%	1.44%
1735 Underground Conduit	46.20		1.33%	32.19		47.34%	1.64%
1740 Underground Conductors and Devices	53.99		1.65%	48.99		12.29%	1.79%
1745 Roads and Trails	35.85		1.62%	30.50		45.38%	1.79%
Total Transmission Plant			1.76%	36.00		35.29%	1.80%
GENERAL PLANT							
Depreciable							
1905D Land - Depreciable	79.48		0.95%	79.48		22.11%	0.98%
1908 Buildings and Fixtures	27.36		2.02%	27.36		42.65%	2.10%
1910 Leasehold Improvements	1.00		-8.03%	1.00		102.39%	-2.39%
1922 Computer Hardware - Major	2.11		6.55%	2.11		87.08%	6.12%
1955 Communication Equipment	12.05		4.48%	12.05		44.56%	4.60%
1980 System Supervisory Equipment	8.60		5.25%	5.09		65.50%	6.78%
Total Depreciable			4.47%	8.88		53.12%	5.18%
Amortizable							
1925 Computer Software - Major	5.04		9.74%	← 6 Year Amortization →			11.49%
Total Amortizable			9.74%	2.11		72.65%	11.49%
Total General Plant			4.53%	8.68		53.33%	5.25%
TOTAL TRANSMISSION OPERATIONS			1.95%	30.80		36.60%	2.03%

HYDRO ONE NETWORKS INC. (BU 210)

Statement B

Comparison of Current and Proposed Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/12 Plant Investment	2013 Annualized Accrual Current	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
1610 Computer Software	$ 14,155,887	$ 165,420	$ 165,420	$ -
Total Intangible Plant	$ 14,155,887	$ 165,420	$ 165,420	$ -
TRANSMISSION PLANT				
1705D Land - Depreciable	$ 971,630	$ 9,328	$ 9,328	$ -
1706 Land Rights	237,412,477	2,255,419	2,279,160	23,741
1708 Buildings and Fixtures	395,445,384	7,118,017	7,197,106	79,089
1715 Station Equipment	6,768,421,520	138,075,799	140,106,325	2,030,526
1720 Towers and Fixtures	2,067,383,296	26,049,030	26,255,768	206,738
1730 Overhead Conductors and Devices	1,503,403,625	21,498,672	21,649,012	150,340
1735 Underground Conduit	267,321,341	3,555,374	4,384,070	828,696
1740 Underground Conductors and Devices	88,755,577	1,464,467	1,588,725	124,258
1745 Roads and Trails	225,602,371	3,654,758	4,038,282	383,524
Total Transmission Plant	$ 11,554,717,221	$ 203,680,864	$ 207,507,776	$ 3,826,912
GENERAL PLANT				
Depreciable				
1905D Land - Depreciable	$ 3,246,691	$ 30,844	$ 31,818	$ 974
1908 Buildings and Fixtures	110,425,948	2,230,604	2,318,945	88,341
1910 Leasehold Improvements	100,228	(8,048)	(2,395)	5,653
1922 Computer Hardware - Major	2,318,969	151,892	141,921	(9,971)
1955 Communication Equipment	379,523,040	17,002,632	17,458,060	455,428
1980 System Supervisory Equipment	356,826,944	18,733,415	24,192,867	5,459,452
Total Depreciable	$ 852,441,820	$ 38,141,339	$ 44,141,216	$ 5,999,877
Amortizable				
1925 Computer Software - Major	$ 9,293,454	$ 905,145	$ 1,067,885	$ 162,740
Total Amortizable	$ 9,293,454	$ 905,145	$ 1,067,885	$ 162,740
Total General Plant	$ 861,735,274	$ 39,046,484	$ 45,209,101	$ 6,162,617
TOTAL TRANSMISSION OPERATIONS	$ 12,430,608,382	$ 242,892,768	$ 252,882,297	$ 9,989,529

HYDRO ONE NETWORKS INC. (BU 210)
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2012

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
1610 Computer Software	$ 14,155,887	$ 18,104,476	127.89%	$ 12,966,316	91.60%	$ 12,966,316	91.60%
Total Intangible Plant	$ 14,155,887	$ 18,104,476	127.89%	$ 12,966,316	91.60%	$ 12,966,316	91.60%
TRANSMISSION PLANT							
1705D Land - Depreciable	$ 971,630	$ 329,745	33.94%	$ 237,078	24.40%	$ 266,540	27.43%
1706 Land Rights	237,412,477	87,221,855	36.74%	60,504,800	25.49%	68,023,922	28.65%
1708 Buildings and Fixtures	395,445,384	166,006,622	41.98%	161,040,395	40.72%	181,053,391	45.78%
1715 Station Equipment	6,768,421,520	2,486,788,958	36.74%	2,139,272,825	31.61%	2,405,126,977	35.53%
1720 Towers and Fixtures	2,067,383,296	502,391,344	24.30%	544,829,893	26.35%	612,537,615	29.63%
1730 Overhead Conductors and Devices	1,503,403,625	617,358,997	41.06%	507,441,991	33.75%	570,503,401	37.95%
1735 Underground Conduit	267,321,341	148,929,722	55.71%	112,553,824	42.10%	126,541,241	47.34%
1740 Underground Conductors and Devices	88,755,577	12,043,790	13.57%	9,698,564	10.93%	10,903,835	12.29%
1745 Roads and Trails	225,602,371	56,253,946	24.93%	91,052,658	40.36%	102,368,058	45.38%
Total Transmission Plant	$ 11,554,717,221	$ 4,077,324,979	35.29%	$ 3,626,632,028	31.39%	$ 4,077,324,979	35.29%
GENERAL PLANT							
Depreciable							
1905D Land - Depreciable	$ 3,246,691	$ 1,015,408	31.28%	$ 665,705	20.50%	$ 717,739	22.11%
1908 Buildings and Fixtures	110,425,948	52,571,320	47.61%	43,687,403	39.56%	47,102,174	42.65%
1910 Leasehold Improvements	100,228	28,826	28.76%	95,186	94.97%	102,626	102.39%
1922 Computer Hardware - Major	2,318,969	2,448,276	105.58%	1,872,932	80.77%	2,019,327	87.08%
1955 Communication Equipment	379,523,040	196,073,459	51.66%	156,871,987	41.33%	169,133,688	44.56%
1980 System Supervisory Equipment	356,826,944	196,371,987	55.03%	216,792,314	60.76%	233,737,612	65.50%
Total Depreciable	$ 852,441,820	$ 448,509,277	52.61%	$ 419,985,527	49.27%	$ 452,813,166	53.12%
Amortizable							
1925 Computer Software - Major	$ 9,293,454	$ 5,917,441	63.67%	$ 6,751,713	72.65%	$ 6,751,713	72.65%
Total Amortizable	$ 9,293,454	$ 5,917,441	63.67%	$ 6,751,713	72.65%	$ 6,751,713	72.65%
Total General Plant	$ 861,735,274	$ 454,426,719	52.73%	$ 426,737,240	49.52%	$ 459,564,879	53.33%
TOTAL TRANSMISSION OPERATIONS	$ 12,430,608,382	$ 4,549,856,174	36.60%	$ 4,066,335,584	32.71%	$ 4,549,856,174	36.60%

HYDRO ONE NETWORKS INC. (BU 210)
Current and Proposed Parameters
Vintage Group Procedure

Statement D

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
1610 Computer Software	10.00	SQ	10.00	7.19			10.00	SQ	10.00	7.19		
Total Intangible Plant									10.00	7.19		
TRANSMISSION PLANT												
1705D Land - Depreciable	100.00	S6	100.00	75.60			100.00	S6	100.00	75.60		
1706 Land Rights	100.00	S6	99.99	81.69			100.00	S6	99.98	74.50		
1708 Buildings and Fixtures	50.00	S6	50.29	29.81			50.00	S6	50.29	29.81		
1715 Station Equipment	45.00	S2	45.56	31.16			45.00	S2	45.56	31.16		
1720 Towers and Fixtures	75.00	S2	75.15	57.56			75.00	S2	75.17	55.36		
1730 Overhead Conductors and Devices	65.00	S3	65.14	44.92			65.00	S3	65.15	43.16		
1735 Underground Conduit	70.00	S2	70.25	46.20			55.00	S2	55.60	32.19		
1740 Underground Conductors and Devices	60.00	S2	60.00	53.99			55.00	S2	55.00	48.99		
1745 Roads and Trails	55.00	S2	55.84	35.85			50.00	S2	51.14	30.50		
Total Transmission Plant									52.47	36.00		
GENERAL PLANT												
Depreciable												
1905D Land - Depreciable	100.00	S6	99.98	79.48			100.00	S6	99.98	79.48		
1908 Buildings and Fixtures	45.00	S4	45.27	27.36			45.00	S4	45.27	27.36		
1910 Leasehold Improvements	10.00	S6	19.88	1.00			10.00	S6	19.88	1.00		
1922 Computer Hardware - Major	10.00	S6	10.97	2.11			10.00	S6	10.97	2.11		
1955 Communication Equipment	20.00	L2	20.54	12.05			20.00	L2	20.54	12.05		
1980 System Supervisory Equipment	15.00	L2	16.99	8.60			10.00	L2	12.97	5.09		
Total Depreciable									17.51	8.88		
Amortizable												
1925 Computer Software - Major	10.00	SQ	10.00	5.04			6.00	SQ	6.00	2.11		
Total Amortizable									6.00	2.11		
Total General Plant									17.16	8.68		
TOTAL TRANSMISSION OPERATIONS									45.72	30.80		

HYDRO ONE NETWORKS INC. (BU 210)
Asset Category Summary
December 31, 2012
Harmonic Weighting

Statement E

Description	Current P-Life		Proposed P-Life		Plant	
	USoA	Category	USoA	Category	USoA	Category
A	B	C	D	E	F	G
INTANGIBLE PLANT						
1610 Computer Software						
1657 Genrl - Adm & Serv-Sys Software		10		10		$ 14,155,887
Total USoA 1610	10 SQ	10	10 SQ	10	$ 14,155,887	$ 14,155,887
TRANSMISSION PLANT						
1705D Land - Depreciable						
1210 Land Purch & Acqui (Old Cap)		100		100		$ 971,630
Total USoA 1705D	100 S6	100	100 S6	100	$ 971,630	$ 971,630
1706 Land Rights						
1111 Rights & Easmnts <Landscaping>		100		100		$ 3,544,158
1212 Easmnts & Rights, Purch& Acqui		100		100		233,868,320
Total USoA 1706	100 S6	100	100 S6	100	$ 237,412,477	$ 237,412,477
1708 Buildings and Fixtures						
1120 Buildings and Fixtures - Stn Building Components		50		50		$ 345,619,818
1121 Cranes & Hoists In Bldgs		50		50		3,467,687
1260 Bldg W U/G Cable		50		50		20,819,205
1270 Tx - Serv Structures		50		50		25,538,673
Total USoA 1708	50 S6	50	50 S6	50	$ 395,445,384	$ 395,445,384
1715 Station Equipment						
1111 Rights & Easmnts <Landscaping>		50		50		$ 312
1112 Landscaping		50		50		21,458,129
1113 Site Imprv - Excl Fence,Rd,Easmt		50		50		323,660,541
1123 Cost Equip Foundations, Excav		65		65		475,501,053
1127 Steel/Pipe Struc For Switch Eq		65		65		357,771,156
1128 Fences,Gates, Bldg		30		30		109,097,535
1150 Rot Elec Eqp(No Wind'G)		65		65		16,655,250
1151 Tx - Stn-Rot Elec Equ(Wind'Gs)		65		65		301,966
1152 Capacitors		30		30		138,464,450
1155 Regulators Incl Instal Cost		40		40		11,274,119
1159 Tx - Stn-Mobile Sub-Stations		30		30		126,618
1160 Misc Stn Eqp - Trsf/Volt Trsf		40		40		300,504,193
1161 Serv Swg - Ac/Dc-Light Trsf		55		55		179,643,386
1162 Control Cable & Conduit		60		60		317,736,659
1163 Grounding Systems		60		60		161,063,072
1164 Metering Units		15		15		48,486,808
1166 Switchboards		60		35 a)		554,649,584
1167 Sup Cntrl - Prim H/Ware & Sys		20		20		337,775,480
1168 Sup Cntrl - Prim Appl S/Ware		20		20		16,754,948
1170 Service Systems		50		50		167,425,565
1175 Transf <=50Kv or <5Mva		40		50 b)		49,152,830
1176 Transf <=115Kv or >5Mva		50		50		261,300,180
1177 Transf <=230Kv		50		50		403,398,574
1178 Transf >230Kv		50		50		254,329,649
1179 Transf Instal Cost		50		50		231,063,873
1181 Switching >=34.5Kv		45		45		191,916,449
1182 Switching >=115Kv		45		45		121,641,761
1183 Switching >=230Kv		45		45		116,068,410
1184 Sf6 Switchgear		45		45		381,599,368
1185 Reclosers		45		40 b)		597,327
1186 Misc Switching		45		45		191,891,813
1187 Bus (Rigid & Strain)		45		45		246,821,957
1188 Cable		45		45		79,265,687

HYDRO ONE NETWORKS INC. (BU 210) Statement E
Asset Category Summary
December 31, 2012
Harmonic Weighting

Description	Current P-Life USoA	Current P-Life Category	Proposed P-Life USoA	Proposed P-Life Category	Plant USoA	Plant Category
A	B	C	D	E	F	G
1190 Cct Breakers >=230Kv		45		45		263,884,929
1191 Cct Breakers >=115Kv		45		45		82,943,149
1192 Cct Breakers <115Kv		45		45		142,612,907
1193 Cct Breakers Install		45		45		146,974,209
1194 Encld Swgr (All Compnt)		45		45		64,607,624
Total USoA 1715	45 S2	45	45 S2	43	$ 6,768,421,520	$ 6,768,421,520
1720 Towers and Fixtures						
1230 Steel Twr, Sup & Ftng		90		90		$ 1,476,468,661
1240 Poles Incl Xarm, Guy, Anchr		50		50		511,350,484
1245 Steel Poles		90		90		78,257,367
1249 Composite Poles		80		80		1,306,784
Total USoA 1720	75 S2	75	75 S2	75	$ 2,067,383,296	$ 2,067,383,296
1730 Overhead Conductors and Devices						
1220 Insulators		60		60		$ 270,146,850
1232 Grounding System		50		50		135,191,887
1235 Opt Grnd Wire		25		50 c)		35,688,078
1250 Overhd Conductor All		75		70 d)		1,003,590,054
1252 Switches&Devce		60		60		18,369,308
1254 Retension Costs		60		60		40,417,449
Total USoA 1730	65 S3	65	65 S3	65	$ 1,503,403,625	$ 1,503,403,625
1735 Underground Conduit						
1220 Insulators		70		55 e)		$ 140,166
1261 Ugrd Conduit		70		55 f)		267,181,175
Total USoA 1735	70 S2	70	55 S2	55	$ 267,321,341	$ 267,321,341
1740 Underground Conductors and Devices						
1262 Ugrd Conductor		60		55 g)		$ 88,755,577
Total USoA 1740	60 S2	60	55 S2	55	$ 88,755,577	$ 88,755,577
1745 Roads and Trails						
1122 Perm Rds & Surfc Area		25		25		$ 43,100,325
1174 Railway Track		30		30		8,027,745
1215 Clrng & Overbldng		70		70		160,275,778
1271 Roads & Trails		70		70		14,198,523
Total USoA 1745	55 S2	50	50 S2	50	$ 225,602,371	$ 225,602,371
GENERAL PLANT						
Depreciable						
1905D Land - Depreciable						
1828 Genrl - Comm-Site Improvement		100		100		$ 3,246,691
Total USoA 1905D	100 S6	100	100 S6	100	$ 3,246,691	$ 3,246,691
1908 Buildings and Fixtures						
1612 Genrl - Adm & Serv-Landscaping		50		50		$ 23,920
1621 Genrl - Adm & Serv-Bld Frame & Mtl		50		50		32,733,977
1622 Genrl - Adm & Serv-Rds & Surfaces		25		25		3,903,065
1623 Genrl - Adm & Serv-Bld Frame		50		50		5,395,287
1628 Genrl - Adm & Serv-Fence,Gate		30		30		4,303,864
1650 Genrl - Adm & Serv-Distn Sys		50		50		4,869,641
1663 Genrl - Adm & Serv-Aux Eq Bld		50		50		12,516,280
1813 Genrl - Comm-Landscaping		50		50		62,867
1820 Genrl - Comm-Buildings		25		50 h)		13,846,414
1853 Genrl - Comm-Str & Footings-Poles		50		50		32,770,631
Total USoA 1908	45 S4	42	45 S4	47	$ 110,425,948	$ 110,425,948
1910 Leasehold Improvements						
1624 Genrl - Adm & Serv-Bldgs-Leased		10		10		$ 100,228
Total USoA 1910	10 S6	10	10 S6	10	$ 100,228	$ 100,228

HYDRO ONE NETWORKS INC. (BU 210) Statement E
Asset Category Summary
December 31, 2012
Harmonic Weighting

Description	Current P-Life USoA	Current P-Life Category	Proposed P-Life USoA	Proposed P-Life Category		Plant USoA		Plant Category
A	B	C	D	E		F		G
1922 Computer Hardware - Major								
1653 Genrl - Adm & Serv-Lan Elect Dev		10		10			$	658,944
1655 Genrl - Adm & Serv-Lan Cable		10		10				672,183
1656 Genrl - Adm & Serv-Lan Fib Opt		10		10				987,842
Total USoA 1922	10 S6	10	10 S6	10	$	2,318,969	$	2,318,969
1955 Communication Equipment								
1654 Genrl - Adm & Serv-Telcm Wire		7		7			$	2,594,458
1658 Genrl - Adm & Serv-Telcm Equip		7		7				628,577
1659 Genrl - Adm & Serv-Telcom Sw		7		7				717,041
1850 Genrl - Comm-Radio Equipment		15		10 b)				40,145,671
1854 Genrl - Comm-Admin Telcom Equp		7		7				12,290,376
1857 Genrl - Comm-Optical Wire 78Mth		7		7				235,440
1863 Genrl - Comm Optical Wire		25		25				91,645,918
1864 Genrl - Comm-Opt Wire Termtn		20		20				149,796,646
1865 Genrl - Comm-Opgw W Fib Cable		25		25				67,936,010
1870 Genrl - Comm-Power Supply Equp		15		15				13,532,902
Total USoA 1955	20 L2	19	20 L2	18	$	379,523,040	$	379,523,040
1980 System Supervisory Equipment								
1840 Genrl - Comm-Pwr Line Equip		15		15			$	152,732,717
1844 Genrl - Comm-Sys Cntrl Comp Eq		7		6 i)				77,118,936
1846 Genrl - Comm-Dacs Appl S/Ware		20		6 i)				2,678,321
1847 Genrl - Comm-Dacs Sys S/Ware		20		6 i)				96,026,915
1860 Genrl - Comm-Pole Comm Cab Bths		25		25				28,253,846
1864 Genrl - Comm-Opt Wire Termtn		20		20				16,209
Total USoA 1980	15 L2	13	10 L2	9	$	356,826,944	$	356,826,944
Amortizable								
1925 Computer Software - Major								
1657 Genrl - Adm & Serv-Sys Software		10		6 i)			$	9,293,454
Total USoA 1925	10 SQ	10	6 SQ	6	$	9,293,454	$	9,293,454
TOTAL BU 210					$	12,430,608,382	$	12,430,608,381

a) Weighted average of old (55 years) and new (25 years).
b) To be consistent with BU 220 (Dx).
c) Same as skywire (Category 1232).
d) Based on engineering studies.
e) U/G cable potheads aligned with Category 1262.
f) Aligned with Category 1262.
g) Based on manufacturer design life.
h) Mostly steel constructed structures.
i) To align with hardware/software refresh policy.

Statements A through E

HYDRO ONE NETWORKS INC. - (BU 300)
Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current Rem. Life	Current Net Salvage	Current Accrual Rate	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
1610 Computer Software	3.63		9.28%	← 10 Year Amortization →			9.28%
Total Intangible Plant			9.28%	6.18		41.96%	9.28%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	33.76		1.00%	32.73		58.88%	1.26%
1910 Leasehold Improvements	1.98		-33.36%	2.79		128.50%	-10.22%
1922 Computer Equipment - Hardware	1.55		-64.94%	9.35		30.50%	7.43%
1955 Communication Equipment	2.39		-30.02%	1.41		156.05%	-39.75%
1980 System Supervisory Equipment	1.00		-86.35%	1.00		157.57%	-57.57%
Total Depreciable			-11.33%	15.56		76.59%	-5.29%
Amortizable							
1915 Office Furniture and Equipment	← 7 Year Amortization →		13.80%	← 7 Year Amortization →			13.80%
1920 Computer Hardware - Minor	← 5 Year Amortization →		18.32%	← 5 Year Amortization →			18.32%
1925 Computer Software - Major	6.92		9.40%	← 6 Year Amortization →			10.22%
1935 Stores Equipment	← 8 Year Amortization →		11.30%	← 8 Year Amortization →			11.30%
1940 Tools, Shop and Garage Equipment	← 6 Year Amortization →		15.29%	← 6 Year Amortization →			15.29%
1945 Measurement and Testing Equipment	← 5 Year Amortization →		18.70%	← 5 Year Amortization →			18.70%
1960 Miscellaneous Equipment	← 5 Year Amortization →		17.63%	← 5 Year Amortization →			17.63%
Total Amortizable			14.48%	2.89		54.23%	14.79%
Total General Plant			6.28%	3.94		61.34%	8.41%
TOTAL COMMON OPERATIONS			7.91%	4.99		50.76%	8.88%

HYDRO ONE NETWORKS INC. - (BU 300)
Comparison of Current and Proposed Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/12 Plant Investment	2013 Annualized Accrual Current	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
1610 Computer Software	$ 365,119,221	$ 33,865,737	$ 33,865,737	$ -
Total Intangible Plant	$ 365,119,221	$ 33,865,737	$ 33,865,737	$ -
GENERAL PLANT				
Depreciable				
1908 Buildings and Fixtures	$ 70,409,754	$ 704,098	$ 887,163	$ 183,065
1910 Leasehold Improvements	9,682,409	(3,230,052)	(989,542)	2,240,510
1922 Computer Equipment - Hardware	4,516,374	(2,932,933)	335,567	3,268,500
1955 Communication Equipment	8,554,760	(2,568,139)	(3,400,517)	(832,378)
1980 System Supervisory Equipment	3,366,771	(2,907,207)	(1,938,250)	968,957
Total Depreciable	$ 96,530,068	$ (10,934,233)	$ (5,105,579)	$ 5,828,654
Amortizable				
1915 Office Furniture and Equipment	$ 8,744,606	$ 1,206,469	$ 1,206,469	$ -
1920 Computer Hardware - Minor	89,152,467	16,329,365	16,329,365	
1925 Computer Software - Major	79,072,023	7,434,939	8,083,886	648,947
1935 Stores Equipment	3,585,824	405,212	405,212	
1940 Tools, Shop and Garage Equipment	8,304,364	1,270,059	1,270,059	
1945 Measurement and Testing Equipment	11,792,701	2,205,421	2,205,421	
1960 Miscellaneous Equipment	6,508,693	1,147,221	1,147,221	
Total Amortizable	$ 207,160,678	$ 29,998,686	$ 30,647,633	$ 648,947
Total General Plant	$ 303,690,746	$ 19,064,453	$ 25,542,054	$ 6,477,601
TOTAL COMMON OPERATIONS	$ 668,809,967	$ 52,930,190	$ 59,407,791	$ 6,477,601

HYDRO ONE NETWORKS INC. - (BU 300)
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2012

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
1610 Computer Software	$ 365,119,221	$ 170,469,173	46.69%	$ 153,190,721	41.96%	$ 153,190,721	41.96%
Total Intangible Plant	$ 365,119,221	$ 170,469,173	46.69%	$ 153,190,721	41.96%	$ 153,190,721	41.96%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	$ 70,409,754	$ 29,573,987	42.00%	$ 24,347,167	34.58%	$ 41,460,694	58.88%
1910 Leasehold Improvements	9,682,409	8,538,767	88.19%	7,306,514	75.46%	12,442,235	128.50%
1922 Computer Equipment - Hardware	4,516,374	826,663	18.30%	808,903	17.91%	1,377,477	30.50%
1955 Communication Equipment	8,554,760	8,230,558	96.21%	7,839,326	91.64%	13,349,558	156.05%
1980 System Supervisory Equipment	3,366,771	5,116,173	151.96%	3,115,332	92.53%	5,305,086	157.57%
Total Depreciable	$ 96,530,068	$ 52,286,149	54.17%	$ 43,417,242	44.98%	$ 73,935,050	76.59%
Amortizable							
1915 Office Furniture and Equipment	$ 8,744,606	$ 4,520,083	51.69%	$ 4,525,746	51.75%	$ 4,525,746	51.75%
1920 Computer Hardware - Minor	89,152,467	38,738,817	43.45%	39,782,809	44.62%	39,782,809	44.62%
1925 Computer Software - Major	79,072,023	58,375,800	73.83%	52,907,562	66.91%	52,907,562	66.91%
1935 Stores Equipment	3,585,824	2,520,667	70.30%	2,500,200	69.72%	2,500,200	69.72%
1940 Tools, Shop and Garage Equipment	8,304,364	3,676,673	44.27%	3,645,527	43.90%	3,645,527	43.90%
1945 Measurement and Testing Equipment	11,792,701	5,088,118	43.15%	5,172,517	43.86%	5,172,517	43.86%
1960 Miscellaneous Equipment	6,508,693	3,801,308	58.40%	3,816,656	58.64%	3,816,656	58.64%
Total Amortizable	$ 207,160,678	$ 116,721,466	56.34%	$ 112,351,017	54.23%	$ 112,351,017	54.23%
Total General Plant	$ 303,690,746	$ 169,007,615	55.65%	$ 155,768,259	51.29%	$ 186,286,067	61.34%
TOTAL COMMON OPERATIONS	$ 668,809,967	$ 339,476,788	50.76%	$ 308,958,980	46.20%	$ 339,476,788	50.76%

HYDRO ONE NETWORKS INC. - (BU 300)

Current and Proposed Parameters
Vintage Group Procedure

Statement D

Account Description	Current Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
1610 Computer Software	10.00	SQ	10.00	3.63			10.00	SQ	10.00	6.18		
Total Intangible Plant									10.00	6.18		
GENERAL PLANT												
Depreciable												
1908 Buildings and Fixtures	50.00	S4	50.01	33.76			50.00	S4	50.03	32.73		
1910 Leasehold Improvements	10.00	S6	10.58	1.98			10.00	S6	11.37	2.79		
1922 Computer Equipment - Hardware	10.00	S6	87.20	1.55			10.00	S6	11.39	9.35		
1955 Communication Equipment	7.00	S6	15.00	2.39			7.00	S6	16.86	1.41		
1980 System Supervisory Equipment	7.00	S6	11.39	1.00			7.00	S6	13.39	1.00		
Total Depreciable									28.27	15.56		
Amortizable												
1915 Office Furniture and Equipment	7.00	SQ	7.00	4.01			7.00	SQ	7.00	3.38		
1920 Computer Hardware - Minor	5.00	SQ	5.00	2.44			5.00	SQ	5.00	2.77		
1925 Computer Software - Major	10.00	SQ	7.00	6.92			6.00	SQ	6.00	3.06		
1935 Stores Equipment	8.00	SQ	8.00	2.86			8.00	SQ	8.00	2.42		
1940 Tools, Shop and Garage Equipment	6.00	SQ	6.00	2.80			6.00	SQ	6.00	3.37		
1945 Measurement and Testing Equipment	5.00	SQ	5.00	2.64			5.00	SQ	5.00	2.81		
1960 Miscellaneous Equipment	5.00	SQ	5.00	2.55			5.00	SQ	5.00	2.07		
Total Amortizable									5.49	2.89		
Total General Plant									7.38	3.94		
TOTAL COMMON OPERATIONS									8.61	4.99		

HYDRO ONE NETWORKS INC. - (BU 300)

Statement E

Asset Category Summary
December 31, 2012
Harmonic Weighting

Description	Current P-Life		Proposed P-Life		Plant	
	USoA	Category	USoA	Category	USoA	Category
A	B	C	D	E	F	G
INTANGIBLE PLANT						
1610 Computer Software						
1657 Genrl - Adm & Serv-Sys Software		10		10		$ 365,119,221
Total USoA 1610	10 SQ	10	10 SQ	10	$ 365,119,221	$ 365,119,221
GENERAL PLANT						
Depreciable						
1908 Buildings and Fixtures						
1621 Genrl - Adm & Serv-Bld Frame&Mtl		50		50		$ 41,070,808
1622 Genrl - Adm & Serv-Rds&Surfaces		25		25		1,485,662
1623 Genrl - Adm & Serv-Bld Frame		50		50		9,414,683
1628 Genrl - Adm & Serv-Fence,Gate		30		30		960,151
1650 Genrl - Adm & Serv-Distn Sys		50		50		565,380
1663 Genrl - Adm & Serv-Aux Eq Bld		50		50		10,146,899
1820 Genrl - Comm-Buildings		50		50		6,766,170
Total USoA 1908	50 S4	49	50 S4	49	$ 70,409,754	$ 70,409,754
1910 Leasehold Improvements						
1624 Genrl - Adm & Serv-Bldgs-Leased		10		10		$ 9,682,409
Total USoA 1910	10 S6	10	10 S6	10	$ 9,682,409	$ 9,682,409
1922 Computer Equipment - Hardware						
1653 Genrl - Adm & Serv-Lan Elect Dev		10		10		$ 4,011,018
1655 Genrl - Adm & Serv-Lan Cable		10		10		505,356
Total USoA 1922	10 S6	10	10 S6	10	$ 4,516,374	$ 4,516,374
1955 Communication Equipment						
1654 Genrl - Adm & Serv-Telcm Wire		7		7		$ 2,272,521
1658 Genrl - Adm & Serv-Telcm Equip		7		7		1,837,766
1850 Genrl - Comm-Radio Equipment		10		10		11,318
1854 Genrl - Comm-Admin Telcom Equp		7		7		4,433,155
Total USoA 1955	7 S6	7	7 S6	7	$ 8,554,760	$ 8,554,760
1980 System Supervisory Equipment						
1840 Genrl - Comm-Pwr Line Equip		15		15		$ 389,017
1844 Genrl - Comm-Sys Cntrl Comp Eq		7		6 a)		2,977,754
Total USoA 1980	7 S6	7	7 S6	6	$ 3,366,771	$ 3,366,771
Amortizable						
1915 Office Furniture and Equipment						
S007 Mfa - 7 Yr Sl		7		7		$ 8,744,606
Total USoA 1915	7 SQ	7	7 SQ	7	$ 8,744,606	$ 8,744,606
1920 Computer Hardware - Minor						
S005 Computers - 40% Db (Default)		5		5		$ 89,152,467
Total USoA 1920	5 SQ	5	5 SQ	5	$ 89,152,467	$ 89,152,467
1925 Computer Software - Major						
1657 Genrl - Adm & Serv-Sys Software		10		6 a)		$ 79,072,023
Total USoA 1925	10 SQ	10	6 SQ	6	$ 79,072,023	$ 79,072,023
1935 Stores Equipment						
S008 Mfa - 8Yr Sl(Def)		8		8		$ 3,585,824
Total USoA 1935	8 SQ	8	8 SQ	8	$ 3,585,824	$ 3,585,824
1940 Tools, Shop and Garage Equipment						
S006 Mfa - 6Yr Sl(Def)		6		6		$ 8,304,364
Total USoA 1940	6 SQ	6	6 SQ	6	$ 8,304,364	$ 8,304,364
1945 Measurement and Testing Equipment						
S005 Mfa - 5Yr Sl(Def)		5		5		$ 11,792,701
Total USoA 1945	5 SQ	5	5 SQ	5	$ 11,792,701	$ 11,792,701
1960 Miscellaneous Equipment						
S005 Mfa - 5Yr Sl(Def)		5		5		$ 6,508,693
Total USoA 1960	5 SQ	5	5 SQ	5	$ 6,508,693	$ 6,508,693
TOTAL BU 300					$ 668,809,967	$ 668,809,965

a) To align with hardware/software refresh policy.

Analysis

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Hydro One Networks transmission and common depreciation review to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 1715 – Station Equipment. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the Hydro One Networks review include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis; and

Schedule E – Graphics Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I. The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 4. Generation Arrangement

Schedule B – Age Distribution

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

Schedule C – Plant History

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant
Account: 1715 Station Equipment

Dispersion: 45 - S2
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2012 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2012	0.5	320,194,337	45.00	44.50	0.9889	1.0000	316,636,709	7,115,434
2011	1.5	594,939,722	45.00	43.50	0.9667	1.0000	575,108,381	13,220,890
2010	2.5	482,241,705	45.00	42.50	0.9445	1.0000	455,469,198	10,716,870
2009	3.5	441,582,716	45.00	41.50	0.9223	1.0000	407,252,465	9,813,137
2008	4.5	197,539,161	45.00	40.50	0.9001	1.0000	177,805,940	4,390,003
2007	5.5	228,634,027	44.99	39.51	0.8781	1.0000	200,754,662	5,081,662
2006	6.5	149,929,458	45.00	38.51	0.8558	1.0000	128,315,327	3,331,835
2005	7.5	224,118,587	45.00	37.52	0.8339	1.0000	186,884,522	4,980,675
2004	8.5	183,202,382	45.00	36.54	0.8120	1.0000	148,751,616	4,071,274
2003	9.5	108,174,398	44.99	35.56	0.7903	1.0000	85,488,990	2,404,150
2002	10.5	123,438,716	45.00	34.59	0.7686	1.0000	94,875,239	2,742,931
2001	11.5	77,826,769	44.97	33.63	0.7477	1.0000	58,193,374	1,730,460
2000	12.5	145,772,642	44.99	32.68	0.7264	1.0000	105,887,078	3,240,162
1999	13.5	102,733,452	44.97	31.74	0.7059	1.0000	72,521,125	2,284,654
1998	14.5	100,104,966	45.00	30.82	0.6849	1.0000	68,566,663	2,224,728
1997	15.5	88,113,657	45.00	29.91	0.6647	1.0000	58,571,346	1,958,060
1996	16.5	96,270,837	44.98	29.02	0.6452	1.0000	62,115,931	2,140,337
1995	17.5	69,893,931	44.89	28.15	0.6270	1.0000	43,826,118	1,557,022
1994	18.5	268,049,727	45.00	27.29	0.6065	1.0000	162,581,642	5,957,219
1993	19.5	98,661,326	44.98	26.45	0.5882	1.0000	58,033,442	2,193,690
1992	20.5	372,369,708	45.09	25.64	0.5686	1.0000	211,712,703	8,258,008
1991	21.5	264,504,815	44.99	24.84	0.5521	1.0000	146,031,328	5,879,076
1990	22.5	385,478,106	45.18	24.06	0.5326	1.0000	205,303,704	8,532,589
1989	23.5	127,364,630	45.23	23.30	0.5153	1.0000	65,627,992	2,816,162
1988	24.5	104,347,610	45.24	22.57	0.4988	1.0000	52,047,497	2,306,334
1987	25.5	154,375,093	45.39	21.85	0.4814	1.0000	74,318,863	3,401,234
1986	26.5	47,506,024	45.41	21.15	0.4659	1.0000	22,131,977	1,046,244
1985	27.5	48,991,303	45.63	20.48	0.4488	1.0000	21,987,606	1,073,771
1984	28.5	46,304,694	45.74	19.82	0.4333	1.0000	20,063,412	1,012,257
1983	29.5	80,275,121	45.84	19.18	0.4184	1.0000	33,590,395	1,751,054
1982	30.5	49,847,269	45.94	18.56	0.4041	1.0000	20,142,442	1,085,015
1981	31.5	49,409,688	46.04	17.96	0.3901	1.0000	19,276,544	1,073,085
1980	32.5	156,869,179	46.31	17.38	0.3753	1.0000	58,877,803	3,387,311
1979	33.5	131,800,915	46.57	16.82	0.3611	1.0000	47,594,578	2,830,081
1978	34.5	54,086,628	46.46	16.27	0.3501	1.0000	18,938,374	1,164,033
1977	35.5	55,485,490	46.91	15.74	0.3355	1.0000	18,614,535	1,182,756
1976	36.5	44,748,367	47.08	15.22	0.3234	1.0000	14,469,744	950,520

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant
Account: 1715 Station Equipment

Dispersion: 45 - S2
Procedure: Vintage Group

Generation Arrangement

Vintage	Age (December 31, 2012)	Surviving Plant (December 31, 2012)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1975	37.5	42,643,494	47.44	14.72	0.3104	1.0000	13,234,970	898,923
1974	38.5	42,893,772	47.72	14.24	0.2984	1.0000	12,798,385	898,888
1973	39.5	30,772,676	47.84	13.77	0.2878	1.0000	8,855,803	643,253
1972	40.5	33,195,576	48.43	13.31	0.2748	1.0000	9,122,715	685,405
1971	41.5	44,663,184	48.72	12.87	0.2641	1.0000	11,794,895	916,739
1970	42.5	52,651,558	49.26	12.44	0.2525	1.0000	13,292,229	1,068,933
1969	43.5	34,113,710	49.63	12.02	0.2421	1.0000	8,258,573	687,294
1968	44.5	18,374,512	50.04	11.61	0.2320	1.0000	4,262,415	367,174
1967	45.5	9,755,387	50.10	11.21	0.2238	1.0000	2,183,344	194,722
1966	46.5	12,698,106	50.89	10.83	0.2128	1.0000	2,701,806	249,538
1965	47.5	36,298,672	51.49	10.45	0.2030	1.0000	7,368,831	704,999
1963	49.5	223,846	53.22	9.73	0.1829	1.0000	40,931	4,206
1962	50.5	839,768	53.85	9.38	0.1743	1.0000	146,351	15,594
1960	52.5	47,255,928	54.55	8.72	0.1598	1.0000	7,552,437	866,358
1958	54.5	812	56.62	8.08	0.1428	1.0000	116	14
1956	56.5	52,288	58.14	7.48	0.1286	1.0000	6,723	899
1955	57.5	48,992,842	58.11	7.18	0.1236	1.0000	6,055,967	843,153
1953	59.5	33,140	60.57	6.62	0.1092	1.0000	3,620	547
1950	62.5	37,775,090	62.33	5.81	0.0932	1.0000	3,520,991	606,055
Total	15.9	$6,768,421,520	45.56	31.16	0.6840	1.0000	$4,629,570,366	$148,557,402

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2012	Derived Additions	2000 Opening Balance	Experience to 12/31/2012 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2012	0.5	320,201,788		320,194,337	1.0000	0.5000
2011	1.5	594,939,722		594,939,722	1.0000	1.5000
2010	2.5	482,756,445		482,241,705	0.9989	2.4984
2009	3.5	442,015,913		441,582,716	0.9990	3.4991
2008	4.5	198,171,306		197,539,161	0.9968	4.4975
2007	5.5	230,328,826		228,634,027	0.9926	5.4918
2006	6.5	150,033,912		149,929,458	0.9993	6.4987
2005	7.5	224,517,398		224,118,587	0.9982	7.4968
2004	8.5	183,878,264		183,202,382	0.9963	8.4972
2003	9.5	108,639,217		108,174,398	0.9957	9.4920
2002	10.5	123,588,139		123,438,716	0.9988	10.4977
2001	11.5	78,218,149		77,826,769	0.9950	11.4668
2000	12.5	146,733,767		145,772,642	0.9934	12.4771
1999	13.5		103,759,535	102,733,452	0.9901	13.4485
1998	14.5		100,878,624	100,104,966	0.9923	14.4699
1997	15.5		89,119,400	88,113,657	0.9887	15.4629
1996	16.5		97,744,204	96,270,837	0.9849	16.4273
1995	17.5		72,352,369	69,893,931	0.9660	17.3192
1994	18.5		273,953,593	268,049,727	0.9784	18.4024
1993	19.5		100,979,518	98,661,326	0.9770	19.3531
1992	20.5		376,946,819	372,369,708	0.9879	20.4352
1991	21.5		273,320,364	264,504,815	0.9677	21.2920
1990	22.5		391,795,023	385,478,106	0.9839	22.4281
1989	23.5		129,608,724	127,364,630	0.9827	23.4179
1988	24.5		106,805,578	104,347,610	0.9770	24.3660
1987	25.5		156,242,738	154,375,093	0.9880	25.4293
1986	26.5		49,042,874	47,506,024	0.9687	26.3546
1985	27.5		49,307,586	48,991,303	0.9936	27.4675
1984	28.5		46,520,300	46,304,694	0.9954	28.4653
1983	29.5		81,400,172	80,275,121	0.9862	29.4289
1982	30.5		51,211,339	49,847,269	0.9734	30.3737
1981	31.5		54,595,330	49,409,688	0.9050	31.3062
1980	32.5		161,477,840	156,869,179	0.9715	32.3834
1979	33.5		133,753,032	131,800,915	0.9854	33.4352
1978	34.5		58,690,866	54,086,628	0.9216	34.0992
1977	35.5		60,188,031	55,485,490	0.9219	35.2954
1976	36.5		47,027,483	44,748,367	0.9515	36.1879
1975	37.5		45,401,199	42,643,494	0.9393	37.2522

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Age Distribution

Vintage	Age as of 12/31/2012	Derived Additions	2000 Opening Balance	Experience to 12/31/2012 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1974	38.5		48,683,278	42,893,772	0.8811	38.2122
1973	39.5		33,251,887	30,772,676	0.9254	38.9880
1972	40.5		35,350,563	33,195,576	0.9390	40.2112
1971	41.5		48,337,891	44,663,184	0.9240	41.1035
1970	42.5		55,558,598	52,651,558	0.9477	42.2190
1969	43.5		36,512,835	34,113,710	0.9343	43.1504
1968	44.5		19,900,875	18,374,512	0.9233	44.0851
1967	45.5		11,147,246	9,755,387	0.8751	44.6412
1966	46.5		14,068,248	12,698,106	0.9026	45.9021
1965	47.5		40,451,405	36,298,672	0.8973	46.9504
1963	49.5		223,846	223,846	1.0000	49.5000
1962	50.5		839,768	839,768	1.0000	50.5000
1960	52.5		53,520,521	47,255,928	0.8829	51.8593
1958	54.5		812	812	1.0000	54.5000
1956	56.5		52,288	52,288	1.0000	56.5000
1955	57.5		55,760,861	48,992,842	0.8786	56.6793
1953	59.5		33,140	33,140	1.0000	59.5000
1950	62.5		42,762,492	37,775,090	0.8834	61.6716
Total	15.9	$3,284,022,844	$3,608,579,097	$6,768,421,520	0.9820	

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	3,614,235,886	118,191,442	2,555,440	22,361,942	3,752,233,829
2001	3,752,233,829	73,238,191	3,982,516	22,536,997	3,844,026,500
2002	3,844,026,500	65,399,789	7,443,045	5,958,147	3,907,941,391
2003	3,907,941,391	106,559,019	2,517,339	(1,040,636)	4,010,942,435
2004	4,010,942,435	118,022,342	14,404,097	51,979,207	4,166,539,886
2005	4,166,539,886	82,292,407	8,645,819	143,492,615	4,383,679,090
2006	4,383,679,090	119,427,072	5,174,411	8,491,077	4,506,422,828
2007	4,506,422,828	230,356,875	17,682,749	42,446,113	4,761,543,066
2008	4,761,543,066	31,412,693	7,078,185	127,829,983	4,913,707,557
2009	4,913,707,557	357,324,800	7,864,743	40,182,801	5,303,350,416
2010	5,303,350,416	557,449,189	8,126,169	(103,974)	5,852,569,462
2011	5,852,569,462	595,247,424	12,298,745	(183,684)	6,435,334,457
2012	6,435,334,457	359,985,856	26,800,834	(97,959)	6,768,421,520

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	3,634,345,417	145,278,841	2,555,440		3,777,068,818
2001	3,777,068,818	76,479,157	3,982,516	(156,246)	3,849,409,213
2002	3,849,409,213	123,475,163	7,443,045	(9,139,843)	3,956,301,487
2003	3,956,301,487	107,667,522	2,503,831	298,348	4,061,763,527
2004	4,061,763,527	183,526,382	14,023,935	(484,553)	4,230,781,420
2005	4,230,781,420	220,882,770	8,645,819	52,925	4,443,071,297
2006	4,443,071,297	149,411,074	5,174,411	(14,173,201)	4,573,134,759
2007	4,573,134,759	230,348,606	17,682,749	6,578,822	4,792,379,437
2008	4,792,379,437	198,171,306	7,078,185	(418,411)	4,983,054,147
2009	4,983,054,147	441,961,102	7,864,743	1,411,494	5,418,562,001
2010	5,418,562,001	488,744,718	8,126,169	(103,974)	5,899,076,575
2011	5,899,076,575	588,305,121	12,298,745	(41,594)	6,475,041,358
2012	6,475,041,358	320,201,788	26,800,834	(20,792)	6,768,421,520

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None

Placement Band: 1950-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2004	78.4	99.2	L1.5 *	1.16	75.7	S1.5	0.45	71.7	S2	0.48
2001-2005	74.2	92.9	L1.5 *	1.43	72.4	S1.5	0.50	69.2	S2	0.55
2002-2006	74.6	95.6	L1.5 *	1.52	74.4	S1.5	0.61	70.6	S2	0.58
2003-2007	73.9	94.9	L1.5 *	1.11	77.2	S1.5	0.51	72.7	R2.5	0.51
2004-2008	74.6	98.1	L1 *	0.98	82.5	S1	0.54	74.8	R2.5	0.55
2005-2009	78.5	106.8	L1 *	0.73	92.7	S1	0.48	81.8	R2.5 *	0.44
2006-2010	80.0	112.4	L1 *	0.79	104.4	S0.5	0.68	105.3	L1.5	0.68
2007-2011	77.0	107.5	L1 *	0.98	93.7	S0.5	0.70	133.7	SC *	0.63
2008-2012	72.3	97.2	L1.5 *	1.57	83.0	S1	1.21	150.2	SC *	0.73

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None
Placement Band: 1950-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2012	72.5	97.3	L1.5 *	1.40	80.6	S1	0.89	132.9	SC *	0.62
2002-2012	71.6	95.3	L1.5 *	1.41	79.6	S1	0.93	132.9	SC *	0.64
2004-2012	71.5	95.2	L1.5 *	1.33	80.7	S1	0.95	135.4	SC *	0.65
2006-2012	73.7	97.8	L1.5 *	1.02	84.6	S1	0.90	146.9	SC *	0.56
2008-2012	72.3	97.2	L1.5 *	1.57	83.0	S1	1.21	150.2	SC *	0.73
2010-2012	71.0	88.2	L1.5 *	1.62	75.8	S1	1.88	144.2	SC *	1.42
2012-2012	63.9	70.3	L1.5 *	3.50	64.9	S1 *	4.09	123.4	SC *	3.82

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None

Placement Band: 1950-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2001	92.9	131.0	S0 *	0.70	101.4	S1.5	0.85	171.1	R1.5 *	0.96
2000-2003	84.9	108.5	L1.5 *	0.67	80.1	S2	0.65	78.5	S2	0.62
2000-2005	75.7	96.5	L1.5 *	1.35	74.1	S1.5	0.45	70.1	S2	0.48
2000-2007	74.4	97.5	L1.5 *	1.30	77.8	S1.5	0.51	74.0	S2	0.55
2000-2009	76.6	103.5	L1.5 *	1.15	84.3	S1	0.51	79.6	S1.5	0.51
2000-2011	75.7	104.5	L1.5 *	1.30	84.7	S1	0.63	92.9	L1.5 *	0.59
2000-2012	72.5	97.3	L1.5 *	1.40	80.6	S1	0.89	132.9	SC *	0.62

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None

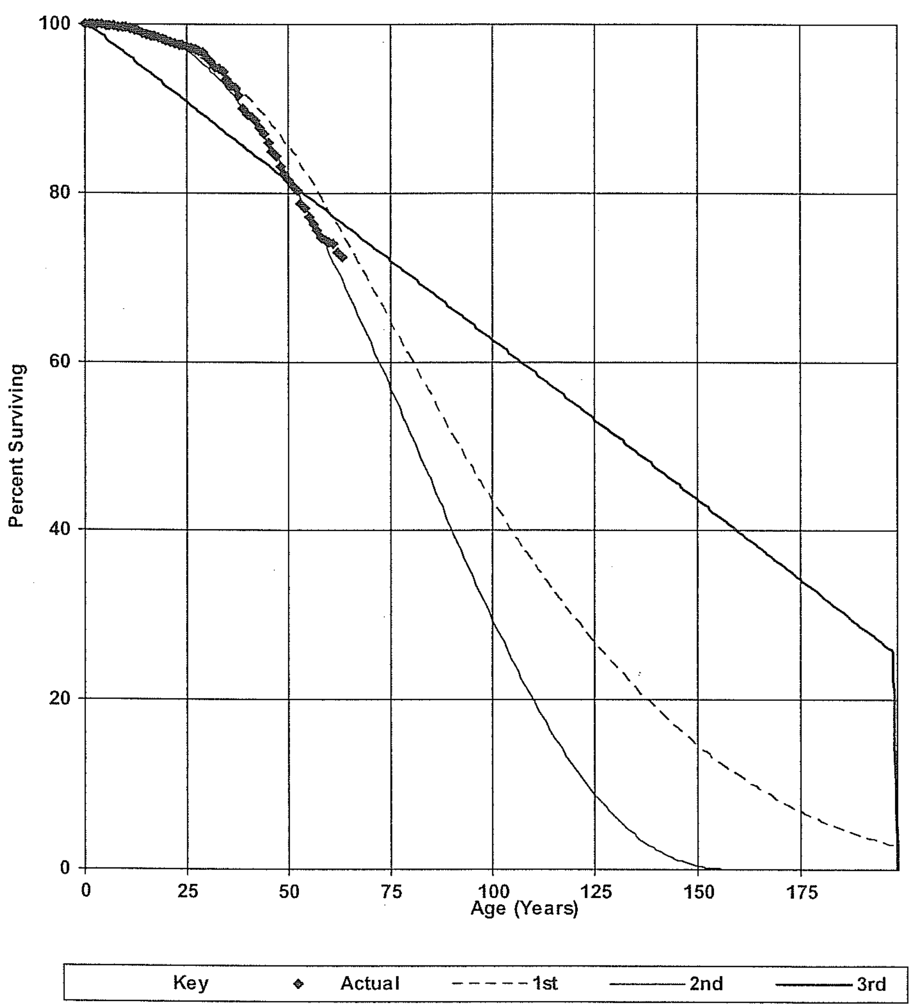
Placement Band: 1950-2012 Observation Band: 2000-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 97.3-L1.5 2nd: 80.6-S1 3rd: 132.9-SC



HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None

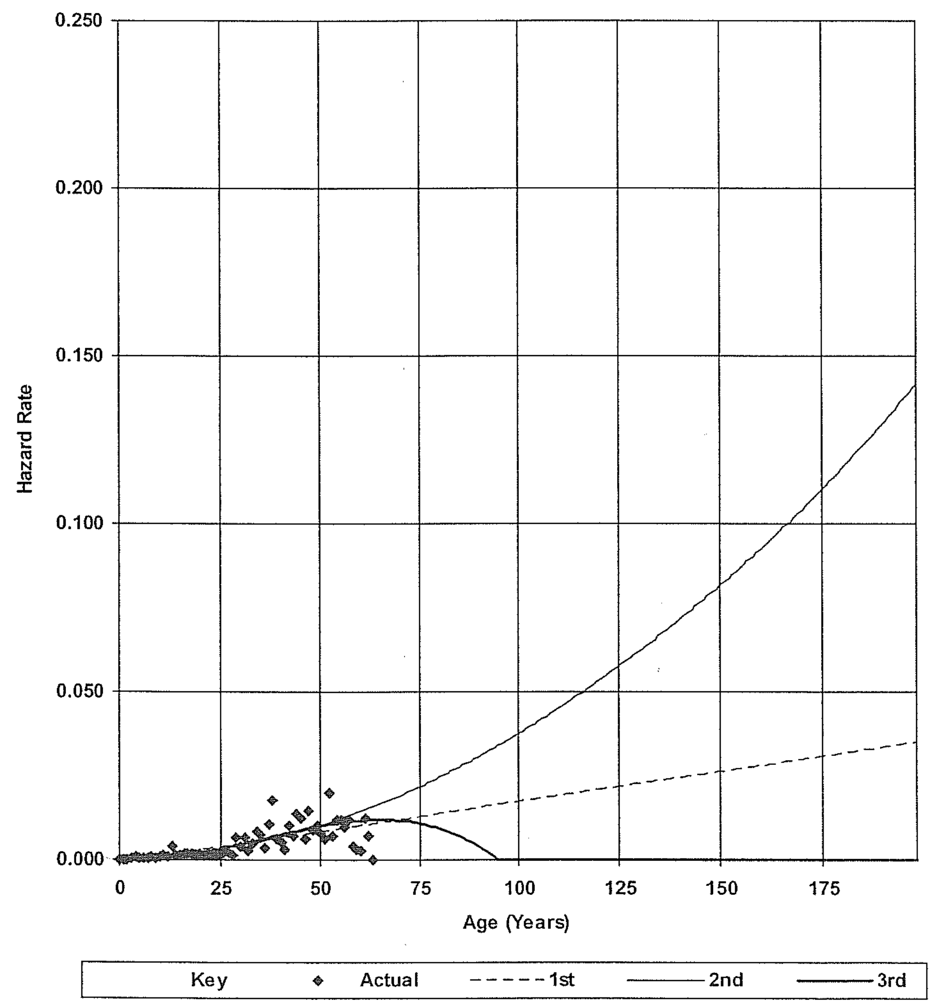
Placement Band: 1950-2012 Observation Band: 2000-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 97.3-L1.5 2nd: 80.6-S1 3rd: 132.9-SC



HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

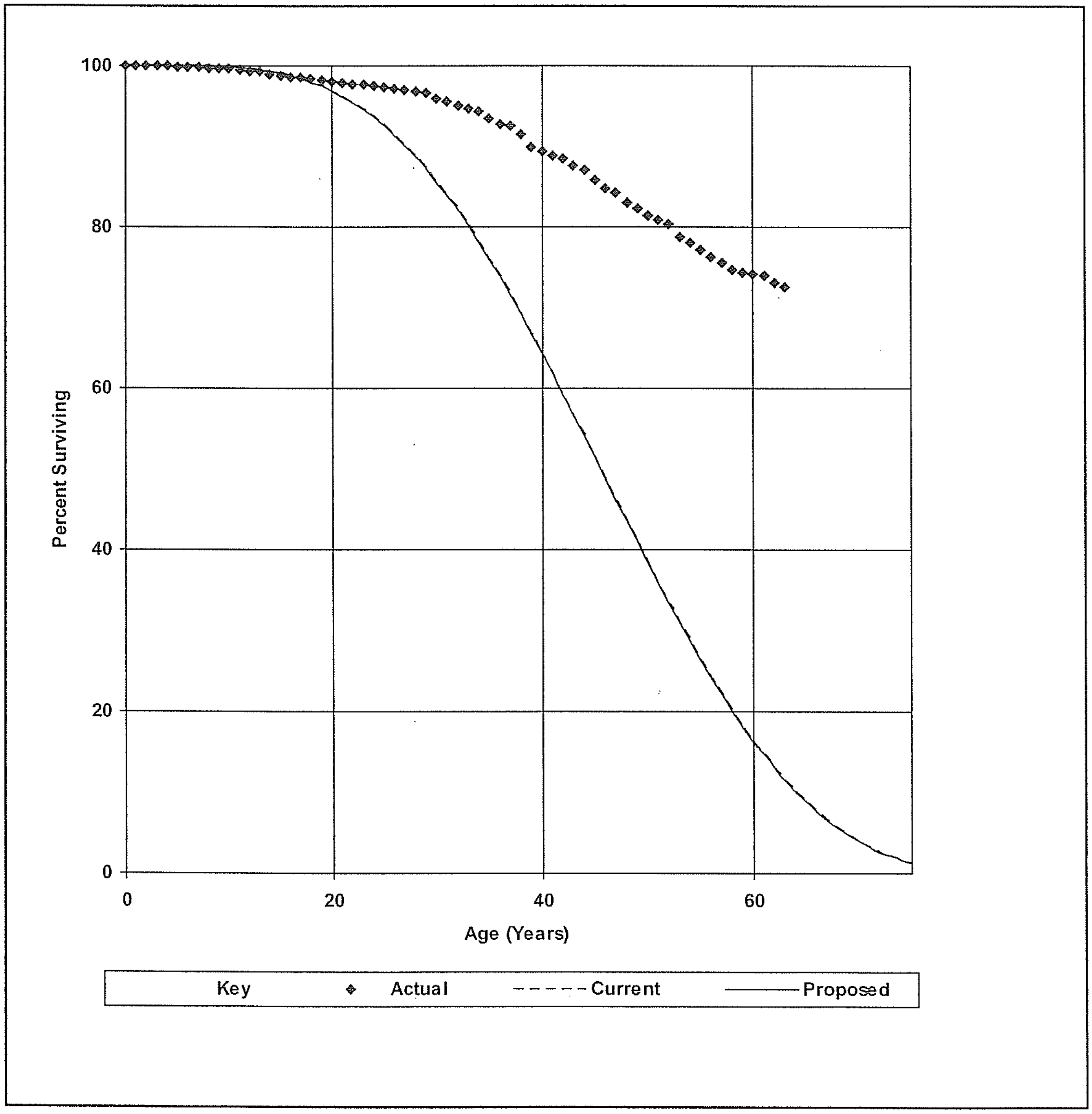
T-Cut: None

Placement Band: 1950-2012

Observation Band: 2000-2012

Current and Proposed Projection Life Curves

Current: 45.0-S2 Proposed: 45.0-S2



Expert Rule 13A

EXPERT RULE 13A

TITLE OF REPORT
2013 Depreciation Rate Review
—Transmission Operations
—Common Operations

CONSULTANT
Ronald E. White, Ph.D.
Foster Associates, Inc.
17595 S. Tamiami Trail, Suite 260
Fort Myers, FL 33908

QUALIFICATIONS
See attached Professional Qualifications.

INSTRUCTIONS PROVIDED
Foster Associates was instructed to conduct a 2013 Depreciation Rate Review and provide recommended depreciation rates for USoA categories derived from service life statistics estimated for category classifications adopted by Hydro One Networks for engineering operations and planning purposes.

BASIS OF EVIDENCE
Specific information and factual assumptions upon which the 2013 Depreciation Rate Review is based are contained within the titled report.

CONFIRMATION
Dr. White has been made aware of and agrees to accept the responsibilities that are or may be imposed as set forth in Rule 13A.

____

Ronald E. White, Ph.D.
January 22, 2014

PROFESSIONAL QUALIFICATIONS

NAME AND ADDRESS

Ronald E. White, Ph.D.
Foster Associates, Inc.
17595 S. Tamiami Trail, Suite 212
Fort Myers, FL 33908

EDUCATION

1961 - 1964 Valparaiso University

Major: Electrical Engineering

1965 Iowa State University

B.S., Engineering Operations

1968 Iowa State University

M.S., Engineering Valuation

Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University

Ph.D., Engineering Valuation

Minor: Economics

Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

EMPLOYMENT

2007 - Present	Foster Associates, Inc. Chairman
1996 - 2007	Foster Associates, Inc. Executive Vice President
1988 - 1996	Foster Associates, Inc. Senior Vice President
1979 - 1988	Foster Associates, Inc. Vice President
1978 - 1979	Northern States Power Company Assistant Treasurer
1974 - 1978	Northern States Power Company Manager, Corporate Economics

1972 - 1974	Northern States Power Company Corporate Economist
1970 - 1972	Iowa State University Graduate Student and Instructor
1968 - 1970	Northern States Power Company Valuation Engineer
1965 - 1968	Iowa State University Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. *99*-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC *Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Ga Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Kansas Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. D.P.U. 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

SPEAKER

Depreciation Training Seminar, Florida Public Service Commission, March 2013.

Depreciation and Obsolescence (Isness and Oughtness), Ninety–Fifth Annual Arizona Tax Conference, August 2012.

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.Page 57

MODERATOR

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #11

Interrogatory

The "Total" Revenue Requirement and the "Rates" Revenue Requirement for 2014, 2015 and 2016 are presented in Exhibit E1, Tab 1, Schedule 1. Please provide the following additional information:

(a) Following the format of Tables 2 and 4 at Exhibit E1, Tab 1, Schedule 1, pages 3 and 6, please provide for each of the years 2010 to 2014 inclusive the following:
   (i) Each of the components of and the Rates Revenue Requirement claimed by Hydro One in each of those years;
   (ii) The Board allowance for each of those components and the Rates Revenue Requirement for each of those years, along with the actual Revenue Sufficiency or Deficiency realized by Hydro One in each of the years 2010 to 2013 inclusive, along with the projected actual Revenue Sufficiency or Deficiency for 2014.

Response

a) Please see the table below for the information requested for years 2010 to 2012. Please refer to response to EP's interrogatory 1, at Exhibit I, Tab 4, Schedule 1 for 2013 actuals and 2014 forecast.

	Approved 2010	Actual 2010	Approved 2011	Actual 2011	Approved 2012	Actual 2012
Total OM&A Expense	426.2	420.8	418.8	414.5	427.1	415.2
Depreciation & Amortization	281.3	272.7	301.8	299.2	332.8	320.0
Capital taxes	6.0	5.3	-	0.4	-	-
Return on Capital*	509.8	536.4	561.0	560.0	607.1	590.5
Income Taxes	34.0	40.7	64.0	77.1	51.4	79.8
Total Gross Revenue Requirement	**1,257.3**	**1,275.9**	**1,345.6**	**1,351.2**	**1,418.4**	**1,405.4**
External Revenues	-18.0	-42.4	-33.7	-41.6	-28.7	-42.0
Export Revenue Credit	-12.0	-12.0	-16.0	-16.0	-16.0	-16.0
Regulatory Assets Recovery	-20.3	-20.3	-7.4	-7.4	0.0	0.0
LV Switch Gear	10.8	10.8	11.1	11.1	11.5	11.5
RATES REVENUE REQUIREMENT	**1,217.7**	**1,212.0**	**1,299.6**	**1,297.3**	**1,385.1**	**1,359.0**

*Return on Capital has been calculated on a deemed basis using the allowed rates of return.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #12

Interrogatory

(a) In Exhibit H1, Tab 5, Schedule 1, Hydro One refers to a cost study prepared by Elenchus which is attached as Exhibit H1, Tab 5, Schedule 1, Attachment 1. Elenchus was one of the experts retained by Hydro-Quebec Energy Marketing Inc. ("HQEM") in the EB-2012-0031 proceeding. Please explain why Hydro One retained the firm HQEM hired in the last proceeding to do the work which the Board directed Hydro One to perform.

(b) The Information Package materials reflect the currently approved ETS rate of $2/MWh. What ETS rate will Hydro One be asking the Board to approve and what is Hydro One's rationale for its ETS proposal?

Response

(a) The Board Decision dated June 6, 2013 in Hydro One's EB-2012-0031 application directed Hydro One to perform a cost allocation study to establish a cost basis for the Export Transmission Service (ETS) rate. Elenchus has recognized expertise in dealing with cost allocation, rate design and regulatory issues. Hydro One hired Elenchus to assist Hydro One in satisfying the Board's direction in a timely and cost-efficient manner.

(b) Please refer to response to CCC IR at Exhibit I, Tab 12, Schedule 18.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #13

Interrogatory

(a) Please provide an exhibit which will identify all of the costs which Hydro One seeks to recover in its Transmission rates which are linked to the costs which Hydro One seeks to recover in Distribution rates for 2015 and 2016 in the EB-2013-0416 proceeding.

(b) What methodology or mechanism does Hydro One suggest that the Board should apply to assure that the levels of OM&A costs and other expenditures in its 2015 and 2016 Transmission rates application are consistent and compatible with the levels of such costs ultimately approved by the Board for recovery in Hydro One's 2015 and 2016 Distribution rates?

Response

(a) Please refer to Exhibit I, Tab 10, Schedule 1 (School Energy Coalition Interrogatory question #1).

(b) Hydro One's rate application for its 2015-2019 distribution rates (EB-2013-0416) is currently before the OEB. The distribution and transmission businesses of Hydro One have common costs that are shared. These common costs will be reviewed and approved by the OEB in Hydro One's EB-2013-0416 proceeding. Hydro One's transmission business will accept the allocation of common costs that is determined as part of the OEB's decision in EB-2013-0416. It is proposed that these settlement discussions will not deal with the allocation of common costs.

London Property Management Association (LPMA) INTERROGATORY #1

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1

Please update Tables 1, 2 and 3 to reflect the most recent forecasts from Global Insight.

Response

Tables 1, 2, and 3 below are updated with the most recent forecasts from Global Insight.

Table 1
Global Insight's Latest Forecast Released in May 2014
(%)

	Historical Years				Bridge Year	Test Years	
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Transmission Cost Escalation for Construction	1.9	3.7	1.6	2.0	1.2	2.0	2.4
Transmission Cost Escalation for Operations & Maintenance	1.6	3.7	2.1	0.9	0.6	1.1	1.1

Table 2
Ontario CPI Forecast Released in June 2014
(%)

	Historical Years				Bridge Year	Test Years	
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
CPI – Ontario	2.4	3.1	1.4	1.1	1.8	2.0	2.0

Table 3
Exchange Rate Forecast Released in June 2014
(CDN$ per US$)

Description	**Historical Years**				**Bridge Year**	**Test Years**	
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Exchange Rate	1.030	0.989	1.000	1.030	1.095	1.077	1.062

London Property Management Association (LPMA) INTERROGATORY #2

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1

Had Hydro One incorporated any impact associated with the potential Ontario pension plan proposal?

Response

Hydro One did not incorporate any impact associated with the "proposed Ontario pension plan" (proposed by the Ontario Government in May 2014).

London Property Management Association (LPMA) INTERROGATORY #3

Interrogatory

Ref: Exhibit B1, Tab 1, Schedule 1

In the Report of the *Board on Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009, it was indicated that it was the OEB's intention to conduct its first regular review in 2014 and any changes to the policy would apply to the setting of rates for the 2015 rate year.

Is Hydro One proposing that any changes that may result from the 2014 review be reflected in the cost of capital for 2015 and 2016 or is the Hydro One proposal strictly based on the proposal shown at the bottom of page 1 and top of page 2?

Response

Hydro One will implement any applicable outcomes from the 2014 OEB review.

London Property Management Association (LPMA) INTERROGATORY #4

Interrogatory

Ref: Exhibit B1, Tab 1, Schedule 1

Please update the deemed short term debt rates of 3.19% for 2015 and 4.45% for 2016 using the most recent Global Insight forecast available.

Response

The deemed short-term rate is 2.27% for 2015 and 4.00% for 2016 using the June 2014 Global Insight BA rate plus the average annual BA spread of 0.9125% as per the OEB's Cost of Capital Parameters, dated November 25, 2013, for Rates effective in 2014.

As stated on page 2 of Exhibit B1-1-1, Hydro One assumes that the deemed short term debt rate for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board would determine the deemed short term debt rate for Hydro One Transmission based on the September 2014 Bank of Canada data which would be available in October 2014 plus the average spread obtained by Board Staff in 2014. Similarly, for 2016, the Board would determine the deemed short term debt rate for Hydro One Transmission based on the September 2015 Bank of Canada data which would be available in October 2015 plus the average spread obtained by Board Staff in 2015.

London Property Management Association (LPMA) INTERROGATORY #5

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1

a) Has Hydro One issued any of the debt for 2014 as shown in Table 2? If yes, please provide complete details of the issuances.

b) Is the forecast of debt issuances shown in Table 3 for 2015 and 2016 still based on the most recent information and projected requirements? If not, please update Table 3 to reflect the most recent forecast.

c) Please update Table 4 to reflect the most recent forecasts for the sources of the information listed.

Response

a) Hydro One has issued the following fixed rate MTN's as shown in Table 2 during 2014:

During January 2014, Hydro One Inc. issued $50 million of 50-year notes with a 4.29% coupon rate, of which $30 million was mapped to Hydro One Transmission.

During June 2014, Hydro One Inc. issued $350 million of 30-year notes with a 4.17% coupon rate, of which $198 million was mapped to Hydro One Transmission.

b) Table 3 is updated below to reflect the most recent forecast. Please see the response to part c) of this question for an explanation of how the coupon rates were derived.

Table 3
Forecast Debt Issues for 2015 and 2016

2015			2016		
Principal Amount ($Millions)	**Term (Years)**	**Coupon**	**Principal Amount ($Millions)**	**Term (Years)**	**Coupon**
159.3	5	3.19%	197.5	5	4.09%
159.3	10	4.22%	197.5	10	5.12%
159.3	30	5.09%	197.5	30	5.99%

c) Table 4 is updated below to reflect the most recent forecast.

Table 4
Forecast Yield for 2014-2016 Issuance Terms

	2014		
	5-year	**10-year**	**30-year**
Government of Canada	1.98%	2.70%	3.23%
Hydro One Spread	0.71%	1.02%	1.35%
Forecast Hydro One Yield	2.69%	3.72%	4.59%
	2015		
	5-year	**10-year**	**30-year**
Government of Canada	2.48%	3.20%	3.73%
Hydro One Spread	0.71%	1.02%	1.35%
Forecast Hydro One Yield	3.19%	4.22%	5.09%
	2016		
	5-year	**10-year**	**30-year**
Government of Canada	3.38%	4.10%	4.63%
Hydro One Spread	0.71%	1.02%	1.35%
Forecast Hydro One Yield	4.09%	5.12%	5.99%

Each rate is comprised of the forecast Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2014 is based on the 3 month forecast and for 2015 is based on the 12 month forecast from the June 2014 Consensus Forecast. The ten-year Government of Canada bond yield forecast for 2016 is based on the April 2014 Long Term Consensus Forecast. The five- and 30-year Government of Canada bond yield forecasts are derived by adding the June, 2014 average spreads (five-year to ten-year for the five-year forecast and 30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for June, 2014 obtained from the Company's MTN dealer group for each planned issuance term.

Hydro One assumes that forecast debt issuance interest rates for each test year will be updated consistent with the ROE methodology, upon the final decision in this case. For rates effective January 1, 2015, the forecast interest rate for Hydro One Transmission debt issues will based on the September 2014 Consensus Forecasts and the average of indicative new issue spreads for September 2014 which will be obtained from the Company's MTN dealer group for each planned issuance term. For rates effective January 1, 2016, the forecast interest rate for Hydro One Transmission debt issues will be based on the September 2015 Consensus Forecasts and the average of indicative new issue spreads for September 2015 which will be obtained from the Company's MTN dealer group for each planned issuance term. In addition Hydro One assumes that long term debt rate will be updated to reflect and take into account the actual issuances of debt since the time of original application consistent with the OEB's Decision on Hydro One Transmission's 2013 and 2014 rate application in EB-2012-0031 and changes in the interest rate forecast.

London Property Management Association (LPMA) INTERROGATORY #6

Interrogatory

Ref: Exhibit E1, Tab 2, Schedule 1

a) How many months of actual expenditures are included in Table 1 in the 2014 Bridge column?

b) Please update the 2014 Bridge column in Table 1 to reflect the most recent year-to-date figures available and the forecast for the remainder of 2014.

c) Please provide the most recent year-to-date actual expenditures in the same level of detail as shown in Table 1 along with the figures for the corresponding period in 2013.

Response

a) 3 months of actual expenditures are included in Table 1 in the 2014 Bridge column.

b) External Revenues ($ Millions)

$M	2014	2014	2014	2014
	Bridge Original	**YTD Actuals Q2**	**Remaining Forecast (July - Dec 2014)**	**Updated YE Forecast**
Secondary Land Use	14.10	7.00	9.50	16.50
Station Maintenance	7.10	7.50	0.80	8.30
Engineering & Project Delivery	0.20	0.00	0.20	0.20
Other External Revenues	6.90	4.00	2.70	6.70
Totals	**28.30**	**18.50**	**13.20**	**31.70**

c)

$M	**2014**	**2013**
	YTD Actuals (Q2 2014)	**YTD Actuals (Q2 2013)**
Secondary Land Use	7.0	9.6
Station Maintenance	7.5	6.2
Engineering & Project Delivery	0.0	0.3
Other External Revenues	4.0	7.4
Totals	**18.5**	**23.5**

London Property Management Association (LPMA) INTERROGATORY #7

Interrogatory

Ref: Exhibit C1, Tab 7, Schedule 1

a) Please provide a copy of the new depreciation study that can be found at Exhibit C1, Tab 7, Schedule 1, Attachment 1.

b) What is the impact on the depreciation expense in each of 2015 and 2016 of the new depreciation study relative to the existing rates?

c) Please provide the detailed depreciation schedules that are found at Exhibit C2, Tab 4, Schedule 1.

Response

a) Please refer to response to CME's interrogatory 10 at Exhibit I, Tab 2, Schedule 10, part a.

b) Please refer to response to CME's interrogatory 10 at Exhibit I, Tab 2, Schedule 10, part b.

c) Please refer to response to SEC's interrogatory 9 at Exhibit I, Tab 10, Schedule 10.

London Property Management Association (LPMA) INTERROGATORY #8

Interrogatory

Ref: Exhibit C1, Tab 8, Schedule 1

a) Please provide the tax credits (federal job creation, Ontario apprenticeship, Ontario co-op education, etc.) claimed in each of 2011 through 2013 and the forecast for 2014 through 2016.

b) Please provide the calculation of the income tax schedules equivalent to Exhibit C2, Tab 5, Schedule 1, Attachments 1 through 7 in EB-2013-0416 for the transmission PILs.

Response

Please see the tax schedules filed as Attachment 1 to 8 to this interrogatory response for part a) and b).

C2-05-01-01 - CALCULATION OF UTILITY INCOME TAXES

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Utility Income Taxes
Test Years (2015 and 2016)
Year Ending December 31
($ Millions)

Line No.	Particulars		2015 (a)			2016 (b)	
	Determination of Taxable Income						
1	Regulatory Net Income (before tax)	$	467.0		$	503.5	
2	Book to Tax Adjustments:						
3	Other Post Employment Benefits expense		22.8			20.4	
4	Other Post Employment Benefits payments		(25.5)			(26.1)	
5	Inergi pension payments		0.0			0.0	
6	Depreciation and amortization		394.2			404.0	
7	Capital Cost Allowance		(509.3)			(512.5)	
8	Removal costs		(1.5)			(1.5)	
9	Environmental costs		(6.3)			(6.0)	
10	Hedge loss - amortization		0.2			0.2	
11	Non-deductible meals & entertainment		3.7			3.7	
12	Capital amounts expensed under $2K		2.8			2.8	
13	Research & Development ITC		0.7			0.6	
14	Federal Apprenticeship Tax Credits		0.2			0.2	
15	Capitalized overhead costs		(31.3)			(30.6)	
16	Capitalized pension costs		(41.4)			(39.9)	
17	Debt Issuance costs - amortization		1.7			1.7	
18	Debt Issuance costs – 21(e) deduction		(2.6)			(2.9)	
19	Premium/Discount - amortization		(0.7)			(0.9)	
20	Bond discount deduction		(0.6)			(1.2)	
21		$	(192.9)		$	(187.8)	
22	Regulatory Taxable Income	$	274.1		$	315.7	
23	Corporate Income Tax Rate		26.50	%		26.50	%
24	Subtotal	$	72.6		$	83.7	
25	Less: R&D ITC / Federal Apprenticeship Tax Credits		(0.9)			(0.8)	
26	Regulatory Income Tax	$	71.8		$	82.8	
	Tax Rates						
27	Federal Tax		15.00	%		15.00	%
28	Provincial Tax		11.50	%		11.50	%
29	Total Tax Rate		26.50	%		26.50	%

C2-05-01-02 - CALCULATION OF CAPITAL COST ALLOWANCE – TEST YEAR (2015, 2016)

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2015 Networks Allocation to Tx
Year Ending December 31
($ Millions)

2015 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,141.0	47.5	2,188.5	23.8	2,164.7	4%	86.6	2,101.9
2	569.9	0.0	569.9	-	569.9	6%	34.2	535.7
3	225.1	0.0	225.1	-	225.1	5%	11.3	213.8
6	60.3	0.0	60.3	-	60.3	10%	6.0	54.3
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	98.2	72.5	170.7	36.3	134.5	20%	26.9	143.8
9	0.7	0.0	0.7	-	0.7	25%	0.2	0.5
10	43.7	12.8	56.5	6.4	50.1	30%	15.0	41.4
12	8.4	7.3	15.6	3.6	12.0	100%	12.0	3.6
13	2.2	0.0	2.2	-	2.2	20%	0.4	1.7
17	53.8	7.0	60.7	3.5	57.3	8%	4.6	56.2
35	0.2	0.0	0.2	-	0.2	7%	0.0	0.2
42	71.8	0.0	71.8	-	71.8	12%	8.6	63.2
45	0.2	0.0	0.2	-	0.2	45%	0.1	0.1
46	7.1	0.0	7.1	-	7.1	30%	2.1	5.0
47	3,081.3	542.9	3,624.2	271.5	3,352.7	8%	268.2	3,356.0
50	44.3	13.6	57.9	6.8	51.1	55%	28.1	29.8
	6408.1	703.6	7,111.7	351.8	6,759.9		504.4	6,607.3
CEC	117.5	4.0	121.5	2.0	119.5	7%	8.4	113.1
	6,525.5	707.6	7,233.2	353.8	6,879.3		512.7	6,720.4

First Nations	(0.3)
CCA not in rates	(3.1)
Total CCA for RR	509.3

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2016 Networks Allocation to Tx
Year Ending December 31
($ Millions)

2016 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,101.9	38.7	2,140.7	19.4	2,121.3	4%	84.9	2,055.8
2	535.7	0.0	535.7	-	535.7	6%	32.1	503.5
3	213.8	0.0	213.8	-	213.8	5%	10.7	203.1
6	54.3	0.0	54.3	-	54.3	10%	5.4	48.9
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	143.8	43.3	187.1	21.6	165.5	20%	33.1	154.0
9	0.5	0.0	0.5	-	0.5	25%	0.1	0.4
10	41.4	14.3	55.7	7.2	48.6	30%	14.6	41.2
12	3.6	5.1	8.8	2.6	6.2	100%	6.2	2.6
13	1.7	0.0	1.7	-	1.7	20%	0.4	1.4
17	56.2	6.8	63.0	3.4	59.6	8%	4.8	58.2
35	0.2	0.0	0.2	-	0.2	7%	0.0	0.2
42	63.2	0.0	63.2	-	63.2	12%	7.6	55.6
45	0.1	0.0	0.1	-	0.1	45%	0.0	0.1
46	5.0	0.0	5.0	-	5.0	30%	1.5	3.5
47	3,356.0	448.3	3,804.3	224.2	3,580.2	8%	286.4	3,517.9
50	29.8	12.4	42.2	6.2	36.0	55%	19.8	22.4
	6,607.3	569.0	7,176.3	284.5	6,891.8		507.6	6,668.7
CEC	113.1	3.6	116.8	1.8	114.9	7%	8.0	108.7
	6,720.4	572.6	7,293.1	286.3	7,006.8		515.7	6,777.4
					First Nations		(0.3)	
					CCA not in rates		(2.9)	
					Total CCA for RR		512.5	

C2-05-01-03 - CALCULATION OF UTILITY INCOME TAXES HISTORIC YEARS

HYDRO ONE NETWORKS INC.
Transmission

Calculation of Utility Income Taxes
Historic Years
Calculation of Utility Income Taxes Historical Years (2011, 2012, 2013)
Year Ending December 31
($ Millions)

Line No.	Particulars		2011		2012		2013*
	Calculation of Federal and ON Taxable Income						
1	Net Income Before Tax (NIBT)	$	457.8	$	536.4	$	598.1
2	**Required Adjustments to accounting NIBT**						
3	**Recurring items included in Revenue Requirement (RR):**						
4	Other Post Employment Benefit expense greater than payments		8.3		(0.5)		1.2
5	Depreciation and amortization		301.5		320.3		326.5
6	Capital Cost Allowance		(389.3)		(448.1)		(487.8)
7	Cumulative Eligible Capital		(4.3)		(9.8)		(9.2)
8	Removal costs		(2.0)		(2.9)		(3.7)
9	Environmental costs paid		(6.9)		(5.9)		(6.1)
10	Non-deductible items (50% Meals & entertainment / interest)		4.3		3.6		4.9
11	R & D Fed ITC/ Apprenticeship (prior yr addback)		0.9		1.4		1.8
12	Capitalized overhead costs deducted		(26.0)		(30.6)		(29.8)
13	Capital additions deducted for accounting		0.4		5.5		12.5
14	Capitalized Pension cost deductions		(23.2)		(42.4)		(50.1)
15		$	(136.3)	$	(209.4)	$	(239.8)
16	**Deferral accounts not part of RR:**						
17	RSVA/RRRP		0.0		0.0		0
18	Restricted Depreciation		19.0		16.3		1.9
19	Smart meter costs deferred		0.0		0.0		0
20	Tx Export credit/Deferred export Rev		9.3		8.3		9.3
21	Deferred Pension		(1.2)		(1.9)		(5.9)
22	Deferral a/c's etc.		1.9		2.4		0.7
23	Tax Changes deferral a/c s		0.0		(0.8)		0
24	Riders 3/6/8		0.0		0.0		0
25	Station Revenue and Secondary Use		0.0		14.0		9.6
26		$	29.0	$	38.3	$	15.6
27	**Reversal of accounting adjustments not part of RR:**						
28	Contingent liability movement		(5.6)		0.8		1.9
29	Capitalized interest deductible for tax		(45.9)		(39.6)		(32.3)
30	Capitalized SRED deducted for tax		0.0		(6.8)		0.0
31		$	(51.5)	$	(45.6)	$	(30.4)
32							

HYDRO ONE NETWORKS INC.
Transmission

Calculation of Utility Income Taxes
Historic Years
Calculation of Utility Income Taxes Historical Years (2011, 2012, 2013)
Year Ending December 31
($ Millions)

Line No.	Particulars		2011		2012		2013*
33	**Recurring items not part of RR:**						
34	Capital Contribution (CCRA True up)		0.0		8.4		0.0
35	First Nations (CCA)		(0.3)		(0.3)		(0.3)
36	CCA on Capital Contributions and OPA directed projects		0.0		0.0		(2.9)
37		$	(0.3)	$	8.1	$	(3.2)
38	**Immaterial items not in business plan detail:**						
39							
40	Reverse Insurance proceeds included in NIBT		(1.0)		(4.1)		0.0
41	Net Underwriting/Finance costs		(2.5)		(2.6)		(0.3)
42	WSIB		(0.8)		0.0		0.0
43	Tenant Inducement		0.7		(0.9)		(0.9)
44	Capital tax paid vs. accrued		0.4		0.0		0.0
45	Other		3.2		0.3		(3.4)
46		$	0.0	$	(7.3)	$	(4.6)
47							
48	NET Adjustments to Accounting NIBT	$	(158.8)	$	(215.9)	$	(262.4)
49							
50	Taxable Income	$	299.0	$	320.5	$	335.7
51							
52	**NOTE:**						
53	Transmission includes Five Nations data						
54							
55	Taxable Income	$	299.0	$	320.5		335.7
56							
57	Corporate Income Tax Rate		28.25	%	26.5	%	26.5
58							
59	Subtotal	$	84.5	$	84.9		89.0
60	Less: Tax credits		(5.5)		(4.7)		(4.3)
61	Income Tax	$	79.0	$	80.2		84.7
63							
64							
65							
66	**Tax Rates**						
67	Federal Tax		17.0	%	15.0	%	15.0
68	Provincial Tax		11.25	%	11.5	%	11.5
69	Total Tax Rate		28.25	%	26.5	%	26.5

*** 2013 Numbers based on estimates as tax returns have not been finalized.**

C2-05-01-04 - CALCULATION OF CAPITAL COST ALLOWANCE - HISTORIC (2011, 2012, 2013)

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2011 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

2011 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,489.7	1.6	2,491.3	-	2,491.3	4%	99.7	2,391.6
2	729.9	-	729.9	-	729.9	6%	43.8	686.1
3	235.6	6.8	242.4	3.7	238.7	5%	11.9	230.4
6	52.4	21.3	73.7	10.6	63.1	10%	6.3	67.4
7	-	-	-	-	-	15%	-	-
8	36.2	8.5	44.7	4.3	40.4	20%	8.1	36.6
9	2.3	(0.1)	2.2	-	2.2	25%	0.5	1.6
10	61.9	10.6	72.5	5.0	67.5	30%	20.3	52.3
12	7.6	20.3	27.9	9.8	18.1	1	18.1	9.8
13	0.2	0.9	1.1	0.4	0.6	N/A	0.1	0.9
17	25.7	11.2	36.9	5.6	31.3	8%	2.5	34.4
35	0.3	-	0.3	-	0.3	7%	-	0.3
42	92.9	3.4	96.3	1.7	94.6	12%	11.4	85.0
45	2.1	-	2.1	-	2.1	45%	0.9	1.1
46	4.6	-	4.6	-	4.6	30%	1.4	3.2
47	1,523.6	549.6	2,073.2	270.6	1,802.9	8%	144.2	1,929.2
50	5.3	62.4	67.7	31.2	36.5	55%	20.1	47.6
52	-	0.3	**0.3**	-	0.3	100%	0.3	-
Total CCA	**5,270.3**	**696.8**	**5,967.1**	**342.9**	**5,624.4**		**389.6**	**5,577.5**
						Less First Nations	(0.3)	
						Total CCA for RR	**389.3**	
CEC	61.2	0.3	61.5	-	61.5	7%	4.3	57.2

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2012 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

2012 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,391.60	0.5	2,392.10	0.3	2,391.90	4%	95.7	2,296.5
2	686.1	-	686.1	-	686.1	6%	41.2	644.9
3	230.4	23.6	254	11.8	242.2	5%	12.1	241.9
6	67.4	5.6	73	2.8	70.2	10%	7	66.0
7	-	-	-	-	0	15%	0	0.0
8	36.6	6.9	43.5	5.7	37.9	20%	7.6	36.0
9	1.6	-	1.6	-	1.6	25%	0.4	1.2
10	52.3	11.2	63.5	5.6	57.9	30%	17.4	46.1
12	9.8	18.9	28.7	9.4	19.3	100%	19.3	9.5
13	0.9	0.2	1.1	0.1	1	20%	0.4	0.7
17	34.4	15.2	49.6	7.6	42	8%	3.4	46.3
35	0.3	-	0.3	-	0.3	7%	0	0.3
42	85	13.9	98.9	7	91.9	12%	11	87.9
45	1.1	-	1.1	-	1.1	45%	0.5	0.6
46	3.2	1.9	5.1	0.9	4.2	30%	1.3	3.9
47	1,929.20	786.5	2,715.70	389.3	2,326.40	8%	186.1	2,529.6
50	47.6	71.4	119	37	82	55%	45.1	73.9
Total CCA	**5,577.5**	**955.8**	**6,533.3**	**477.5**	**6,056.0**		**488.4**	**6,085.1**
						First Nations	(0.30)	
						Total CCA for RR	**448.1**	
CEC	57.2	82.3	139.5		139.5	7%	9.8	129.7

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
2013 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

2013 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,296.5	(16.1)*	2,280.4	2.6	2,277.7	4%	91.1	2,189.3
2	644.9	0.0	644.9	-	644.9	6%	38.7	606.2
3	241.8	7.4	249.2	3.7	245.5	5%	12.3	236.9
6	66.0	8.1	74.0	4.0	70.0	10%	7.0	67.0
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	36.0	19.4	55.3	9.7	45.6	20%	9.1	46.2
9	1.2	0.0	1.2	-	1.2	25%	0.3	0.9
10	46.1	13.8	59.9	6.9	53.0	30%	15.9	44.0
12	9.4	24.4	33.8	12.2	21.6	100%	21.6	12.2
13	0.7	2.3	3.0	1.2	1.8	20%	0.4	2.6
17	46.3	7.9	54.2	3.9	50.2	8%	4.0	50.1
35	0.3	(0.1)	0.2	-	0.2	7%	0.0	0.2
42	87.9	4.5	92.4	2.3	90.1	12%	10.8	81.6
45	0.6	0.0	0.6	-	0.6	45%	0.3	0.3
46	3.9	8.8	12.7	4.4	8.3	30%	2.5	10.2
47	2,529.6	439.1	2,968.7	213.5	2,755.2	8%	220.4	2,748.3
50	73.9	57.7	131.6	28.9	102.7	55%	56.5	75.1
Total CCA	**6,085.1**	**577.0**	**6,662.1**	**293.3**	**6,368.9**		**491.0**	**6,171.2**
						First Nation	(0.3)	
						Less CCA not in rates	(2.9)	
						Total CCA for RR	**487.8**	
CEC	129.7	2.1	131.8	-	131.8	7%	9.2	122.6

*Due to audit adjustments which resulted in reclassification of CCA Class

C2-05-01-05 - CALCULATION OF CAPITAL COST ALLOWANCE

BRIDGE YEAR 2014

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost Allowance (CCA)
2014 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

2014 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,189.3	40.1	2,229.4	20.0	2,209.3	4%	88.4	2,141.0
2	606.2	0.0	606.2	-	606.2	6%	36.4	569.9
3	236.9	0.0	236.9	-	236.9	5%	11.8	225.1
6	67.0	0.0	67.0	-	67.0	10%	6.7	60.3
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	46.2	68.1	114.3	34.0	80.2	20%	16.0	98.2
9	0.9	0.0	0.9	-	0.9	25%	0.2	0.7
10	44.0	15.2	59.2	7.6	51.6	30%	15.5	43.7
12	12.2	16.7	28.9	8.4	20.5	100%	20.5	8.4
13	2.6	0.0	2.6	-	2.6	20%	0.4	2.2
17	50.1	8.0	58.1	4.0	54.1	8%	4.3	53.8
35	0.2	0.0	0.2	-	0.2	7%	0.0	0.2
42	81.6	0.0	81.6	-	81.6	12%	9.8	71.8
45	0.3	0.0	0.3	-	0.3	45%	0.2	0.2
46	10.2	0.0	10.2	-	10.2	30%	3.1	7.1
47	2,748.3	575.9	3,324.2	288.0	3,036.2	8%	242.9	3,081.3
50	75.1	14.5	89.6	7.3	82.3	55%	45.3	44.3
	6,171.2	738.5	6,909.6	369.2	6,540.4		501.6	6,408.0
CEC	122.6	3.6	126.2	1.8	124.4	7%	8.7	117.5
	6,293.7	742.0	7,035.8	371.0	6,664.8		510.3	6,525.5
					First Nations		(0.30)	
					CCA not in rates		(3.4)	
					Total CCA for RR		506.5	

C2-05-01-06 - CALCULATION OF APPRENTICESHIP AND EDUCATION TAX CREDIT TEST YEARS

HYDRO ONE NETWORKS INC.
Transmission
Calculation of Apprenticeship and Education Tax Credit
Tax Credit Test Years (2015, 2016)
Year Ending December 31
($ Thousands)

Line No	Particulars	2015	2016
1	ON Coop Education Credit	$ 560	$ 560
2	Eligible Positions	189	189
3			
4	ON Apprenticeship Credit	$ 2,448	$ 2,448
5	Eligible Positions	293	293
6			
7	Ontario Business Research		
8	Institute Credit	$ 62	$ 62
9			
10	Federal Apprenticeship Credit	$ 200	$ 200
11	Eligible positions	137	137
12			
13	SR&ED	700	600
14			
15	**TOTAL TAX CREDIT**	**$ 3,970**	**$ 3,870**
16			
17			
18	Tax Credit included in tax expense (1)	$ 900	$ 800
19	Tax Credit included in OM&A (1)	$ 3,070	$ 3,070
20	**Total**	**$ 3,970**	**$ 3,870**

(1) In accordance with US GAAP, refundable tax credits included are recorded in OM&A and non refundable tax credits are recorded as a reduction to tax expense. Consequently, the tax credits relating Ontario Co-op, Ontario, Apprenticeship, and Ontario Business Research are recorded in OM&A

C2-05-01-07 - CALCULATION OF APPRENTICESHIP AND EDUCATION TAX CREDIT - HISTORIC YEARS

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Apprenticeship and Education Tax
Historic Years
2011, 2012
Year Ending December 31
($ Thousands)

Line No	Particulars	2011	2012
1	ON Coop Education Credit	$ 690	$ 525
2	Eligible Positions	230	175
3			
4	ON Apprenticeship Credit	$ 3,127	$ 2,303
5	Eligible Positions	341	288
6			
7	Federal Apprenticeship Credit	$ 342	$ 169
8	Eligible positions	177	99
9			
10	SR&ED	$ 1,327	$ 1,738
11			
12	**TOTAL TAX CREDIT**	**$ 5,486**	**$ 4,735**

HYDRO ONE NETWORKS INC.
Transmission
Calculation of Utility Income Taxes
Tax Credit Test Years (2014, 2015)
Year Ending December 31
($ Thousands)

Line No	Particulars	2013*	2014	
1	ON Coop Education Credit	$ 655	$ 560	
2	Eligible Positions	218	189	
3				
4	ON Apprenticeship Credit	$ 2,443	$ 2,448	
5	Eligible Positions	313	293	
6				
7	Ontario Business Research			
8	Institute Credit	$ 53	$ 62	
9				
10	Federal Apprenticeship Credit	$ 310	$ 200	
11	Eligible positions	163	137	
12				
13	SR&ED	1,065	700	
14				
15	**TOTAL TAX CREDIT**	**$ 4,526**	**$ 3,970**	
16				
17				
18	Tax Credit included in tax expense	$ 1,375	$ 900	(1)
19	Tax Credit included in OM&A	$ 3,151	$ 3,070	(1)
20	**Total**	**$ 4,526**	**$ 3,970**	

* 2013 numbers based on the 2013 Tax returns filed for Hydro One Networks

(1) In accordance with US GAAP, refundable tax credits included are recorded in OM&A and non refundable tax credits are recorded as a reduction to tax expense. Consequently, the tax credits relating Ontario Co-op, Ontario, Apprenticeship, and Ontario Business Research are recorded in OM&A.

London Property Management Association (LPMA) INTERROGATORY #9

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1

a) Please provide the percentage salary increases that are "consistent with ratified collective agreement over the length of the agreement" for Society Staff and PWU Staff.

b) What is the impact on the revenue requirement if the assumed net annual increase for both 2015 and 2016 is reduced by one percentage point in both years for the Society Staff and PWU Staff?

c) What is the impact on the revenue requirement if the assumed annual increase for MCP staff is reduced in each of 2015 and 2016 by one percentage point?

d) Please provide Exhibit C1, Tab 4, Schedule that is referred to on page 6.

Response

a) In the most recent PWU settlement, the negotiated salary increases are 2.5% and 2.5% for 2013 and 2014. In the most recent Society settlement , negotiated salary increases are 2%, 2.25% and 2.25% for 2013, 2014 and 2015 respectively.

   Note – The deadline for response to this IR does not allow enough time to do the analysis for parts b and c. On a best efforts basis, answers have been prepared based on the previous Transmission filing.

b) During Hydro One's EB-2012-0031 Transmission rate filing, the Consumers Council of Canada asked what the revenue requirement impact would be if wage escalations were reduced by 1% for Society, PWU, and MCP. Hydro One estimates that the impact on 2015 and 2016 revenue requirement would be in the same range as the previously filed responses. The EB-2012-0031 responses can be found in I-7-10.01 CCC 23, I-7-10.02 CCC 24, and I-7-10.03 CCC 25, and are summarized in the table below.

Revenue Requirement impact of a 1% change in wage escalation rates, by Representation

($ millions)	2013	2014
Society	0.40	0.45
PWU	0.85	0.96
MCP	0.23	0.26

c) See part b)

d) Please see Attachment 1 to this interrogatory.

COMPENSATION, WAGES, BENEFITS

Included in Attachment 1 is as follows:

- Compensation, Wages, Benefits Attachment 1
- Compensation Cost Benchmarking Study – Hydro One Networks Inc. Attachment 1
- Expert Evidence Statement from Mercer (Canada) Limited Attachment 2

COMPENSATION, WAGES, BENEFITS

1.0 INTRODUCTION

In previous Board decisions, the Board has expressed concerns with rising compensation levels at Hydro One. In a 2006 Board Decision, Hydro One was directed to conduct a total compensation study and in a subsequent decision, the Board directed that the study be updated. At the first stakeholder session for EB 2013-0416 a stakeholder enquired as to whether Hydro One would be updating the compensation study. In response to this request, Hydro One initiated another study to update the two previous studies. In total, three total compensation studies have been conducted and the results show that Hydro One has succeeded in lowering total employee compensation as compared to market median. The results of this Compensation Cost Benchmarking Study are detailed later in this exhibit as Attachment 1.

While lowering compensation cost relative to market median is desirable from a rate payer point of view, the fact remains, that Hydro One must attract, and engage a highly skilled workforce, in the face of an aging workforce and worldwide competition for similar skills. Coupled with the fact that Hydro One is heavily unionized and Hydro One was created with legacy collective agreements only adds to the challenge of further reducing compensation costs. For full details regarding the Hydro One corporate staffing strategy, see Exhibit C1, Tab 4, Schedule 1

Despite these challenges, Hydro One has been successful in balancing the competing pressures of reducing compensation costs relative to market median at the same time as attracting and maintaining an engaged workforce. Ultimately, the rate payers benefit from the quality, expertise and reliability of Hydro One employees.

2.0 TOTAL COMPENSATION STUDIES

In EB-2006-0501, the Board directed Hydro One to file a total compensation study that "will provide useful and reliable information concerning Hydro One's compensation costs, and how they compare to those of other regulated transmission and/or distribution utilities in North America". Following stakeholder sessions to obtain input on how this study would be conducted, Mercer undertook a Compensation Cost Benchmarking Study (the "2008 Study") and the results were filed in EB-2008-0272.

In EB-2010-0002, the Board directed Hydro One "to revisit its compensation cost benchmarking study in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America. Further stakeholder sessions took place and Mercer once again conducted a total compensation study (the "2011 Study") that was filed in EB-2012-0031.

Responding to a stakeholder request for an updated study in the EB 2013-0416 application, Hydro One requested Mercer to conduct another study (the "2013 Study").

Table 1 compares the study results for all three studies.

Table 1

Mercer Compensation Benchmarking Study Results vs. Market Median

Total Compensation

Employee Group	2013 Survey Results	2011 Survey Results	2008 Survey Results	Total Change from 2008 to 2013
Management	-1%	-17%	-1%	0%
Society	9%	5%	5%	4%
PWU	12%	18%	21%	-9%
Overall	10%	13%	17%	-7%

The 2013 study findings show that on an overall weighted average, Hydro One is positioned approximately 10% above market median. This is an improvement relative to the 2008 Mercer study where Hydro One's overall weighted average was found to be 17% above market median. Mercer stated the shift towards market median was notable, especially given the peer group, like Hydro One, had worked to minimize labour costs through the substantial economic downturn which began in 2008. In other words, Hydro One improved its standing against others in the peer group who were also attempting to reduce compensation costs.

For the individual groups, Hydro One management classifications surveyed were found to be 1% below market median. Compared to the 2011 study, this shows that non-represented compensation has moved toward market median. The 2011 study result was mainly due to the impact of a two year wage freeze on non-represented compensation. The 2013 study results would indicate that non-represented classifications are closer to the desired non-represented compensation policy of being at the 50th percentile. Professionals (Society of Energy Professionals – "the Society") classifications were found to be 9% above market median. Power Workers' Union (PWU) represented classifications were found to be 12% above market median, a significant improvement from the 2008 result of 21% above market median reflecting the increased use of hiring hall staff and the increased pension contributions negotiated as part of the new collective agreement.

3.0 THE UNIONIZED ENVIRONMENT

Approximately 90% of the Hydro One work force is unionized. Hydro One has collective agreements with the Power Workers' Union (PWU), The Society of Energy Professionals (The Society), the Canadian Union of Skilled Workers (CUSW), and each of the 15 Building Trade Unions (BTUs) (via EPSCA).

The collective agreements establish the terms and conditions of the employment relationship for a fixed period of time. It is critical to understand that Hydro One inherited collective agreements from Ontario Hydro which established terms of employment. These legacy collective agreements established a 'floor' upon which future negotiations were based. While legacy collective agreements continue to strongly influence current Hydro One collective agreements, Hydro One has done much to change the status quo. Hydro One has been successful in incrementally reducing costs and/or increasing productivity through collective bargaining. Obtaining dramatic compensation reductions in the environment facing Hydro One is unrealistic.

Collective Agreements are legal contracts. In labour agreements, more so than commercial contracts, parties must also consider their longer term relationship. Hydro One's Human Resources strategy is to negotiate fair and reasonable collective agreements to foster and promote healthy union–management relationships.

4.0 COLLECTIVE BARGAINING

4.1 PWU

The PWU represents over 70% of Hydro One employees. The PWU is an industrial union that represents the trades, controllers, technicians and clerical workers. Its members perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work.

An attempt by Hydro One to achieve significant cost reductions in wages, benefits and pension would likely result in a strike. The last PWU strike was in 1985 and lasted 12 days. It was handled by placing management and Society-represented staff in key functions to maintain operations/service to the extent possible. However, as a result of numerous downsizing programs, and reorganization of work, there is fewer management staff available today with the requisite skills and experience to occupy key PWU positions during a strike. Furthermore, unlike other industries, Hydro One does not have a product that can be stockpiled. As a result, the Company would be unable to continue operations for a sustained period of time during a PWU strike.

Rather than risk jeopardizing the supply of reliable electricity, the company has sought to achieve overall cost reductions by negotiating increased management flexibility to run the operations, as opposed to wide scale reductions in wages, benefits and pensions.

4.2 The Society of Energy Professionals

The Society represents approximately 20% of Hydro One employees. Society-represented staff performs engineering, high level technical and administrative work as well as supervisory functions. The majority of the Society-represented employees in Hydro One have either post-secondary education (university degrees) and/or post-graduate education. These include graduate engineers, finance and telecommunication specialists.

In 2005, the Society initiated a fifteen week strike in response to Hydro One's desire to reduce wages and benefits and increase hours of work for new employees. Hydro One was requested by the Shareholders to enter into mediation–arbitration to end the strike. The arbitration award resulted in some cost savings for future hires, highlighted with less costly pension provisions for new Society employees.

5.0 COLLECTIVE BARGAINING

The collective bargaining relationships at Hydro One are very complex and sophisticated. Hydro One and the bargaining agents with whom the Company negotiate are professionals and very seasoned in the area of collective bargaining. Hydro One has been able to achieve reasonable settlements with incremental cost reductions and increased flexibility in a variety of areas in every round of collective bargaining since 2001. Examples include:

- elimination of costly incentive pay plans
- reasonable economic increases;
- reductions and cost containment in benefit improvements;
- introduction of new salary schedules with lower starting rates and lower maximum rates;
- introduction of a less costly pension plan;
- increased employee pension contributions;
- increased flexibility to contract out work;
- reduction in the hourly rate for a variety of jobs;
- increased flexibility to move staff;

- increased utilization of contingent workers;
- introduction of less costly classifications;
- greater shift scheduling flexibility; and
- reduction in temporary work headquarter costs.

5.1 Recent Negotiation Highlights

5.1.1 PWU Negotiations

In 2013, a new 2 year collective agreement was successfully negotiated by the bargaining committees of Hydro One and the PWU and ratified by the PWU-represented staff. The term of this collective agreement ends on March 31st, 2015. Modest economic increases were negotiated (2.5% in each year). To lessen the cost impact of these increases, they were phased in on April 1st and October 1st in 2013 and 2014.

Employee pension contributions were also increased. In the last Transmission Decision, the Board commented that it expects to see demonstrated measurable progress towards increasing employee pension contributions. The Board stated that "Hydro One must demonstrate measurable progress towards having its pension contributions reflect those prevailing in the public sector generally. The evidence suggests that an employee contribution level of 50% is the norm". In 2011, Hydro One negotiated a 0.5% increase to the PWU employee pension contributions and in the most recent negotiations, employee contributions have increased by a further 0.75% in 2013 and 1.0% in 2014.

To address rising benefit costs, the parties agreed to the requirement to use mandatory generic prescribed drugs and to establish a joint committee to make recommendations to reduce costs in the area of biological and other expensive drugs.

Increased resourcing flexibility was achieved by negotiating enhancements to use more temporary staff and to contract out more work.

5.1.2 Society Negotiations

In 2013, a new three year collective agreement was successfully negotiated by the bargaining committees of Hydro One and the Society and ratified by the Society-represented staff. The term of this collective agreement ends on March 31st, 2016.

Modest economic increases were negotiated (2%, 2% and 2.25%). Employee pension contributions were increased by 0.75%, 1% and 0.75% in each year of the term of the collective agreement.

Increased flexibility was achieved by increasing the length of new hire probationary periods and formalizing the deletion of the Purchase Service Agreement so that contracting out can be fully utilized when appropriate.

6.0 MANAGEMENT (MCP) COMPENSATION

Changes to management compensation are wholly at the discretion of senior management. The management compensation structure is comprised of two key programs, merit pay and short term incentive pay.

Merit Pay

Merit pay is designed to reflect and reward increasing competency and performance in an employee’s current role while also taking into account the extent to which Hydro One wishes to recognize and retain the employee. On this basis, merit pay is not an across-the-board base pay program but rather it is recognition of performance/ potential based on managerial judgment.

The *Broader Public Sector Accountability Act (BPSAA) 2010* froze all management compensation from 2010 to 2012. The 2012 Ontario Budget amended this Act so that compensation for Vice President's and above are frozen until such time that there is no deficit in the Budget.

Since the wage freeze legislation expired for management positions below the Vice President level, Hydro One has had a limited base merit pay program in 2013. A rigorous process was used to align pay for performance by considering a number of factors such as overall performance, engagement scores, pay relative to performance of peers and potential flight risk. In 2013, all MCP employees increased their pension contributions by 0.75%.

In 2014, MCP employees were eligible for a merit pay program. A 2.5% merit pay adjustment fund was established for MCP employees Band 5 level and below. The merit program once again aligned pay and performance and was allocated in a manner that differentiates between levels of performance. For a second consecutive year, all MCP employees had their pension contributions increased by another 0.75%.

Short Term Incentive Pay

A short term incentive (STI) program is a discretionary program and is based on the Hydro One Board and Senior Management's assessment of achievement of the corporate scorecard and achievement of individual performance agreements.

The STI program is a compensation strategy that drives performance and is separate and distinct from the merit pay program. The STI program is designed to establish a strong correlation between corporate performance, individual performance and at-risk pay. The

STI program provides an opportunity for MCP employees to earn an annual cash incentive based on two elements. The first is the achievement of corporate performance targets set by the Board of Directors. Corporate performance measures and targets are set annually through the use of a balanced scorecard. A balanced scorecard is designed to measure corporate performance broadly, covering key aspects of corporate performance. Measures included in the scorecard are designed to ensure the corporate strategy is achieved. The second element of the STI program is individual contributions to these targets. MCP employees have annual performance contracts that specify key goals and targets that individual performance is measured against.

The maximum percentage of funding for the STI program is at the discretion of the Hydro One Board of Directors, based on a recommendation by the Human Resources Committee of the Board. The maximum allowable individual short term incentive is established for each MCP salary band.

7.0 COMPENSATION STRATEGY

Hydro One has experienced rapidly increasing transmission and distribution work programs since 2004. Resourcing of these work programs must occur on the most cost effective basis possible within a highly competitive labour market.

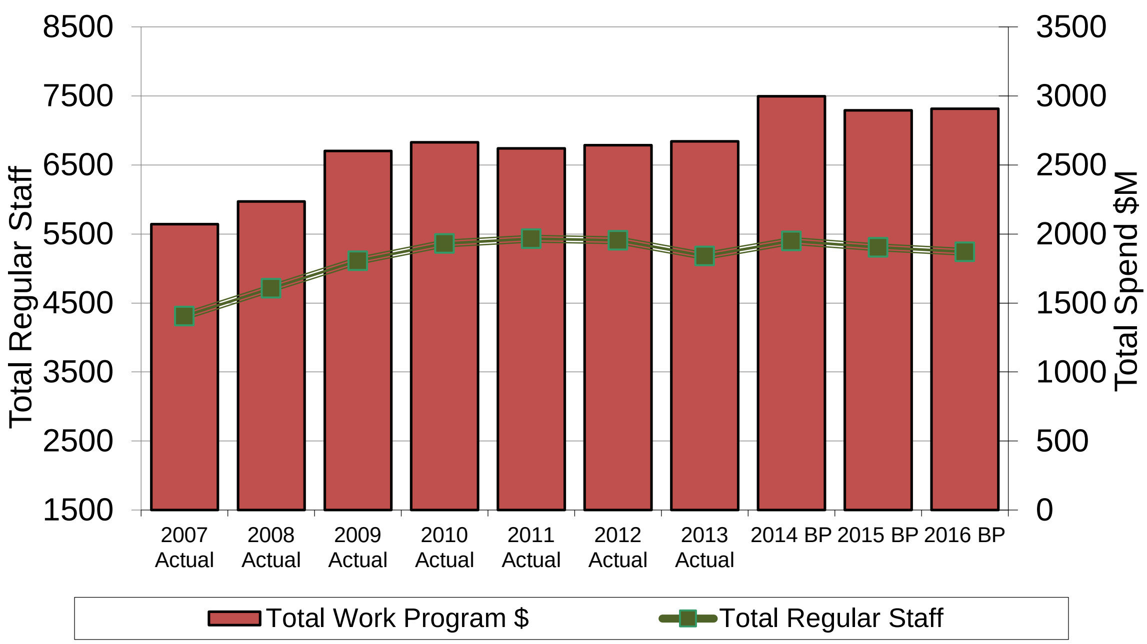
Attachment 2 provides year end compensation costs for Hydro One Networks (Transmission and Distribution) from 2010 to 2013 and forecasted year end compensation cost for the bridge year (2014) and test years (2015-2016). The Company believes that the upward trend in these costs is reasonable in light of the steadily increasing transmission and distribution work programs since 2004, as well as the negotiated increases in labour rates.

Note this data represents year end payroll costs for Hydro One Networks in total (i.e. Distribution and Transmission). The purpose of this table is to illustrate the trend in compensation costs.

For the period 2015-2016, the total Networks (Transmission and Distribution) work program is expected to increase by approximately 0.4% while the regular headcount is expected to decrease by 1.3 % by year end 2016.

Table 2

Work Program and Head Count Forecast (2007 to 2016)



Hydro One believes that the goal of reducing overall wages, pension and benefits for future new hires reflects a reasonable balance between the need to attract and retain new staff while pursuing a more favourable cost structure. This is a difficult balance to achieve. Too much of a reduction in compensation and benefits will impact the ability to attract the new skills necessary to replenish the workforce. However, as outlined in Exhibit C1, Tab 3, Schedule 1, as the proportion of Hydro One staff qualifying for and taking early retirement is growing substantially, the goal of reducing compensation for future new hires will reduce overall compensation costs for Hydro One and its ratepayers. Hydro One's best performers are highly marketable, and a number of management staff have left the company in recent years. The Hydro One succession plan has facilitated internal promotion and a smooth transition in most cases, but our internal replacement capacity is now significantly diminished in key areas. External recruitment has proven challenging as our compensation levels and structures have fallen below the market for top people.

8.0 COMPARISON OF COLLECTIVE AGREEMENTS

When assessing the prudency of Hydro One's collective agreements, a useful comparison is the compensation wage scales for similar PWU (table 3) and Society (table 4) classifications in the Ontario Hydro successor companies as Hydro One competes for staff with these companies and is vulnerable to losing staff to these organizations. Such a comparison is instructive since all these wage scales have the same starting point, which is the establishment of the successor companies in 1999. It is important to compare compensation escalation based on <u>total</u> "dollar" base rates of similar classifications. Simply comparing accumulated base rate percentage increases does not capture the true difference between <u>total</u> base compensation paid at the successor companies.

In the two wage scale comparison tables for each of PWU and Society staff which follow the wage scale rates shown are for the top end of the wage scale band.

As shown in Table 3 for PWU staff, Hydro One has negotiated substantially lower wage scales than OPG and Bruce Power for all seven positions with the exception of one.

Table 3

Power Workers' Union – Wage Comparisons, 1999 and 2013

	1999	2013	Percent Change
Mechanical Maintainer/Regional Maintainer - Mechanical			
Hydro One	$ 28.23	$ 42.48	50 %
OPG	$ 29.08	$ 50.08	72 %
Bruce Power	$ 29.08	$ 57.10	96 %
Shift Control Technician/Regional Maintainer – Electrical			
Hydro One	$ 28.23	$ 42.48	50 %
OPG	$ 30.31	$ 50.08	65 %
Bruce Power	$ 30.31	$ 57.27	89 %
Clerical – Grade 56 (based on a 35-hour work week)			
Hydro One	$ 21.46	$ 32.30	51 %
OPG	$ 21.46	$ 31.99	49 %
Bruce Power	$ 21.46	$ 35.59	66 %
Clerical – Grade 58 (based on a 35-hour work week)			
Hydro One	$ 24.20	$ 36.42	50 %
OPG	$ 24.20	$ 38.95	61 %
Bruce Power	$ 24.20	$ 40.13	66 %
Regional Field Mechanic/Transport & Work Equipment Mechanic			
Hydro One	$ 26.20	$ 39.43	51 %
OPG	$ 26.20	$ 50.08	91 %
Bruce Power	$ 26.20	$ 49.71	90 %
Stockkeeper			

	1999	2013	Percent Change
Hydro One	$ 23.27	$ 36.75	58 %
OPG	$ 23.27	$ 38.95	67 %
Bruce Power *	$ 23.27	$ 44.88	93 %
Labourer			
Hydro One	$ 19.03	$ 28.63	50 %
OPG	$ 19.03	$ 38.95	105 %
Bruce Power *	$ 19.03	$ 44.88	136 %

* Assumes that the position falls within the Civil Maintainer II classification and corresponding wage rate

Table 4

Society of Energy Professional – Wage Comparisons 1999 and 2013

	1999	2013	Percent Change
MP2			
Hydro One	$ 77,954.79	$ 100,078.50	28 %
OPG	$ 77,954.79	$ 101,333.39	30 %
Bruce Power	$ 77,954.79	$ 102,113.46	31 %
IESO	$ 77,954.79	$ 118,068.03	51 %
MP4			
Hydro One	$ 88,651.39	$ 113,801.46	28 %
OPG	$ 88,651.39	$ 115,171.67	30 %
Bruce Power	$ 88,651.39	$ 116,045.14	31 %
IESO	$ 88,651.39	$ 134,218.03	51 %

	1999	2013	Percent Change
MP6			
Hydro One	$ 100,756.80	$ 129,350.68	28 %
OPG	$ 100,756.80	$ 130,950.99	30 %
Bruce Power	$ 100,756.80	$ 131,907.42	31 %
IESO	$ 100,756.80	$ 152,617.49	51 %

For Society staff, Hydro One, OPG and Bruce Power have successfully negotiated lower end rates as compared to the PWU wages. However, for all three Society categories, Hydro One has lower wage scales than OPG and Bruce Power. The IESO has continued with the wage schedule structure that existed at demerger.

It is quite clear that compared to these four other companies, Hydro One has been quite successful in controlling costs in collective bargaining over the past ten years to the benefit of all ratepayers.

9.0 POWER LINE TECHNICIAN RATE COMPARISON

Within Ontario, the largest LDCs are Hydro One Networks Inc., Toronto Hydro Electric System Limited, Hydro Ottawa Limited, Enersource Hydro Mississauga Inc., London Hydro Inc., Horizon Utilities Corp. and Powerstream Inc. Each of the LDCs employ Power Line Maintainers (PLMs). Table 5 compares the PLM rate at each of the LDCs to the PLM rate paid at Hydro One Networks. The PLM classification was chosen since it represents a highly skilled and highly populated classification that is core to the other LDCs.

Table 5

POWER LINE MAINTAINER WAGE COMPARISON

Company	Classification	Wage – 2012($hr)	H1 % Difference
Hydro One	Power Line Maintainer	38.75	-
Toronto Hydro	Power Line or Cable Person	40.26	-3.9%
Enersource	Power Line Technician	38.95	-.5%
Powerstream	Linesperson	38.31	+1.1%
Horizon	Power Line Maintainer	37.88	+2.3%
London Hydro	Power Line Maintainer	36.42	+6.0%
Hydro Ottawa	Power Line Maintainer	36.53	+6.0%

Hydro One uses a multi-skilled position called a Regional Maintainer–Lines classification (RLM). The RLM uses the PLM as the base job with additional duties such as lead hand, contract monitor, establishment and holding of work protection as well as additional technical, trade and customer relations skills beyond the Power Line Maintainer classification.

Table 4 illustrates that the PLM rate at Hydro One ranges from being slightly below to slightly above the larger LDCs in Ontario. Despite the rates being very close, the type of work and skills required at Hydro One are often more complex. Hydro One employees often work in a more rural setting than their counterparts in other LDCs. As a consequence, Hydro One employees can work in conditions and with equipment not normally required at these LDCs. Trades employees working on lines maintenance often work on both Distribution and Transmission assets and are required to be knowledgeable and proficient with overhead, underground and submarine cable. Again, this is not typical of the PLM role in other Ontario LDCs.

10.0 SUMMARY

Compensation levels at Hydro One are reasonable and appropriate given the environment in which the Company operates. In recent years, despite significantly increased work volumes, overall costs have been minimized by the simplification of required job skills and pay levels where appropriate. Hydro One's demographic challenge requires the Company to be active in the labour market and with worldwide competition for these skills there is a need for competitive compensation.

The updated Mercer Total Compensation Benchmarking Study demonstrates that there has been a significant improvement in total compensation costs at Hydro One relative to market median. It is important to emphasize that in a time where other organizations are facing similar cost pressures, Hydro One has lowered its overall total compensation from 2008 to 2013 by 7% against the peer group.

A strong barometer of Hydro One's ability to restrict compensation increases is a direct comparison to companies such as OPG, Bruce Power, and IESO. Hydro One competes directly with these organizations for skilled workers. Hydro One is also at risk of losing experienced staff to these organizations if our compensation is not competitive. Despite these competitive pressures, Hydro One has negotiated compensation levels that are less costly than OPG, Bruce Power and the IESO.

In addition, in a heavily unionized environment, there are significant constraints on an employer's ability to reduce compensation costs per employee. However, despite these constraints, the Corporation has made gains with the reduction in the area of compensation and benefit reductions.

MERCER

TALENT • HEALTH • RETIREMENT • INVESTMENTS

COMPENSATION COST BENCHMARKING STUDY

HYDRO ONE NETWORKS INC.

09 DECEMBER 2013

MARSH & McLENNAN COMPANIES

CONTENTS

1

Executive Summary

Hydro One Networks Inc. ("Hydro One") has retained Mercer to prepare an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's total compensation levels including salary, short-term incentives, long-term incentives, pension and employer paid health and group benefits relative to a select peer group. This study was conducted in 2008 and 2011, and repeated, following a similar methodology, in 2013. Year-over-year trend analysis is provided.

The preliminary results of our analysis were presented at the October 16, 2013 stakeholder session in Toronto. This document represents the results of our analysis. Specifically:

Compensation Benchmarking

Consistent with the Stakeholder feedback, the compensation benchmarking component of the study compared Hydro One with the 2011 Transmission, Distribution and Generation market peer group, supplemented with participants from the Similar Regulatory Environment group.

The study reflected approximately 3,050 Hydro One employees in 32 benchmark positions representing 57% of Hydro One's employee population (excluding non-full time employees). In total, our analysis reflected approximately 14,000 incumbents employed in the Canadian energy and/or adjacent sectors.

On an overall weighted average basis, for the positions we reviewed in 2013, Hydro One is positioned approximately 10% above the market 50th percentile ("P50"). In comparison to the 2011 study, Hydro One's overall weighted average positioning has decreased from 13% above the market total compensation P50.

The shift in Hydro One's competitive position towards the median is notable given that the peer group, like Hydro One, has worked to reduce labour costs as a response to both the substantial economic downturn beginning in 2008 and expectations of key stakeholders over the entire period between the 2008 and 2013 during the compensation cost benchmarking studies.

The overall Hydro One positioning is driven by a combination of competitive base salaries, especially for the most highly skilled Power Workers' Union ("PWU") positions and Professionals ("Society") members, and the high relative value of legacy, pension and benefits programs (the legacy Management pension and benefit and Professional pension plans are now closed to new members).

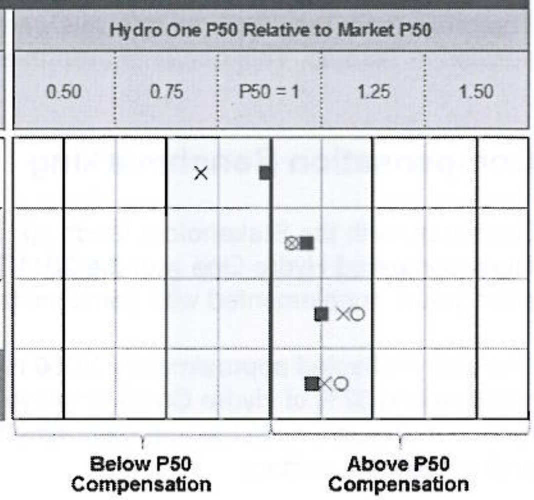
The table below summarizes the results of the 2013 Compensation Cost Benchmarking Study compared to the results of the 2011 and 2008 study.

Table 1

Legend

■ 2013 Hydro One Position Relative to Market
X 2011 Hydro One Position Relative to Market
O 2008 Hydro One Position Relative to Market

			Total Remuneration (Current)		
			Multiple of P50		
	Hydro One Group	*# of Hydro One Incumbents*	2013	2011	2008
Weighted Average	Non-Represented	*206*	0.99	0.83	0.99
	Professionals	*746*	1.09	1.05	1.05
	Power Workers	*2,100*	1.12	1.18	1.21
	Overall	*3,052*	*1.10*	*1.13*	*1.17*



2

Introduction

Hydro One Networks Inc. ("Hydro One") has retained Mercer to prepare an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's total compensation levels including salary, short-term incentives, long-term incentives, pension and employer paid health and group benefits relative to a select peer group. This study was conducted in 2008 and 2011, and repeated, following a similar methodology, in 2013. Year-over-year trend analysis is provided.

This report is intended to help Hydro One in preparing a two year Cost of Service application for Transmission rates (2015-2016) and a five year Custom Cost of Service Application for Distribution (2015-2019). The results of the Compensation Cost Benchmarking study will be filed as evidence for both rate setting applications.

To provide independent and reliable information on Hydro One's relative compensation costs, Mercer has undertaken a customized survey of total compensation costs in the market ("Compensation Benchmarking").

The total compensation (i.e., base salary, short-term incentives, long-term incentives, pension and benefits) benchmarking analyses focused on assessing Hydro One's overall competitiveness in the marketplace.

3

Guiding Principles

Based on our typical benchmarking approach and the benchmarking principles that guided the compensation benchmarking, as well as how Mercer applied them, these include:

1. Principle objective – to revisit the 2011 and 2008 Mercer Study to reasonably compare Hydro One compensation costs to those of regulated utilities in Canada.
   - The 2011 and 2008 Mercer Studies were revisited following the same general overall methodology to provide appropriate study-over-study comparisons.

2. Keep it simple to entice survey participants.
   - The data collection process was reviewed and streamlined, where possible, to encourage survey participants to share data. Additional follow-up was provided by Mercer to support comparator participation in the study.

3. Be independent, testable, repeatable and market-based.
   - The study was conducted in a manner that meets each of the criteria listed.

4. Provide participants with the assurance that their information could not be attributable to them.
   - All participants were assured that data would be held confidentially by Mercer and only be shared in aggregate form.

5. Be based on the groups surveyed in the 2011 Mercer Study and expanded as deemed appropriate by the consultant.
   - The 2013 study targeted the same benchmark jobs and organizations as the 2011 study. Three (3) organizations were also added to the 2011 invitation list, in addition to the organizations that were invited to participate in 2011. This resulted in a total of four (4) new participants in the 2013 study – the three (3) new organizations noted above plus one (1) organization that was invited to participate in 2011 and declined at that time.

6. Mirror the scoping in the 2011 and 2008 Mercer Studies for peer selection, job classes, etc. and changes as deemed appropriate by the consultant.
   - The same methodology used in 2011 and 2008 was followed in the 2013 Mercer Study for both peer company selection and job classes for inclusion. As noted in 5. above, four (4) additional comparator companies were added to the peer group. The selected benchmark job classes represented 57% of Hydro One's employee population (excluding non-full time employees), an increase over the 2011 study.

7. Enable reasonable comparison to the last Mercer study and provide trending analysis for Hydro One.
   - By including approximately 85% of peers and 94% of jobs from the 2011 Mercer Study, reasonable comparisons have been made and trending has been assessed.

8. Compare to market median rather than market average
   - The 2013 Mercer Study is based on a comparison of Hydro One median compensation against market median compensation. Comparison of medians is standard compensation practice; medians are representative of the middle data point in a sample and are less sensitive to outliers than the mean.
     - The 2008 and 2011 studies also compared Hydro One to the median.
   - Appendix A provides a comparison of Hydro One's total compensation median against market average. On an overall weighted average basis, there is no difference in Hydro One's median positioning relative to market median and market arithmetic mean.

9. No adjustments to reflect regional costs of living amongst the study participants.

10. Request data about pension as a percentage of total benefits, and benefits as a percentage of compensation.
    - It is standard benchmarking practice to assess benefits and pension costs as part of the total compensation value provided to employees; therefore, we have not provided the details of this analysis showing benefit and pension separately.

11. Rely on the expertise of the selected consultant to recommend appropriate changes in methodology and assumptions.
    - Hydro One relied on Mercer's expertise in conducting the study.

4

Compensation Benchmarking

Peer Groups

Mercer selects peer organizations, for compensation benchmarking purposes, based on a stable metric that reflects the size and operating complexity of the organization (typically, this is revenue and/or total assets). Where there is a relatively small sample of relevant comparator organizations, Mercer establishes limits of 33% to 300% of the scope criteria for the organization we are analyzing. Some organizations were included in the analysis despite falling below the 33% of revenue threshold value. These organizations were primarily Ontario based local distribution companies that are seen as important benchmarks by stakeholders.

As a result, to develop a single peer group for Hydro One, we considered all organizations, with 2011 or 2012 annual revenues or total assets between 33% and 300% of Hydro One's 2012 annual revenue or total assets, from the following areas:

1. Electric utilities, multi-utilities, generators, and gas utilities industries in Canada as classified by their Global Industry Classification Standard ("GICS")

2. 73 Local Distribution Companies ("LDCs") in Ontario

3. Other comparable regulated businesses (i.e., integrated telecommunication services, railroads, etc.)

Overall, 24 organizations were invited to participate in the study:

- All 13 organizations included in the 2011 study were invited
  - Of these organizations, 2 declined (Altalink, Canadian Utilities)
- Three new organizations were invited
  - Of these organizations, 2 agreed to participate (Enersource Corporation, Horizon Utilities Corporation)

Organizations that did not participate in the compensation benchmarking indicated that they were unable to participate due to either resource constraints or an insufficient number of relevant benchmark positions.

Following standard industry practice, comparisons were made between Hydro One's incumbents, at the 50th percentile, to the market peer group 50th percentile on base salary, total cash compensation and total compensation.

To ensure that no one organization biased the results, we have weighted our analysis by organization for each job class and not by incumbents to determine Hydro One's position relative to the market (i.e., the analysis is "Org Weighted"). To preserve the confidentiality of compensation data at both Hydro One and participating organizations, we have aggregated our results.

Market Sample

Summarized below are the participating organizations in the compensation benchmarking.

Table 2

Company Name	Revenue[1]	# of Employees[1,2]
Hydro-Québec	$12,228.0	21,000
BC Hydro Power & Authority	$4,898.0	5,862
Ontario Power Generation Inc.	$4,732.0	10,691
EPCOR Utilities Inc.*	$4,036.0	4,036
ENMAX Corporation	$3,160.1	1,840
Toronto Hydro Electric System Ltd.	$2,852.0	1,526
Enbridge Gas Distribution Inc.	$2,400.0	2,200
TransAlta Corporation	$2,262.0	3,140
Bruce Power L.P.*	$2,103.7	4,200
Manitoba Hydro	$1,902.0	6,637
SaskPower	$1,862.0	3,000
New Brunswick Power	$1,697.0	2,361
PowerStream Inc.	$1,029.0	541
Enersource Corporation*	$822.0	374
Horizon Utilities Corporation*	$570.6	404
75th %ile	$3,598.1	5,031
50th %ile	$2,262.0	3,000
25th %ile	$1,779.5	1,683
Average	$3,103.6	4,521
Hydro One	$5,728.0	5,337

[1] *Data as reported by survey participants in CAD ($MM)*

[2] *Representative of full-time employees and equivalents only*

* *New participants in 2013*

Benchmark Positions

The compensation survey was designed to benchmark compensation levels from a cross-section of Hydro One's population. To determine the roles to be included in our benchmark analysis, we reviewed positions that represented all of Hydro One's major business units and at least 50% of Hydro One's employee population.

To assist with study over study comparisons, it was determined that Hydro One should collect incumbent data using 33 of the same benchmark roles surveyed in the 2011 study. Due to limited data in the market from previous years, the following role was not surveyed in 2013:

- Tree Trimmer - Journeyman (Power Workers)

In total, 33 benchmark positions were included in the compensation benchmarking study and we were able to report data on 32 of these job. Due to limited data in the market, the following role was excluded from the final analysis:

- Regional Maintainer - Forestry

As a result, ***the 2013 Compensation Cost Benchmarking Study directly reflected approximately 3,050 Hydro One employees in 32 benchmark positions representing 57% of Hydro One's employee population (excluding non-full time employees).***

In the market, we collected approximately 14,000 individual incumbent observations across the benchmark positions (excluding the 3,050 Hydro One incumbents) ***employed in the Canadian energy and/or adjacent sectors.***

Summarized below are the benchmark positions organized by major employee group. The results in this report are summarized by the following employee groups. Specifically (sorted in descending total compensation by Group):

Table 3

Hydro One Group	Job #	Benchmark Survey Title
Non-Represented	1	Financial Director
	2	Top Rates and Regulatory Affairs Executive
	3	Senior Legal Counsel
	4	Engineer F
	5	Area Superintendent
	6	Human Resource Manager / Consultant
	7	Field Service Coordinator
	8	Administrative Assistant
Professionals	9	Engineer E
	10	Business Analyst C
	11	Engineer D
	12	Engineer C
	13	Engineer B
	14	Business Analyst A
	15	Engineer A
Power Workers	16	System Operator (Controller)
	17	Regional Maintainer - Lines (Supervisory)
	18	Protection and Control Technician
	19	Area Distribution Engineering Technician
	20	Regional Maintainer - Lines
	21	Regional Maintainer - Electrical
	22	Fleet Mechanic
	23	Lineman - Journeyman
	24	*Regional Maintainer - Forestry**
	25	Service Dispatcher
	26	Drafter II
	27	Stock Keeper
	28	Data Entry Clerk
	29	Production Field Administrator III
	30	Electrical Apprentice
	31	Lines Apprentice
	32	Meter Reader
	33	General Labourer/Roustabout

**Insufficient data to report*

"Professionals" refers to Hydro One positions represented by the Society of Energy Professionals (i.e., "Society") and "Power Workers" refers to Hydro One positions represented by the Power Workers' Union (i.e., "PWU").

See Appendix B for a summary of position descriptions.

Methodology

As outlined in Appendix B, summarized below is the methodology used to determine compensation levels. Specifically:

Base Salary/Wage – Annual base salary at July 1, 2013. If an hourly rate was reported, we annualized the value by multiplying the standard number of work hours per week by 52 weeks per year. If a weekly rate was reported, we annualized the value by multiplying by 52 weeks per year.

- Data effective July 1, 2013 captures Hydro One's most recent collective agreement terms.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive or bonus paid where applicable.

- Hydro One does not provide short-term incentive or bonus programs to Professional or Power Worker positions.

Benefits and Pensions – To value benefit and pension programs, we applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans.

Total Compensation – Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., expected value of stock options or share awards) and pensions and benefits.

- Hydro One does not provide long-term incentive programs to any positions.

Findings

Summarized below are the results of our compensation benchmarking analysis.

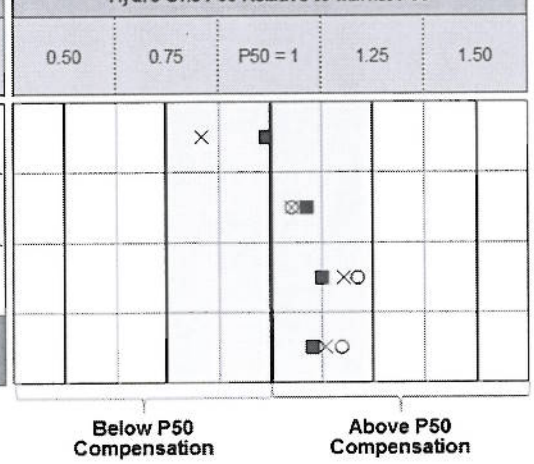
Overall, **on a weighted average basis, Hydro One's total compensation cost is 10% above market median**. Hydro One's position relative to the market 50th percentile varies by employee group from a low of 1% below market P50 for the non-represented group and a high of 12% above the market P50 for the PWU.

In the 2011 study, Hydro One's overall weighted average was 13% above the market total compensation P50 – a 3% shift towards the market median has occurred since 2011.

Table 4

Legend
- ■ 2013 Hydro One Position Relative to Market
- X 2011 Hydro One Position Relative to Market
- O 2008 Hydro One Position Relative to Market

			Total Remuneration (Current)		
			Multiple of P50		
	Hydro One Group	# of Hydro One Incumbents	2013	2011	2008
Weighted Average	Non-Represented	206	0.99	0.83	0.99
	Professionals	746	1.09	1.05	1.05
	Power Workers	2,100	1.12	1.18	1.21
	Overall	*3,052*	*1.10*	*1.13*	*1.17*



The results are driven by a combination of competitive base wages, especially for the most highly skilled Power Workers' Union ("PWU") positions, and the relatively high value of legacy collective agreement wages, pension and benefits programs (the legacy non-represented pension and benefit and Society pension plans are now closed to new members).

We understand that these legacy plans relate to collective agreements negotiated prior to the formation of Hydro One. All PWU employees continue to be covered by the legacy plans. Even if all Non-Represented and Professional employees were covered by the new plans, the difference in overall cost on a weighted average basis appears to be minimal as the high population Power Worker positions continue to be covered by the legacy plans; however, the use of the "hiring hall" for several of the PWU benchmarks does appear to reduce compensation costs relative to both other PWU positions and our market data.

For new employees hired into Non-Represented and Professional job classifications, the value of pensions and/or benefits, where applicable, have decreased due to recent amendments to these plans (see "Future" column on the following pages).

We note that, when measured on revenue, Hydro One is the second largest organization in the sample. Although size has a limited impact on middle management and unionized roles, size may have an impact on compensation for executive roles, as these roles tend to be larger and more complex in larger organizations.

As requested by stakeholders in 2011, in addition to comparing Hydro One P50 to market P50, a comparison was also made of Hydro One median to market average (mean). On a weighted average basis, Hydro One's total compensation cost is 10% above market average. Hydro One's position relative to market varies by employee group from a low of 3% below market average for the non-represented group and a high of 13% above the market average for the PWU. In conclusion, there is relatively little difference between the market median and market average. See Appendix A for detailed results.

Non-Represented

Summarized below are our results for the Non-Represented roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2011, the 2013 Total Compensation (Current) results have increased from 17% below market median to 1% below market median.

Table 5

			Hydro One P50 Relative to Market P50[1]			
					Total Compensation[3]	
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Current[4]	Future[5]
Non-Represented	Financial Director	3	3%	20%	21%	21%
Non-Represented	Top Rates and Regulatory Affairs Executive	4	-5%	-5%	-1%	-3%
Non-Represented	Senior Legal Counsel	8	-7%	0%	12%	6%
Non-Represented	Engineer F	83	-10%	-17%	-15%	-19%
Non-Represented	Area Superintendent	16	-6%	-3%	0%	-2%
Non-Represented	Human Resource Manager / Consultant	8	-30%	-29%	-26%	-29%
Non-Represented	Field Service Coordinator*	76	11%	10%	14%	6%
Non-Represented	Administrative Assistant	8	-3%	-4%	-3%	-4%
	2013 Weighted Average Non-Represented	206	-2%	-4%	-1%	-6%
	2011 Weighted Average Non-Represented	137	-17%	-20%	-17%	-18%
	2008 Weighted Average Non-Represented	151	-2%	-4%	-1%	-5%

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs. The results do not reflect a 0.75% employee pension contribution increase effective October 1st, 2013.

Professionals ("Society")

Summarized below are our results for the Professional roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2011, the 2013 Total Compensation (Current) results have increased from 5% above market median to 9% above market median.

Table 6

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market P50[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	Future[5]
Professionals	Engineer E	132	-2%	-6%	-3%	-6%
	Business Analyst C	15	26%	21%	38%	32%
	Engineer D	258	4%	-1%	7%	5%
	Engineer C	18	14%	3%	19%	14%
	Engineer B	271	10%	9%	12%	12%
	Business Analyst A	11	25%	23%	30%	30%
	Engineer A	41	18%	11%	12%	12%
	2013 Weighted Average Professionals	746	7%	3%	9%	7%
	2011 Weighted Average Professionals	779	6%	-3%	5%	4%
	2008 Weighted Average Professionals	578	8%	-2%	5%	3%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)*
[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*
[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*
[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*
[5] *Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.*

Power Workers

Summarized below are our results for the Power Worker roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2011, the 2013 Total Compensation results have improved from 18% above market median to 12% above market median.

Table 7

Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market P50[1] Base Salary	Total Cash[2]	Total Compensation[3] Current[4]
System Operator (Controller)	92	25%	16%	28%
Regional Maintainer - Lines (Supervisory)	92	18%	18%	24%
Protection and Control Technician	82	20%	18%	30%
Area Distribution Engineering Technician	180	12%	12%	23%
Regional Maintainer - Lines	742	7%	7%	22%
Regional Maintainer - Electrical	238	2%	2%	17%
Fleet Mechanic	68	8%	7%	21%
Lineman - Journeyman	80	14%	14%	4%
Regional Maintainer - Forestry	n/a	-	-	-
Service Dispatcher	20	33%	29%	41%
Drafter II	33	18%	18%	30%
Stock Keeper	49	21%	21%	37%
Data Entry Clerk	63	11%	9%	21%
Production Field Administrator III	3	-38%	-36%	-31%
Electrical Apprentice	63	-17%	-21%	-24%
Lines Apprentice	285	-4%	-8%	-13%
Meter Reader	10	-2%	-6%	-7%
General Labourer/Roustabout	10	-13%	-16%	-27%
2013 Weighted Average Power Workers	2,100	8%	6%	12%
2011 Weighted Average Power Workers	2,411	10%	9%	18%
2008 Weighted Average Power Workers	1,966	20%	10%	21%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)*
[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*
[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*
[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*

APPENDIX A

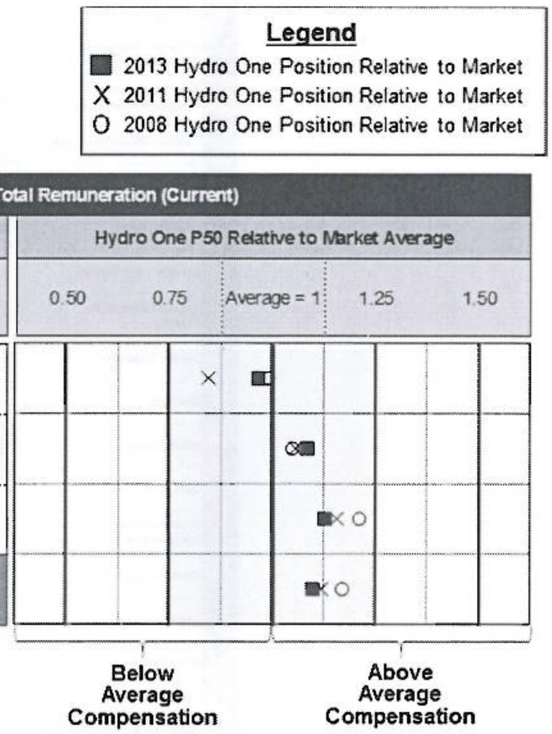
Hydro One vs. Market Average

As requested by stakeholders, summarized below are the results of our compensation benchmarking analysis comparing Hydro One median to market average.

Overall, **on a weighted average basis, Hydro One's total compensation cost is 10% above the market average (mean).** Hydro One's position relative to market varies by employee group from a low of 3% below the market average for the non-represented group to a high of 13% above the market average for the PWU.

Table 8

	Hydro One Group	# of Hydro One Incumbents	Total Remuneration (Current) – Multiple of Average 2013	2011	2008
Weighted Average	Non-Represented	206	0.97	0.84	0.99
	Professionals	746	1.09	1.06	1.05
	Power Workers	2,100	1.13	1.15	1.21
	Overall	*3,052*	*1.10*	*1.12*	*1.17*



Non-Represented

Summarized below are our results for the Non-Represented roles that we benchmarked at Hydro One relative to the market peer group.

Table 9

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market Average[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	Future[5]
Non-Represented	Financial Director	3	-1%	6%	7%	7%
Non-Represented	Top Rates and Regulatory Affairs Executive	4	-14%	-15%	-17%	-18%
Non-Represented	Senior Legal Counsel	8	-6%	-4%	3%	-2%
Non-Represented	Engineer F	83	-13%	-18%	-15%	-20%
Non-Represented	Area Superintendent	16	-7%	-8%	-8%	-9%
Non-Represented	Human Resource Manager / Consultant	8	-32%	-34%	-32%	-35%
Non-Represented	Field Service Coordinator*	76	11%	10%	14%	6%
Non-Represented	Administrative Assistant	8	-7%	-8%	-8%	-8%
	2013 Weighted Average Non-Represented	206	-4%	-6%	-3%	-8%
	2011 Weighted Average Non-Represented	137	-15%	-17%	-16%	-17%

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.
The results do not reflect a 0.75% employee pension contribution increase effective October 1st, 2013.

Professionals ("Society")

Summarized below are our results for the Professional roles that we benchmarked at Hydro One relative to the market peer group.

Table 10

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market Average[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	Future[5]
Professionals	Engineer E	132	0%	-8%	-1%	-5%
Professionals	Business Analyst C	15	23%	18%	31%	26%
Professionals	Engineer D	258	6%	-2%	4%	3%
Professionals	Engineer C	18	13%	7%	19%	14%
Professionals	Engineer B	271	12%	5%	14%	14%
Professionals	Business Analyst A	11	16%	13%	19%	19%
Professionals	Engineer A	41	12%	6%	15%	15%
	2013 Weighted Average Professionals	746	8%	1%	9%	7%
	2011 Weighted Average Professionals	779	6%	-1%	6%	4%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)*
[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*
[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*
[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*
[5] *Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.*

Power Workers

Summarized below are our results for the Power Worker roles that we benchmarked at Hydro One relative to the market peer group.

Table 11

			Hydro One P50 Relative to Market Average[1]		
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Total Compensation[3] Current[4]
Power Workers	System Operator (Controller)	92	17%	13%	25%
	Regional Maintainer - Lines (Supervisory)	92	14%	13%	25%
	Protection and Control Technician	82	20%	18%	28%
	Area Distribution Engineering Technician	180	11%	9%	21%
	Regional Maintainer - Lines	742	8%	6%	19%
	Regional Maintainer - Electrical	238	7%	7%	21%
	Fleet Mechanic	68	12%	10%	19%
	Lineman - Journeyman	80	13%	10%	5%
	Service Dispatcher	20	29%	26%	41%
	Drafter II	33	9%	6%	15%
	Stock Keeper	49	21%	19%	31%
	Data Entry Clerk	63	6%	5%	16%
	Production Field Administrator III	3	-37%	-37%	-32%
	Electrical Apprentice	53	-19%	-22%	-28%
	Lines Apprentice	285	3%	1%	-7%
	Meter Reader	10	0%	-3%	-6%
	General Labourer/Roustabout	10	-13%	-14%	-27%
	2013 Weighted Average Power Workers	2,100	9%	7%	13%
	2011 Weighted Average Power Workers	2,411	10%	8%	15%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.*

[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*

[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*

[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*

APPENDIX B

Position Descriptions

Benchmark Position	Survey Code	Generic Description
Administrative Assistant	220.108.430	Requires a general knowledge of departmental procedures, practices and office routine. Possesses good office and computer skills including word processing, spreadsheets, graphics software, dictaphone transcription, and filing. May provide assistance to a more senior Administrative Assistant in a large department.
Area Distribution Engineering Technician	999.999.001	Perform Technical support work for the Distribution Section of the area: such as monitoring the performance of the distribution system by performing various technical studies, identifying and recommending solutions to the supervisor, providing field data and preliminary analysis for engineering studies. Negotiate property settlements on distribution lines and perform joint use activities. Provide administrative support related to preparation of estimates and work orders (WO) work schedules, line layouts, joint use, provision of underground cable and fault location service. Perform staking activities and prepare design packages for new connections, service upgrades, extensions, betterments and relocations.
Area Superintendent	700.792.211	Responsible for providing construction management and supervision within the construction group. Administers construction contracts. Is accountable for construction costs, schedules, safety, product quality and environment performance. Provides input into Project Execution Plans and the associated schedules and estimates. Usual qualifications include 10 to 12 years of experience including supervisory experience. Requires experience in construction management and supervision of various trades.
Business Analyst A	320.392.360	Assists with analyzing internal metrics. Performs responsible and varied business analytical or administrative functions. Assists with preparation documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree.
Business Analyst C	320.392.340	Analyzes internal metrics. Performs responsible and varied business analytical or administrative functions. Prepares documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree with a minimum of 4 years' related experience; technical diploma with a minimum of 6 years' related experience.
Data Entry Clerk	999.999.002	Perform data processing services including inputting, updating, to various computerized databases and applications of external service providers. Perform clerical/administrative duties in support of system processes. Work with various internal and external contacts and customers in the setup, maintenance, reporting and follow up of non-electricity accounts, customer service orders, materials, corporate charge cards, time reporting, management reporting, damage claims, accounts receivable, etc. Perform administrative services for provincial client group and special projects.
Drafter II	510.656.420	Incumbent works on standard drafting assignments. Methods are detailed and standard but judgment is required in planning tasks and choice of methods. Accountable for accuracy and adequacy of work performed. May provide technical guidance to less experienced Drafters. Usual qualifications include a technical school diploma or equivalent, with a minimum of 5 years' related experience.
Electrical Apprentice	999.999.112	A five year apprenticeship leading to a Construction and Maintenance Electrician

Benchmark Position	Survey Code	Generic Description
Engineer A	510.780.360	Incumbent receives "on-the-job" training in various phases of office, plant or field engineering through assignments or, in some cases, classroom instruction. Tasks assigned are simple and routine in nature. Assists more senior engineers in the preparation of plans, calculations, reports, etc. Few technical decisions are made and these are routine, with clearly defined procedures and guidelines. Works under close supervision and work is reviewed for accuracy, adequacy and conformance with prescribed procedures. Usual qualifications include a university degree in engineering with minimal experience.
Engineer B	510.780.350	Uses a variety of standard problem solving techniques. May assist more senior engineers in carrying out technical tasks requiring computation methods. Duties are assigned with detailed oral and occasionally written instructions. Work is reviewed in detail with guidance given. May give limited technical guidance to junior professionals or technicians working on a common project. Usual qualifications include a university degree in engineering with a minimum of 2 years' related experience.
Engineer C	510.780.340	Incumbent is responsible for varied engineering assignments requiring a broad knowledge of an engineering specialty and the effect the work has upon other fields. Solves problems using a combination of standard or modified procedures. Participates in planning objectives. Performs independent studies, and analyzes, interprets and draws own conclusions; more complex work projects are referred to more senior authorities. Not supervised in detail except on more difficult assignments. May give periodic technical guidance to less experienced professionals or technicians assigned to work on a common project. Usual qualifications include a university degree in engineering with a minimum of 4 years' related experience.
Engineer D	510.780.330	This is the first level of full engineering specialization and is considered the senior level position. Alternatively may be the level at which an individual acts as group leader or work task force leader of a small group of technical personnel. Requires application of well-developed technical knowledge in planning, conducting and coordinating difficult assignments. The position requires the modification of established guidelines and initiation of new approaches. Makes independent decisions in planning, organizing and completing technical assignments. Work is reviewed for soundness of judgment but accepted technically as accurate and feasible. Work is assigned in terms of objectives and priorities but informed guidance is available. Advises on technical problems and supervision, and may plan, schedule and review work of professional engineers and technicians. May make recommendations concerning selection, training, discipline and remuneration of staff.
Engineer E	510.780.320	May have responsibility for coordinating engineering work assignments and making recommendations on technical applications developed by other professional personnel or consultants. May involve the direct supervision of a group of professionals. Provides guidance and training to less experienced staff. Checks work for accuracy and completeness. As a specialist, conducts special, complex and advanced level studies. Work is generally reviewed for results only. Makes independent decisions within broad guidelines and policies. May make recommendations concerning selection, training, discipline and remuneration of staff. May also responsible for construction.
Engineer F	510.780.310	Incumbent is considered an authority in an engineering field of specialization and acts as a technical consultant to the organization. This level is a dual-stream first level managerial position. Incumbents may be responsible for directing a staff of professional and support employees or act as a technical specialist. Responsible for planning and directing large engineering programs/projects; sets priorities and allocates resources; makes necessary decisions on all day-to-day operating matters within constraints of company policy. Receives work in terms of broad objectives.
Field Service Coordinator	700.793.240	Manage and supervise trade, technical and clerical staff. Develop work programs, organize schedules, provide instructions, guidance and checks, monitor work to ensure work quality and accuracy and in conformity to governing regulations. Ensure the administration of procedures, applicable legislation and collective agreements are met. Administer and control contract work. Review work methods, ensure appropriate training. Develops, maintains and enhance customer relationships through direct contact both internally and externally. This position is non-represented.
Financial Director	210.100.130	Responsible for providing overall direction for tax, insurance, budget, credit and treasury functions for the organization. Provide short to medium term direction for all corporate financial functions so that financial transactions, policies, and procedures meet the organization's short and medium-term business objectives and are conducted in accordance with regulations, and standards. Activities may include: credit control; cash flow; investment management; tax; insurance; treasury; internal audit; budgeting and forecasting; and foreign exchange. Lead, direct, evaluate, and develop a team of senior managers to ensure that the organization's financial strategy is implemented effectively, consistently and according to established guidelines.

Benchmark Position	Survey Code	Generic Description
Fleet Mechanic	999.999.011	Be responsible for the inspection, repair and maintenance, as well emergency repair of vehicles (e.g. bucket truck, all-terrain vehicles, go track, digger truck, ladder truck forklift, backhoe, manlift, vans/pickup trucks and the hydraulic equipment of the vehicles e.g. booms, buckets. Maintain inspection schedules and coordinate scheduling repairs to be contracted out. Work is performed in a garage or on site.
General Labourer/Roustabout	700.792.431	This is the level at which individuals with no previous experience enter into the company. Acts as a general labourer. Works under close supervision within well-defined procedures. Duties involve general field/plant maintenance or clean-up work. Minimum qualifications include a high school diploma with minimal related experience.
Human Resource Manager / Consultant	120.100.220	This position plans, designs, develops, implements and administers policies and programs through functional supervision in all or some of the following areas: employee relations, executive compensation, wage and salary administration, job evaluation, performance management, recruitment and selection and employment equity/ human rights.
Lineman - Journeyman	920.788.410	Responsible for the installation, maintenance, removal, and inspection of transmission/distribution power lines. Typically requires 4 years of experience and certification as a Power Line Technician (or equivalent).
Lines Apprentice	999.999.113	A four year apprenticeship leading to a Power Line Technician position.
Meter Reader	920.680.430	Responsible for reading electric, gas, or water meters and keeping track of their average use by recording information. Other duties would include inspecting meters for damages and defects. Entry level position which typically requires a high school education.
Production Field Administrator III	220.778.413	Works independently. Works closely with field operations. Assists in all areas of production and general accounting duties, clerical and office administration functions. Provides analysis and input of operational accounting information and codes and inputs all payables and production volumes. May assist in preparing special production reports. Requires broad knowledge of department procedures. Orders all stationery/supplies and runs office. Monitors, troubleshoots and co-ordinates with head office maintenance of existing computer systems. May check work of junior staff and provide guidance. Working with a Supervisor, assists in preparing field accruals and analyzes actual performance versus budget. Possesses a solid understanding of basic accounting principles. Requires advanced PC and database management knowledge. An accounting background or diploma with 8 years' office experience is typically required.
Protection and Control Technician	999.999.004	Perform initial inspections, conduct trouble-shooting and preventative maintenance, carry out modifications and repairs as required, on all types of protection, telecommunications, metering and control equipment which comes under Protection and Control (P&C) jurisdiction. Discuss and review results with supervisor, if the equipment is highly critical from the standpoint of system operation, before putting the equipment into service.
Regional Maintainer - Electrical	999.999.007	Responsible for the general maintenance and repair work on electrical systems and equipment at various geographical locations. Requires overhauling, maintaining and inspecting equipment such as conductors & insulators i.e. batteries, station bus, cable, compressed air systems, fire protection equipment switchgear i.e. circuit breakers, load interrupters metalclad switchgear, oil circuit breakers, SF6 breakers, air blast breakers, transformers, rotating machines, distribution stations & equipment. Has the necessary knowledge of the trade theory, operating principles, charts, tables, testing equipment and other reference works, to test, dismantle, repair, clean and assemble station electrical equipment within the required specifications. Requires certification as a construction and maintenance electrician. Also performs mechanical and protection and control work.

Benchmark Position	Survey Code	Generic Description
Regional Maintainer - Forestry	999.999.005	Perform line clearing adjacent to power lines and associated apparatus. Carries out all phases of vegetation management including the application of pesticides. Understands and operates tools associated with the trade, various types of vehicles and aerial equipment, hand or power-operated pesticide application equipment. Must provide at own expense, any tools listed for this classification if required in his/her work, in accordance with the attached tool list. In addition to the above, may have the following skills: • Lead Hand Skills (including documentation, job planning and knowledge of work management systems as required) • Work Protection Code Skills (including establishing, and holding) • Contract Monitoring Skills • Environment Skills (such as PCB management, WHMIS, waste management, etc.)
Regional Maintainer - Lines	999.999.006	Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Understands and is able to operate the tools of his/her trade, and is familiar with the various instruments, i.e. voltmeters, ammeters and ohmmeters. Must be familiar with hydraulically-operated articulated or telescopic aerial devices. Must provide at own expense any tools listed for the classification if required in his/her work in accordance with the attached tool list. This classification also includes the requirement to hold a Power Line Technician certification (or equivalent).
Regional Maintainer - Lines (Supervisory)	999.999.008	This position is responsible for the safety, quality and quantity of the work performed by his/her crew. They plan work including staffing requirements, assigning work, co-ordinate work with other work groups, ensure proper work practices are followed, report on work performed and engage in good public relations. He/she performs the following physical work activities. Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Also responsible for contract monitoring and lead hand responsibilities.
Senior Legal Counsel	115.100.340	Responsible for providing management and employees with advice on a broad range of moderately complex conflicting legal principles. The applicable laws and regulations are numerous and varied, and present difficult problems of interpretation. Applies independent judgment in recommending a course of action for a client department, providing input as to the ramifications of a course of action, a legal decision, or a new piece of legislation. Usual qualifications include a law degree, membership in a law society/bar association and/or other relevant jurisdiction with a minimum of 8 year's related experience.
Service Dispatcher	430.612.340	Responsible for handling incoming consumer calls to schedule and dispatch service technicians to problem areas (including high voltage switching). Maintains documentation of crew activities for continuous knowledge of line and substation work. Key coordinator during power failures provides notification to internal and external customers regarding restoration of power services.
Stock Keeper	999.999.009	Receives, receipts, stores, issues and ships materiel used in operations. Manages materiel, in accordance with established practices and regulations. Is responsible for materiel under his/her control. Performs maintenance, not requiring formal trades qualifications, and assists in tasks where unskilled or semi-skilled ability is required.
System Operator (Controller)	999.999.010	Monitor and operate the transmission/distribution system assets on a 24-hour basis. Determine condition and recommend on availability of equipment. Carry out Manual Block and Rotational Load Shedding Schedules procedures. Monitor, approve and report LV - load transfers. Direct / monitor personnel on a 24 hour basis (i.e. - switching agents, field crews) in the operation of the Transmission / Distribution network system assets. Troubleshoot & sectionalize for low voltage feeder faults.
Top Rates and Regulatory Affairs Executive	110.200.130	Executive with primary responsibility for preparing, managing, and leading company's testimony in utilities rate cases before local, regional or federal agencies. Responsibilities include development of all research associated with regulatory activities including activity across other regulatory entities and maintaining relationship with all regulators. Develops cost factors in association with utilities rate cases, may or may not, be involved in delivery of testimony. Typically reports to a Top Legal Executive, Chief Operations Officer or a Top Utilities Executive.

APPENDIX C

Detailed Compensation Benchmarking Methodology

Summarized in this appendix is supporting descriptions of how we determined values for each of the major components of compensation. Specifically:

Base Salary – Annual base salary at July 1, 2013. If an hourly rate was reported, we annualized the value by multiplying the standard number of hours per week by 52 weeks per year. If a weekly rate was reported, we annualized the value by multiplying by 52 weeks per year.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive or bonus paid.

Benefits and Pensions – To value benefit and pension programs, we applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans. See detailed methodology below.

Total Compensation - Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., expected value of stock options or share awards) and pensions and benefits.

Detailed Benefits and Pension Methodology – Total remuneration includes the following values for benefits and pensions:

- Mercer's relative value process applies a broad set of standard cost factors, plus actuarial and demographic assumptions to measure all of the financially significant features of benefit programs on a benefit line basis.
- Effectively, this process isolates the plan design and removes variable factors such as historical experience, demographics, and utilization trends specific to each participant in the study. For example, if two survey participants have an identical benefit offering, the values will be equal regardless of the actual plan costs to each of the employers.

Aligning Values with Hydro One's Actual Costs

- For the purpose of this Total Compensation Cost Study, we adjusted the manual rates within our relative value tools so that the results by line of benefit more closely reflect Hydro One's actual benefit costs and liability figures.

Participation & Anti-Selection:

Active Flex Benefits:

- Participation: We use a standardized set of participation assumptions for all participants that vary only by the number of options that are offered under the plan. Therefore, two identical flex programs will produce similar relative Total Values.

- Anti-Selection: A unique feature of flex plans is that employees who choose richer options are likely to be higher claimers than those choosing poorer options. This is reflected within our methodology by increasing the value of the richer options and reducing the value of the poorer options. The final relative values of the flex plan are a weighted average of the values of each of the options.

- Optional plans that are fully employee-paid (such as optional life) are excluded from the review.

- Low value core plans / catastrophic core plans and spousal top-up plans are excluded from the valuation.

Projection Methodology for Pension Plans

Defined Benefit Plans

- For defined benefit plans, annual service costs were estimated for each company's plan design at various earnings levels using a common sample employee demographic (age and years of service). The annual service costs were converted into company provided values by deducting any required employee contributions under each plan. The resulting company provided values were expressed as a percentage of earnings to be applied to the earnings associated with each benchmark position.

Defined Contribution Plans

- For defined contribution benefit plans, the company provided value was set equal to the company contributions.

- Where employees are entitled to choose the level of their contributions, employees were assumed to contribute at the level that would maximize company contributions.

Projection Methodology for Post Retirement Non-Pension (PRNP)

Employee-specific factors including earnings and service are projected to each of the assumed retirement ages at which point the benefit payable is determined, actuarially valued and discounted with interest to the current age of the employee. The resulting values are split pro-rata on service into the benefit in respect of past service and the benefit in respect of future service, and the future service benefit value is converted to a level percentage of future pensionable earnings.

- The results are weighted by the assumed retirement rates and combined to produce a single value of future benefit accruals, as a percentage of future earnings, per member.
- Benefits are projected both before and after retirement based on benefit-specific (e.g. medical, dental) inflation assumptions.
- Benefits are coordinated with provincial medical and drug plans.
- Lifetime maximums are reflected where applicable.

Flex Premium Cost Sharing & Credit Allocation:

- Cost sharing is determined using each participant's actual price tag and credit formula.
- Assumptions are made as to where credits would commonly be used, unless they are allocated to specific benefits. These assumptions coordinate with the standardized participation assumptions outlined earlier.

Standard Demographic Assumptions:

- A common population reflecting the general demographics of a Canadian workforce group and adjusted to more closely mirror Hydro One's workforce is used in the analysis.
  - This population reflects a group of employees with an average age of 45, average service of 15 years, and average annual earnings of $110,000 (average earnings used for benefit purposes).
- For Pension and Post Retirement Non-Pension benefits, the above population is assumed to retiree approximately as follows:
  - 25% of the group retire at age 55
  - 60% of the group retire at age 60
  - 15% of the group retire at age 65
  - 70% of the active members are assumed to be married over their career while 90% of members are assumed to be married at the time of their retirement

Other Actuarial Assumptions:

- The following assumptions were used in the review:
  - Discount rate: 4.25% per annum
  - Inflation: 2.00% per annum
  - Salary Increase: 4.00% per annum
  - Post Retirement mortality UP 1994 generational mortality (80% male)
  - Termination rates of 2% each year prior to age 55 (for pension values)
  - Medical and Dental inflation/utilization increases

MERCER

Mercer (Canada) Limited
161 Bay Street, P.O. Box 501
Toronto, Ontario M5J 2S5
+1 416 868 2000

ATTACHMENT 3
Expert Evidence Statement from Mercer (Canada) Limited

This Expert Evidence Statement is provided in response to the Ontario Energy Board, Rules of Practice and Procedure, Rule 13A regarding the use of an expert to provide evidence. This Statement is for the preparation of the Compensation Cost Benchmarking Study, dated December 2, 2013, prepared by Mercer (Canada) Limited.

Title of Report:
Compensation Cost Benchmarking Study

Consultant:
Iain Morris
Partner, Talent Business Leader – Central Canada
Mercer (Canada) Limited
161 Bay Street
Toronto, Ontario M5J 2S5

- Human Resource consultant to major Canadian and multi-national employers
- Extensive experience on total reward strategy, rewards program design, benchmarking and cost analyses

Qualifications:
Education: Bachelor of Arts Queen's University 1980

Experience: Mr. Morris consults to many of Canada's leading organizations with a focus on reward strategy design and implementation. This includes business needs driven rewards strategy development and the design and implementation of performance-linked compensation systems. Iain has worked with organizations in a number of industries including: mining, utilities, financial services, retail, and manufacturing. Recent projects include:

- Leading a comprehensive total reward benchmarking and cost analysis for a major gas distribution company

- Developing and implementing a total reward strategy for a major engineering consulting firm

- Assessing the effectiveness of the total reward strategy and program design for a leading retailer

Iain has more than 30 years of rewards consulting experience with Mercer and another global H.R. consulting firm.
.

Instructions Provided:
The primary sources of instructions were the RFP, (RFP #7000003202, May 3rd 2013) that Hydro One issued for this project and various conversations with Hydro One in verifying scope and progress.

The following are excerpts from the RFP:
“in its December 23, 2010 Decision approving Transmission Revenue Requirements for 2011 and 2012, the Ontario Energy Board provided direction and the other expectations for further information on compensation and efficiency comparisons”.

The Board directed “Hydro One to revisit compensation cost benchmarking study [the Mercer study] in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America.” Towards that end, the Board directed “Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses”.

Mercer met with Stakeholders and with Hydro One during the course of conducting the study to receive feedback on the project methodology and progress.

Basis of Evidence:
1) 2008 Compensation Cost Benchmarking Study, Mercer (Canada) Limited
2) 2011 Compensation Cost Benchmarking Study, Mercer (Canada) Limited
3) 2013 Compensation Cost Benchmarking Study, Mercer (Canada) Limited
4) Total Compensation data and program design information for Hydro One provided by the Company Human Resources Department
5) Mercer and industry standard analytical methods and assumptions

Context of Evidence:
NA

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert: Iain Morris

Date: 14 January 2014

London Property Management Association (LPMA) INTERROGATORY #10

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1

a) Please provide the actual/forecast payout under the MCP Short Term Incentive Plan for each of 2011 through 2016.

b) Please provide the total potential payout under the MCP Short Term Incentive Plan for each of 2011 through 2016.

c) Please show how the 15% that is assumed to be the payout in each year has been calculated.

d) Please provide the criteria and payout amounts associated with the MCP Short Term Incentive Plan.

Response

a)

Year	Forecast (Max) STI	Actual STI Payment*
2011	$10,778,255	$10,750,950
2012	$11,094,546	$9,522,858
2013	$10,876,838	$8,391,901

*HONI total

b)

Year	Forecasted STI*
2014	$11,149,916
2015	$10, 824,382
2016	$10,705,167

*based on Exhibit C1-3-2 Attachment 2

c) The 15% assumption for STI payout is based on total MCP base compensation.

d) The Short Term Incentive Program is an ‘at risk’ and ‘re-earnable’ variable pay compensation program. It is discretionary and based on Hydro One Board and Senior Management’s assessment of achievement of the corporate scorecard targets and achievement of individual performance agreements.

There are 10 pay bands for MCP employees . Each band has a corresponding base pay salary pay range and a percentage eligible for STI.

London Property Management Association (LPMA) INTERROGATORY #11

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 2

a) Are the 2013 figures shown in Table 2 actual figures? If not, are 2013 actual figures now available? If yes, please update Table 2 to reflect these actual figures for 2013.

b) The evidence states that a total of 471 MW of embedded generation was assumed to be in place in 2013. What was the actual amount of embedded generation in 2013?

c) The evidence indicates that an additional 91 MW of embedded generation would be added in 2014. What is the most recent estimate of the amount of embedded generation that will be added in 2014?

Response

a) The CDM impacts in Table 2 are consistent with the 2013 LTEP and as such all 2013 figures are forecast. Actual figures for 2013 have not been made available by the OPA at this time.

b) 471 MW of embedded generation in 2013 is considered the actual value.

c) The value of 562 MW of embedded generation in 2014 was estimated in March 2014 and is the most current estimate available.

London Property Management Association (LPMA) INTERROGATORY #12

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 2

What would be the impact on the revenue and deficiency if the normal weather data were changed from the current 31 year average to:

a) the most current 20 year average; and

b) the most current 20 year trend?

Response

a) Using the most current 20 year average instead of the current 31 year average will increase the base-year (2013) forecast by 0.68%. Assuming all other assumptions remained the same, higher load forecast will mean rates will be lower in order to get the required revenue in the test years.

b) Using the most current 20 year trend instead of the current 31 year average will increase the base-year (2013) forecast by 0.98%. Assuming all other assumptions remained the same, higher load forecast will mean rates will be lower in order to get the required revenue in the test years.

London Property Management Association (LPMA) INTERROGATORY #13

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 2

At page 11 the evidence indicates that most utilities use long term weather data to calculate weather normal conditions ranging from 10 years to more than 30 years. How many of these use the simple average over the number of years selected? Please provide a list of any other methodologies used, along with the number of years that the methodology is applied to.

Response

Hydro One did not ask this question as part of the study on weather normalization practices. However based on discussions with various utilities Hydro One is not aware of any utilities using methodologies other than the simple average over the number of years selected.

London Property Management Association (LPMA) INTERROGATORY #14

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 1

a) How many months of actual expenditures are included in Table 3 in the 2014 Projected column?

b) Please update the 2014 Projected column in Table 3 to reflect the most recent year-to-date figures available and the forecast for the remainder of 2014.

c) Please provide the most recent year-to-date actual expenditures in the same level of detail as shown in Table 3 along with the figures for the corresponding period in 2013.

Response

a) The 2014 bridge year data was prepared in 2013 so there are no actual expenditures included in the 2014 Projected column in Table 3 of Schedule C1-2-1.

b) The current forecast based on the most recent actual results is the same as what has been provided in the information package in May.

c)

OM&A Categories	**May 2013 YTD** ($ million)	**May 2014 YTD** ($ million)	**Variance** ($ million)
Sustaining	91.0	100.6	9.6
Development[1]	3.8	2.6	(1.2)
Operations	21.3	23.4	2.1
Customer Care	2.5	2.3	(0.2)
Common Corporate & Other Costs	43.6	32.5	(11.1)
Taxes other than Income Taxes*	(17.2)	26.3	43.5
Total	**144.9**	**187.6**	**42.7**

* The large variance in the Taxes other than Income Taxes area is mainly because the company recognized a one-time Property tax rebate (about $43 M) in 2013. See CME Interrogatory # 8 for more information.

[1] Development costs are net of Licence Amendment to Upgrade TS's to Facilitate Renewable Generation amounts

London Property Management Association (LPMA) INTERROGATORY #15

Interrogatory

Ref: Exhibit C1, Tab 3, Schedule 3

Please expand Table 12 to reflect actual and bridge year information for 2011 through 2014.

Response

Table 12
Total Transmission Other OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Capitalized Overhead	(105.5)	(107.0)	(109.3)	(126.4)	(122.2)	(119.2)
Environmental Provision	(6.9)	(5.9)	(6.2)	(6.3)	(6.3)	(6.0)
Indirect Depreciation	(5.4)	(5.8)	(6.2)	(6.2)	(6.4)	(6.7)
Other	(6.2)	14.4	(40.0)	2.0	0.9	0.8
Total	**(124.0)**	**(104.2)**	**(161.6)**	**(136.9)**	**(134.0)**	**(131.1)**

London Property Management Association (LPMA) INTERROGATORY #16

Interrogatory

Ref: Exhibit D1, Tab 1, Schedule 1

Please provide versions of Table 3 that shows actual 2011 and 2012 rate base compared to the Board approved figures for those years.

Response

Please see tables below for the comparison of the actual rate base to Board Approved for both 2011 and 2012.

2011 Board Approved versus 2011 Rate Base
($M)

Rate Base Component	2011 Actual	2011Board Approved
Gross Plant	12,307.5	12,263.1
Accumulated Depreciation	(4,436.5)	(4,428.4)
Net Utility Plant	**7,871.0**	**7,834.7**
Cash Working Capital[1]	7.1	7.1
Materials & Supplies Inventory	14.4	10.7
Total Rate Base	**7,892.5**	**7,852.5**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2011 approved amount was used for illustrative purposes.

2012 Board Approved versus 2012 Rate Base
($M)

Rate Base Component	2012 Actual	2012 Board Approved
Gross Plant	13,260.0	13,443.8
Accumulated Depreciation	(4,700.8)	(4,688.4)
Net Utility Plant	**8,559.2**	**8,755.4**
Cash Working Capital[1]	5.0	5.0
Materials & Supplies Inventory	14.7	14.0
Total Rate Base	**8,578.9**	**8,774.4**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2012 approved amount was used for illustrative purposes.

London Property Management Association (LPMA) INTERROGATORY #17

Interrogatory

Ref: Exhibit F1, Tab 1, Schedule 1

a) Is Table 2 a complete list of the existing regulatory accounts with balances at the end of December, 2014? If not, please provide a version on Table 2 that includes a complete list of the regulatory accounts and for each account not proposed to be cleared, please explain why it is not proposed to be cleared.

b) How many months of actual data are included in the 2014 column?

c) Please update Table 2 to reflect the most recent year-to-date figures available for 2014, along with a forecast for the remainder of the year.

Response

a) Exhibit F1, Tab 1, Schedule 1, page 3, Table 2 is a complete list of existing regulatory accounts with balances that Hydro One is seeking disposition of during the current rate filing. The two regulatory accounts not listed in this table [1 – Excess Export Service Revenue and 2 – Long Term Projects Development Costs], where Regulatory Balances currently do exist, is due to HONI not requesting disposition of theses balances. HONI is not seeking recovery of these balances because they were approved for disposition in the prior rate filing EB-2012-0031 and will be Nil at the end of 2014.

Please refer to the additional supplementary evidence provided in response to SEC interrogatory 17, notably Exhibit F2-1-1, F2-1-2 and F2-1-3.

By referring to F2-1-3, and the column titled “Total Projected Balances as at Dec 31 2014 Requested for Disposition”, for the two aforementioned accounts, the year-end 2014 forecast balance is $Nil.

b) In reference to Exhibit F1, Tab 1, Schedule 1, Page 3, Table 2, there are Nil 2014 actual amounts included. The 2014 forecast column includes only Interest Improvement on 2013 actual balances and any Board approved balances for disposition during 2014 as a result of EB-2012-0031 filing.

c) For regulatory accounts where Hydro One Transmission is requesting disposition, the below table includes YTD June 30, 2014 actuals and the forecast as at year-end 2014.

Transmission
Regulatory Accounts Requested for Approval ($ Millions)

Description	US of A Account Ref.	Balance as at Dec. 31, 2012	Balance as at Dec 31, 2013	Balance as at Jun 30, 2014	Forecast Balance as at Dec 31, 2014
Excess Export Service Revenue	2405	(31.8)	(41.9)	(33.8)	(23.4)
External Secondary Land Use Revenue	2405	(24.4)	(32.8)	(25.9)	(18.5)
External Station Maintenance, E&CS Revenue and Other External Revenue	2405	(5.0)	(6.4)	(1.1)	(1.3)
Tax Rate Changes	1592	(3.5)	(3.6)	(3.6)	0.8
Rights Payments	2405	2.7	(3.6)	(4.1)	(1.9)
Pension Costs Differential	2405	14.7	20.8	13.6	8.2
Long Term Future Corridor	1508	0.0	0.1	0.1	0.1
Total Regulatory Accounts for Disposition		**(52.8)**	**(67.4)**	**(54.8)**	**(36.0)**

London Property Management Association (LPMA) INTERROGATORY #18

Interrogatory

Ref: Exhibit F1, Tab 1, Schedule 3

How is any variance between the Board approved amounts for disposition in 2014 (EB-2012-0031) and the actual amounts disposed of in 2014 based on actual billing determinants accounted for in the regulatory accounts?

Response

There is not expected to be any variance between the Board approved disposition balances from EB-2012-0031 and the actual amounts disposed of by the end of 2014. Board approved Hydro One Transmission revenue requirement for 2014 was reduced by the total approved Variance/Deferral account balance amounts.

Energy Probe Research Foundation (EP) INTERROGATORY #1

Interrogatory

Ref: Exhibit A, Tab 3, Schedule 2, Page 4, Table 1, Financial Highlights 2015

Please Check/Populate the attached Energy Probe Excel Summary Schedule(s)

Response

Please see the table on the next page for the information requested.

1

	Financial Summary 2013-2016					
	Approved	Actual	Approved	Forecast	Proposed	Proposed
	2013	2013	2014	2014	2015	2016
Total OM&A Expense	440.3	388.4	449.7	448.6	452.0	457.4
Depreciation & Amortization	345.0	326.3	371.5	366.5	394.2	404.0
Capital Expenditures	982.4	718.5	1,121.5	899.2	899.4	866.3
Rate Base	9,353.4	9,209.3	9,933.8	9670.7	10,176.5	10,558.0
Return on Capital*	609.3	605.3	659.7	659.6	694.3	739.9
Income Taxes	43.1	78.5	54.5	51.3	71.8	82.8
Total Gross Revenue Requirement	**1,437.7**	**1,398.5**	**1,535.3**	**1535.3**	**1,617.1**	**1,689.2**
External Revenues	-31.6	-46.6	-36.6	-36.6	-28.4	-28.8
Export Revenue Credit	-27.0	-27.0	-34.1	-34.1	-33.4	-34.3
Regulatory Assets Recovery	0.0	-67.4	-30.3	-36.1	-18.0	-18.1
LV Switch Gear	11.6	11.6	12.1	12.1	13.2	13.9
RATES REVENUE REQUIREMENT	**1,390.8**	**1,269.1**	**1,446.4**	**1440.6**	**1550.5**	**1621.9**
Variation		**-121.7**		**-5.9**		
Total Debt*	5,612.1	5,525.6	5,960.3	5,802.4	6,105.9	6,334.8
Common Equity*	3,741.4	3,683.7	3,973.5	3,868.3	4,070.6	4,223.2
Total Rate Base	9,353.4	9,209.3	9,933.8	9,670.7	10,176.5	10,558.0
Variation		**-144.1**		**-263.1**		
	CAPEX and In Service Asset Additions					
Capital Expenditures						
Total Sustaining Capital	584.3	480.0	652.1	579.3	581.9	548.6
Total Development Capital	277.8	171.7	354.4	195.6	209.7	211.8
Total Operations Capital	38.5	17.7	42.7	38.5	38.4	37.4
Total Capital Common Corporate Costs& Other	80.6	49.1	71.0	85.8	69.4	68.5
Total Transmission Capital	**981.2**	**718.5**	**1120.4**	**899.2**	**899.4**	**866.3**
Variation		**-262.7**		**-221.2**		
In-Service Asset Additions						
Sustaining	443.3	403.8	701.1	701.1	572.2	480.9
Development	261.8	231.7	205.8	205.8	134.7	119.4
Operations	15.1	5.9	48.0	48.0	50.4	10
Common & Other	64.0	62.4	68.0	68.0	64.1	63.1
TOTAL ISAs	**784.2**	**703.8**	**1022.9**	**1,023.1**	**821.4**	**673.4**
Variation		**-80.4**		**0.2**		
	OM&A					
Sustaining	235.7	221.0	246.5	236.2	238.7	241.1

	Financial Summary 2013-2016					
	Approved	**Actual**	**Approved**	**Forecast**	**Proposed**	**Proposed**
	2013	**2013**	**2014**	**2014**	**2015**	**2016**
Development	13.7	8.6	14.7	12.9	12.9	13.4
Operations	57.7	56.7	58	57.4	58.5	59.1
Customer Care	4.9	5.3	4.7	5.8	5.5	5.5
Common Corporate and Other OM&A	61.9	75.8	59	70.6	70.2	71.3
Property Taxes & Rights Payments	66	21.2	66.8	65.6	66.3	67
TOTAL	**439.9**	**388.6**	**449.7**	**448.6**	**452.1**	**457.4**
Variation		**-51.3**		**-1.1**		

*Return on Capital has been calculated on a deemed basis using the allowed rates of return.

Energy Probe Research Foundation (EP) INTERROGATORY #2

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1, Page 5 and
Exhibit D1, Tab 6, Schedule 1. (not provided)

Preamble:
Hydro One will base its interest capitalization rate on its embedded cost of debt used to finance the capital expenditures made. The rates used in calculating Capitalized Interest for the Bridge and Test years represent the effective rate of Hydro One Transmission's forecasted average debt portfolio during the year.

a) For the historic, bridge and test years, please provide the amounts of capital work in progress and show the capitalized interest calculation.

b) Where is the WIP capitalized interest amount shown in the Revenue Requirement and/or how is it recovered in rates?

Response

a) Please find the interest capitalized amounts and capitalization percentages for Transmission for Historic, Bridge and Test years:

	Historic			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Interest Capitalized ($ millions)	46.2[1]	39.6	33.1	31.9	30.1	30.9
Capitalization Rate	4.2%	5.2%	4.8%	4.8%	4.8%	5.0%

[1]Based on the former OEB-prescribed methodology *Allowance for Funds Used During Construction (AFUDC)*, which used the DEX Mid Term Corporate Bond Yield Index as the capitalization rate.

b) Capitalized interest is included in the capital expenditures shown in Exhibit D1, Tab 3, Schedule 1. These expenditures are recovered through Revenue Requirement once they become in-service additions to Rate Base.

Energy Probe Research Foundation (EP) INTERROGATORY #3

Interrogatory

Ref.: Exhibit A, Tab15, Schedule 1, Page 5 and
Exhibit C1, Tab 4, Schedule 2 (not provided)

a) Please provide a Schedule that shows total staff complement, payroll and compensation for the 2013-2016 years

b) Please provide comments on any material changes to staffing, compensation or benefits and the associated costs.

Response

a) Please see Attachment 1 to this interrogatory.

b) Regular staff complement will decline over the test years.

A negotiated settlement with the PWU includes a 2.5% base wage increase in 2014 with a .75% increase in employee pension contributions. No significant increase in benefits.

A negotiated settlement with the Society includes a 2.25% base wage increase in 2014 and 2015 with a 1.0% and .75% increase in employee pension contributions. No significant increase in benefits.

2013

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,321	361,121,121	282,009,791	63,909,056	5,000.00	15,197,274	84,917
SOCIETY Reg	1,260	137,307,219	127,603,743	6,218,672	18,650.00	3,466,154	101,273
MCP Reg	600	82,932,593	70,297,687	176,885	8,236,068	4,221,953	117,163
Total Reg	**5,181**	**581,360,932**	**479,911,220**	**70,304,613**	**8,259,718**	**22,885,381**	**92,629**
PWU Temp	205	6,747,274	6,521,171	189,533	0.00	41,214	31,811
Society Temp	46	3,144,181	2,911,798	115,174	0.00	117,601	63,300
MCP Temp	25	1,221,374	1,175,065	1,172	0	45,138	47,003
Total Temp	**276**	**11,112,830**	**10,608,034**	**305,878**	**0.00**	**203,953**	**38,435**
CASUAL	1781	127,908,507	98,518,887	14,668,063	11,000.00	14,710,557	55,317
TOTAL	**7,238**	**720,387,304**	**589,038,140**	**85,278,555**	**8,270,718**	**37,799,890**	**81,381**

2014

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,467	381,570,832	300,295,846	65,187,237		16,087,749	86,615
SOCIETY Reg	1,311	145,456,033	135,424,029	6,343,045		3,688,958	103,298
MCP Reg	622	90,121,621	74,332,774	180,423	11,149,916	4,458,508	119,506
Total Reg	**5,400**	**617,148,485**	**510,052,648**	**71,710,705**	**11,149,916**	**24,235,215**	**94,454**
PWU Temp	381	12,624,883	12,362,231	193,323	0.00	69,328	32,447
Society Temp	103	7,035,467	6,650,294	117,477	0.00	267,695	64,566
MCP Temp	56	2,789,114	2,684,789	1,195	0	103,131	47,943
Total Temp	**540**	**22,449,464**	**21,697,314**	**311,996**	**0.00**	**440,154**	**40,180**
CASUAL	2283	167,171,831	128,813,583	19,178,514		19,179,734	56,422.94
TOTAL	**8,223**	**806,769,780**	**660,563,545**	**91,201,215**	**11,149,916**	**43,855,104**	**80,331**

2015

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,435	386,223,662	303,474,633	66,490,982		16,258,047	88,348
SOCIETY Reg	1,281	145,118,122	134,971,583	6,469,906		3,676,634	105,364
MCP Reg	592	87,499,293	72,162,544	184,032	10,824,382	4,328,336	121,896
Total Reg	**5,308**	**618,841,077**	**510,608,760**	**73,144,919**	**10,824,382**	**24,263,017**	**96,196**
PWU Temp	410	13,842,539	13,569,252	197,190	0.00	76,097	33,096
Society Temp	132	9,162,915	8,693,161	119,827	0.00	349,927	65,857
MCP Temp	85	4,317,515	4,156,628	1,219	0	159,669	48,902
Total Temp	**627**	**27,322,970**	**26,419,041**	**318,236**	**0.00**	**585,693**	**42,136**
CASUAL	2283	170,515,267	131,389,854	19,562,084		19,563,329	57,551.40
TOTAL	**8,218**	**816,679,314**	**668,417,655**	**93,025,239**	**10,824,382**	**44,412,039**	**81,336**

1

2016

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,414	391,954,343	307,651,717	67,820,801		16,481,826	90,115
SOCIETY Reg	1,252	144,818,913	134,554,340	6,599,304		3,665,268	107,472
MCP Reg	574	86,541,326	71,367,780	187,712	10,705,167	4,280,666	124,334
Total Reg	**5,240**	**623,314,582**	**513,573,837**	**74,607,818**	**10,705,167**	**24,427,760**	**98,010**
PWU Temp	437	15,035,958	14,752,093	201,134	0.00	82,731	33,758
Society Temp	148	10,464,228	9,941,815	122,224	0.00	400,189	67,174
MCP Temp	94	4,870,026	4,688,676	1,243	0	180,106	49,880
Total Temp	**679**	**30,370,212**	**29,382,585**	**324,600**	**0.00**	**663,026**	**43,273**
CASUAL	2283	173,925,572	134,017,651	19,953,325		19,954,596	58,702.43
TOTAL	**8,202**	**827,610,366**	**676,974,074**	**94,885,744**	**10,705,167**	**45,045,382**	**82,538**

Energy Probe Research Foundation (EP) INTERROGATORY #4

Interrogatory

Ref: Exhibit A, Tab 18, Schedule 1, Page 4, Table 2

a) Please provide a Table similar to Table 2 that shows the total and breakout of Tx and DX Productivity Savings over the years 2011-2016

b) Explain which Productivity savings are common to Tx and Dx and how the relative savings have been allocated.

c) Please provide the Productivity savings related to Cornerstone (Tx and Dx and Other)

d) Please provide a copy of the Cornerstone Benefits Realization Plan and relate the savings to the Plan by year and allocation to Tx, Dx and Other

Response

a) For 2011-2016 Tx and Dx productivity savings please refer to the following tables.

Distribution	**Historical**			**Bridge Year**	**Test Years**		**Distribution Cumulative**
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2011 - 2016**
Back Office	4.1	6.5	18.0	23.3	26.7	26.7	**105.3**
Business Systems	13.2	18.6	29.9	30.6	30.8	31.0	**154.0**
Business Transformations	0.0	0.0	0.4	13.6	30.9	33.9	**78.9**
Centralized Operations	0.0	0.6	5.0	5.0	5.3	5.4	**21.3**
Leveraging Technology	0.0	1.9	3.4	5.7	8.1	9.3	**28.4**
Miscellaneous Admin	0.0	5.3	5.1	5.2	5.3	5.5	**26.4**
Process Improvement	0.0	1.0	0.2	0.6	2.4	2.4	**6.6**
Staff Flexibility	0.0	2.8	5.0	5.1	7.0	10.2	**30.2**
Telephony	0.0	2.1	1.0	1.5	1.9	2.1	**8.6**
Total Distribution	**17.3**	**38.8**	**68.0**	**90.7**	**118.4**	**126.5**	**459.7**

Transmission	Historical			Bridge Year	Test Years		Transmission Cumulative 2011 - 2016
	2011	2012	2013	2014	2015	2016	
Back Office	4.1	6.5	6.4	8.3	9.5	9.5	**44.4**
Business Systems	13.2	18.6	27.5	28.1	28.3	28.4	**144.2**
Business Transformations	0.0	0.0	0.5	3.0	5.7	7.5	**16.7**
Centralized Operations	0.0	0.6	6.2	6.3	6.6	6.8	**26.5**
Leveraging Technology	0.0	0.0	0.2	2.1	2.1	2.8	**7.2**
Miscellaneous Admin	0.0	5.3	6.4	6.5	6.7	6.8	**31.7**
Process Improvement	0.0	0.1	1.1	2.3	2.2	2.2	**7.9**
Staff Flexibility	0.0	2.8	5.0	3.6	3.8	3.8	**19.0**
Telephony	0.0	1.0	1.2	1.9	2.3	2.6	**9.0**
Total Transmission	17.3	34.9	54.6	62.1	67.2	70.5	**306.5**

b) For initiatives that have costs that are common to both Transmission and Distribution, the common cost allocation provided in the Black & Veatch studies is used to determine the percentage allocation between Transmission and Distribution. See the below table for the listing of the common initiatives and the associated percentages.

Category	Initiative Name	Percentage Allocation	
		Tx	Dx
Back Office	Contract Replacement	26.0%	73.0%
Back Office	Inergi Contract Extension	26.0%	73.0%
Business Systems	Cornerstone Ph1, 2	47.9%	52.1%
Business Transformations	AA	41.6%	58.4%
Business Transformations	AIP - Asset Investment Planning	55.6%	44.4%
Business Transformations	HR Pay Project	55.6%	44.4%
Business Transformations	Process Improvements & BPC	55.6%	44.4%
Business Transformations	Workflow of the Future	55.6%	44.4%
Centralized Operations	Electrical Safety Awareness available online	55.6%	44.4%
Centralized Operations	Make Spills Management training available via E Learning	55.6%	44.4%
Centralized Operations	Regular Head Count Reduction	55.6%	44.4%
Centralized Operations	Vendor Rebates	55.6%	44.4%
Leveraging Technology	Employee Travel Policy	55.6%	44.4%
Leveraging Technology	Facilities Energy Efficiency Retrofits	55.6%	44.4%
Leveraging Technology	SMNO - Smart Meter Network Operating	55.6%	44.4%

Category	Initiative Name	Percentage Allocation	
		Tx	Dx
Leveraging Technology	Standards Development for Design	42.3%	57.7%
Leveraging Technology	Work Program Optimization (TSOGs)	55.6%	44.4%
Miscellaneous Admin	Admin Spend Controls	55.6%	44.4%
Process Improvement	Maintain Stock of Regularly Used Items	55.6%	44.4%
Process Improvement	Project Trailer Purchase	55.6%	44.4%
Process Improvement	Smart MFA spend	42.3%	57.7%
Staff Flexibility	Facilities & Real Estate Outsourcing	40.0%	60.0%
Staff Flexibility	Fleet Mechanic Reduction	55.6%	44.4%
Staff Flexibility	Inhouse Retorques on Light Vehicles	55.6%	44.4%
Staff Flexibility	Initial Training: union pays for basic	55.6%	44.4%
Staff Flexibility	Manage Stations Work for Facilities	55.6%	44.4%
Staff Flexibility	Outsourcing Drawing Backlog	55.6%	44.4%
Staff Flexibility	TWHQ - Stations	55.6%	44.4%
Telephony	Cell Contracts	55.6%	44.4%
Telephony	Telecom Expense Management (TEM)	55.6%	44.4%

c) Please refer to table Cornerstone Productivity Summary Savings below in response to part d).

d) Please refer to the following two tables below that make up the Cornerstone Benefits Realization Plan.

Transmission and Distribution
CORNERSTONE COST Summary
(for 2014-2019 Business Plan)

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Forecast	2014 BP	Total Projected Spend (per 2014-2019 BP)	Board Approval
Phase 1												
OMA	3.8	4.6	2.4	0.1	0.0	-	-	-	-	-	10.9	
CAPITAL	-	60.4	49.3	0.8	0.2	-	-	-	-	-	110.7	
MFA	-	3.2	2.4	-	-	-	-	-	-	-	5.6	
Total	**3.8**	**68.2**	**54.1**	**0.9**	**0.2**	**-**	**-**	**-**	**-**	**-**	**127.2**	**146.0**
Phase 2												
OMA	-	-	0.3	7.0	0.1	0.0	-	-	-	-	7.4	
CAPITAL	-	-	50.6	90.0	11.2	1.5	-	-	-	-	153.3	
MFA	-	-	4.5	0.2	-	-	-	-	-	-	4.7	
Total	**-**	**-**	**55.4**	**97.2**	**11.3**	**1.5**	**-**	**-**	**-**	**-**	**165.4**	**183.0**
Phase 3												
OMA	-	-	-	-	1.6	0.6	0.6	1.2	0.1	4.5	7.4	
CAPITAL	-	-	-	-	7.4	16.6	20.8	10.8	20.6	18.9	84.3	
MFA	-	-	-	-	0.3	1.2	0.0	-		-	1.6	
Total	**-**	**-**	**-**	**-**	**9.4**	**18.4**	**21.5**	**12.0**	**20.6**	**23.3**	**93.2**	**60.0**
Phase 4												
OMA	-	-	-	-	-	0.8	7.9	17.1	18.4	-	27.1	
CAPITAL	-	-	-	-	-	41.5	58.6	42.9	43.0	-	143.1	
MFA	-	-	-	-	-	10.1	-	0.2	0.2	-	10.3	
Total	**-**	**-**	**-**	**-**	**-**	**52.4**	**66.5**	**60.2**	**61.5**	**-**	**180.5**	**180.0**
TOTAL												
OMA	3.8	4.6	2.7	7.1	1.8	1.4	8.6	18.3	18.4	4.5	52.8	
CAPITAL	-	60.4	99.9	90.8	18.8	59.6	79.4	53.7	63.5	18.9	491.4	
MFA	-	3.2	7.0	0.2	0.3	11.3	0.0	0.2	0.2	-	22.2	
Total	**3.8**	**68.2**	**109.6**	**98.0**	**20.9**	**72.3**	**88.1**	**72.2**	**82.2**	**23.3**	**566.3**	**569.0**
Total Capital (inc. MFA)	**-**	**63.5**	**106.9**	**90.9**	**19.1**	**70.9**	**79.5**	**53.9**	**63.7**	**18.9**	**513.6**	

OEB Filings	EB-2012-0031 Tx 2013-2014
	EB-2012-0136 Dx 2013 IRM
	EB-2013-0416 Dx 2015-2019

Transmission and Distribution
CORNERSTONE Productivity Summary Savings
(for 2009-2019)

	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Total Projected Savings (per 2009-2019 BP)
Phase 1												
OMA	8.9	16.0	18.2	16.5	16.8	17.6	18.0	18.3	18.7	19.1	19.4	187.4
CAPITAL	6.4	11.1	12.9	27.0	36.6	36.6	36.6	36.6	36.6	36.6	36.6	313.4
Total	**15.3**	**27.1**	**31.1**	**43.5**	**53.4**	**54.2**	**54.5**	**54.9**	**55.3**	**55.6**	**56.0**	**500.8**
Phase 2												
OMA	1.6	3.8	4.6	3.4	4.0	4.5	4.5	4.5	4.5	4.5	4.5	44.5
CAPITAL	1.2	2.7	3.2	-	-	-	-	-	-	-	-	7.1
Total	**2.8**	**6.5**	**7.8**	**3.4**	**4.0**	**4.5**	**4.5**	**4.5**	**4.5**	**4.5**	**4.5**	**51.5**
Phase 3												
OMA	-		0.2	0.2	0.9	2.9	3.8	7.0	7.2	7.4	7.5	37.1
CAPITAL	-		2.3	2.3	-	2.8	4.6	4.8	5.0	5.2	5.2	32.2
Total	**-**	**-**	**2.5**	**2.5**	**0.9**	**5.7**	**8.5**	**11.8**	**12.2**	**12.6**	**12.7**	**69.3**
Phase 4												
OMA	-	-	-	-	-	10.3	19.8	19.8	19.8	19.8	19.8	109.2
CAPITAL	-	-	-	-	-	2.8	4.6	4.8	5.1	5.2	5.3	27.9
Total	**-**	**-**	**-**	**-**	**-**	**13.1**	**24.4**	**24.6**	**24.8**	**25.0**	**25.1**	**137.1**
TOTAL												
OMA	10.5	19.8	23.0	20.1	21.7	35.3	46.1	49.6	50.2	50.8	51.2	378.2
CAPITAL	7.6	13.8	18.4	29.3	36.6	42.2	45.8	46.2	46.6	47.0	47.0	380.5
Total	**18.1**	**33.6**	**41.4**	**49.4**	**58.3**	**77.5**	**91.9**	**95.7**	**96.8**	**97.8**	**98.3**	**758.7**

Reported in previous rate filings (blue: 2009–2011 Actual)
Current Productivity Reporting (orange: 2012–2019)

Notes:
Phase 1 includes: 50% of headcount reduction savings
Phase 2 includes: 50% of headcount reduction savings, IT application reduction savings
Phase 3 includes: E3, AIP, AA, WWF & BPC
Phase 4 includes: CIS

Energy Probe Research Foundation (EP) INTERROGATORY #5

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1, Page 3.

Preamble:
Hydro One Transmission's embedded long term debt, which was issued during the period from 2000 to 2013, is shown on lines 1 to 34 of Exhibit B2, Tab 1, Schedule 2, page 5 to 6. The rates on these embedded debt issues were approved by the Board as part of the Board's 2014 Rate Order in EB-2012-0031, dated January 9, 2014.

a) Please provide a schedule that shows both the actual and forecast (Board Approved) embedded debt at the end of 2013. include the gross amount as well as the mounts mapped to Tx and Dx.

b) Please provide a discussion/explanation of differences and the financial consequences (e.g. Revenue Requirement impact) of these differences.

Response

Please see Hydro One's response to CME's interrogatory 4 Attachment 1 for the historical and forecast long term debt schedules. This exhibit was not included as part of the HONI Tx Rates Information Package.

Please find attached a revised Exhibit B1, Tab 2, Schedule 1 (Attachment 1). The references to Exhibit B2, Tab 1, Schedule 2 have been updated due to a change in the format of the tables.

Please also note that Exhhibit B1, Tab 1, Schedule 1, page 3, line 9-10 should read "Historical long-term debt cost information is filed at Exhibit B2, Tab 1, Schedule 2, pages 1 to 6." (instead of pages 1 to 12), due to a change in format of tables.

In addition, Exhibit B2, Tab 1, Schedule 2 from EB-2013-0416 for Hydro One's Distribution rate application, updated May 30, 2014 has been included as Attachment 2.

a) See page 4 of Exhibit B2, Tab 1, Schedule 2 (CME interrogatory #4 Attachment 1) for the year 2014 for both the actual and forecast (Board Approved) embedded debt at the end of 2013 (lines 1 to 32) for Hydro One Transmission.

   See page 5 of Exhibit B2, Tab 1, Schedule 2 (Attachment 2) for the year 2014 from EB-2013-0416 for both the actual and forecast debt at the end of 2013 (lines 1 to 32) for Hydro One Distribution.

b) Embedded debt shown on lines 1 to 32 is identical to 2014 Rate Order in EB-2012-0031, dated January 9, 2014. For forecast debt issues shown on lines 33 to 35, the coupon rates are identical but the amounts have declined. This results in the average embedded cost of debt rate increasing from 4.94% (Approved) vs. 4.97% updated. There is no impact on the 2014 Revenue requirement.

B1-02-01 - COST OF THIRD PARTY LONG-TERM DEBT

1.0 HYDRO ONE TRANSMISSION LONG-TERM DEBT

The debt portfolio for Hydro One Transmission, as set out in Exhibit B2, Tab 1, Schedule 2, is based on debt issued by Hydro One Networks Inc. to Hydro One Inc., of which the Transmission business is mapped a portion. Hydro One Networks Inc. issues debt to Hydro One Inc., reflecting debt issues by Hydro One Inc. to third party public debt investors.

Third party public debt investors hold all of the long term debt issued by Hydro One Inc. Hydro One Inc.'s debt financing strategy takes into consideration the objectives of cost effectiveness, distributing debt maturities evenly over time, and ensuring the term of the debt portfolio is compatible with the long life of the Company's assets.

Hydro One Inc. has a Medium Term Note ("MTN") Program that provides ready access to issue debt with a term greater than one year into the Canadian debt capital markets. The standard maturity terms in the area of five, ten and thirty years are preferred by investors and represent the main financing which Hydro One Inc. utilizes to execute its financing strategy and raise the required funds. The short form base shelf prospectus for the current $3.0 billion MTN Program is provided in Exhibit A, Tab 13, Schedule 2.

2.0 CREDIT RATINGS

As Hydro One Inc. issues medium term notes in the Canadian public debt markets, credit ratings are a requirement. The credit ratings of Hydro One Inc.'s debt obligations by Dominion Bond Rating Service, Moody's Investors Service and Standard & Poor's Rating Services are as follows:

Table 1
Credit Ratings for Hydro One Inc.

Rating Agency	Short-term Debt	Debt
Standard & Poor's Rating Services (S&P)	A-1	A+
Dominion Bond Rating Service (DBRS)	R-1(middle)	A(high)
Moody's Investors Service (Moody's)	Prime-1	A1

The most recent rating agency reports are provided in Exhibit A, Tab 12, Schedule 1.

3.0 COST OF LONG-TERM DEBT

The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2014, 2015 and 2016. The weighted average rate on long term debt rate is 5.02% for 2015 and 5.08% for 2016. Details of Hydro One Transmission's long term debt rate calculation for the 2014 bridge year and 2015 and 2016 test years are identified at Exhibit B2, Tab 1, Schedule 2, pages 4 to 6.

The amount of each Hydro One Networks Inc. debt issue that is mapped to the Transmission business is based on its most recent forecast of borrowing requirements. Borrowing requirements are driven mainly by debt retirement, capital expenditures net of internally generated funds, and the maintenance of its capital structure. For example, in January of 2012, Hydro One Inc. issued $300 million of ten-year notes with a 3.20% coupon rate, of which $154 million was mapped to Hydro One Transmission, as shown on line 25 of Exhibit B2, Tab 1, Schedule 2, page 5.

The interest rates of debt issues mapped to the Transmission business, as shown in Exhibit B2, Tab 1, Schedule 2, are equal to the actual interest rates on debt issued by

Hydro One Networks Inc. to Hydro One Inc., and by Hydro One Inc. to third party public debt investors.

3.1 Embedded Debt

The Board has determined in its Cost of Capital Report that for embedded debt, the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt. Hydro One Transmission’s embedded long term debt, which was issued during the period from 2000 to 2013, is shown on lines 1 to 34 of Exhibit B2, Tab 1, Schedule 2, page 3. The rates on these embedded debt issues were approved by the Board as part of the Board’s 2014 Rate Order in EB-2012-0031, dated January 9, 2014.

3.2 New Debt

The Board has determined in its Cost of Capital Report that the rate for new debt that is held by a third party will be the prudently negotiated contract rate. This would include recognition of premiums and discounts.

3.3 Forecast Debt

Hydro One Transmission’s forecast borrowing requirements are $206 million for 2014, $478 million for 2015 and $592 million for 2016. For planning purposes it is assumed that debt issuance will be evenly distributed over the standard terms in the area of five, ten and thirty years, which are preferred by investors, while limiting total annual maturities for Hydro One Inc. to $750 million to avoid undue refinancing risk.
Table 2 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2014, and will be mapped to the Transmission business, as shown on lines 33 to 35 of Exhibit B2, Tab 1, Schedule 2, page 4.

Table 2
Forecast Debt Issues for remainder of 2014

2014		
Principal Amount ($Millions)	**Term (Years)**	**Coupon**
68.5	5	3.10%
68.5	10	4.09%
68.5	30	4.93%

Table 3 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2015, and 2016 will be mapped to the Transmission business, as shown on lines 34 to 39 of Exhibit B2, Tab 1, Schedule 2, page 6.

Table 3
Forecast Debt Issues for 2015 and 2016

2015			2016		
Principal Amount ($Millions)	**Term (Years)**	**Coupon**	**Principal Amount ($Millions)**	**Term (Years)**	**Coupon**
159.3	5	3.80%	197.5	5	4.30%
159.3	10	4.79%	197.5	10	5.29%
159.3	30	5.63%	197.5	30	6.13%

3.3 Interest Rates for 2014, 2015 and 2016 Forecast Debt Issues

Transmission business borrowing will be financed at market rates applicable to Hydro One Inc. Table 4 summarizes the derivation of the forecast Hydro One Inc. yield for each of the planned issuance terms for 2014, 2015 and 2016.

Table 4
Forecast Yield for 2014-2016 Issuance Terms

	2014		
	5-year	**10-year**	**30-year**
Government of Canada	2.23%	2.90%	3.40%
Hydro One Spread	0.87%	1.19%	1.53%
Forecast Hydro One Yield	3.10%	4.09%	4.93%
	2015		
	5-year	**10-year**	**30-year**
Government of Canada	2.93%	3.60%	4.10%
Hydro One Spread	0.87%	1.19%	1.53%
Forecast Hydro One Yield	3.80%	4.79%	5.63%
	2016		
	5-year	**10-year**	**30-year**
Government of Canada	3.43%	4.10%	4.60%
Hydro One Spread	0.87%	1.19%	1.53%
Forecast Hydro One Yield	4.30%	5.29%	6.13%

Each rate is comprised of the forecast Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2014 is based on the average of the 3 month and 12 month forecast from the September 2013 Consensus Forecast. The ten-year Government of Canada bond yield forecast for 2015 and 2016 is based on the average of the October 2013 Long Term Consensus Forecast. The five- and 30-year Government of Canada bond yield forecasts are derived by adding the September, 2013 average spreads (five-year to ten-year for the five-year forecast and 30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for September, 2013 obtained from the Company's MTN dealer group for each planned issuance term.

Hydro One assumes that forecast debt issuance interest rates for each test year will be updated consistent with the ROE methodology, upon the final decision in this case. For rates effective January 1, 2015, the forecast interest rate for Hydro One Transmission debt issues will based on the September 2014 Consensus Forecasts and the average of indicative new issue spreads for September 2014 which will be obtained from the Company's MTN dealer group for each planned issuance term. For rates effective January 1, 2016, the forecast interest rate for Hydro One Transmission debt issues will be based on the September 2015 Consensus Forecasts and the average of indicative new issue spreads for September 2015 which will be obtained from the Company's MTN dealer group for each planned issuance term. In addition Hydro One assumes that long term debt rate will be updated to reflect and take into account the actual issuances of debt since the time of original application consistent with the OEB's Decision on Hydro One Transmission's 2013 and 2014 rate application in EB-2012-0031 and changes in the interest rate forecast.

3.4 Treasury OM&A Costs

Treasury OM&A costs are incurred to:

- execute borrowing plans and issue commercial paper and long term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage the company's daily liquidity position, control cash and manage the company's bank accounts;
- settle all transactions and manage the relationship with creditors; and
- communicate with debt investors, banks and credit rating agencies.

These costs are $1.6 million for both 2015 and for 2016 as shown on line 39, page 5 and line 41, page 6 of Exhibit B2, Tab 1, Schedule 2.

3.5 Other Financing-Related Fees

Column (e) of Exhibit B2, Tab 1, Schedule 2 ("Premium, Discount and Expenses") represents the costs of issuing debt. These costs are specific to each debt issue and include commissions, legal fees, debt discounts or premiums on issues or re-openings of issues relative to par, and hedge gains or losses.

Other financing related fees, $2.9 million in 2015 and $3.0 million 2016, identified on line 40, page 5 and line 42, page 6 of Exhibit B2, Tab 1, Schedule 2, include the Transmission allocation of Hydro One Inc.'s standby credit facility, annual credit rating agency, banking, custodial and trustee fees.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Historical Year (2010)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/09 ($Millions)	Total Amount Outstanding: at 12/31/10 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.400%	1-Dec-11	76.0	(0.2)	76.2	100.28	6.36%	76.0	76.0	76.0	4.8	
3	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
4	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.55	5.83%	213.0	213.0	213.0	12.4	
5	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
6	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.48	5.70%	111.0	111.0	111.0	6.3	
7	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
8	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
9	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
10	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
11	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
12	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
13	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	90.0	90.0	4.2	
14	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
15	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	90.0	90.0	4.3	
16	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
17	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
18	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
19	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
20	10-Nov-08	5.000%	12-Nov-13	160.0	0.8	159.2	99.53	5.11%	160.0	160.0	160.0	8.2	
21	19-Nov-08	3.890%	19-Nov-10	40.0	0.1	39.9	99.78	4.01%	40.0	0.0	33.8	1.4	
22	13-Jan-09	3.890%	19-Nov-10	35.0	(0.2)	35.2	100.65	3.52%	35.0	0.0	29.6	1.0	
23	14-Jan-09	5.000%	12-Nov-13	70.0	(2.0)	72.0	102.85	4.34%	70.0	70.0	70.0	3.0	
24	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
25	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
26	19-Nov-09	3.130%	19-Nov-14	75.0	0.3	74.7	99.63	3.21%	75.0	75.0	75.0	2.4	
27	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	0.0	80.0	80.0	4.4	
28	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	0.0	120.0	120.0	5.3	
29	13-Sep-10	2.950%	11-Sep-15	100.0	0.4	99.6	99.62	3.03%	0.0	100.0	100.0	3.0	
30	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	0.0	100.0	100.0	5.0	
31		**Subtotal**							2305.9	2630.9	2694.4	146.0	
32		Treasury OM&A costs										0.8	
33		Other financing-related fees										3.2	
34		**Total**							2305.9	2630.9	2694.4	149.9	5.56%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Historical Year (2011)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/10 ($Millions)	Total Amount Outstanding at 12/31/11 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.400%	1-Dec-11	76.0	(0.2)	76.2	100.28	6.36%	76.0	0.0	70.2	4.5	
3	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
4	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.55	5.83%	213.0	213.0	213.0	12.4	
5	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
6	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.48	5.70%	111.0	111.0	111.0	6.3	
7	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
8	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
9	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
10	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
11	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
12	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
13	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	90.0	90.0	4.2	
14	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
15	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	90.0	90.0	4.3	
16	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
17	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
18	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
19	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
20	10-Nov-08	5.000%	12-Nov-13	160.0	0.8	159.2	99.53	5.11%	160.0	160.0	160.0	8.2	
21	14-Jan-09	5.000%	12-Nov-13	70.0	(2.0)	72.0	102.85	4.34%	70.0	70.0	70.0	3.0	
22	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
23	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
24	19-Nov-09	3.130%	19-Nov-14	75.0	0.3	74.7	99.63	3.21%	75.0	75.0	75.0	2.4	
25	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
26	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
27	13-Sep-10	2.950%	11-Sep-15	100.0	0.4	99.6	99.62	3.03%	100.0	100.0	100.0	3.0	
28	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
29	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	0.0	75.0	75.0	3.3	
30	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	0.0	30.0	30.0	1.2	
31		**Subtotal**							2630.9	2659.9	2730.1	147.7	
32		Treasury OM&A costs										0.8	
33		Other financing-related fees										3.3	
34		**Total**							2630.9	2659.9	2730.1	151.8	5.56%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Historical Year (2012)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/11 ($Millions)	Total Amount Outstanding at 12/31/12 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.55	5.83%	212.0	0.0	179.4	10.5	
4	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
5	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.48	5.70%	111.5	0.0	94.4	5.4	
6	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
7	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
8	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
9	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
10	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
11	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
12	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	90.0	90.0	4.2	
13	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
14	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	90.0	90.0	4.3	
15	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
16	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
17	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
18	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
19	10-Nov-08	5.000%	12-Nov-13	160.0	0.8	159.2	99.53	5.11%	160.0	160.0	160.0	8.2	
20	14-Jan-09	5.000%	12-Nov-13	70.0	(2.0)	72.0	102.85	4.34%	70.0	70.0	70.0	3.0	
21	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
22	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
23	19-Nov-09	3.130%	19-Nov-14	75.0	0.3	74.7	99.63	3.21%	75.0	75.0	75.0	2.4	
24	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
25	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
26	13-Sep-10	2.950%	11-Sep-15	100.0	0.4	99.6	99.62	3.03%	100.0	100.0	100.0	3.0	
27	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
28	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
29	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
30	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	0.0	126.0	126.0	4.1	
31	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	0.0	135.0	135.0	4.2	
32	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	0.0	56.3	56.3	2.3	
33	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	0.0	22.5	22.5	0.9	
34	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	0.0	94.0	94.0	3.6	
35		**Subtotal**							2659.5	2769.7	3043.5	155.4	
36		Treasury OM&A costs										0.8	
37		Other financing-related fees										3.3	
38		**Total**							2659.5	2769.7	3043.5	159.4	5.24%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Historical Year (2013)
Year ending December 31

Line No.	Offering Date (a)	Coupon Rate (b)	Maturity Date (c)	Principal Amount Offered ($Millions) (d)	Premium Discount and Expenses ($Millions) (e)	Net Capital Employed: Total Amount ($Millions) (f)	Net Capital Employed: Per $100 Principal Amount (Dollars) (g)	Effective Cost Rate (h)	Total Amount Outstanding at 12/31/12 ($Millions) (i)	Total Amount Outstanding at 12/31/13 ($Millions) (j)	Avg. Monthly Averages ($Millions) (k)	Carrying Cost ($Millions) (l)	Projected Average Embedded Cost Rates (m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
10	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	90.0	90.0	4.2	
11	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
12	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	90.0	90.0	4.3	
13	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
14	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
15	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
16	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
17	10-Nov-08	5.000%	12-Nov-13	160.0	0.8	159.2	99.53	5.11%	160.0	0.0	135.4	6.9	
18	14-Jan-09	5.000%	12-Nov-13	70.0	(2.0)	72.0	102.85	4.34%	70.0	0.0	59.2	2.6	
19	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
20	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
21	19-Nov-09	3.130%	19-Nov-14	75.0	0.3	74.7	99.63	3.21%	75.0	75.0	75.0	2.4	
22	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
23	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
24	13-Sep-10	2.950%	11-Sep-15	100.0	0.4	99.6	99.62	3.03%	100.0	100.0	100.0	3.0	
25	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
26	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
27	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
28	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
29	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
30	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
31	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
32	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
33	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	0.0	195.8	45.2	2.1	
34	9-Oct-13	2.780%	9-Oct-18	337.5	1.4	336.1	99.59	2.87%	0.0	337.5	77.9	2.2	
35		**Subtotal**							2769.7	3072.9	2857.4	142.1	
36		Treasury OM&A costs										1.0	
37		Other financing-related fees										2.2	
38		**Total**							2769.7	3072.9	2857.4	145.2	5.08%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Bridge Year (2014)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/13 ($Millions)	Total Amount Outstanding at 12/31/14 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
10	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	90.0	90.0	4.2	
11	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
12	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	90.0	90.0	4.3	
13	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
14	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
15	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
16	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
17	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
18	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
19	19-Nov-09	3.130%	19-Nov-14	75.0	0.3	74.7	99.63	3.21%	75.0	0.0	63.5	2.0	
20	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
21	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
22	13-Sep-10	2.950%	11-Sep-15	100.0	0.4	99.6	99.62	3.03%	100.0	100.0	100.0	3.0	
23	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
24	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
25	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
26	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
27	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
28	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
29	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
30	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
31	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	195.8	195.8	195.8	9.1	
32	9-Oct-13	2.780%	9-Oct-18	337.5	1.4	336.1	99.59	2.87%	337.5	337.5	337.5	9.7	
33	15-Mar-14	4.928%	15-Mar-44	58.8	0.3	58.6	99.50	4.96%	0.0	58.8	45.3	2.2	
34	15-Jun-14	4.091%	15-Jun-24	58.8	0.3	58.6	99.50	4.15%	0.0	58.8	31.7	1.3	
35	15-Sep-14	3.101%	15-Sep-19	58.8	0.3	58.6	99.50	3.21%	0.0	58.8	18.1	0.6	
36		**Subtotal**							3072.9	3174.5	3156.4	150.8	
37		Treasury OM&A costs										1.0	
38		Other financing-related fees										2.0	
39		**Total**							3072.9	3174.5	3156.4	153.8	4.87%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Test Year (2015)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/14 ($Millions)	Total Amount Outstanding at 12/31/15 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
10	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	90.0	90.0	4.2	
11	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
12	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	90.0	90.0	4.3	
13	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
14	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
15	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
16	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
17	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
18	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
19	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
20	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
21	13-Sep-10	2.950%	11-Sep-15	100.0	0.4	99.6	99.62	3.03%	100.0	0.0	69.2	2.1	
22	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
23	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
24	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
25	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
26	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
27	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
28	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
29	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
30	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	195.8	195.8	195.8	9.1	
31	9-Oct-13	2.780%	9-Oct-18	337.5	1.4	336.1	99.59	2.87%	337.5	337.5	337.5	9.7	
32	15-Mar-14	4.928%	15-Mar-44	58.8	0.3	58.6	99.50	4.96%	58.8	58.8	58.8	2.9	
33	15-Jun-14	4.091%	15-Jun-24	58.8	0.3	58.6	99.50	4.15%	58.8	58.8	58.8	2.4	
34	15-Sep-14	3.101%	15-Sep-19	58.8	0.3	58.6	99.50	3.21%	58.8	58.8	58.8	1.9	
35	15-Mar-15	5.628%	15-Mar-45	89.6	0.4	89.2	99.50	5.66%	0.0	89.6	68.9	3.9	
36	15-Jun-15	4.791%	15-Jun-25	89.6	0.4	89.2	99.50	4.86%	0.0	89.6	48.3	2.3	
37	15-Sep-15	3.801%	15-Sep-20	89.6	0.4	89.2	99.50	3.91%	0.0	89.6	27.6	1.1	
38		**Subtotal**							3174.5	3343.3	3288.5	158.3	
39		Treasury OM&A costs										1.0	
40		Other financing-related fees										1.8	
41		**Total**							3174.5	3343.3	3288.5	161.1	4.90%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Test Year (2016)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/15 ($Millions)	Total Amount Outstanding: at 12/31/16 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
10	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	0.0	20.8	1.0	
11	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
12	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	0.0	20.8	1.0	
13	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
14	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
15	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
16	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
17	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
18	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
19	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
20	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
21	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
22	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
23	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
24	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
25	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
26	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
27	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
28	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
29	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	195.8	195.8	195.8	9.1	
30	9-Oct-13	2.780%	9-Oct-18	337.5	1.4	336.1	99.59	2.87%	337.5	337.5	337.5	9.7	
31	15-Mar-14	4.928%	15-Mar-44	58.8	0.3	58.6	99.50	4.96%	58.8	58.8	58.8	2.9	
32	15-Jun-14	4.091%	15-Jun-24	58.8	0.3	58.6	99.50	4.15%	58.8	58.8	58.8	2.4	
33	15-Sep-14	3.101%	15-Sep-19	58.8	0.3	58.6	99.50	3.21%	58.8	58.8	58.8	1.9	
34	15-Mar-15	5.628%	15-Mar-45	89.6	0.4	89.2	99.50	5.66%	89.6	89.6	89.6	5.1	
35	15-Jun-15	4.791%	15-Jun-25	89.6	0.4	89.2	99.50	4.86%	89.6	89.6	89.6	4.4	
36	15-Sep-15	3.801%	15-Sep-20	89.6	0.4	89.2	99.50	3.91%	89.6	89.6	89.6	3.5	
37	15-Mar-16	6.128%	15-Mar-46	144.0	0.7	143.3	99.50	6.17%	0.0	144.0	110.8	6.8	
38	15-Jun-16	5.291%	15-Jun-26	144.0	0.7	143.3	99.50	5.36%	0.0	144.0	77.5	4.2	
39	15-Sep-16	4.301%	15-Sep-21	144.0	0.7	143.3	99.50	4.41%	0.0	144.0	44.3	2.0	
41	**Subtotal**								3343.3	3595.3	3437.5	168.2	
42	Treasury OM&A costs											1.0	
43	Other financing-related fees											1.9	
44	**Total**								3343.3	3595.3	3437.5	171.1	4.98%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Test Year (2017)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/16 ($Millions)	Total Amount Outstanding at 12/31/17 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
10	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
11	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
12	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
13	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	0.0	57.7	3.0	
14	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	0.0	92.3	4.6	
15	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
16	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
17	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
18	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
19	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
20	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
21	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
22	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
23	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
24	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
25	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
26	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
27	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	195.8	195.8	195.8	9.1	
28	9-Oct-13	2.780%	9-Oct-18	337.5	1.4	336.1	99.59	2.87%	337.5	337.5	337.5	9.7	
29	15-Mar-14	4.928%	15-Mar-44	58.8	0.3	58.6	99.50	4.96%	58.8	58.8	58.8	2.9	
30	15-Jun-14	4.091%	15-Jun-24	58.8	0.3	58.6	99.50	4.15%	58.8	58.8	58.8	2.4	
31	15-Sep-14	3.101%	15-Sep-19	58.8	0.3	58.6	99.50	3.21%	58.8	58.8	58.8	1.9	
32	15-Mar-15	5.628%	15-Mar-45	89.6	0.4	89.2	99.50	5.66%	89.6	89.6	89.6	5.1	
33	15-Jun-15	4.791%	15-Jun-25	89.6	0.4	89.2	99.50	4.86%	89.6	89.6	89.6	4.4	
34	15-Sep-15	3.801%	15-Sep-20	89.6	0.4	89.2	99.50	3.91%	89.6	89.6	89.6	3.5	
35	15-Mar-16	6.128%	15-Mar-46	144.0	0.7	143.3	99.50	6.17%	144.0	144.0	144.0	8.9	
36	15-Jun-16	5.291%	15-Jun-26	144.0	0.7	143.3	99.50	5.36%	144.0	144.0	144.0	7.7	
37	15-Sep-16	4.301%	15-Sep-21	144.0	0.7	143.3	99.50	4.41%	144.0	144.0	144.0	6.4	
38	15-Mar-17	6.528%	15-Mar-47	133.8	0.7	133.1	99.50	6.57%	0.0	133.8	102.9	6.8	
39	15-Jun-17	5.691%	15-Jun-27	133.8	0.7	133.1	99.50	5.76%	0.0	133.8	72.0	4.1	
40	15-Sep-17	4.701%	15-Sep-22	133.8	0.7	133.1	99.50	4.81%	0.0	133.8	41.2	2.0	
41		**Subtotal**							3595.3	3801.6	3766.4	186.8	
42		Treasury OM&A costs										1.0	
43		Other financing-related fees										2.0	
44		**Total**							3595.3	3801.6	3766.4	189.8	5.04%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Test Year (2018)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/17 ($Millions)	Total Amount Outstanding at 12/31/18 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
10	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
11	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
12	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
13	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
14	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
15	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
16	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
17	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
18	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
19	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
20	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
21	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
22	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
23	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
24	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
25	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	195.8	195.8	195.8	9.1	
26	9-Oct-13	2.780%	9-Oct-18	337.5	1.4	336.1	99.59	2.87%	337.5	0.0	259.6	7.4	
27	15-Mar-14	4.928%	15-Mar-44	58.8	0.3	58.6	99.50	4.96%	58.8	58.8	58.8	2.9	
28	15-Jun-14	4.091%	15-Jun-24	58.8	0.3	58.6	99.50	4.15%	58.8	58.8	58.8	2.4	
29	15-Sep-14	3.101%	15-Sep-19	58.8	0.3	58.6	99.50	3.21%	58.8	58.8	58.8	1.9	
30	15-Mar-15	5.628%	15-Mar-45	89.6	0.4	89.2	99.50	5.66%	89.6	89.6	89.6	5.1	
31	15-Jun-15	4.791%	15-Jun-25	89.6	0.4	89.2	99.50	4.86%	89.6	89.6	89.6	4.4	
32	15-Sep-15	3.801%	15-Sep-20	89.6	0.4	89.2	99.50	3.91%	89.6	89.6	89.6	3.5	
33	15-Mar-16	6.128%	15-Mar-46	144.0	0.7	143.3	99.50	6.17%	144.0	144.0	144.0	8.9	
34	15-Jun-16	5.291%	15-Jun-26	144.0	0.7	143.3	99.50	5.36%	144.0	144.0	144.0	7.7	
35	15-Sep-16	4.301%	15-Sep-21	144.0	0.7	143.3	99.50	4.41%	144.0	144.0	144.0	6.4	
36	15-Mar-17	6.528%	15-Mar-47	133.8	0.7	133.1	99.50	6.57%	133.8	133.8	133.8	8.8	
37	15-Jun-17	5.691%	15-Jun-27	133.8	0.7	133.1	99.50	5.76%	133.8	133.8	133.8	7.7	
38	15-Sep-17	4.701%	15-Sep-22	133.8	0.7	133.1	99.50	4.81%	133.8	133.8	133.8	6.4	
39	15-Mar-18	6.628%	15-Mar-48	169.5	0.9	168.6	99.49	6.67%	0.0	169.5	130.4	8.7	
40	15-Jun-18	5.791%	15-Jun-28	169.5	0.8	168.6	99.50	5.86%	0.0	169.5	91.3	5.3	
41	15-Sep-18	4.801%	15-Sep-23	169.5	0.8	168.6	99.50	4.91%	0.0	169.5	52.1	2.6	
42		**Subtotal**							3801.6	3972.5	3997.5	203.6	
43		Treasury OM&A costs										1.1	
44		Other financing-related fees										2.0	
45		**Total**							3801.6	3972.5	3997.5	206.7	5.17%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Test Year (2019)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/18 ($Millions)	Total Amount Outstanding at 12/31/19 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
2	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.1	98.78	7.03%	47.7	47.7	47.7	3.4	
3	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.57	6.65%	142.0	142.0	142.0	9.4	
4	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
5	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
6	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
7	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
8	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
9	19-May-05	5.360%	20-May-36	98.1	3.7	94.4	96.19	5.62%	98.1	98.1	98.1	5.5	
10	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
11	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
12	13-Mar-07	4.890%	13-Mar-37	160.0	0.9	159.1	99.45	4.93%	160.0	160.0	160.0	7.9	
13	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.41	6.07%	105.0	105.0	105.0	6.4	
14	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.36	5.53%	90.0	90.0	90.0	5.0	
15	15-Mar-10	5.490%	24-Jul-40	80.0	(0.5)	80.5	100.58	5.45%	80.0	80.0	80.0	4.4	
16	15-Mar-10	4.400%	4-Jun-20	120.0	0.5	119.5	99.55	4.46%	120.0	120.0	120.0	5.3	
17	13-Sep-10	5.000%	19-Oct-46	100.0	(0.2)	100.2	100.25	4.98%	100.0	100.0	100.0	5.0	
18	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.35	4.43%	75.0	75.0	75.0	3.3	
19	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.47	4.03%	30.0	30.0	30.0	1.2	
20	13-Jan-12	3.200%	13-Jan-22	126.0	0.7	125.3	99.47	3.26%	126.0	126.0	126.0	4.1	
21	22-May-12	3.200%	13-Jan-22	135.0	(1.3)	136.3	100.97	3.08%	135.0	135.0	135.0	4.2	
22	22-May-12	4.000%	22-Dec-51	56.3	0.3	56.0	99.51	4.02%	56.3	56.3	56.3	2.3	
23	31-Jul-12	3.790%	31-Jul-62	22.5	0.1	22.4	99.47	3.81%	22.5	22.5	22.5	0.9	
24	16-Aug-12	3.790%	31-Jul-62	94.0	0.8	93.2	99.20	3.83%	94.0	94.0	94.0	3.6	
25	9-Oct-13	4.590%	9-Oct-43	195.8	1.1	194.6	99.42	4.63%	195.8	195.8	195.8	9.1	
26	15-Mar-14	4.928%	15-Mar-44	58.8	0.3	58.6	99.50	4.96%	58.8	58.8	58.8	2.9	
27	15-Jun-14	4.091%	15-Jun-24	58.8	0.3	58.6	99.50	4.15%	58.8	58.8	58.8	2.4	
28	15-Sep-14	3.101%	15-Sep-19	58.8	0.3	58.6	99.50	3.21%	58.8	0.0	40.7	1.3	
29	15-Mar-15	5.628%	15-Mar-45	89.6	0.4	89.2	99.50	5.66%	89.6	89.6	89.6	5.1	
30	15-Jun-15	4.791%	15-Jun-25	89.6	0.4	89.2	99.50	4.86%	89.6	89.6	89.6	4.4	
31	15-Sep-15	3.801%	15-Sep-20	89.6	0.4	89.2	99.50	3.91%	89.6	89.6	89.6	3.5	
32	15-Mar-16	6.128%	15-Mar-46	144.0	0.7	143.3	99.50	6.17%	144.0	144.0	144.0	8.9	
33	15-Jun-16	5.291%	15-Jun-26	144.0	0.7	143.3	99.50	5.36%	144.0	144.0	144.0	7.7	
34	15-Sep-16	4.301%	15-Sep-21	144.0	0.7	143.3	99.50	4.41%	144.0	144.0	144.0	6.4	
35	15-Mar-17	6.528%	15-Mar-47	133.8	0.7	133.1	99.50	6.57%	133.8	133.8	133.8	8.8	
36	15-Jun-17	5.691%	15-Jun-27	133.8	0.7	133.1	99.50	5.76%	133.8	133.8	133.8	7.7	
37	15-Sep-17	4.701%	15-Sep-22	133.8	0.7	133.1	99.50	4.81%	133.8	133.8	133.8	6.4	
38	15-Mar-18	6.628%	15-Mar-48	169.5	0.9	168.6	99.49	6.67%	169.5	169.5	169.5	11.3	
39	15-Jun-18	5.791%	15-Jun-28	169.5	0.8	168.6	99.50	5.86%	169.5	169.5	169.5	9.9	
40	15-Sep-18	4.801%	15-Sep-23	169.5	0.8	168.6	99.50	4.91%	169.5	169.5	169.5	8.3	
41	15-Mar-19	6.628%	15-Mar-49	78.1	0.4	77.7	99.50	6.67%	0.0	78.1	60.1	4.0	
42	15-Jun-19	5.791%	15-Jun-29	78.1	0.4	77.7	99.50	5.86%	0.0	78.1	42.1	2.5	
43	15-Sep-19	4.801%	15-Sep-24	78.1	0.4	77.7	99.50	4.91%	0.0	78.1	24.0	1.2	
44		**Subtotal**							3972.5	4148.0	4080.6	216.2	
45		Treasury OM&A costs										1.1	
46		Other financing-related fees										2.0	
47		**Total**							3972.5	4148.0	4080.6	219.3	5.37%

Energy Probe Research Foundation (EP) INTERROGATORY #6

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1, Page 3

Preamble:
Table 2 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2014,and that will be mapped to the Transmission business, as shown on lines 33 to 35 of Exhibit B2, Tab 1, Schedule 2, page 8.

a) For historic year 2013 please provide the regulatory schedules that showed the forecast (Board approved) amount of debt to be issued by Hydro One Inc. for Networks and the "as filed" amounts and rates and the forecast amounts mapped to Tx and Dx.

b) For Historic Year 2013 provide the Actual amounts, rates and amounts mapped to TX and DX. Please explain all material differences.

c) For Bridge year 2014 please provide the schedules that show the (Board-Approved) amount of debt to be issued by Hydro One Inc. for Networks and the as filed amounts issued or to be issued, rates and the forecast amounts mapped to Tx and Dx.

d) For Bridge year 2014 provide the Actual amounts issued, rates and amounts mapped to Tx and Dx. Also update for year to date and provide a 2014 projection. Please explain all material differences.

Response

a) Please see response to interrogatory CME 4 Attachment 1, page 3 of Exhibit B2, Tab 1, Schedule 2 for the long term debt schedule for the historic year 2013 for the Transmission Business. In addition, please see page 4 of Exhibit B2, Tab 1, Schedule 2 from EB-2013-0416 for Hydro One Distribution updated May 30, 2014 for the long term debt schedule for the historic year 2013 for the Distribution Business.

b) Please see response to part (a) above as the amounts issued and rates provided in the schedule are Actual.

c) Please see response to interrogatory I-2-4 Attachment 1, page 4 of Exhibit B2, Tab 1, Schedule 2 for the long term debt schedule for the Bridge year 2014 for the

Transmission Business. In addition, please see page 5 of Exhibit B2, Tab 1, Schedule 2 from EB-2013-0416 for Hydro One Distribution updated May 30, 2014 for the long term debt schedule for the Bridge year 2014 for the Distribution Business.

d) Please see response to part (c) above, amounts issued and rates for debt issues shown on lines 1 to 32 are Actual to the end of 2013. Projected debt issues for 2014 are shown on lines 33 to 35. Please see response to interrogatory I-03-05 part (a) for actual issuances during 2014.

Energy Probe Research Foundation (EP) INTERROGATORY #7

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1, Page 4

Preamble:
Table 3 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2015 and 2016 that will be mapped to the Transmission business, as shown on lines 34 to 39 of Exhibit B2, Tab 1, Schedule 2, page 12.(not provided)

a) Please provide the 2015 and 2016 gross amounts by issue of debt to be issued on behalf of Networks. Provide forecast rates.

b) Please provide the calculations that map the 2015 and 2016 amounts of new debt to both Tx and Dx and provide a Table that show shows the total amounts of.
   i) Embedded debt, and
   ii) New debt.

Allocated to each business.

Response

a) Please see response to CME 4 Attachment 1, page 6 of Exhibit B2, Tab 1, Schedule 2 for the test year 2016 for the Transmission Business. Lines 34 to 39 provides the forecast amounts of debt for the Transmission Business for 2015 and 2016.

   In addition, please see page 7 of Exhibit B2, Tab 1, Schedule 2 from EB-2013-0416 for Hydro One Distribution updated May 30, 2014 for the test year 2016 for the Distribution Business. Lines 34 to 39 provides the forecast amounts of debt for the Distribution Business for 2015 and 2016.

   The amount of debt issued by Hydro One Networks for 2015 and 2016 is the total of the principal amounts offered for the Transmission Business and the Distribution Business for each issue as provided in the referenced two schedules. The forecast rates are provided in the two schedules are identical.

b) Please see response to CME 4 Attachment 1, attached Exhibit B2, Tab 1, Schedule 2 for the Transmission Business. Lines 1 to 31 of Page 5 Exhibit B2, Tab 1, Schedule 2 for the test year 2015 provides the amounts of Embedded debt for the Transmission

Business. Lines 31 to 39 of Page 6 Exhibit B2, Tab 1, Schedule 2 for the test year 2016 provides the amounts of forecast debt for the Transmission Business.

In addition, please see Exhibit B2, Tab 1, Schedule 2 from EB-2013-0416 for Hydro One Distribution updated May 30, 2014 for the Distribution Business. Lines 1 to 31 of Page 6 Exhibit B2, Tab 1, Schedule 2 for the test year 2015 provides the amounts of Embedded debt for the Distribution Business. Lines 31 to 39 of Page 7 Exhibit B2, Tab 1, Schedule 2 for the test year 2016 provides the amounts of forecast debt for the Distribution Business.

Energy Probe Research Foundation (EP) INTERROGATORY #8

Interrogatory

Ref: Exhibit B1, Tab 2, Schedule 1, Page 5

Preamble:
Hydro One assumes that forecast debt issuance interest rates for each test year will be updated consistent with the ROE methodology, upon the final decision in this case.

a) Confirm when the forecast of debt rates is updated. Are the amounts and terms of debt to be issued also updated?

b) Are the amounts of debt and costs and the allocation to Tx and Dx trued up post facto? Please discuss and provide an example.

Response

a) As discussed on lines 12 to 17, page 3 of Exhibit B1, Tab 1 Schedule 1 shown below, Hydro One will update the forecast debt rates as part of the rate order for the following year:

> "As discussed in this exhibit, forecast interest rates will be updated consistent with the methodology used for the return on common equity and deemed short term interest rate. In addition Hydro One assumes that long term debt rate will be updated to reflect and take into account the actual issuances of debt since the time of original application consistent with the OEB Decision on Hydro One Transmission 2013 and 2014 rate application in EB-2012-0031."

b) Please see response to part (a). The long term debt rate will be updated annually to take into account actual debt issuances.

Energy Probe Research Foundation (EP) INTERROGATORY #9

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 2, Page 7 (Attachment 1 not provided)

Preamble:
Details of the information provided by the OPA and the methodology used by Hydro One to derive the CDM impacts for the 3 charge determinants are documented in Attachment 1 of this Exhibit. Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2016. These CDM peak impacts are consistent with the 2013 LTEP.

a) Please provide a summary of Attachment 1.

b) Please provide the comparable 2013-2016 CDM amounts from the 2013 LTEP.

c) Please clarify which years OPA data are actuals and which are estimates.

d) Do the OPA data reflect the extension of the current CDM plan to 2015?

e) Confirm if the data for 2016 include any estimates for the new CDM plan requested by the Minister this spring?

Response

a) A summary of Attachment 1 is provided below:

Attachment 1 discusses the CDM impacts in Hydro One Network's transmission load forecast. The methodology for incorporating CDM impacts in the load forecast was presented in Hydro One's last transmission rates application (EB-2012-0031) and was approved by the Ontario Energy Board.

In December of 2013, the Ministry of Energy released Ontario's updated Long-Term Energy Plan, *Achieving Balance* ("the 2013 LTEP"). The detailed breakdown of assumptions underpinning the 2013 LTEP was released by the OPA in February 2014. Based on consultation with the OPA, Hydro One has adopted the OPA's province-wide conservation forecast and used a similar methodology to incorporate these CDM impacts into the load forecast.
While the OPA provided total CDM impacts for the province, it did not provide this information by charge determinant. Hydro One derived CDM impacts by charge determinant to support its load forecast.

Table 1 shows CDM impacts by the three charge determinants used in this rate application.

Table 1: Annual CDM Impacts by Charge Determinant

(12-Month Average Peak MW)

Year	Ontario Demand (MW)	Charge Determinant		
		Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
2014	1,723	1,711	1,602	1,377
2015	1,872	1,858	1,740	1,495
2016	2,087	2,071	1,939	1,667

Note: Charge Determinants are at wholesale purchase level

b) The 2013-2016 peak demand savings (MW) from 2013 LTEP are provided below.

	2013	2014	2015	2016
Peak Demand Reduction Associated with Energy Savings Targets	**1621**	**1820**	**1942**	**2167**
EE (historical and future programs)	1248	1435	1528	1662
Codes and Standards (existing and forecast)	373	386	413	505
Peak Reduction from Existing and Future Demand Response Resources	**1352**	**1399**	**1425**	**1437**
Dispatchable Load	377	377	377	377
Industrial Conservation Initiative	300	300	300	300
Time-of-Use Rates	137	184	221	232
Existing DR Programs (assume capacity maintained)	539	539	528	528
Total	**2973**	**3219**	**3367**	**3604**

c) In the OPA data 2006 to 2012 are actuals and 2013 to 2016 are forecasted savings.

d) Savings from the current CDM plan for 2011-2014 as well as the new CDM plan for 2015-2020 are reflected in the OPA data consistent with the 2013 LTEP.

e) Yes, the new CDM plan requested by the Minister is included in the OPA data.

Energy Probe Research Foundation (EP) INTERROGATORY #10

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 1, Page 5 of 6, Table 2

Preamble:
The reduction in the Sustaining, Development, and Operations work program spend reflects Cornerstone savings (both are included in the Board Approved Shared Services and Other total in Table 2).

a) Please provide details of 2013 Cornerstone savings by category and Total for both Dx and Tx

b) Relate these savings to the Cornerstone Benefits Realization Plan

Response

a) Aspects of the Cornerstone Program are embedded in many areas of the corporation such as planning tools, billing processes, design and engineering tools that are used by different groups in the company. Some of this work overlaps between areas such as Sustaining and Development. Therefore the breakdown of the savings by category is not available. However, Exhibit I, Tab 4, Schedule 4, part d illustrates the breakdown between transmission and distribution.

b) Please see response to Exhibit I, Tab 4, Schedule 4, part d.

Energy Probe Research Foundation (EP) INTERROGATORY #11

Interrogatory

Ref: Exhibit C1, Tab 6, Schedule 3, Page 4 of 4

Preamble:
Due to the significance of Cornerstone as a Shared Asset, Hydro One has developed transfer price charge rates to allocate a portion of the revenue requirement related to certain Shared Assets to the Telecom and Remotes businesses. The methodology and impact of the transfer price charges are described in more detail in Attachment 1 to this Exhibit.

a) Please provide referenced Attachment.

b) Please provide the amount and 2014-2016 shared services schedule(s) showing Cornerstone- related increases in common costs to Telecom and Remotes

Response

a) Please see Attachment 1 for the Common Asset Allocation study requested.

b) Please see table below.

FEES PAYABLE BY AFFILIATES TO NETWORKS FOR SERVICES TO BE PROVIDED BY NETWORKS: (in $Thousands)				
Services	**Hydro One Inc.**	**Remotes**	**Telecom**	**Brampton**
Lease of HONI's IT Assets				
• **2015**	0	300	580	0
• **2016**	0	300	580	0

REVIEW OF SHARED ASSETS ALLOCATION (TRANSMISSION) – 2014

PREPARED FOR

Hydro One Networks Inc.

17 MARCH 2014

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

I. Summary

A. BACKGROUND AND PURPOSE

Black & Veatch ("B&V" or "we") is pleased to submit this Report on our Review of Shared Assets Allocation (Transmission) – 2014 to Hydro One Networks Inc. ("HONI"). This Report describes the review that B&V performed, at the request of Hydro One, of Hydro One's allocation of the costs of Shared Assets in its 2015-2016 Transmission Rates filing before the Ontario Energy Board ("OEB"). In this Report, "cost" is original cost (i.e., gross book value) as derived of December 31, 2012.

In 2005, B&V recommended, Hydro One adopted, and the OEB accepted a methodology for Hydro One to allocate the costs of Shared Assets between its Distribution business and Transmission business, and issued our *Report on Shared Assets Methodology Review* dated June 15, 2005 ("2005 Assets Report"). B&V's objective in allocating the Shared Assets was to ensure that the allocation was reasonable, reflected best practices and was consistent with the allocation of common corporate costs, as discussed in our *Review of Allocation of Common Corporate Costs (Transmission)-* dated March 17, 2014 ("2014 Common Corporate Costs Report- Transmission").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW / ASSET VALUES	HYDRO ONE FILING	B&V REPORT
2006 Review 12/31/2005	2006 Distribution Rates	*Report on Common Assets Methodology 2006* dated May 31, 2006
2008 Review 12/31/2007	2008 Transmission Rates	*Report on Common Assets Methodology 2008* dated September 10, 2008
2009 Review (Distribution) 12/31/2008	2010/2011 Distribution Rates	*Report on Common Assets Allocation- 2009* dated June 29, 2009
2009 Review (Transmission) 12/31/2008	2011/2012 Transmission Rates	*Report on Common Assets Allocation (Transmission) - 2010* dated February 26, 2010
2011 Review (Transmission) 12/31/2010	2013/2014 Transmission Rates	*Report on Shared Assets Allocation (Transmission) 2012* dated February 1, 2012
2013 Review (Distribution) 12/31/2012	2015-2019 Distribution Rates	*Report on Shared Assets Allocation (Distribution) 2013* dated September 19, 2013

The OEB-accepted methodology has been applied by Hydro One to its Business Plan for 2014-19 ("BP 2014-19") data for its 2015-2016 Transmission Rates filing. This Report describes the "Review of Shared Assets Allocation (Transmission)" that B&V performed, at Hydro One's request, of Hydro One's application of the methodology to its BP 2014-19, and presents B&V's conclusions.

In its 2015-2016 Transmission Rates filing, Hydro One has allocated 42.3% of the cost of the Shared Assets to its Transmission business, and 57.7% to its Distribution business. These ratios are the same as used in its 2015-19 Distribution Rates filing, and approximately the same as in its 2011/2012 Transmission Rates filing which allocated 40.1% to the Transmission business and 59.9% to the Distribution business.

In addition, Hydro One has developed transfer price charge rates for the Telecom and Remotes businesses, to be used in allocating to those businesses a portion of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return). In the past, before Cornerstone assets had been placed in service, no Shared Assets were assigned to Telecom or Remotes because the amounts would have been very small.

No Shared Assets are allocated to Brampton, because it does not use these assets.

B. TYPES OF SHARED ASSETS

Hydro One provided B&V with a list of the Shared Assets, by Asset Group and Asset Subgroup, as shown in Table 1.

Table 1 - Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	▪ Software ▪ Buildings and Telecommunications equipment
Minor Fixed Assets ("MFA")	▪ Aircraft ▪ Computer Hardware ▪ Office equipment ▪ Service equipment- Miscellaneous ▪ Service equipment- Measurement and Testing ▪ Service equipment- Storage ▪ Tools ▪ Transportation Work Equipment ▪ Transportation Work Equipment- Power equipment

If an asset was estimated to be used at least 95% in either Transmission or Distribution, the cost of that asset was removed from Shared Assets and directly assigned to that business.

C. SUMMARY OF APPROACH

Allocation of Asset Costs to Transmission and Distribution

A cost driver was assigned to each asset (i.e., a building within Major Assets), asset type (i.e., Pickup Trucks within TWE) or Asset Subgroup, based on discussions with Hydro One personnel to ascertain what cost driver was most closely related to the usage of the asset or the Asset Subgroup. The cost drivers used to allocate the Shared Assets were selected from among, or derived from, the cost drivers used to allocate the costs of the common corporate functions and services. The specific steps used for each Asset Group and Subgroup are discussed below. The amounts allocated to Transmission and Distribution are summarized in Table 2.

Development of Transfer Price Charge Rates for Telecom and Remotes

The transfer price charge rates represent the usage of the Shared Assets by the Telecom and Remotes businesses. Our approach to developing the transfer price charge rates was as follows:

- The portion of each asset that should be allocated to Telecom and Remotes based on the appropriate cost driver was determined.
- The total dollar amount allocated to Telecom, representing Shared Asset cost, was computed for each asset by multiplying the Telecom share of usage by the asset cost; these dollar amounts were summed and divided by the category total cost to determine the Telecom share for the category. The same was done for Remotes. Table 3 presents the Telecom and remotes shares.
- The percentages should be applied to each component of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return), to compute the dollar amount charged to Telecom and Remotes. The amounts charged to Telecom and Remotes should be applied to reduce the revenue requirement recovered from rate payers of the Transmission and Distribution businesses.

  For example, the study determined that Telecom uses 0.42% (Table 3) of the shared Major Assets owned by HONI. As such, 0.42% of the revenue requirement associated with major assets is charged to Telecom. The revenue requirement calculated for HONI will include 100% of the assets, however, the other revenues received from the Hydro One Inc. subsidiaries will reduce the revenue requirement which is used to derive the tariff rates.

II. Descriptions of Asset Groups

A. MAJOR ASSETS

Software

Most of the software included in Shared Assets was for Hydro One's Cornerstone project, an enterprise-wide system to support work management, asset management, human resources, financial and other functions. These costs were allocated using a cost driver that reflects the activities supported. Infrastructure costs related to each phase were allocated based on the activities those phases support.

Buildings and Telecommunications Equipment

Each asset included in Buildings and Telecommunications Shared Assets was discussed with Hydro One personnel, and allocated using one of the following methods:

- **Specific estimation for a building.** For example, Sudbury Service Centre has estimated usage of Transmission-20% / Distribution-80%.
- **Direct assignment based on type of usage**. For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2009-2012 and determined that Fleet usage is Transmission- 27.26% and Distribution- 72.74%; therefore the costs for buildings used for Fleet were allocated using these percentages.

  Buildings used for Training were allocated using the cost driver Headcount.
- **Cost drivers based on usage.** For example, Buildings used to manage both Distribution and Transmission projects are allocated using the cost driver *ProgramProjectCosts*, developed as part of the 2014 Common Corporate Costs Report- Transmission study.

B. MINOR FIXED ASSETS

Each component of Minor Fixed Assets includes many individual items. B&V reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft –** Helicopter and supporting components. Usage was based on an analysis of time charges (which are recorded to time sheets concurrently with usage) for years 2009-2012.
- **Computer Hardware –** Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using a cost driver based on the number of *Workstations* (50% weight) and the cost driver *Headcount* (50% weight).
- **Office equipment –** Includes office furniture and other office equipment. Allocated using the cost driver *Headcount*.
- **Service equipment - Miscellaneous** – Includes miscellaneous equipment. Allocated using *Total Common Costs* cost driver, developed as part of the 2014 Common Corporate Costs Report- Transmission study.
- **Service equipment- Measurement and Testing** – Includes Meters, Splicers etc. used for Distribution. Directly assigned to *Distribution*.

- **Service equipment- Storage** – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on spending for *Operating and Maintenance costs and Capital spending*.
- **Tools** – Includes Rental tools. Allocated Distribution-20% / Transmission-80% reflecting estimated usage based on information as to which business units are renting the tools.
- **Transportation & Work Equipment** – Includes primarily Vehicles. Allocated using the cost driver "Fleet", which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2009-2012. Except for items representing less than 1.0% of cost, the usage for all of the Transportation & Work Equipment Shared Assets were recorded on time sheets and included in the computation of the Fleet cost driver.

The results are summarized in Table 2.

III. Summary of Results

Table 2 presents the allocation of Shared Assets to Transmission and Distribution.

Table 2 - Summary of Shared Assets Allocation

YEAR - END 2012 $ MILLIONS COST	TOTAL	TRANS-MISSION	DISTRIBU-TION	TRANS-MISSION %	DISTRIBU-TION %
Major Assets					
Software	$444.1	$238.2	$205.9	53.6%	46.4%
Building / Telecom	95.1	51.4	43.7	54.0%	46.0%
Total	**539.2**	**289.6**	**249.6**	**53.7%**	**46.3%**
Minor Fixed Assets					
Aircraft	19.1	13.9	5.2	72.8%	27.2%
Computer Hardware	89.2	48.8	40.4	54.7%	45.3%
Office Equipment	10.0	5.5	4.5	55.0%	45.0%
Service- Misc.	5.2	2.4	2.8	46.2%	53.8%
Service- Measure/Test	11.8	--	11.8	0.0%	100.0%
Service- Storage	3.6	2.1	1.5	58.3%	41.7%
Tools	8.3	6.6	1.7	79.5%	20.5%
Transportation & Work Equipment	524.0	142.9	381.1	27.3%	72.7%
Total	**671.2**	**222.2**	**449.0**	**33.1%**	**66.9%**
Total - All Shared Assets	**$1,210.4**	**$511.8**	**$698.6**	**42.3%**	**57.7%**

Table 3 presents the Shared Assets transfer price charges for Telecom and Remotes.

Table 3 - Transfer Price Charges for Other Businesses

ASSET GROUP	TELECOM	REMOTES
Major Assets	0.42%	0.24%
Minor Fixed Assets	0.25%	0.12%
Total - All Shared Assets	**0.30%**	**0.16%**

Energy Probe Research Foundation (EP) INTERROGATORY #12

Interrogatory

Ref.: Exhibit C1, Tab 2, Schedule 1, Page 6, Table 3

Preamble:
The reduction in the Sustaining, Development, and Operations work program spend was driven by the need to stay within the overall Transmission business OM&A envelope approved in the Board's last Decision, and also reflects Cornerstone savings.

a) Please provide details of 2014 Cornerstone savings by category and Total for both Dx and Tx.

b) Relate these savings to the Cornerstone Benefits Realization Plan.

Response

a) Please refer to Exhibit I, Tab 4, Schedule 10, part a for response.

b) Please refer to Exhibit I, Tab 4, Schedule 4, part d for response.

Energy Probe Research Foundation (EP) INTERROGATORY #13

Interrogatory

Ref: Exhibit C1, Tab 3, Schedule 3, Page 2, Table 1

Preamble:
Total CCFS costs increase by $13.1 million from 2013 to 2015.

a) Please confirm the difference in Total and Tx allocated costs are the allocations to Dx; and

b) Confirm the 2014-2016 amounts reconcile to the Dx Multi-year COS Application

Response

a) Materially, the difference in Total and TX allocated costs is the allocation to Dx. However, very small portions of the total CCFS costs are also allocated to Hydro One Telecom, Hydro One Brampton, Hydro One Inc. and Hydro One Remotes. Please see EB-2013-0416, Exhibit C1, Tab 5, Schedule 1 for more information.

b) Confirmed.

Energy Probe Research Foundation (EP) INTERROGATORY #14

Interrogatory

Ref: Exhibit C1, Tab 6, Schedule 1, Page 3, Table 1

Please provide a summary table showing 2013-2016 Common CCFS service costs and the allocations to Dx, Tx and other corporate Business Units including each of Hydro One Inc., Remotes, Telecom and Brampton Hydro.

Response

Please refer to the Interrogatory response in Exhibit I, Tab 10, Schedule 7.

Energy Probe Research Foundation (EP) INTERROGATORY #15

Interrogatory

Ref: Exhibit C1, Tab 6, Schedule 3, Page 2, Table 3

Preamble:
Hydro One has used the approved B&V Asset Allocation methodology in this proposed application and Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2012.

Please provide a version of Table 3 showing the Allocations for each of 2013-2016. Comment on any material changes.

Response

The numbers in Table 3 were produced by Black & Veatch as part of their "Review of Shared Assets Allocation (Transmission) – 2014" study at a point in time when actuals were only available for 2012. Therefore, a version of Table 3 for 2013 was not included. The intent of the study was to develop allocation rates to Transmission and Distribution, the results of which have been applied to all test years in the Transmission rate application.

Energy Probe Research Foundation (EP) INTERROGATORY #16

Interrogatory

Ref: Exhibit C1, Tab 7, Schedule 1

Please explain big increase in Asset Removal Costs 2013 to 2014-16.

Response

This is due to increase in capital expenditures, in particular due to the increase in Sustaining i.e replacement of existing assets requiring removal expense. Please refer to Exhibit D1, Tab 3, Schedule 1.

Energy Probe Research Foundation (EP) INTERROGATORY #17

Interrogatory

Ref: Exhibit D1, Tab 1, Schedule 1, Page 4/5, Tables 1 and 2

Preamble:
Total (2013) rate base was $143.9 million below the Board approved amount; a variance of 1.5%. Total (2014) rate base was $263.0 million below the Board approved amount, a variance of 2.6%.

a) Please provide calculations showing for each year relative to Board-approved baseline, the impact on the Revenue Requirement and Rates of the lower 2013 and 2014 ratebase.

b) Is the reduction in 2013 and 2014 ratebase a result of lower capital expenditures or lower Assets in Service? Please discuss.

c) Please provide the 2013 and 2014 ISA schedules provided in the EB-2012-0031 Settlement Process. Highlight major and material differences.

Response

a) Please see the tables below for the requested information. All amounts have been rounded to the nearest million.

Impact of lower Rate Base in 2013	**Rate Order**	**Updated Rate Base**	**Variance**
Rate Base	9,353	9,209	(144)
Revenue requirement			
OM&A	440	440	-
Depreciation (excl. rate rider amortization)	345	341	(4)
Return on rate base	604	595	(9)
AFUDC	5	5	-
Income tax (incl. LCT)	43	46	3
	1,438	1,427	(10)

Impact of lower Rate Base in 2014	Rate Order	Updated Rate Base	Variance
Rate Base	9,934	9,671	(263)
Revenue requirement			
OM&A	450	450	-
Depreciation (excl. rate rider amortization)	371	364	(8)
Return on rate base	655	637	(17)
AFUDC	5	5	-
Income tax (incl. LCT)	55	58	3
	1,535	1,514	(22)

b) Rate Base growth did not achieve the approved levels in 2013 and 2014 due to lower than planned in-service additions.

c) Please see the information provided in response to SEC's interrogatory 11 filed at Exhibit I, Tab 10, Schedule 11.

Energy Probe Research Foundation (EP) INTERROGATORY #18

Interrogatory

Ref: Exhibit D1, Tab 1, Schedule 2, Page 4, Table 2

Please expand the list of all major 2014-2016 project ISAs by category and ratebase addition date (year and Quarter).

Response

Please see response to SEC's interrogatory 12 at Exhibit I, Tab 10, Schedule 12.

Energy Probe Research Foundation (EP) INTERROGATORY #19

Interrogatory

Ref: Exhibit D1, Tab 1, Schedule 2, Page 5

Preamble:
In the Common Corporate Costs area, there are in-service additions in 2015 and 2016 for IT systems, transport & work equipment and head office and field facility improvements.

Please list all major 2014-2016 project ISAs by category and ratebase addition date (year and Quarter).

Response

Please see table below. These projects/programs are in serviced throughout the year, thus no quarterly in service date can be identified.

	In-Service Additions ($M)		
Description	**2014**	**2015**	**2016**
Information Technology	20.3	15.2	17.0
Fleet	17.7	14.9	17.1
Work Equipment (Service Equipment & Tools)	5.3	4.9	4.2
Real Estate Facilities	24.3	29.2	24.7
Cornerstone	11.1	0.0	0.0
Total	**78.7**	**64.1**	**63.1**

Energy Probe Research Foundation (EP) INTERROGATORY #20

Interrogatory

Ref: List of (Development) Capital Projects directed by OPA, IESO or Government (Rosenberg E-mail) and Exhibit D1, Tab 3, Schedule 3, Page 11 of 36, Table 1

a) Please include in first reference table any prior year expenditures future year costs and Total Costs.

b) Please reconcile the Table to Table 3 in the second Reference.

c) Please provide an expanded Table that consolidates the 2013-2016 projects and shows the In-Service date(s) and Assets to be added to Rate base by Quarter and year for each project.

Response

a) Please see Table 1on the next page.

Table 1

ISD#	Project Name	CAP EX ($ millions)													
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Gross Total**
Inter-Area Network Transfer Capability															
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	1.2	6.6	44.8	150.0	173.2	204.1	100.1	9.6	6.9	3.3	3.2	6.5	0.0	709.4
D02	Clarington TS: New 500/230kV Station	0.0	0.0	0.0	0.0	0.0	0.0	6.8	4.5	36.9	91.7	101.1	53.2	0.0	294.1
D03	Installation of Shunt Capacitor Banks at Cherrywood TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	3.4	7.0	3.5	14.0
Local Area Supply Adequacy															
D05	Guelph Area Transmission Reinforcement	0.0	0.0	0.2	0.2	0.4	0.1	0.5	1.1	13.5	48.3	29.9	0.0	0.0	94.3
D06	Preston TS Transformation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	10.0	4.6	10.0	0.0	24.9
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	0.0	0.0	0.0	0.0	0.1	0.2	5.2	5.8	3.4	5.7	3.9	0.0	0.0	24.3
D08	Hawthorne TS: Replace two existing Transformers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	7.0	4.5	0.0	12.5
D09	York Region - Increase Transmission Capability for B82V/B83V Circuits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	5.0	7.0	7.0	0.0	20.0
Load Customer Connection															
D12	Supply to Essex County Transmission Reinforcement	0.0	0.1	0.3	0.5	0.3	0.8	0.2	0.3	2.0	25.0	37.5	10.0	0.0	77.0
Generation Customer Connection															
D13	Napanee Gas Generation Connection	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.0	4.5	0.5	0.0	6.5
P&C Modifications for Enablement of Distribution Connected Generation															
D14	Transmission Station P&C Upgrades for DG	0.0	0.0	0.0	2.4	6.1	4.3	8.6	3.3	17.5	17.5	18.0	6.7	0.1	N/A*

*This category involves multiple small projects which do not have multi-year expenditures.

b) The project costs in this table represent the individual projects from the 10 tables in Exhibit D1, Tab 3, Schedule 3, Appendix A which is provided in Exhibit I, Tab 10, Schedule 15, Attachment 1. Table 1 in Exhibit D1, Tab 3, Schedule 3 summarizes the capital expenditures for tables 2 to 10 in Appendix A.

c) The in-service additions are shown in Table 2 below.

Table 2

ISD#	Investment Summary Description	I/S (Year)	I/S (Quarter)	2013	2014	2015	2016
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	2012	Q2	9.6	6.9	3.3	3.2
D02	Clarington TS: Build new 500/230kV Station	2017	Q3	0.0	0.0	0.0	0.0
D03	Installation of Shunt Capacitor Banks at Cherrywood TS	2018	Q2	0.0	0.0	0.0	0.0
D05	Guelph Area Transmission Reinforcement	2016	Q2	0.0	0.0	0.0	94.3
D06	Preston TS Transformation	2017	Q2	0.0	0.0	0.0	0.0
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate*	2016	Q2	7.4	0.0	0.0	16.2
D08	Hawthorne TS: Replace two existing Transformers	2017	Q2	0.0	0.0	0.0	0.0
D09	York Region - Increase Transmission Capability for B82V/B83V Circuits	2017	Q2	0.0	0.0	0.0	0.0
D12	Supply to Essex County Transmission Reinforcement	2017	Q1	0.0	0.0	0.0	0.0
D13	Napanee Gas Generation Connection	2017	Q1	0.0	0.0	0.0	0.0
D14	Transmission Station P&C Upgrades for DG*			0.0	0.0	0.0	0.0

*The costs in Table 1 are Gross Costs and these are Net Costs.

Energy Probe Research Foundation (EP) INTERROGATORY #21

Interrogatory

Ref.: Exhibit D1, Tab 2, Schedule 1, Page 15, Table - Cost Trends and Impacts

a) Please provide a version of Table that shows added Historic year Board Approved and 2014 YTD columns and data.

b) Please provide the unit average costs.

c) Please discuss any variances and associated cost impacts.

Response

a) Please see the revised table below for the inclusion of the 2014 YTD *(as of June 30, 2014)* information. The OEB Decisions provide approved amounts for programs and projects but not specific asset levels, so historical Board Approved amounts are not available.

Transformer Portfolio	Historic			Bridge		Test	
	2011	2012	2013	2014	2014 YTD	2015	2016
# of Replacements	16	12	15	26	8	26	26
% of Fleet	2.2%	1.7%	2.1%	3.6%	1.1%	3.6%	3.6%
Capital ($M)	81.1	100.5	120.7	162.9	27.9	105.7	120.1
OM&A ($M)	30.2	23.2	21.8	23.3	10.6	23.7	22.8

b) Average unit costs for transformer replacements are as follows:

Transformer Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Unit Cost ($M)	5.1	8.4	8.0	6.3	4.1	4.6

c) The costs of replacement of transformers varies based on the specification of the equipment as well as the site specific details. Typical transformer installation costs can range from $4 million to $25 million.

The higher unit costs in the historic years are a result of a greater number of higher MVA transformers being replaced which carry a higher unit cost than the transformers to be replaced in the test years.

Energy Probe Research Foundation (EP) INTERROGATORY #22

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Page 24, Table - Cost Trends and Impacts

a) Please provide a version of Table that shows added Historic year Board Approved and 2014 YTD columns and data.

b) Please provide the unit average costs.

c) Please discuss any variances and associated cost impacts.

Response

a) Please see the revised table below for the inclusion of the 2014 YTD *(as of June 30, 2014)* information. The OEB Decisions provide approved amounts for programs and projects but not specific asset levels, so historical Board Approved amounts are not available.

Circuit Breaker Portfolio	**Historic**			**Bridge**		**Test**	
	2011	**2012**	**2013**	**2014**	**2014 YTD**	**2015**	**2016**
# of Replacements	100	55	57	125	28	150	147
% of Fleet	2.2	1.2	1.2	2.7	0.6	3.3	3.2
Capital ($M)	55.8	39.7	54.5	68.9	30.9	82.7	83.2
OM&A ($M)	19.3	18.5	20.7	17.3	11.0	19.4	19.8

b) Average unit costs for circuit breaker replacements are as follows:

Circuit Breaker Portfolio	**Historic**			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Unit Cost ($M)	0.6	0.7	1.0	0.6	0.6	0.6

c) The costs of replacement of breakers varies based on the specifications of the equipment as well as the site specific details. Typical breaker installation costs can range from $100 thousand to $3 million.

The higher unit cost in 2013 is mostly a factor of increased completion of work associated with air blast breaker replacements which have a higher unit cost compared with other types of circuit breakers.

Energy Probe Research Foundation (EP) INTERROGATORY #23

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Page 36, Table - Cost Trends and Impacts

a) Please provide a version of Table that shows added Historic year Board Approved and 2014 YTD columns and data.

b) Please provide the unit average costs.

c) Please discuss any variances and associated cost impacts.

Response

a) Please see the revised table below for the inclusion of the 2014 YTD *(as of June 30, 2014)* information. The OEB Decisions provide approved amounts for programs and projects but not specific asset levels, so historical Board Approved amounts are not available.

Protection Systems Portfolio	**Historic**			**Bridge**		**Test**	
	2011	**2012**	**2013**	**2014**	**2014 YTD**	**2015**	**2016**
# of Replacements	389	350	340	350	50	365	450
% of Fleet	3.5%	2.9%	2.8%	2.9%	0.4%	3.0%	3.7%
Capital ($M)	28.5*	53.5	53.8	56.3	31.7	57.9	70.5
OM&A ($M)	11.3	9.7	9.7	10.6	6.3	10.3	11.7

**Note: Excludes capital expenditures for protection replacements included under Station Re-Investment*

b) Average unit costs for protection system replacements are as follows:

Protection Systems Portfolio	**Historic**			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Unit Cost ($K)	73.3*	152.9	158.2	160.9	158.6	156.7

**Note: Excludes capital expenditures for protection replacements included under Station Re-Investment*

c) The average unit cost for protection system replacements over the period has remained essentially constant.

Energy Probe Research Foundation (EP) INTERROGATORY #24

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Page 43, Table - Cost Trends and Impacts

a) Please provide a version of Table that shows added Historic year Board Approved and 2014 YTD columns and data.

b) Please provide the unit average costs.

c) Please discuss any variances and associated cost impacts.

Response

a) Please see the revised table below for the inclusion of the 2014 YTD *(as of June 30, 2014)* information. The OEB Decisions provide approved amounts for programs and projects but not specific asset levels, so historical Board Approved amounts are not available.

Conductor Portfolio	Historic			Bridge		Test	
	2011	2012	2013	2014	2014 YTD	2015	2016
Kms of Circuit Replacements	37	22	75	113	59	99	60
% of Fleet	0.1%	0.1%	0.3%	0.4%	0.2%	0.3%	0.2%
Capital ($M)	10.2	8.6	17.8	33.2	17.6	36.8	29.3
OM&A ($M)	10.6	10.6	9.4	13.1	6.2	14.2	14.5

b) Average unit costs for conductor replacements are as follows:

Conductor Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Unit Cost ($M)	0.3	0.4	0.2	0.3	0.4	0.5

c) The costs of replacement of conductor varies based on the specifications and the extend of the refurbishment required. The unit cost in 2013 is lower than other years, as work largely focused on a 115kV single circuit wood pole line which is less costly than the typical steel structure circuit.

Energy Probe Research Foundation (EP) INTERROGATORY #25

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Page 50, Table - Cost Trends and Impacts

a) Please provide a version of Table that shows added Historic year Board Approved and 2014 YTD columns and data.

b) Please provide the unit average costs.

c) Please discuss any variances and associated cost impacts.

Response

a) Please see the revised table below for the inclusion of the 2014 YTD *(as of June 30, 2014)* information. The OEB Decisions provide approved amounts for programs and projects but not specific asset levels, so historical Board Approved amounts are not available.

Wood Pole Portfolio	**Historic**			**Bridge**		**Test**	
	2011	**2012**	**2013**	**2014**	**2014 YTD**	**2015**	**2016**
# of Replacements	862	763	830	850	432	850	850
% of Fleet	2.1%	1.8%	2.0%	2.0%	1.0%	2.0%	2.0%
Capital ($M)	30.1	27.2	32.7	27.2	23.3	27.7	28.2
OM&A ($M)	2.9	4.4	3.1	4.4	2.3	4.1	4.2

b) Average unit costs for wood pole replacements are as follows:

Wood Pole Portfolio	**Historic**			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Unit Cost ($K)	34.9	35.6	39.4	32.0	32.6	33.2

c) The costs of wood pole replacement varies based on the structure specifications, extent of the work required, as well as the site specific details. Typical pole replacement costs can range from $20,000 to $80,000. The higher unit cost in 2013 was attributed to a higher percentage of 230 kV structure replacements in the overall program. These 230kV structures are larger and the most costly to replace.

Energy Probe Research Foundation (EP) INTERROGATORY #26

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Page 58, Table - Cost Trends and Impacts

a) Please provide a version of Table that shows added Historic year Board Approved and 2014 YTD columns and data.

b) Please provide the unit average costs.

c) Please discuss any variances and associated cost impacts.

Response

a) Please see the revised table below for the inclusion of the 2014 YTD *(as of June 30, 2014)* information. The OEB Decisions provide approved amounts for programs and projects but not specific asset levels, so historical Board Approved amounts are not available.

Steel Structure Portfolio	**Historic**			**Bridge**		**Test**	
	2011	**2012**	**2013**	**2014**	**2014 YTD**	**2015**	**2016**
# of Refurbishments	0	226	218	350	4	350	400
# of Replacements	0	0	17	4	0	4	12
% of Fleet	0%	0.5%	0.5%	0.7%	0.0%	0.7%	0.8%
Capital ($M)	0.6	8.7	13.3	11.1	5.4	10.7	16.0
OM&A ($M)	4.7	4.8	3.1	4.4	2.1	4.1	4.2

b) The capital costs provided in table above include a combination of structure refurbishment and complete structure replacement. The average unit costs by type of work are as follows.

Steel Structure Portfolio	**Historic**			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Unit Cost Refurbishment ($K)	N/A	38.5	23.4	26.4	25.1	25.8
Unit Cost Replacement ($K)	N/A	N/A	482.4	462.5	475.0	475.0

c) The unit costs for structures are generally consistent over the time period, with some variation based on the structure specifications, extent of the work required, as well as the site specific details. The higher unit cost for refurbishment in 2012 is attributed to the restarting of the program after a suspension for a portion of 2010 and 2011 due to an internal joint health and safety committee (JHSC) review of work practices.

Energy Probe Research Foundation (EP) INTERROGATORY #27

Interrogatory

**Ref: Exhibit E1, Tab2, Schedule 1, Page2, Table 1 &
Exhibit F1, Tab1, Schedule 1, Page 3, Table 2**

a) Please confirm and list which External Revenues are subject to Deferral/Variance Account Treatment in 2013-2016.

b) Please provide the Amounts in the Accounts for 2013 and YTD and Forecast for 2014.

c) Are the Forecast amounts included in the Rates Revenue Requirement? Please provide details.

Response

a) All HONI Transmission External Revenues are subject to the Deferral/Variance Account. The External Revenues are listed as show in Exhibit E1, Tab 2, Schedule 1, page 2, Table 1.

The Variance/Deferral related accounts that capture any variances are listed in Exhibit F1, Tab 1, Schedule 1, page 3, Table 2, for 2013-2016 in the second and third categories of that Table respectively;

- Secondary Land Use: (line 2 of the table)
- External Stations Maintenance: (combined in line 3 of the table)
- E&CS Revenues: (combined in line 3 of the table)
- Other External Revenues: (combined in line 3 of the table)

b) Please refer to the Table provided in Exhibit I, Tab 3, Schedule 17 [Response to IR from LPMA, Q17, Part c].

c) The amounts in Exhibit E1, Tab 2, Schedule 1, Page 3, Table 1 are included in the Board approved 2014 [EB-2012-0031] revenue requirement. These 2014 amounts and any variance to actual are not included in this disposition request and will not impact the revenue requirement amount requested in this rate file proceeding for the test years 2015 and 2016. Additionally, Hydro One is not forecasting any actual variance to forecast for the year-end 2014, however, any variances that may occur will be tracked in the Board approved variance/deferral account established for this purpose.

Energy Probe Research Foundation (EP) INTERROGATORY #28

Interrogatory

Ref: Exhibit F1, Tab 1, Schedule 1, Page 3, Table 2

a) Does Dx also have a Pension Cost Deferral account?

b) Please explain the amounts allocated to each account are calculated and provide the 2013-2016 amounts.

c) Please explain why the Long Term Future Corridor Account 1508 is still required and why "This amount is expected to grow over the next few years."

Response

a) Yes.

b) The method of allocation of Pension costs to OM&A and Capital is consistent with the methodology reviewed during RP-2005-0020/EB-2005-0378, EB-2006-0501, EB-2007-0681 and EB-2008-0272, EB-2009-0096, EB-2010-0002 and EB-2012-0031.

The following table shows the allocated Transmission Pension amounts between OM&A and Capital for the years 2013-2016.

Transmission Allocated Pension Components	2013 [1] $M	2014 [1] $M	2015 [2] $M	2016 [2] $M
Tx OM&A [3]	32	33	29	29
Tx Capital	38	42	42	40
Total	**70**	**75**	**71**	**69**

1. 2013 and 2014 values are per the Board approved amounts in the Business Plan supporting Hydro One Transmission rate filing EB-2012-0031.
2. 2015 and 2016 values are as per the Business Plan that supports the Hydro One Transmission rates application for 2015 and 2016 as filed with Intervenors
3. It should be highlighted when reading the above response that the Board approved Pension Costs Differential regulatory account tracks the difference between estimated and actual OM&A pension costs. This is also consistent for Hydro One Distribution.

c) Hydro One has not included any costs relating to Long-Term Transmission Future Corridor Acquisitions and Development, in the rate filing for 2015 & 2016 revenue requirement. Due to the variable and unpredictable nature of the work and the expected materiality of the costs, Hydro One Transmission continues to request approval to collect the costs in a deferral account.

As the regulatory account is a full deferral account, any expenditures relating to Long-Term Transmission Future Corridor Acquisitions and Development will see a growth of the balance in the account. As mentioned, Hydro One does expect money to be spent and subsequently recorded in this account, however the timing remains uncertain and predominately out of the control of Hydro One.

Energy Probe Research Foundation (EP) INTERROGATORY #29

Interrogatory

Ref: Exhibit G1, Tab 1, Schedule 1, Page 1, Table 1 &
Exhibit E1, Tab 1, Schedule 1, Table 4 (not provided)

a) Please provide a version of Table 3 with the Rates Revenue Requirement Allocations to TX pools for the Historic and Bridge years as well as 2015/2016.

b) Please include the % allocations for each pool.

Response

a) Hydro One assumes the question is referring to Table 1 of Exhibit G1, Tab 1, Schedule 1. The information requested is provided in the Table below.

Tariff Pool	**Historic**		**Bridge**		**Test Years**			
	2013		**2014**		**2015**		**2016**	
	$ (M)	**%**	**$ (M)**	**%**	**$ (M)**	**%**	**$ (M)**	**%**
Network	857.6	61.7%	882.9	61.0%	933.6	60.2%	972.0	59.9%
Line Connection	170.6	12.3%	183.2	12.7%	206.3	13.3%	218.0	13.4%
Transformation Connection	361.7	26.0%	379.7	26.2%	410.8	26.5%	432.1	26.6%
Wholesale Meter	0.9	0.1%	0.7	0.0%	0.3	0.0%	0.2	0.0%
TOTAL	**1,390.9**		**1,446.4**		**1,550.9**		**1,622.3**	

b) Please see response to part a) above.

Energy Probe Research Foundation (EP) INTERROGATORY #30

Interrogatory

Ref: Exhibit H1, Tab 3, Schedule 1, Page 1, Table 1

a) Please provide a version of Table 1 that shows the Charge Determinants for the Historic and Bridge Years.

b) Please highlight and explain material changes.

c) In particular, please explain changes to the Wholesale Meter Pool 2013-2016.

d) Why should the Exit Fee for Wholesale Meter installations, remain at $5,200?

Response

a) The requested information for the Network, Line Connection and Transformation Connection pools is provided in the information package at Exhibit A, Tab 15, Schedule 2, Table 4. The requested information for the Wholesale Mater pool is provided below.

Charge Determinants for Wholesale Mater Pool (MW)

Tariff Pool	Historic	Bridge	Test	
	2013	**2014**	**2015**	**2016**
Wholesale Meter	77	53	35	25

b) Please refer to the load forecast details provided in the information package, at Exhibit A, Tab 15, Schedule 2.

c) The change in Wholesale Meter Points from 2013 to 2016 reflects the number of wholesale meters that have, or are forecast, to exit the wholesale meter pool based on the experience in the meter exits completed to date, as well as knowledge of the exit requirements for the remaining meter points.

d) The $5,200 value is an average exit fee associated with the transfer of ownership and Meter Service Provider responsibilities from Hydro One to the metered market participant for all wholesale revenue metering facilities that were inherited from the former Ontario Hydro. This average fee was specifically reviewed and approved by Board Order dated March 11, 2004 under proceeding EB-2003-0233 and subsequently approved as part of Hydro One’s Transmission applications under EB-2006-0501, EB-2008-0272, EB-2010-0002 and EB-2012-0031.

Energy Probe Research Foundation (EP) INTERROGATORY #31

Interrogatory

Ref: Exhibit H1, Tab 5, Schedule 1, Page 4

Preamble:
For 2015 and 2016 the ETS revenue will continue to be disbursed through a decrease to the revenue requirement for the Network Pool, as per the cost allocation process approved by the Board in EB-2012-0031. The forecast for ETS revenue is $33.4 million and $34.3 million per year for 2015 and 2016, respectively.

Hydro One proposes to revise its rates revenue requirement to reflect the OEB's Decision and Order with respect to the ETS tariff as part of the Draft Rate Order to be submitted in connection with finalizing the 2015 Uniform Transmission Rates to be approved.

a) Confirm the impacts on the Rates Revenue Requirement and Rates of adopting the proposed $1.70/MW ETS rate for 2015/16.

b) Will there be any increase in Export Revenues as a result of the lower charge? Please discuss and provide estimates.

Response

a) Adopting the proposed $1.70/MW ETS rate will result in ETS revenue of $28.4M in 2015 and $29.2M in 2016. This will increase the rates revenue requirement of the Network pool by $5.0M in 2015 (0.32% increase in rates) and by $5.1M in 2016 (0.31% increase in rates).

b) Hydro One has not forecast any increase in Export Revenues as a result of the lower charge. Many factors contribute to changes in export volumes. The Board previously approved a variance account, as described in Exhibit F1, Tab 1, Schedule 1, to track the difference between forecast export revenues approved by the Board and the actual export revenues. Any increase in revenues resulting from higher exports will be captured and subsequently refunded to transmission customers as part of a subsequent transmission revenue requirement application.

Society of Energy Professionals (SEP) INTERROGATORY #1

Interrogatory

The following questions are with regards to all evidence, documentation, materials and correspondence on the record in the Hydro One Networks Inc. proceeding which is currently underway as EB-2013-0416 "2015 - 2019 Distribution Custom Incentive Rate Setting Application".

a) Please confirm that all interrogatory replies filed by Hydro One in the Distribution proceeding on the 4th July, 2014, in particular those dealing with "common" evidence, can be used by interested parties in the Transmission proposal negotiations which are currently underway. If Hydro One believes there are exceptions which cannot be used in these negotiations please list them and provide the Company's rationale for their opinion.

b) Please confirm that all human resources, compensation, staffing and headcount evidence in the Distribution proceeding [e.g. exhibits Exhibit C1, Tab 3, Schedule 1; Exhibit C1, Tab 3, Schedule 2 and all of its attachments; Exhibit C1, Tab 3, Schedule 3; Exhibit C2, Tab 3, Schedule 1; etc.] is the same as that prepared for but not necessarily provided in this Transmission proposal and can be used in the negotiations which are currently underway. Or if there are differences, please provide the relevant Transmission information as well as explanations of any and all differences from the Distribution evidence.

Response

a) Distribution evidence supports the revenue requirement and rates for distribution and is generally not relevant to transmission. However, descriptions and costs associated with common costs or processes are relevant to all Networks and can be used in the transmission discussion. This would include evidence such as Common Costs, Business Planning, Corporate Staffing and Compensation, Wages and Benefits.

   The following interrogatory responses should be applicable to distribution and transmission:

I-1.0-10-CCC-1	I-6.02-11-EP-44	I-4.03-01-Staff-69	I-4.02-09-SEC-32	I-6.04-09-SEC-53
I-4.02-10-CCC-24	I-2.03-01-Staff-15	I-4.03-01-Staff-70	I-4.02-09-SEC-35	I-2.06-09-SEC-9
I-4.02-10-CCC-25	I-2.03-01-Staff-16	I-4.03-01-Staff-71	I-4.02-09-SEC-36	I-3.03-12-SEP-1
I-4.02-10-CCC-26	I-2.06-01-Staff-33	I-4.03-01-Staff-72	I-4.04-09-SEC-37	I-3.03-12-SEP-9
I-4.04-10-CCC-27	I-2.06-01-Staff-37	I-4.03-01-Staff-73	I-4.04-09-SEC-38	I-3.02-02-SIA-35
I-4.04-10-CCC-28	I-3.02-01-Staff-47	I-4.04-01-Staff-74	I-4.04-09-SEC-39	I-3.02-02-SIA-44
I-3.02-11-EP-28	I-3.02-01-Staff-48	I-4.04-01-Staff-75	I-2.02-09-SEC-4	I-4.02-02-SIA-50
I-4.03-11-EP-32	I-3.02-01-Staff-49 c & d only	I-4.04-01-Staff-76	I-4.04-09-SEC-40	I-2.03-06-VECC-42
I-4.03-11-EP-33	I-3.02-01-Staff-50	I-3.01-09-SEC-20	I-4.04-09-SEC-41	I-2.06-06-VECC-49
I-4.03-11-EP-34	I-4.02-01-Staff-62	I-3.01-09-SEC-21	I-4.04-09-SEC-42	I-3.01-06-VECC-59
I-4.03-11-EP-35	I-4.02-01-Staff-63	I-3.01-09-SEC-22	I-4.04-09-SEC-43	I-3.02-06-VECC-60
I-4.04-11-EP-36	I-4.03-01-Staff-64	I-3.01-09-SEC-23	I-4.04-09-SEC-44	I-4.02-06-VECC-67
I-4.04-11-EP-37	I-4.03-01-Staff-65	I-3.01-09-SEC-24	I-4.04-09-SEC-45	I-4.02-06-VECC-68
I-4.04-11-EP-38	I-4.03-01-Staff-66	I-3.02-09-SEC-29	I-4.04-09-SEC-46	I-4.04-06-VECC-70
I-4.04-11-EP-39	I-4.03-01-Staff-67	I-3.03-09-SEC-30	I-4.04-09-SEC-47	I-4.04-06-VECC-71
I-6.02-11-EP-42	I-4.03-01-Staff-68	I-3.03-09-SEC-31	I-6.02-09-SEC-52	I-4.04-06-VECC-72
				I-4.04-06-VECC-73

b) The Corporate Staffing exhibit is consistent between the 2 filings. The Compensation, Wages and Benefits exhibit is consistent except for:

- Exhibit C1 Tab 4 Schedule 2 (page 9) Transmission filing has an added section for Short Term Incentive Pay
- Exhibit C1 Tab 4 Schedule 2 (page 11) reflects the changing work program and regular headcount for the period 2015-2016
- Exhibit C1 Tab 4 Schedule 2 Attachment 3 shows year end compensation for 2011-2016

Exhibit C1, Tab 4, Schedule 2 can be found as Exhibit I, Tab 3, Schedule 9 Attachment 1.

Society of Energy Professionals (SEP) INTERROGATORY #2

Interrogatory

With reference to Exhibit A, Tab 18, Schedule 1 "Cost Efficiencies/ Productivity":

a) Please provide all exhibits which are referenced as providing further explanation of the savings discussed [e.g. on pg 6 ln 10 there is reference to Exhibit C1, Tab 3, Schedule 2; on pg 7 ln 17 there is reference to Exhibit A, Tab 16, Schedule 3; on pg 7 lns 27, 28 as well as pg 13 lns 7, 13 there is reference to Exhibit A, Tab 16, Schedule 6; on pg 10 lns 8,9 there is reference to Exhibit C1, Tab 5, Schedule 1; on pg 11 lns 13, 14 there is reference to Exhibit C1, Tab 4, Schedule 1; on pg 16, lns 15, 16 there is reference to Exhibit A, Tab 4, Schedule 1].

Response

a) The exhibits referenced in Exhibit A, Tab 18, Schedule 1 can be found as attachments to this exhibit as follows:

   Exhibit A, Tab 4, Schedule 1 – Attachment 1
   Exhibit A, Tab 16, Schedule 6 – Attachment 2
   Exhibit C1, Tab 3, Schedule 2 – Attachment 3
   Exhibit C1, Tab 4, Schedule 1 – Attachment 4
   Exhibit C1, Tab 5, Schedule 1 – Attachment 5

   For Exhibit A, Tab 16, Schedule 3 – See Exhibit I, Tab 10, Schedule 13, Attachment 1C.

VOICE OF THE CUSTOMER

1.0 INTRODUCTION

Hydro One is fully committed to continuing to improve the customer's experience and satisfaction with the services received. Hydro One listens to its customers, analyzes their needs and modifies the work planning and activities to address those needs.

Customers are a major driver of long-term success. Hydro One uses various means to proactively obtain feedback from its customers. Customer survey research (impression and perception) is the largest channel used to evaluate the overall satisfaction of transmission customers and to understand their perception of Hydro One personnel and the services provided. The data collected and used to identify customer issues and priorities to be addressed.

2.0 CUSTOMER SURVEY RESEARCH

Surveys are conducted to gain an understanding of the key drivers impacting transmission customer satisfaction. Hydro One considers the results of the survey research in its risk assessment, prioritization and decision-making processes described in Exhibit A, Tab 16, Schedules 1-7 to address satisfaction gaps. Customer oriented investment proposals are developed that span the Sustaining, Development, Operating and Customer Care investment categories, described in Exhibits C1, Tab 2, Schedules 2 through 5.

Formalized Customer Satisfaction Research began at the Company in 1999. The goal of the research is to be timely, representative, unbiased, and conclusive providing the Company with the opportunity to listen, understand and respond.

All research is conducted by independent experts ensuring results are unbiased. **Northstar Research** conducts our Trasmission Customer studies. To ensure findings are representative, Northstar Research ensures the sample size and methodology are appropriate. The trending of results identifies opportunities to improve satisfaction and focus investments according to the customers.

2.1 2013 Transmission Customer Surveys

Transmission Customer Surveys are perception surveys that include all Large Industrial Customers, Local Distribution Companies and Transmission-connected Generators. Survey work was conducted in two waves; wave one was conducted on April 29, 2013 – June 12, 2013 and wave two was conducted from October 28, 2013 – November 8, 2013. Wave 1 started with on-line surveys followed by telephone interviewing, while in the fall on-line and telephone interviewing occurred simultaneously.

This survey included a total universe size of one hundred seventy-nine (179). The primary notification customers received was an e-mail invitation to participate, followed by two reminder e-mails to non-respondents. Telephone calls were then placed to customers who did not respond to the web option and for whom a telephone number was provided. Of the total pool of these customers, a total of one hundred thirty (130) customers completed the survey (73% response rate), broken down as follows:

- 35 Tx Generator customers;
- 41 Industrial customers; and
- 54 LDC customers.

An additional 7 respondents were partial completions, answering the overall satisfaction question. This represents a significant increase over 2012 (46% response rate) and 2011 (36% response rate).

These customers are asked about the main issue they would like to see Hydro One address. Attachment 1 shows the results of this survey research.

2.2 Ontario Grid Control Centre (OGCC) Transactional Surveys

The OGCC conducts a transactional survey every two years. The intent of the survey is to obtain transmission customer feedback on their operating experience. Feedback is essential in the continuing effort to understand customer needs surrounding the delivery of a reliable electricity service. Areas the survey focuses on include overall impression and contact with OGCC staff.

3.0 CUSTOMER ENGAGEMENT BEYOND THE SURVEY

Understanding the voice of the customer and their needs and preferences goes beyond structured customer research processes. The additional channels of customer engagement facilitated by Hydro One to assist in understanding customer needs are described in this section.

3.1 Customer Account Executives

Hydro One Customer Account Executives are a key part of managing the customer experience. They interface between Hydro One and transmission customers to manage the commercial relationship. The Account Executive meets with the customer on an as required basis to ensure:

- The diverse customer needs are appropriately investigated and brought to resolution and communicated back to the customer with a follow up to attempt to satisfy and ensure the customer understands the situation.

- The customer has a common understanding and satisfaction with contractual aspects such as:
  - Feasibility Study;
  - Connection Cost Estimate; and
  - Capital Cost Recovery Agreement. The Recovery Agreement stretches twenty-five years from the in-service date of the customer.

Accounts are usually grouped into customer segments; large industrial customers, LDCs and transmission-connected generators. Account Executives are assigned to a specific category of customer. This helps the Account Executive to develop the expertise required to work with and assist the transmission customers.

3.2 Customer Advisory Board (CAB)

Hydro One's Customer Advisory Board (CAB) was established in September 2002 to provide a forum for ongoing communication with customers. The CAB mandate is to provide advice to the management of Hydro One on how to best provide improved services to Hydro One customers. The CAB meets up to four times a year to review company initiatives, work program progress and to understand key customer concerns. Specific activities include:

- Review of the transmission survey in combination with action plans to address any customer concerns or issues; and
- Review of proposed asset policies that may affect the transmission customer.

The Advisory Board is designed to be representative of Hydro One's customer base, including both Transmission and Distribution customers. The Advisory Board includes but is not limited to customers / representatives who are affiliated with the following associations and groups:

- Association of Major Power Consumers in Ontario (AMPCO) Electricity Distributors Association (EDA)
- Association of Power Producers of Ontario (APPrO)
- Consumer's Council Canada (CCC)
- Ontario Federation of Agriculture (OFA)
- Canadian Manufacturers and Exporters (CME)
- Vulnerable Energy Consumers Coalition (VECC)
- Federation of Ontario Cottagers Associations (FOCA)
- Small, Medium and Large LDC's
- End Use Industrial

3.3 Customer Engagement Groups

3.3.1 Power Quality Working Group (PQWG)

The Power Quality Working Group consists of Hydro One staff and key account customers including LDCs and Industrial customer representatives who are normally engaged in PQ at their own facilities. The PQWG meets on a regular basis and is involved in collecting information from across the province to identify patterns of power quality issues for the transmission and distribution systems. After identifying a pattern, the WG tries to determine the causal factor. An example of a causal factor is site equipment too sensitive for utility grade power. A resolution might be the installation of supplemental equipment or new technology to dampen the unwanted effects.

The PQWG provides viable solutions for power quality issues to share with others who may be affected by the same issues.

3.3.2 Sarnia Area Reliability Oversight Committee (SAROC)

The SAROC consists of Hydro One staff plus industrial and generation-connected customers in the Sarnia area. The group meets twice a year to identify issues regarding reliability in the Sarnia Area and to review the proposed investment plans to ensure issues will be addressed appropriately. The industry in the Sarnia Area is very sensitive to any type of voltage excursion and can result in health and safety issues such as gas flares.

3.4 Meetings and Stakholder Sessions

Hydro One uses other channels such as stakeholder sessions to communicate with customers.

3.4.1 Aboriginal Communities Meetings

Hydro One meets with the First Nations Communities for consultation when any new facilities or maintenance activities are of interest.

3.4.2 Export Transmission Service (ETS) Rates Stakeholder Session

Hydro One recently held a stakeholder session to present the Elenchus prepared ETS Cost Allocation Study. This stakeholder session is discussed further in Exhibit A, Tab 19, Schedule 1.

3.4.3 Power Quality (PQ) Stakeholder Sessions

Hydro One holds stakeholder sessions with transmission customers to discuss the issue of PQ. These sessions are held to ensure Hydro One and the customers understand the impact PQ events have on customers and their production activities and to promote a common understanding of what a PQ event is. Even small voltage sags or spikes and wave form problems can disrupt businesses and production processes due to the sensitivity of installed programmable controllers and computers.

4.0 EXECUTIVE CUSTOMER EXPERIENCE COUNCIL

The Hydro One Executive Customer Experience Council (CE Council) reviews the prioritized list of customer concerns to determine the appropriate internal processes and policies to be updated or introduced. This cross-functional executive group assigns initiatives to internal business units where research analysis has shown opportunities for customer experience satisfaction improvement.

Hydro One's Customer Experience Vision, illustrated in Figure 1, was developed by the CE council and assists Hydro One in consistently delivering positive customer experiences and providing focus on customer-centricity. Investing in the CE Vision assists Hydro One in:

- building a trusted relationship with its customers;
- implementing low cost communication channels;
- driving work efficiencies;
- lowering operational costs;
- meeting the company's commitments to customers; and
- having seamless service delivery.

Figure 1

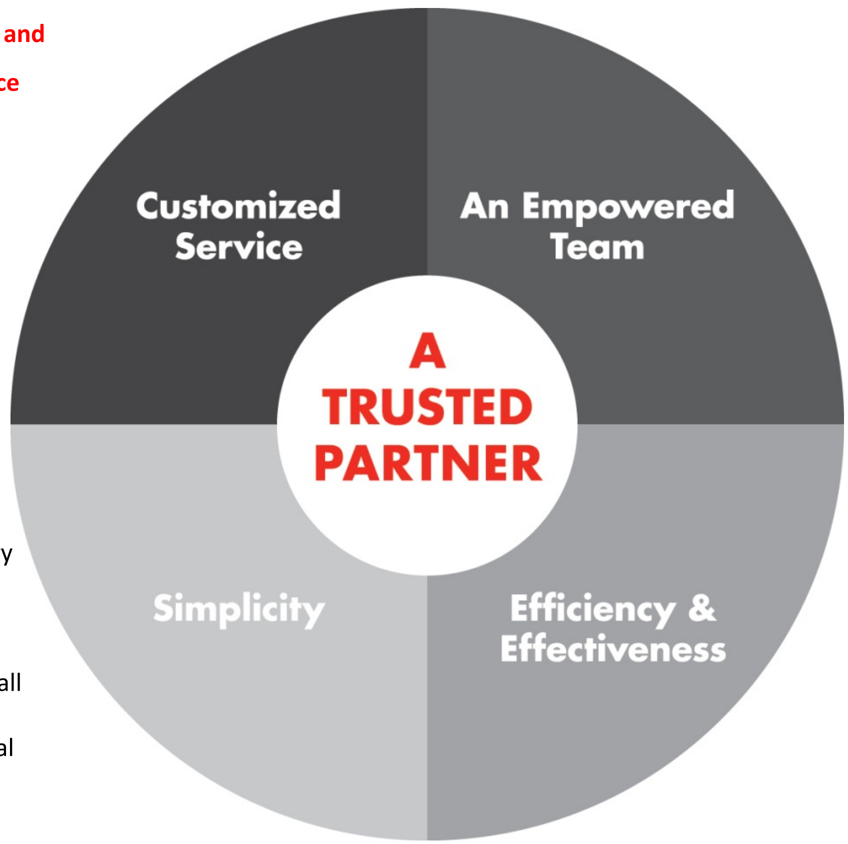
Customer Vision

Ability to develop customized solutions and deliver a superior customer experience

- Gather and leverage customer information
- Proactively segment and treat customers individually
- Respect the customer's time and privacy – be responsive and efficient

Fully connected across Hydro One, enabling seamless service

- Information is consolidated, updated and accessible in real time
- We are engaged and empowered, able to make decisions and get on with the job
- We adapt quickly to changing customer needs



Drive for simplicity in our internal processes and systems

- Strive for 'one and done' at every interaction, reduce hand-offs
- Enhance accessibility: in person, on phone, on web
- Ensure effective self-service for all simple transactions
- Drive for simplicity in our internal processes and systems

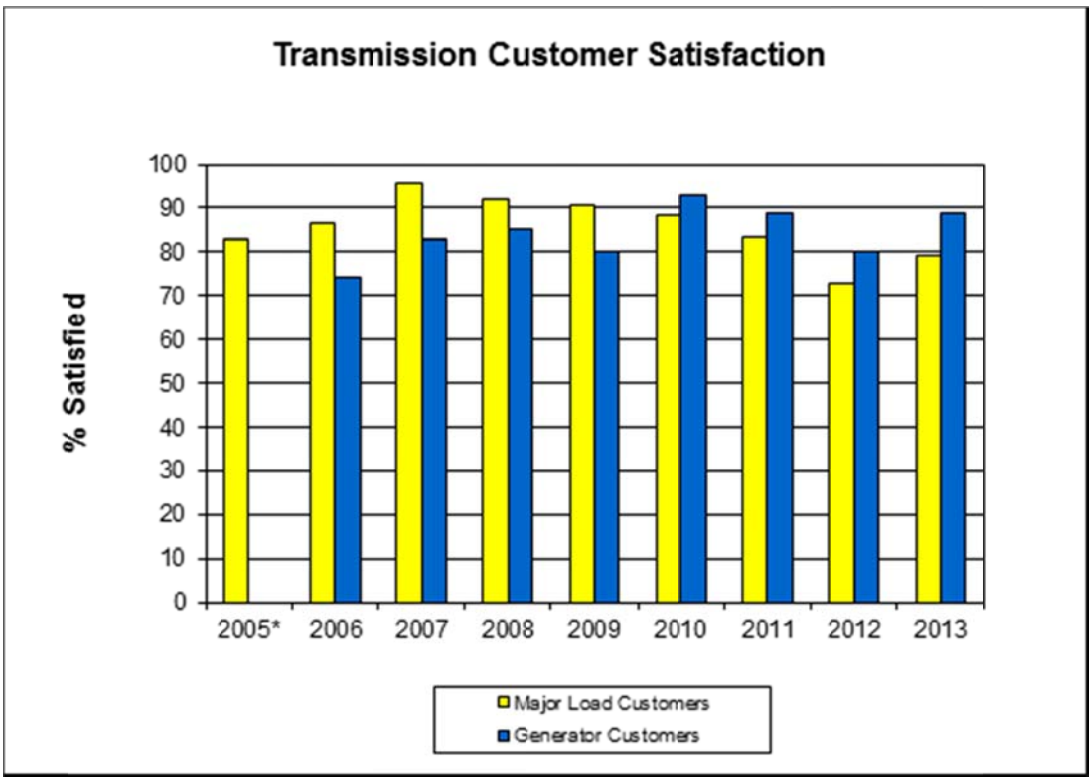
Driving efficiency & effectiveness through innovating & service delivery transformation

- Exploit Mobile and GIS to simplify field work
- Focus on reducing overhead costs and improving productivity
- Make timely, prudent investments which add value for customers

5.0 CUSTOMER SATISFACTION

As evidenced by the results in Figure 2, Hydro One's major load customers have indicated a relatively high satisfaction during the past several years, though a gradual decline in customer satisfaction in the major load customer sector since 2007 has been noted. This segment trend has seen its first year of improvement in 2013. This segment includes industrial customers and Local Distribution Companies (LDCs).

Figure: 2



To find how to continue the upward swing in satisfaction, Large Transmission customers were asked what main issue they would like to see Hydro One address. In order of priority, customers concerns were:

1. Responsiveness / follow up / promptness
2. Communications / proactive phone calls / accessibility
3. Reliability / line maintenance / restoration time
4. Outage planning / outage notifications
5. Cost / Cost effectiveness

6.0 ADDRESSING CUSTOMER CONCERNS

Hydro One is actively working to address these customer concerns. The following are some of the initiatives being worked on and developed:

6.1 Meetings and Workshops

6.1.1 Large Customer Conference

Annually, Hydro One hosts a Large Customer Conference for transmission customers; LDCs, transmission-connected generators and large industrial customers. The conference gives customers an overview of the Investment Plan and an opportunity to inform the Investment Plan for Capital and Sustainment investments that affect reliability. This is a forum for Hydro One and the transmission customers to speak face to face and for the customer to ask questions or follow up individually with Hydro One staff. The Power Quality Working Group discussed in Section 3.3 of this exhibit was a result of the Large Customer Conference.

6.1.2 New or Revised Connections Workshops

In the past, Hydro One documented connections at a high level and filed the documents with the Ontario Energy Board (OEB). An opportunity was identified to gather more information on the progress of cycle times, handoffs, timelines, costs, schedule over runs, etc.

In the past eighteen months, Hydro One started hosting workshops that include customer representatives to develop a new documented process. The Customer Relationship Management (CRM) tool is used to track customer connection projects and identify any delays or gaps. To date, there has been a strong internal focus and two workshops with the customer consultants to ensure customer pain points have been identified. This will lead to much improved communications being sent out to the customers regarding their projects. Hydro One has become much better at understanding the tools, processes and reports needed to better keep the customers informed.

6.1.3 Executive Sponsor Program

Hydro One has refreshed and expanded its Executive Sponsor Program whereby large transmission customers are assigned to a Hydro One executive. The executive will meet with the customer at their discretion to hear their comments and concerns. The executive is accountable to have any identified issues resolved and follow up with the customer to advise them of the status of the resolution and ensure satisfaction. The intent of this program is to ensure transmission customers know they can communicate with Hydro One senior management and they have another channel into the company to be heard.

This program has received very positive comments from transmission customers.

6.2 Outage Planning and Notifications

6.2.1 The Transmission System Outage Grouping (TSOG) Process

The TSOG process is a planning project that is being implemented to better coordinate the outage process. Its focus is to eliminate multiple outages on the same equipment by coordinating the various LOBs within Hydro One. This reduces the number of outages impacting customer facilities. Communication in customer groups or individually is initiated by the Long Term Planners to coordinate Hydro One work with any work the customer is planning. This program started in 2013 for the 2014 planning year and has been well received. Currently the Planners are meeting with the customers to review this year’s program and to obtain any planned work for future years from the customers. Other benefits of the TSOG include:

- A bundling feature that will identify customer's planned outages that can be "bundled" with Hydro One work. (COORDINATION)
- Conflict feature will identify customer's planned work that will be in conflict with Hydro One planned work. (CHURN REDUCTION)
- Correspondence; Customers will always receive notification correspondence in a consistent formatted template throughout the planning phase. (CONSISTENCY)

6.2.2 Upcoming Outage Reports

Hydro One has developed a set of SAP reports customized for the transmission-connected customers that provides a rolling one year outage window of planned outages that affect their delivery point. The customized report is sent to individual customers every Thursday and includes information such as outage start and end dates, equipment involved, purpose, recall time, schedule profile and a column for customer comments.

These reports keep Hydro One customers advised of upcoming outages and gives them an opportunity to capitalize on the outage for their own maintenance or advise Hydro One of any issues with the outage in the planning timeframe.

6.3 Programs and Projects

Other programs and projects to improve communication and reliability include the following:

6.3.1 Integrated Voice Communications and Telephony (IVCT) System Replacement Porject

The IVCT is used in 24-hour, seven day operations at the Ontario Grid Control Centre (OGCC) and the Back Up Control Centre (BUCC). This mission critical system provides effective voice communication management between the control centres and Hydro One field staff, connected customers, emergency services and the IESO. The current system was put in-service in 2003 and is now technologically obsolete. Further details can be found in Exhibti D1, Tab 3, Schedule 4.

6.3.2 Fault Location (Distance to Fault) Project (ISD O05)

Presently, information regarding a fault's location is communicated verbally to the OGCC by protection and control staff once they have travelled to the station, interrogated the devices and performed the necessary calculations manually. This investment will allow for determination of the likely fault location in nearly real time and enable faster restoration. Further details are discussed in Exhibit D1, Tab 3, Schedule 4.

6.3.3 Telemetry Expansion Program

The key deliverables of this program are the splitting of critical bundled alarms and the addition of more detailed monitoring of transmission equipment. This will enable OGCC to make an immediate determination of the cause of an alarm and the appropriate response. This will eliminate the need for unnecessarily removing equipment from service and urgent costly field staff dispatches to investigate the cause of the alarms. Further details are discussed in Exhibit D1, Tab 3, Schedule 4.

6.4 Business Investment Planning and Prioritization

Based on customer priorities and customer satisfaction strategies, investment alternatives are developed and included in the Investment Prioritization Process (IPP) found in Exhibit A, Tab 16, Schedule 4. Customer focused considerations are evaluated in conjunction with asset and business needs as well as risks and objectives to guide the planning activities. The result of the IPP is a balanced work program that is mindful of cost effectiveness and include customer expectations associated with reliability.

6.5 Other Exhibits to Address Customer Concerns

Current initiatives to address customer concerns regarding cost efficiencies can be found in the Cost Efficiencies / Productivity exhibit (Exhibit A, Tab 18, Schedule 1).

The Trasmission Business Perfomance Exhibit (Exhibit A, Tab 17, Schedule 1) discusses the reliability trends of the Hydro One Transmission System.

7.0 SUMMARY

Hydro One listens to the voice of the customer, analyzes their needs and then modifies or creates new work programs to address the customer's needs. Thorough analysis of the customer survey research and other feedback is undertaken using several analytic tools to ensure the results are timely, representative and unbiased leading to customer-centric business and investment planning. This customer and business outcome focus is demonstrated throughout the evidence filed in this application.

Results of the Large Transmission Customer Surveys

All **Large Transmission** customers are asked about the main issue they would like to see Hydro One address. As shown in the table below, the growing concern regarding follow ups and communication observed in 2012 has continued to strengthen in importance into 2013.

Customers whose RATING were 3 OR LESS:

What issues or concerns were you thinking of when you rated Hydro One?

Large Transmission	2011	2012	2013
Responsiveness/ follow up/ promptness	6%	19%	22%
Communications/proactive phone calls/accessibility	8%	18%	19%
Reliability / line maintenance / restoration time	16%	16%	19%
Outage planning/outage notifications	7%	13%	13%
Cost/cost effectiveness	9%	8%	6%
No issues	15%	17%	16%
Other	6%	14%	11%
Don't Know			2%
n	124	133	135

WORK EXECUTION STRATEGY

1.0 BACKGROUND

Hydro One’s Transmission Work Execution Strategy provides increased work execution capacity and the necessary flexibility to accommodate any required adjustments to the transmission work program due to changing priorities. A focus on efficiency, customer satisfaction and safety continue throughout Hydro One’s work planning and execution activities and processes.

The strategy addresses the continuing global business challenges such as material availability and shortage of qualified personnel to undertake the work. Execution of Hydro One’s transmission work program must be considered jointly with its distribution work program, as the resources required are part of an integrated workforce.

2.0 MAJOR FACTORS IMPACTING FUTURE WORK PROGRAMS

Transmission system projects and programs are more complex to plan and execute than in past years due to an increase in the total volume of work required, limited system outage availability, increasing compliance requirements, aging equipment, material availability and long lead times, and workforce demographics. Initiatives are being implemented to address such factors and are discussed in the following sections. A full discussion of test year capital expenditure requirements is provided in the schedules found in Exhibit D1, Tab 3.

2.0 AGING SYSTEM

An increasing percentage of the system is approaching or has reached its end of service life (typically 40 or 50 years) and requires or will soon require replacement. Currently 24% of the power transformers connected to the transmission system are over 40 years old. This vital need for infrastructure re-investment will continue to increase substantially throughout the decade as discussed further in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 2, Schedule 1. Addressing aging assets will increase reliability in that particular area and reduce maintenance costs of that unit. The Investment Plan for 2015 and 2016 will not change the average age of the system.

2.1 System Expansion and Growth

Over the past few years, significant transmission investments in the addition or substantive upgrade of major circuits and stations have been required due to changing system needs resulting from the retirement of coal-fired generation, the significant addition of new generation sources and load growth in a number of regions in Ontario.

Hydro One’s largest project underway is the construction of Clarington Transformer Station (TS). This station is being built to enable additional 500/230kV transformation in the East GTA area due to the planned retirement of the Pickering Nuclear Generating Station. Further details are provided in Exhibit D2, Tab 2, Schedule 3.

2.2 Material, Equipment and Vendor Availability

Material and equipment incorporated into transmission projects and programs account for approximately 40% of the total cost of work. Rapid growth in work programs at utilities across North America has resulted in an increased demand for specialized materials and equipment needed to build electrical generation, transmission and distribution facilities. Manufacturing plants for specialized equipment are reaching full capacity. Supply Chain initiatives to address this issue are further discussed in Exhibit C1, Tab 5, Schedule 1.

2.3 Work Execution Capacity Challenges

Although, Hydro One realizes economies of scale and efficiencies by integrating the workforce for its transmission and distribution businesses, the continuing loss of skilled staff through attrition has forced Hydro One to review its staffing strategies to accomplish the work program. Specialized staff such as Protection and Control (P&C) engineers, field technicians and linemen are more difficult to recruit than in the past, due to competing needs from other organizations in Ontario and across North America.

As the Hydro One work program grows, a greater volume of transmission work is required to be outsourced. More effective use of the external resources and services is required to increase the ability to complete the work program.

3.0 IMPLEMENTATION OF WORK EXECUTION STRATEGY FOR THE 2015 - 2016 WORK PROGRAM

Hydro One is taking a number of actions to increase the volume of work the Company completes in future years, of which safety is at the forefront. An increased focus on the safe execution of work is expected to reduce Lost Time Incidents (LTIs) and result in greater focus on work and productivity. Hydro One Transmission is now using fully integrated work planning methods that balance and optimize the use of internal and external resources, costs, system outages, customer needs and material availability. Key initiatives to increase work accomplishment include, but are not limited to the following:

- Work Planning and Management;
- Material Planning and Management;

- Work Force Augmentation; and
- Managing Relationships with Regulators

3.1 Work Planning and Management

Hydro One continuously focuses efforts on managing work more effectively. The Company has made changes to the way it prioritizes, plans and releases work, to execute work more efficiently.

3.1.1 <u>Work Prioritization</u>

Hydro One uses an improved investment prioritization process which assesses asset risk. This process, outlined in Exhibit A, Tab 16, Schedule 4, is a multi-criteria analysis which quantifies business risks so that objective decisions can be made to achieve the optimal balance of cost effectiveness, customer expectations, asset and business needs. The asset risk assessment process outlined in Exhibit A, Tab 16, Schedule 7, is Hydro One Transmission's methodology to identify current and future asset needs and improve the decision making process through the systematic evaluation of risk associated with transmission assets.

3.1.2 <u>Earlier and Multi-Year Work Program Releases</u>

Hydro One aims to continually improve project definitions and timelines by which work is released. Earlier releases allow service groups to plan and execute work more efficiently, schedule work and outages when site conditions are optimal, and minimize delays associated with approvals (i.e. environmental approvals, Section 92s, etc.) and assessments (i.e. Land Assessment and Remediation program).

Hydro One is releasing more of the work program early in the year as illustrated in Table 1.

Table 1:
Total Work Released to Engineering and Construction (E&C)

Total Work Released to E&C	Planned ($M)	Released ($M)	Released (%)
Total released for 2013, as of January 2013	$1,099	$741	67.4%
Total released for 2014, as of January 2014	$1,018	$785	77.1%

Early and multi-year work releases for Sustainment capital and Operations, Maintenance and Administration (OM&A) programs are particularly beneficial for the field execution and commissioning teams as this type of work involves considerable planning for outages, materials, staff skills, the preparation of new commissioning and maintenance documents for new equipment, and coordination with other capital or maintenance work. Earlier and multi-year releases better prepare the field teams for the Sustainment program in the test years, and allow a more complete work package to be prepared for execution.

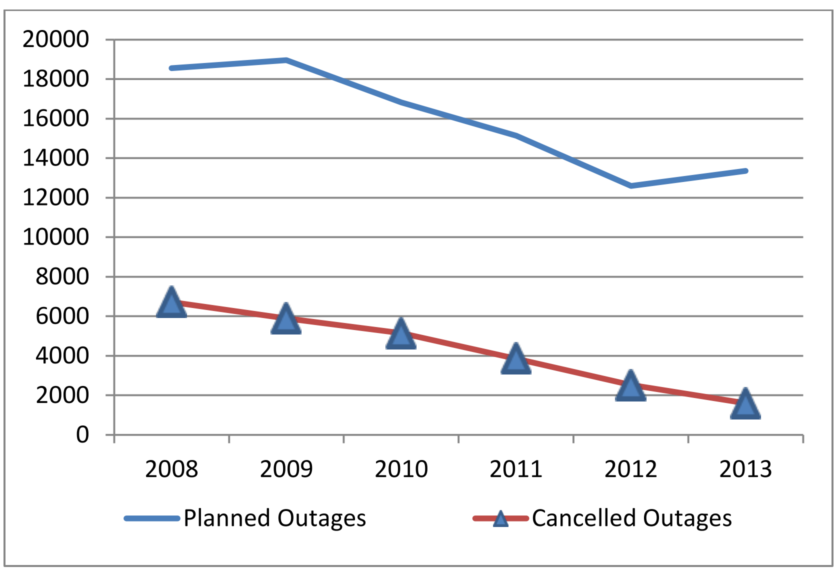
3.1.3 Station-Centric Work Release, Bundling and Outage Optimization

Hydro One is now planning and bundling work at the station level rather than the asset level for sustainment work. This holistic approach allows the Company to utilize resources more efficiently and increase work accomplishment. The station-centric approach results in a reduction of mobilization and demobilization activities, lessens the number of transmission system outages required, reduces maintenance requirements and increases the level of safety for field staff at site as they are aware of all work and tests being performed and the boundaries of the safe work area according to the points of isolation and de-energization.

Hydro One optimizes outages and bundles both capital and OM&A work to decrease project costs and maximize work accomplishment. By bundling work and outages, work efficiencies are realized, travel time is reduced for field staff and impact to customers is reduced. The volume of planned equipment outages processed annually from 2008 to 2013 has decreased on average by six percent per year. The noted decrease is a result of more work being completed per outage due to bundling initiatives. Over the same time period, the average volume of cancelled outages decreased by 24%, as shown in Figure 1. Reductions in cancelled outages can be attributed to a reduction in the number of total outages and to greater coordination between the Ontario Grid Control Centre (OGCC), Independent Electricity System Operator (IESO), transmission customers and the executing Line of Business (LOB). These improvements were realized through the use of improved outage planning tools and processes.

Figure 1:

Planned and Cancelled Outages Year-Over-Year



3.1.4 Continuous Improvement

Hydro One is continually introducing new software to optimize processes and leverage current Enterprise Resource Planning (ERP) tools. One such tool, Primavera (P6), is being used to ensure alignment of work groups during execution of key deliverables as well the ability to manage resources during work program planning. Improvements are also being enabled through the use of new work management reports, and by incorporating lessons learned into existing processes.

3.2 Material Planning and Management

Hydro One's resourcing strategy leverages collaborative planning, strategic sourcing and logistics support to increase efficiency by minimizing work delays and lowering costs for both capital and OM&A work. To realize further efficiencies, Hydro One is using repeatable designs and investigating the benefits of new technology.

3.2.1 Strategic Sourcing

Hydro One's strategic sourcing program proactively manages critical materials and services contracts to ensure work execution needs are being met. Collaborative planning and strategic sourcing are used to ensure contracts are in place and long lead time materials are effectively managed. Transmission class insulators and high voltage circuit breakers are used in most station-related projects, and have lead times that range between four to six months on average. Long lead times make it important to commit to forecasts early on to book manufacturing space in the plants to ensure timely delivery of the material.

Strategic sourcing is a significant contributor to Hydro One's cost saving initiatives and the Company's ability to complete the capital and OM&A work programs. Improvements incorporated into the strategic sourcing plan allow Hydro One to better negotiate with manufacturers of specialized materials to ensure a spot in their production schedules for required materials. Improvements include the following:

- Bulk purchasing;
- Negotiation of volume discounts with suppliers;
- Longer term contracts;
- Requests for Proposal (RFPs) jointly issued to market with Ontario Power Generation for safety-related equipment to realize increased volume discounts;
- Leveraging of Ministry of Government Services' Vendor of Record agreements where financially beneficial to Hydro One
- Increased use of Requests for Information (RFIs) to better determine what products, new technology and services are available in the market, scope business requirements, and/or estimate project costs
- Greater use of Requests for Pre-Qualification (RFPQs) to solicit Supplier capabilities and qualifications, with the intention of creating a list of pre-qualified Suppliers/VOR, against which future work will be awarded

These initiatives enable Hydro One to ensure the required services and materials are available at the right time and place for the right price in a manner that is fair and transparent to all stakeholders, in order to meet the requirements of the demanding transmission work program.

3.2.2 Logistics Support

Optimizing the material stocked in the Company's warehouse is an important element of the Work Execution Strategy. Hydro One is provisioning core materials from stock rather than waiting to purchase these materials after projects have received final approval. This approach reduces materials bottlenecks associated with vendor lead times. Warehouse facilities also store emergency and strategic spares such as transformers, bushings, breakers and an oil farm, in case of existing equipment failure in the electrical system.

For OM&A programs, inventories at the Company's warehouse are automatically maintained. Equipment such as tap changers and breakers have minimum level requirements. If the inventory reaches the minimum level, an order is automatically generated for additional parts to top-up the inventory.

In the case of large projects, Hydro One has materials delivered to the project site in a direct shipment. This avoids the handling of the materials multiple times and helps to decrease warehousing costs.

3.2.3 Introduction of New Technology

The original protection and control systems used to monitor and manage the transmission system have been replaced by new modern technologies. As a result, what a few years ago would have been a simple like-for-like replacement, now often requires a fundamental redesign and replacement of the complete system at a location. This renewal work began several years ago and continues through the test years at a higher level. For example, Hydro One is removing electromechanical relays and replacing them with modern digital relays to achieve cost savings and efficiencies. Not only are efficiency gains seen during the capital installation phase, which utilizes more efficient designs, but the new designs also use modern computer-based P&C equipment that has the ability to perform a self-diagnostic check to ensure the health of the relay and requires less ongoing maintenance.

3.2.4 Standards and Repeatable Designs

Hydro One uses standards and repeatable designs wherever possible to minimize design effort and maximize opportunities for strategic sourcing savings. The following are examples of standardized applications used by the Company:

3D Standardized Model-Based Design Applications

Integrating three dimensional (3D) design applications in station engineering using model-based design methodology allows Hydro One to streamline the design process by automating complex, repetitive design and drafting tasks. This ensures consistent quality, increases construction safety, and maximizes the efficiency of work execution. The use of these applications for new load-connecting stations has resulted in the design time being reduced from six months to one month.

Auto-wiring Design Applications

Standardized auto-wiring design applications for engineering design projects, as well as protection, control and telecom, allow teams to produce designs with greater accuracy and consistency in less time.

Standard designs are also beneficial during the commissioning phase of an asset's life, when field crews must validate functionality. The standard designs allow for common commissioning processes and procedures to be developed. This also decreases amount of training and equipment required by field staff.

3.3 Work Force Augmentation

Transmission system work programs are completed by Hydro One resources, external resources or a combination of both. Internal work capacity represents a challenge to work execution. A significant wave of retirements has begun and is expected to continue over the next decade. In addition, specialist power sector engineers are more difficult to recruit than in the past, due to competing needs from other organizations in Ontario, Alberta and from international organizations. As a result, Hydro One has had to review how to best utilize internal skilled staff, accelerate required training for Hydro One trainees to attain qualifications and certifications and how to leverage external resources to assist in the completion of the work program. A full discussion of the Hydro One staffing strategy including enhanced internal training programs, educational partnerships and increased utilization of casual workers and temporary employees is provided in Exhibit C1, Tab 4, Schedule 1.

3.3.1 Internal Resources

The optimal deployment of Hydro One expert internal resources is needed to maximize work program execution. The Company temporarily re-assigns staff to areas of extreme work demand (for example, Southwestern Ontario) to optimize resources. A relatively small group of highly skilled senior engineers oversees the execution of several tasks performed by various teams. Mentoring by senior engineers facilitates accelerated skills development and allows projects to be efficiently delivered while ensuring qualified resource succession.

3.3.2 Outsourcing

Hydro One prides itself in having a highly flexible Construction workforce which can meet the demands of the work program. Although this workforce is scalable, there is a practical limit to its size defined by the volume of work that can be safely and efficiently planned and managed by internal staff. The work contracted out, typically greenfield as well as some major refurbishment projects, is completed using a combination of internal resources, engineering subcontracts, construction contracts or arrangements contracted on a fixed-price basis. Through a combination of regular staff, casual trades, temporary, and overtime, both skill sets and cost are optimized.

In order to provide greater visibility to our outsourcing requirements to implement work that is beyond our internal compliment, we are developing resourcing models to identify allocation conflicts.

3.3.2.1 Augmenting Resource Compliment

The current work program presents challenges to Hydro One's specialized resources when work exceeds the Company's internal capacity to meet the demand. To address these challenges, Hydro One is implementing the following strategic resourcing plans:

- Outsourcing of drafting and designs:
  - Engineering consulting firms are contracted to design and draft station projects. $12 million service purchases were made in both 2012 and 2013, representing an engineering resource capacity expansion of 60 full-time employees
- Establishment of a Purchased Services Agreement (PSA) with the Power Workers' Union (PWU) to:
  - Enable outsourcing when a skill set required on temporary basis is not available internally;
  - Free internal resources to complete work for Regulatory requirement compliance and additional capital and O&M work
  - Ensure efficient execution of the work program; and
  - Address the variation in requirements for specific skills on a weekly basis

3.3.2.2 Engineering, Procurement, Construction (EPC) Contracts

Where work is integrated with existing facilities, it is managed by Hydro One staff with support from outsourced specialist engineering or construction services when needed. This approach is referred to as the Engineering, Procurement, Construction (EPC) approach. The EPC approach allows Hydro One to increase its resource availability and is instrumental in accomplishing the work identified in the test years. Outsourcing will be used strategically wherever the Collective Agreement permits.

The EPC approach is used where the execution expertise may be more appropriately done by contractors, for example: high voltage Gas Insulated Switchgear (GIS) stations and tunnel boring through the core of Toronto. Work that has sensitive timelines, scope that is not fully defined, or where there are overlapping engineering and construction requirements, is typically performed by internal resources, for example, a break-fix emergency.

Where it makes more sense to do so, work can be done externally. Decision factors whether to execute work internally or externally may include the following:

- most technically qualified with the lowest costs;
- can achieve the committed In-service date;
- work is of a complex nature that will interface with energized Hydro One Transmission system elements;
- has the expertise and equipment required to perform the work; and
- Is this an opportunity to develop the skill set of internal staff;

New business models are being explored to determine how to achieve optimal business outcomes, which include the Company’s ability to accomplish work; the acceleration of projects into the execution phase; and flexibility in how the Company implements work.

The models vary in percentages and type of work being performed internally versus externally. Models that appear to be best aligned with business outcomes are being tested on brownfield and greenfield projects to verify their effectiveness, and will be leveraged for future work wherever possible.

3.3.3 Utility Work Protection Code (UWPC) Training for Contractors

The Utility Work Protection Code is a rules-based procedure that provides guaranteed safe conditions for work. It governs the submission, review and approval of applications, provides the means to isolate and/or de-energize equipment to be worked on, co-ordinates the work and test activities of multiple work groups in a common safe work area, and defines terminology to be used to ensure a common understanding and safety of all staff.

Hydro One has recently started providing project-specific UWPC training to contract staff. For the first time, contractors who successfully attain those UWPC qualifications through Hydro One, will be allowed to hold work protection and interface with Hydro One staff under the same work permit on a specific project. This initiative will provide Hydro One flexibility of its work force to assist in the completion of the transmission work program throughout the test years.

3.4 Monitoring Regulation and Managing Relationships with Regulators

Hydro One understands the importance of monitoring developing legislation, policies and procedures at the federal, provincial and municipal levels. Projects are planned to address all applicable legislation. Agreements are being reached on the content of approval applications including design standardization that permits improved timelines. Collaborative workshops and meetings are used to address key project issues, and to improve working relationships. Hydro One has also recommended changes to policies and procedures to address areas of jurisdictional overlap and uncertainty. For instance, the Company collaborated with Municipal Affairs when municipalities requested to make Development Charges a pre-requisite to granting Building Permits. In this scenario, there was an overlap between the Planning Act, Development Charges Act and Education Act.

Hydro One works closely with the Ministry of Environment, other Provincial Ministries and agencies, Class EA proponents including the First Nations, Métis communities and Local Distribution Companies (LDCs) to amend the Class Environmental Assessment (Class EA) for Minor Transmission Facilities. The Class EA is an approved process for compliance of transmission facilities under the Environmental Assessment Act. The Class EA provides an efficient and timely approval relative to the Individual EA processes under the EA Act.

Some local and municipal government agencies seek to implement controls beyond the Pesticides Act that seek to restrict or prohibit the use of herbicides for selective brush control. Hydro One continues to work with these bodies to complete its brush control work programs within the confines of these controls.

4.0 SUMMARY

There are many factors changing the volume and characteristics of the future work program and the key enablers for successful completion of the transmission work program. The past few years had a large component of Development work whereas now there is a greater proportion of Sustainment programs. As Hydro One has greater control over the Sustainment work program, there is an increased chance of achieving the committed work accomplishments. Together with the items outlined in this exhibit, there are numerous incremental efficiency initiatives recently undertaken and planned in 2015 and 2016 throughout the business as discussed in Exhibit A, Tab 18, Schedule 1. Hydro

One’s work execution strategy will meet customer needs, improve overall system performance and accommodate the expanded work program necessary to meet the Company’s Sustainment and Development program needs.

OUTSOURCING

1.0 BACKGROUND

Hydro One Networks Inc. ("Networks") entered into a 10-year master services agreement with Inergi LP ("Inergi") on December 28, 2001 for services commencing on March 1, 2002 (the "Original Agreement"). Inergi is a limited partnership, a wholly-owned subsidiary of Capgemini Canada (formerly known as Cap Gemini Ernst & Young Canada Inc.) held by Capgemini SA. Under the Original Agreement, Hydro One outsourced its information technology services, customer service operations, settlements, source-to-pay, payroll, and finance and accounting services.

The Original Agreement provided for an optional 3-year extension to the original 10-year term.

Before the initial term of the Original Agreement expired, the parties agreed to amend the underlying business terms, effective as of May 1, 2010, to make them consistent with then current market practices and business requirements. The scope of work remained largely unchanged. Networks and Inergi both agreed to extend the Original Agreement by 3 years. The renewal permitted Networks to benefit from updated business terms earlier, including a 12% average annual reduction in fees over the remaining term of extended Original Agreement ("Current Agreement").

Leading up to the negotiations, Networks retained EquaTerra Inc. to develop and document expectations for the extended agreement to reflect market comparators, and provide negotiation support. In EquaTerra Inc.'s professional judgment the Current Agreement, taken as a whole, is market competitive. Inergi's affiliate, Capgemini US LLC, has provided a financial guarantee for payment upon demand of all guaranteed financial obligations, as well as a performance guarantee for the performance of all obligations under the Current Agreement.

The Current Agreement is subject to a *Declaration of the Sole Shareholder regarding the power of the Hydro One Inc.'s Board of Directors to enforce, including any and all other powers related to the Transfer ("Offshoring") of jobs out of the Province of Ontario under the Outsourcing Agreement entered into by Hydro One Inc. with Inergi LP ("Inergi") on or about December, 2001 (the "Outsourcing Agreement")* issued on September 24, 2008. The Current Agreement and the above Declaration will expire on February 28, 2015.

2.0 THE CURRENT AGREEMENT

2.1 Scope of Work

The scope of work under the Current Agreement is comprised of services ("Base Services") and project services performed over a finite period to produce a project deliverable, solution or result ("Project Services"). Base Services are divided into the following six areas (individually, a "statement of work" or a "SOW"), each of which relates to a line of business within Networks: (1) information technology services; (2) customer service operations; (3) settlements; (4) source-to-pay; (5) payroll; and (6) finance and accounting services. Appendix A contains the descriptions of Base Services contracted for each SOW.

2.2 Fees

Under the Current Agreement, Inergi provides Base Services based on a declining fee structure, except for the Settlements SOW for which the parties settled on a "cost-plus" pricing model due to the complex nature of the work. The fees for Base Services will decline over time so long as transaction volumes remain within normal volume ranges as defined in the Current Agreement while meeting or exceeding prevailing service levels. Additional charges apply if there are higher transaction volumes than the prescribed volumes. (For example, an increase in the number of Networks' customers may cause Networks to exceed certain volumes in the customer service operations SOW.) Conversely, Networks is entitled to fee credits if transaction volumes are lower than prescribed volumes.

For Project Services, Networks pays time-and-material rates. Networks receives an annual volume discount of up to 15% based on qualifying annual expenditures for Project Services.

All fees are subject to cost-of-living adjustments, using Statistics Canada indices of compensation for employees in Ontario and of the total number of employees in Ontario.

Appendix B to this exhibit sets out the outsourcing fees spent in the historical period 2010 to 2013 and the forecasted outsourcing expenditures for bridge year 2014 and test years 2015 to 2019.

2.3 Benchmarking Review of Fees

The Current Agreement provides for optional benchmarking reviews of fees by an independent third party, the costs of which are borne equally by Networks and Inergi. The third party analyst ("Analyst") is selected from a predetermined list included in the Current Agreement. Fees for the Settlements SOW are excluded from the review due to the unique and complex nature of the services and the absence of comparable suppliers.

The sample group in the benchmarking review consists of companies comparable to Inergi, meaning companies with the same line(s) of business and a comparable ratio of unionized and non-unionized resources. Where the proportion of unionized and non-unionized differs between companies, the Analyst shall normalize this difference. The Analyst will compare Inergi's fees with those of the sample group, adjusted for differences in volumes, scope of services, service levels, cost components and applicable cost of living increases with the market price.

In the fourth quarter of 2013, Networks exercised its right to a benchmarking review of Inergi's fees under the Current Agreement. The report was completed in February 2014 by TPI Sourcing Consultants Canada Corp, an affiliate of Information Services Group Inc. In regards to all Base Services excluding Settlements, the report concluded that the adjusted fees charged by Inergi do not exceed the "benchmark price" as defined in Current Agreement. As a result, there were no changes to the fees charged by Inergi as of March 1, 2014.

2.4 Royalty Payment and Provision of Facilities

Under the Current Agreement, Inergi makes annual payments to Networks in consideration of Networks' support of Inergi's broader marketing efforts.

Where Inergi staff are located in Networks' facilities, the cost of those facilities and facility overhead costs (communication services, heating, lighting, consumable goods, etc.) are borne by Networks.

2.5 Service Quality Assurances and Continuous Improvement

The Current Agreement sets out a methodology to measure Inergi's performance, which includes defined service levels or performance indicators ("PIs") and client satisfaction surveys. Inergi's services are measured regularly (monthly, quarterly, and yearly) for achievement of PIs. The PIs vary based on the nature of the service in question and set both minimum and targeted service levels. When Inergi fails to meet certain PIs, Networks is entitled to either: (a) a service credit(s) calculated in accordance with predetermined formuli, (b) at Inergi's cost, remediation action based on a remediation plan that Networks has approved, or (c) both, depending on the level of criticality and frequency of such failures.[1] The PIs are adjusted upwards annually, where applicable, to drive continuous improvement. In the contract year ending February 2013, Inergi met or exceeded 97% of all PIs.

Inergi performs client satisfaction surveys of Networks' relevant business managers and internal users. Inergi must address dissatisfaction revealed by the surveys. Together, the parties are to identify opportunities and strategies for responding to any issues the surveys reveal. The scores of these surveys have recently been 3.9 out of 5 for Base Services and 4.0 out of 5 for Project Services.

The Current Agreement also prescribes a process whereby Inergi continually introduces global best practices from Capgemini to Networks. Inergi has generated initiatives which have resulted in cost savings, primarily across strategic sourcing and infrastructure storage reductions. The initiatives are presented to and reviewed by Networks.

[1] Termination of individual statements of work or any part thereof is allowed under defined circumstances without payment of any penalties or termination charges.

The Current Agreement sets out a governing structure to manage the parties' relationship, which includes the Joint Executive Committee, the Joint Governance Committee, the Joint SOW Oversight Committee, and the Joint Service Leadership Committee. These committees meet regularly, at different intervals, to ensure strategic alignment between the parties, oversee relationship, review Inergi's global business strategies, review operational performance, change management, business planning, continuous improvement, and manage and resolve any risks and issues.

2.6 Protecting against business interruption

There are multiple safeguards against business interruption in the Current Agreement. Inergi is required to develop, maintain, test and execute business continuity and disaster recovery plans. Inergi must maintain and exercise these plans in a state of readiness for execution at all times. If there is a change in the services which impacts the plans, Inergi must modify the plans and, where necessary, retest them to maintain the state of readiness.

2.7 Transition at the end of the Current Agreement

To prepare for the expiration or full or partial termination of the Current Agreement, Inergi must: (a) provide and maintain a comprehensive termination transition plan at its own cost, and (b) for additional compensation, provide termination transition services described therein. The transition plan must lay out all the information required to enable Networks or a third party to take over provision of the services on a partial or full termination of the Current Agreement in an orderly, cost-efficient, and timely manner. This is expected to reduce the risks of transition and operational problems by facilitating knowledge transfer to the successful supplier(s).

The termination transition plan was activated on September 1, 2013 (the “Transition Plan”), 18 months before the expiry date of the Current Agreement. The plan includes a number of preparatory activities in the first stage which Inergi is to undertake. Inergi is required to provide termination transition services until such time as Networks no longer requires such services up to a maximum of 18 months following the expiry date of the Current Agreement. The latest end date for transition services is September 1, 2016. Base Services will continue at the agreed upon rates, and “transition services” will be provided, in parallel, on a time-and-materials basis.

3.0 RETURNING TO MARKET

To prepare for the Current Agreement’s expiry on February 28, 2015, a project to re-tender the services in scope for the Current Agreement commenced in late 2012. The project is referred to internally as the Outsourcing Agreement Re-tendering (OAR) project. Networks has retained Information Services Group Inc. as an external advisor to assist the company through the process. Osler, Hoskin and Harcout LLP have been retained as external counsel.

Multiple factors are shaping Networks’ foray back into the marketplace. The outsourcing market has changed significantly since services under the Original Agreement commenced in 2002; shorter term contracts and multi-supplier environments are the norm. Networks anticipates that its next outsourcing arrangement may reflect this new commercial reality. Overall Networks seeks a new contract(s) which reflects market-based pricing, an improved service delivery model, flexibility for Networks, support of and access to new technologies and delivery of value to its customers and shareholder.

A governance structure has been established to monitor the OAR project and execute decisions throughout the process. The OAR project team is comprised of representatives from lines of business, the Outsourcing Services Department, Information Services

Group, Inc. and internal and external legal counsel. The OAR project team meets on a weekly basis to review status of the project. The project team is governed by a Steering Committee which includes senior management from the affected lines of business, the Executive Committee and the Board of Directors. On a quarterly basis, the project director reports on the OAR project's progress to all of the committees noted above. The procurement process for the OAR project is being monitored by Internal Audit to ensure that the process is fair and transparent. To date, Internal Audit has determined that the process has been compliant.

Networks has structured its OAR project into three phases: Phase 1 (Development of Strategy and Commercial Documents); Phase 2 (Supplier Selection and Contract); and Phase 3 (Transition). These phases are detailed below.

3.1 Phase 1 – Development of Strategy and Commercial Documents

Any outsourcing arrangement must allow Networks to focus on its core businesses and meet its strategic objectives. Networks is considering all market options and risks associated with contract length and number of suppliers. Senior management explored the risks associated with the outsourcing strategy at two workshops, one held in December 2012 and another held in April 2013. The key risks discussed at these workshops were (a) the possibility of an inadequate response from the market, (b) the complexity of managing a multi-supplier environment, (c) challenges in transitioning to the successful supplier(s), and (d) possible claims by unsuccessful proponents that the procurement process was not fair and transparent. Key mitigation strategies that Networks has employed to minimize these risks are actions such as engaging outsourcing advisors, communicating openly and frequently with potential suppliers, requiring potential suppliers to address transition challenges, and having Internal Audit conduct an independent review of the procurement process. The risks are reviewed at the various committees within the governance structure on an ongoing basis to ensure that mitigation is occurring and is effective.

With the results of the workshops and guidance from external advisors and lines of businesses, the outsourcing strategy was developed. The strategy is based on the following key objectives:

(a) continually improve value received for money spent;
(b) reflect current global best practices in the outsourced services;
(c) ensure effective and robust performance management and governance; and
(d) maximize Networks' flexibility to adjust volumes and scope of work and the technology employed to perform it.

All of these objectives reflect Networks' commitment to continuous improvement in productivity which should drive its overall operational and cost effectiveness. The last objective also provides Networks the flexibility to respond to customer preferences, which may change over time.

This phase involved formulating clear expectations for the next outsourcing contract(s), including a contract term of 5 years with 2 one-year extensions at Networks' option. These expectations have been clearly articulated through the key elements of the outsourcing strategy:

a) multi-source different service offerings;
b) issue a Request for Pre-qualification ("RFPQ") to pre-qualify suppliers and gather market intelligence over "bundling" of services offerings in preparation for a Request for Proposal ("RFP");
c) issue a RFP to pre-qualified suppliers to down select and negotiate terms and conditions; and

d) request Board of Director approval over new contract(s).

In early 2013, the Board of Directors approved the above outsourcing strategy.

The introduction of a multi-supplier environment would require a new governance structure to monitor and measure the outcomes of the outsourcing contract(s). In this phase, the project team developed a working service integration and management model ("SIAM"). SIAM would coordinate and oversee the performance of the outsourced services in a multi-supplier arrangement. This function will specify the processes and procedures to be implemented across all of the suppliers and as well ensures adherence by all suppliers. A multi-supplier arrangement may result in some SIAM work being outsourced under a separate competitive process.

Other considerations in formulating the outsourcing strategy is the Shareholder Declaration and Resolution (the "2013 Directive") dated September 30, 2013 issued in October 2013. The 2013 Directive restricts Hydro One Inc.'s Board of Directors regarding new procurements for provision of services set out in the Current Agreement upon expiration of the agreement. The Minister of Energy exercised those powers to require such services be performed by persons who are employed in Ontario to perform those services and physically located in Ontario at that time they perform those services. A copy of the 2013 Directive is attached to this exhibit as Appendix C.

The strategy was further impacted by the Power Worker's Union grievance challenging Networks' ability to seek another supplier to perform the outsourced services through a competitive process filed on March 25, 2013. On December 10, 2013 a settlement was reached between Networks and the Power Worker's Union. The settlement requires the RFP to be amended such that, all pre-qualified proponents, as a condition of being permitted to respond, agree to voluntarily recognize the Power Worker's Union as the bargaining agent for the work and to enter into a Memorandum of Agreement prior to responding to the RFP. A completed collective agreement must be executed before the work commences. Networks has also extended this settlement to the Society of Energy Professionals.

The RFPQ was designed to screen possible suppliers based on certain evaluation criteria and to gather market intelligence on potential bundling options for the outsourced services. The RFPQ was issued in February 2013. It made no commercial commitments to any suppliers. As part of the evaluation process, the responses were reviewed and suppliers were selected to give oral presentations. Upon completion of the evaluation of the written responses and oral presentations, suppliers were pre-qualified to receive the RFP.

Networks held a common executive alignment session simultaneously with all pre-qualified suppliers where Executive Management delivered key common messages. Executive alignment sessions were also held individually with pre-qualified suppliers to provide feedback on the responses to the RFPQ and to solicit input on the bundles. Networks also met individually with the pre-qualified suppliers in discovery sessions to scope out the terms of reference and the bundles for the RFP. These activities were key in developing the RFP documents to ensure a competitive market response.

Based on the responses to the RFPQ, the project team developed a RFP which provisionally divided the outsourced services into four bundles of work. The proposed bundles were reviewed with senior management at a third risk workshop held in mid-2013. In the RFP, Networks' management has retained the right to re-bundle services based on market response to the RFP. Through the RFPQ process, the project team also determined that SIAM could be covered in a subsequent RFP once the supplier landscape has been determined.

With the Board of Directors' approval, the RFP was issued in November 2013 to pre-qualified suppliers.

3.2 Phase 2 – Supplier Selection & Contract Negotiations

In early December 2013, the project team held individual discovery sessions to provide the pre-qualified suppliers with an opportunity to seek clarification regarding the RFP. Responses to the RFP were originally anticipated by February 18, 2014. RFP responses were deferred to April 10, 2014, pending the clarification of certain matters related to the Power Workers' Union settlement. After the written responses are reviewed, pre-qualified proponents will be short-listed to give oral presentations in May 2014. Following these presentations, the pre-qualified supplier submissions and oral presentations will be evaluated against each other and against the option of performing any or all services internally based on a cost and risk assessment. As Networks deems appropriate, finalists will be selected to proceed to negotiate business terms. The project team will then make a final business recommendation. The project team anticipates that Networks will enter into any final contract negotiations in the summer of 2014, and final contract(s) will be approved by the Board of Directors in the fall of 2014.

3.3 Phase 3 – Transition

Once the supplier(s) have been selected, the next step will be to transition to the successful supplier(s). Networks will establish a project management office that will govern the overall transition and ensure that all accountable parties are performing the activities as agreed to in the transition plans of the successful suppliers and the incumbent's termination transition plan. The project management office will also monitor the transition risks to ensure that they have been mitigated through this phase. The key elements in this phase include:

a) migration of workload;
b) migration of services;
c) knowledge transfer; and
d) historical data transfer.

There will be costs associated with all of these transition activities for all of the parties in this phase. As well, the costs related to delivery of services under the Current Agreement throughout the transition phase will continue to be incurred.

<u>Appendices</u>

Appendix A – Base Services outsourced under the Current Agreement
Appendix B – Fees (Historical, Bridge and Test Years)
Appendix C – 2013 Minister Directive

APPENDIX A - BASE SERVICES OUTSOURCED UNDER THE INERGI AGREEMENT

Appendix A: Base Services Outsourced under the Current Agreement

SOW	Domain	Service Description
Information Technology Services	Infrastructure Operations	Services that are required by the user community and that facilitate the operation of shared devices and servers on a corporate level as well as the Services required to engineer and manage the computing network infrastructure.
	End User Support	IT Service Desk and Desktop Support
	Application Development and Maintenance	Services to provide technology platform, operational, quality control and application support services customized to the service requirements and needs of the application.
	Cross Functional Services	Provides general service functions to all other IT domains, including Service Management, Asset Management, Resource Management and Quality Assurance. Services also include project-related responsibilities for all IT domains.
Customer Service Operations[2]	Inbound Call Contact Handling	Provides customer call handling services for billing, customer services, collections, outages and emergencies for residential and small business segment. It includes corporate switchboard, maintain the day-to-day operational configuration of the Interactive Voice Response system, and responding to other contacts such as letters and email.
	Bill Production	Issue electricity bills, including bill print, insert delivery to Canada Post and remittance, managing exceptions, accuracy and timely delivery. Maintain accuracy of customer billing records to enable timely and accurate billing and print, envelope and dispatch bills to Canada Post.
	Credit and Collections	Manage the collection of outstanding customer debts and negotiate

[2] Inergi subcontracts the performance of all customer service operations to Vertex Customer Management (Canada) Limited ("**Vertex Canada**"), a wholly-owned subsidiary of Vertex Data Science Limited, a UK-based business process outsourcing company which is held by a consortium of US-based private equity firms.

Appendix A: Base Services Outsourced under the Current Agreement		
SOW	**Domain**	**Service Description**
		and collect deposits.
	Business Customer Centre	Selection of services for business customers, including inbound call and contact handling, retail settlements, billing exceptions and manual bills. Also handle contacts regarding Asset Tampering and Measurement Canada Requests.
	Business Support and Sustainment	Provide business support and analysis service pertaining to all business processes, applications, and interfaces related to CSO services, which include day-to-day management and resolution of Break / Fix issues, bill channel changes, and regulatory changes.
	Cross-Functional	Provide the following in support of all other CSO domains: • Business process support • Training and communications • Courier and mailroom service • Forecasting • Quality monitoring and assurance • Continuous improvement • Performance reporting • Audits • Maintain quality standards • Incident notification • Implement small discretionary business changes
Settlements		Wholesale Settlements – Provide settlement and reconciliation services for power procured from the Independent Electricity System Operator and embedded Retail Generators with due consideration to legislative initiatives for fixed energy prices for low volume customers, transmission revenues and inter-utility load transfers, and cost of power reporting. Retail Settlements – Provide complex billing for interval meter accounts.
Source to Pay	Procurement & Sourcing	Maintain market intelligence of applicable commodities, source commodities and services, manage and develop supply strategies (strategic sourcing), process purchase transactions, monitor spend on all commodities and services.
	Process & Quality	Services supporting the execution of daily transactions, maintenance and development of job aids, training, provision of audit files for compliance, quality checks and records management.

Appendix A: Base Services Outsourced under the Current Agreement		
SOW	**Domain**	**Service Description**
	Customer Support	Provision of Order Desk, expediting services, inspection services, general inquiries and transportation.
	Systems Support & Reporting	Provision of support systems, statistical and data reporting.
	Accounts Payable (AP)	Services required for processing disbursements which include: invoice processing, payments management, AP inquiries support, period-end reconciliations, management reporting and special projects.
Payroll	Pay Operations	Services necessary to calculate all pay cycles, remit pay to all staff and pensioners, remit deductions to the appropriate authorities and organizations, and to provide appropriate supporting documentation and filing systems.
	Payroll Accounting	Services necessary to account for the pay cycles and to provide appropriate supporting documentation.
	Inquiries and Application Support	Services necessary to support Pay Operations and Payroll Accounting Domains, including tool support and issue resolution.
	Contingencies	Includes responsibilities to deal with eventualities which disrupt pay, such as system outages and inclement weather.
Finance and Accounting Services	General Accounting	General Accounting – ensuring financial recognition consistent with corporate requirements, accounting adjustments, processing of transactions, and support of financial systems.
	Non-Energy Billing Accounts Receivable (AR)	Services required for processing non-energy miscellaneous billings and AR which include: customer invoicing, customer collections support, applying AR payments and adjustments, AR inquiries support, period end and reconciliation, and management reporting.
	Fixed Assets	Provides fixed assets and project costing transaction processing, transfer of projects to fixed assets, recording sales and retirement of assets, minor fixed assets inventory certification, and depreciation analysis.
	Financial Planning and Analysis	Provide advice, guidance, consultation and project support on routine operating processes and business support initiatives for areas such as Regulatory Accounting, Primary Revenue and Cost of Power, Actuarial Support, and Planning and Budgeting.
	Cross Domain	Provision of Centre of Excellence for analysis and reconciliation of

Appendix A: Base Services Outsourced under the Current Agreement		
SOW	**Domain**	**Service Description**
	Accounting	general ledger accounts ensuring appropriate financial recognition according to corporate and legislative requirements. Also support and analysis for accounts that cross into other domains e.g. Vendor Master, Material Master, and Fixed Assets.

APPENDIX B – OUTSOURCING FEES (HISTORICAL, BRIDGE AND TEST YEARS)

Table 1
HYDRO ONE NETWORKS
TRANSMISSION
Summary of Total Outsourcing Fees ($ Million)

Description	Historic				Bridge	Test	
	2010	2011	2012	2013	2014	2015	2016
Fees for Base Services	133.3	140.2	134.2	128.3	116.9	116.5	112.9
Volume, Scope & Other	2.6	2.2	10.3	13.1	10.8	5.1	4.5
COLA	4.0	1.3	3.6	6.4	10.7	12.3	14.3
Subtotal Fees for Base Services	**139.9**	**143.7**	**148.1**	**147.8**	**138.5**	**134.0**	**131.7**
Project Spend (all LOB's)	18.4	34.7	52.0	49.7	30.2	30.2	30.2
Total Payments	**158.3**	**178.4**	**200.1**	**197.5**	**168.6**	**164.2**	**161.8**

Table 2 - Allocation of Fees to Transmission ($ Million)

	2015	2016
Finance and Accounting	$ 4.1	$ 4.0
Payroll	$ 2.1	$ 2.0
Information Technology Services	$ 25.0	$ 24.3
Accounts Payable	$ 0.9	$ 0.9
Settlements	$ 0.4	$ 0.5
Customer Service Operations	$ -	$ -
Subtotal Fees for Base Services	**$ 32.6**	**$ 31.7**
Project Spend (all LOB's)	$ 2.7	$ 5.0
Total Payments	**$ 35.3**	**$ 36.7**

[TITLE]

Ministry of Energy
Office of the Minister
4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie
Bureau du ministre
4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

OCT 16 2013

MC-2013-2347A

OCT 17 2013

Mr. Carmine Marcello
President and CEO
Hydro One Inc.
483 Bay Street
North Tower, 15th Floor
Toronto ON M5G 2P5

Dear Mr .Marcello:

I am writing to advise you that I am exercising my powers as the Sole Shareholder of Hydro One Inc. to require that all new procurements by Hydro One Inc. for work currently being done by Inergi LP under its existing outsourcing agreement with Hydro One Inc. include a requirement that the work be performed in Ontario by persons employed and residing in Ontario.

Thank you for your prompt attention to this matter.

Sincerely,

Bob Chiarelli
Minister

CORPORATE STAFFING

1.0 OVERVIEW

Hydro One continues to face the prospect of a scarcity of skilled and professional staff to operate, sustain and develop its transmission and distribution systems at a time in which a greater number of our employees are reaching eligibility and are in fact, opting to retire. Hydro One's greatest corporate risk with respect to its human resources continues to be an aging workforce and a world-wide scarcity of core skills in the electricity industry, in a highly competitive labour market.

This issue and associated risks are not unique to Hydro One, but apply to the Canadian electricity sector as a whole. In the Canadian electricity industry, the Power in Motion, 2011 Labour Market Information (LMI) Study, states "Between 2011 and 2016, Canada's electricity and renewable energy industry will need to recruit 45,000 new employees – almost half of the starting workforce, and more than twice the number recruited in the last five years. Of these new employees, 23,000 will be in critical occupations that are specific to the electricity industry. Many will replace a wave of specialized and experienced retirees".

Employee Demographics

"Electricity industry workforce dynamics are notably skewed towards a high and rising number of retirements that will run well above other industries" (Source: *Power in Motion - 2011 LMI Study).*

Table 1 illustrates the trend of an increasing eligibility rate for retirement and an increase in actual uptake in retirement for Hydro One employees.

Table 1

Annual Retirements

Date	# of Networks staff eligible to retire	# of Retirements	% of eligible staff
December 31, 2009	1,000	105	10.5
December 31, 2010	1,300	137	10.5
December 31, 2011	1,150	166	14.4
December 31, 2012	1,158	192	16.5
December 31, 2013	919	253	28

Table 2 illustrates the forecasted number of eligible retirements up to 2019.

Table 2

Annual Retirement Forecast

Date	# of Networks staff eligible to retire	Retirements Forecasted
2014	1,085	194
2015	1,322	217
2016	1,536	179

To address this demographic challenge, Hydro One has been proactive by implementing a number of initiatives. These initiatives include implementation of a new People Strategy and the continuation of a staffing strategy for the recruitment and training of new staff. These initiatives are discussed in the sections which follow.

2.0 PEOPLE STRATEGY

The Hydro One Vision is to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. To accomplish this, we require a stable workforce, top talent and highly engaged employees. The newly created People Strategy provides Hydro One's management team with a framework to help guide decision-making, inform policy and program development, and define practices, procedures, systems and collective agreements, all with a view to ensuring they are aligned, and consistent with, those of a high-performing corporate culture.

Employee Engagement and Craft of Management

Two key initiatives in support of the People Strategy are employee engagement and the *Craft of Management*.

Employee engagement is a key differentiator in terms of business success, is the extent to which employees commit to someone or something in their organization. It can influence how hard they work and how long they stay as a result of that commitment. Engaged employees provide greater discretionary effort which often leads to increased productivity and other positive business outcomes. Hydro One continues to monitor and make improvements to employee engagement.

Since 2010, Hydro One has been active in implementing the *Craft of Management* program throughout the managerial levels. The *Craft of Management* is designed to introduce managers to a comprehensive and rigorous accountability based performance management system – a system that is based on clarity of accountabilities and authorities. The *Craft of Management* will lead to structures which better reflect the needs of the work and the accountabilities associated with the effective performance of that work, vertically and laterally within the organization. *Craft of Management* and Engagement are linked. Good managerial leadership – combined with an organization structure suitable for the needs of the work, with an effective process to allow and encourage employees to do that work, together will drive engagement.

2.1 Staffing Strategy

Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. Examples would include a centralized control centre, centralized fleet operations, and an integrated asset management strategy.

Hydro One utilizes a work-based approach to staffing, whereby the Company resources according to work programs rather than plans the work around the number of internal resources available. To address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, temporary, hiring hall and contract staff.

Matching staff to dynamic work programs requires a rigorous approach to staff planning. The company must consider the amount of work to be done, the nature of the work and the skills required, while at the same time looking for the most cost effective means of acquiring those skills, within the constraints of the collective agreements. Demographic and skills analyses are conducted annually to ensure that Hydro One retains the appropriate talent in the present and is positioned properly in the market to attract the talent needed in the future. In order to more accurately forecast retirements, human resources has developed a retirement forecasting model that will allow for more accurate data especially in key hiring classifications.

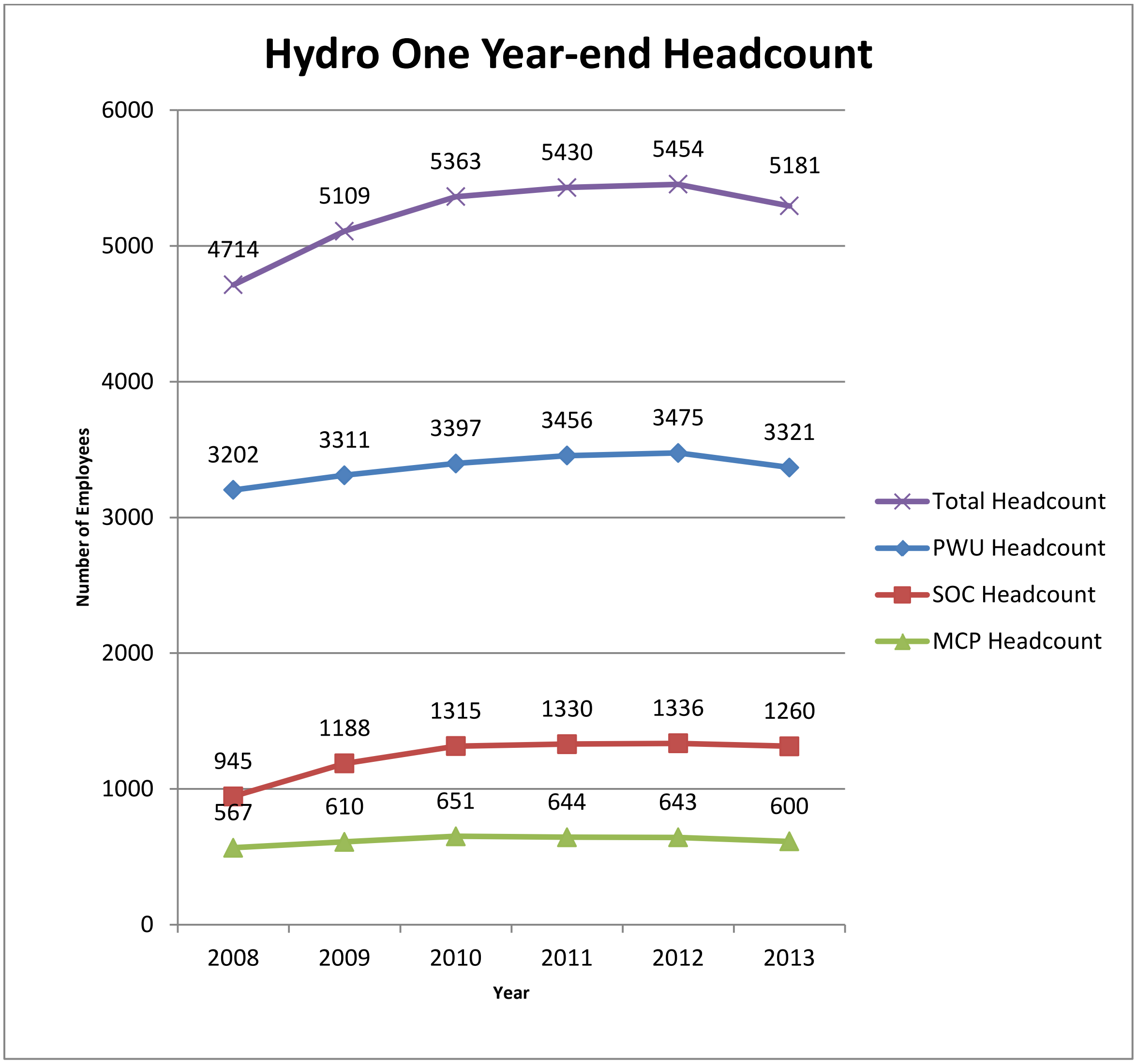
Progress has been made in attaining the optimal number and mix of staff required to complete the Company's increasing work programs. However, increases in Hydro One’s Transmission and Distribution programs will result in additional challenges, given the tight competition for labour and power system professionals. It is essential that the Company hires well in advance of expected retirements due to the long learning curves required for competent performance of Hydro One's highly skilled jobs.

Headcount

Hydro One recognizes the concerns raised in previous Decisions with respect to increasing headcount. Increases to regular headcount are tightly managed. Currently, all requests for additional regular employees must be approved by the Chief Executive Officer. Table 3 shows the year end headcount from 2008 to 2013 has risen by approximately 10%. Over the same time period, Hydro One's work program has increased by 19.5%. Furthermore, regular headcount is trending downwards with 2013 year end regular headcount less than year end 2010 levels. The business plan covering 2014-19 shows that regular headcount will continue to decrease until we reach 5000 employees.

Table 3

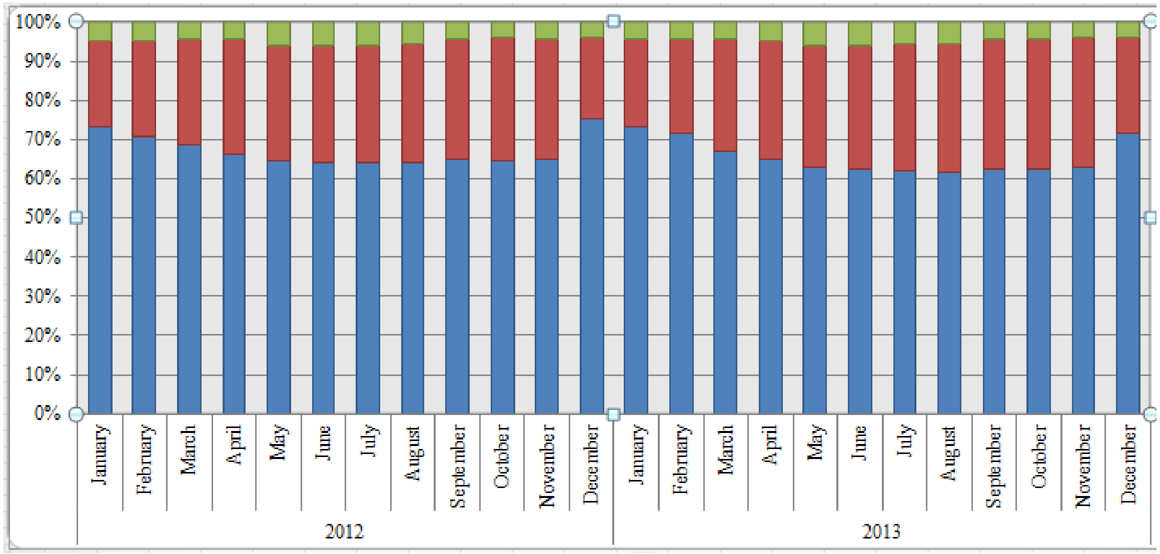
Annual Year-end Headcount



In order to complete the rising work program with fewer regular staff, Hydro One uses non–regular resources (Power Workers Union Hiring Hall, temporary employees, Consultants/Contractors). Table 4 illustrates Hydro One employs a large number of non–regular staff throughout the year to assist with its various work programs and match fluctuating requirements from month to month.

Table 4

Staffing Profile



3.0 STAFFING

Critical to the People Strategy and ultimately to the success of Hydro One in meeting our customer needs, is a comprehensive and robust staffing strategy.

To help address the significant wave of retirements in critical trades, technical and engineering groups, Hydro One continues to hire, albeit at a lesser level than previous years, into its Apprentice and Graduate Training Programs. Since January 1, 2004, 440 graduate trainees have been hired through the Company's on-campus recruitment program. New Graduates bring not only much needed skills but also new perspectives and fresh energy to the work of Hydro One.

Hydro One also continues its recruitment into trades apprenticeship and technical training programs and has partnered with universities and colleges to develop curricula that educate students in areas where the Company faces a shortage of skilled professionals and trades people. Hydro One has taken a leadership role in support for power system engineering programs, assisting in developing on-line power system engineering programs and providing scholarships to encourage enrolment in key areas where the Company faces a labour shortage. Hydro One received a Partnership Award which recognizes the very successful Hydro One College Consortium. Hydro One partnered with four community colleges and provides support for scholarships, curriculum development, co-op placements and equipment to educate the next generation of energy professionals. In 2013, one of the College Consortium members launched an innovative Women in Electrical Engineering Technology (WEET) program. Hydro One's role in the WEET program will be to provide work terms for the students between their first and second year. This will provide a significant cohort of women on-the-job experience in a utility, and provide them with skills to assist in their employment upon graduation.

In addition, Hydro One, with the clear support of the PWU and the Society of Energy Professionals, has become a corporate participant in Career Bridge – a national, private-sector, non-profit initiative, which aims to provide internationally qualified professionals with Canadian work experience in their field of expertise in order to gain entry into the permanent workforce.

Hydro One will also continue its support of the University and College Co-Op Education Program, hiring approximately 300 co-op students a year. This is a mutually beneficial process in that Hydro One gains bright, skilled workers trained in the latest theories and practices for four-month or eight-month work-terms, while the students gain practical and relevant work experience that can be used to develop their future careers. Hydro One has also found that the Co-op programs have proven a rich source of talented candidates for Graduate Trainee positions by offering the Company an opportunity to assess the student's "fit" and long-term potential with the company. Once hired Hydro One's experience shows that these former co-op students have a shorter learning curve than other new hires with no previous Hydro One experience.

External recruitment into entry level new graduate or apprentice positions has been successful. However, Hydro One has had some difficulty attracting more experienced external candidates into higher rated technical, engineering and management positions. For these positions, factors such as compensation and head office location sometimes act as barriers to successful recruitment.

Hydro One believes a more sustainable and longer term strategy to deal with large scale retirements, is to invest in programs where knowledge transfer is the key objective. Programs such as New Grad and Apprentice Hiring, and knowledge documentation all contribute to ensuring knowledge is transferred to more junior staff.

4.0 TRAINING

To address the demographic issue, it is not enough to only hire new staff. Hydro One is active in developing current staff in order to enhance and/or develop new skills.

4.1 Trades and Technical Training

Hydro One provides a comprehensive selection of trades and technical training, designed to target the specific needs of field staff in relation to the work requirements of the asset base.

4.2 Leadership and Senior Management Development

The primary objective of this program is to ensure that Hydro One has a systematic management development framework. This helps ensure the Company retains a competitive advantage by developing, maintaining, and enhancing those management competencies deemed to be essential.

4.3 Succession Planning

A Succession Planning Process has been developed for all senior management staff within the Company. The program's goal is to ensure that for each of the senior management positions, at least two successor candidates have been identified, and that a developmental plan for each of the candidates is developed and implemented.

Other human resources productivity initiatives are described in Exhibit C1, Tab 3, Schedule 2.

5.0 HYDRO ONE'S LABOUR PROFILE

As part of Hydro One's strategy to efficiently and economically manage its fluctuating work requirements, Hydro One utilizes four broad groups of staff: regular employees, temporary employees, casual workers (the Building Trade Unions -BTU's under agreements with the Electrical Power Sector Construction Association – EPSCA, the Labourers' International Union of North America - LIUNA, the Canadian Union of Skilled Workers - CUSW, and Power Workers Union - PWU Hiring Hall employees) and contract staff, discussed below.

5.1 Regular Employees

Regular Employees of Hydro One can be placed in three categories:

i) PWU represented staff: The PWU is an industrial union that represents the trades, operators, technicians and clerical workers, totaling roughly two thirds of Hydro One regular staff. They perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work.

ii) Society represented staff: The Society is a professional union that represents engineers, technical, administrative and supervisory staff, totaling about one quarter of regular staff. They perform engineering, high level technical and administrative work as well as supervisory functions.

iii) Management staff is excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

5.2 Temporary Employees

Temporary employees are employees in any of the three categories set out above, engaged in work that is not of a continuing nature.

5.3 Casual Workers

Although the PWU does perform some construction work, the majority is performed by the PWU Hiring Hall, the Building Trades Unions (under agreements with EPSCA), and members of the Canadian Union of Skilled Workers (CUSW).

i) Hiring Hall Employees (PWU) are utilized to meet fluctuating work demands, performing primarily supplemental construction and maintenance work on the distribution system. Non-recurring work peaks and special projects are resourced through the hiring hall.

ii) Fifteen construction BTUs supply a contingent workforce through their hiring halls, negotiating their collective agreements with EPSCA. These represent the construction trades employed by Hydro One, with the exception of those represented by the CUSW.

iii) The CUSW represents lines and electrical tradespersons who work on transmission construction, including the construction of lines over 50kV, transmission stations, switchyards, substations, system control centres, and associated telecommunications systems. Construction employees are contingent workers, accessed through the hiring halls to perform specific work programs and then laid off. They are paid a total wage package (including benefits and pension payments) for each hour worked. This relationship ensures that workers with the required skill set are hired in the right location for only the exact duration of the work assignment and that Hydro One has no on-going obligations with respect to benefits or pension for them.

5.4 Contract Staff

Contract staff are individuals engaged as independent contractors, not on the Corporation's payroll. Contract staff are retained for their particular skill sets on projects, or to perform other work that is not of an ongoing nature. They are engaged at Hydro One for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill. Contract staff are tracked by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions.

6.0 SUMMARY

Attracting, motivating and retaining the right people is key to Hydro One's success. Despite the Company's efforts to ensure that it has an adequate supply of labour, it continues to face staffing challenges. Hydro One will continue to utilize a mix of regular, non-regular and contract staff in order to maintain the necessary flexibility to respond to this increased workload.

In an industry with aging demographics and a highly competitive labour market, Hydro One needs to be positioned as an attractive employer if it is to succeed in recruiting and retaining staff with the requisite skills. To do so, it must provide challenging and rewarding job opportunities and a competitive compensation package. Hydro One believes its staffing strategy will allow it the flexibility to respond effectively and efficiently to any scenario that will arise over the test years.

COSTING OF WORK

1.0 OVERVIEW

Hydro One Transmission's work program is bundled into packages of work identified as programs or projects. Program and project costs are comprised primarily of activities associated with labour, equipment and material acquisition. This Exhibit details the breakdown of each of these three cost activities, and how the costs are applied to programs and projects. This costing approach is consistent with the requirements of US Generally Accepted Accounting Principles ("USGAAP").

Hydro One Transmission categorizes its costs into two major classifications - common and direct. Common costs, both OM&A and capital expenditures, are allocated to Transmission and Hydro One's other lines of business. Direct costs charged to work orders include labour (comprising of salaries, benefits and pension costs), material, fleet and supply chain. Labour costs are calculated as a product of actual time multiplied by the standard labour rate. Material costs are charged directly to the work program or project. Fleet costs are charged using a fleet rate. Supply Chain costs are charged via a material surcharge. All of these elements are described in detail in this Exhibit.

2.0 PROJECT AND PROGRAM MAJOR COST CATEGORIES

2.1 Labour Rate

Labour hours are distributed directly to benefiting programs and projects by using timesheets, consistent with common industry practice. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work.

On an annual basis, the standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components: forecast billable (direct charged) hours, forecast non-billable hours and forecast non-billable expenses. Total payroll and expense costs along with an assignment of support activity costs, divided by the forecast billable hours, create the standard labour rate. Table 1, below, shows an example of the composition of a standard labour rate for one category, the Regional Maintainer Electrical – Regular Staff, over the period 2011 to 2016.

Table 1
Standard Hourly Labour Rate Composition
Regional Maintainer Electrical – Regular Staff

	Historic			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Payroll Obligations	73.58	77.56	78.32	79.03	79.63	80.22
Contractual time away from work	9.65	9.10	9.33	9.42	9.49	9.56
Time not directly benefiting a specific Program or Project	8.65	8.30	8.51	8.59	8.66	8.72
Field Supervision and Technical Support	17.18	17.24	18.74	17.88	18.02	18.15
Support Activities	17.94	16.80	18.10	18.07	18.21	18.35
Hourly Rate	**127.00**	**129.00**	**133.00**	**133.00**	**134.00**	**135.00**

The cost elements embedded in the standard rate as illustrated in Table 1 are explained in the pages following, using the position of Regional Maintainer Electrical – Regular Staff and the 2014 cost composition, as an example.

2.1.1 Payroll Obligations ($79.03)

A brief description of the cost elements included in this category is provided below. Compensation, wages and benefits are more fully explained in Exhibit C1, Tab 3, Schedule 2.

Base Labour and Payroll Allowances (57.4% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in wage schedules.
- Payroll Allowances: Allowances are also contractually negotiated and stated in collective agreements. Regular staff (PWU) is entitled to travel, footwear, and on-call allowances. Casual trades are entitled to board and travel allowances where circumstances require it.

Company Benefits (37.6% of Payroll Obligations)

- Regular Staff: Comprising pension (30.9% of base pensionable earnings) and current and post-employment benefits; health, dental, etc. (24.2% of base pensionable earnings).
- Non-Regular Staff (for example, casual trades): Pension and welfare contributions made on behalf of the non-regular employee. These contributions are significantly lower in comparison to the Company benefit contributions made on behalf of the regular employee.

Government Obligations (5% of Payroll Obligations)

- Consists of Canada Pension Plan (CPP), Employment Insurance (EI), Employee Health Tax (EHT) and Workplace Safety and Insurance Board (WSIB) contributions.

2.1.2 Contractual Time Away from Work ($9.42)

This category consists primarily of employee vacation and statutory holidays, all established and identified in the Company's collective agreements. Sickness and accident costs are also included and are based on historical trends and consider current Company initiatives.

2.1.3 Time Not Directly Benefiting a Specific Program or Project ($8.59)

This category includes time for attendance of safety meetings, housekeeping and downtime often created due to inclement weather. These estimates are based primarily on historical trends.

2.1.4 Field Supervision and Technical Support ($17.88)

This category includes the costs associated with field trades supervision and other management and technical staff providing support services to manage and monitor the status of the assigned programs and projects.

2.1.5 Support Activities ($18.07)

Administrative Expenses and Support (70.8% of Support Activities)

These costs include administrative expenses such as travel costs, cell-phones and other miscellaneous expenses that cannot be specifically attributed to a particular program or project. Also included is an assignment of costs for clerical support activities and other centralized support to facilitate work management system requirements.

Work Methods & Training (15.7% of Support Activities)

Costs to design, develop, continually update and maintain and deliver work methods and training programs. Costs are assigned based on the forecast consumption of these services as agreed to by the Work Methods & Training function and service recipient.

Health, Safety & Environmental Support (13.5% of Support Activities)

Costs to design, develop, continually update and maintain and deliver health, safety and environmental practices primarily for staff working in field locations. Costs are assigned based on the forecast consumption of these services as agreed to by the Health, Safety & Environment function and the service recipient.

2.2 Fleet Rate

Hydro One controls and manages approximately 7,300 vehicles and other fleet equipment to support its work programs and staffing requirements used for both Distribution and Transmission work. The fleet has grown by 1,600 vehicles and other fleet equipment since 2009 reflecting an increase in the work program to be executed. Fleet Management is described in Section 3.0 of this Exhibit.

Fleet assets are categorized into 59 classes of equipment. For each equipment class, a standard equipment rate is calculated by dividing the annual forecast cost to maintain each class of equipment by the annual forecast hours that the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming work program. Utilization hours are defined as the hours the equipment is being used "on the job". Table 2 displays the hourly fleet rate for one of the commonly used classes of equipment as an example in the Transmission business (a line maintenance truck) for historical, bridge and test years, illustrating that the rate includes all costs attributable to the benefiting work.

Table 2

Hourly Fleet Rate - Line Maintenance Truck

	Historic			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Operations & Repairs	35.28	37.43	35.44	35.72	35.99	36.27
Fuel Costs	6.28	7.88	8.78	8.85	8.92	8.99
Depreciation	18.44	18.69	19.78	19.93	20.09	20.24
Hourly Rate	**60.00**	**64.00**	**64.00**	**64.50**	**65.00**	**65.50**

Below is a listing of each cost category, with percentages reflective of the 2014 fleet rate. A further description of each cost category is more fully explained in Section 3.4 of this Exhibit.

Operations & Repair Costs (55% of Fleet Rate)
Fuel Costs (14% of Fleet Rate)
Depreciation (31% of Fleet Rate)

2.3 Material Surcharge Rate

A standard material surcharge rate, which captures supply chain procurement costs benefiting a particular program or project, is applied to material costs. A detailed description of Hydro One's approach to Supply Chain Services is found in Section 4.0 of this Exhibit.

Material costs charged to a project or program is based on the issue cost from Inventory, which is the Moving Average Price (MAP) or the direct-shipped purchase order price. On a monthly basis, total monthly material charges are surcharged with a fixed percentage cost to recover costs associated with purchasing, transportation and inventory management. The percentages range from 11% to 17%, depending on work program service requirements. The percentages are derived by assigning the costs of these activities to the work programs based on an annual assessment of the consumption of these services divided by the annual forecast of purchased material.

The costs recovered in the surcharge are as follows:

- Hydro One Costs: Management, demand planning, warehousing and transportation of material, and investment recovery (comprising approximately 60% of the total costs); and
- Inergi Contract Costs: Procurement (comprising approximately 40% of the total costs).

2.4 Other Program and Project Costs

Depending on the nature of the work, Hydro One Transmission's program or project costs also include additional costs beyond the major contributors identified above. These additional costs may include the costs of external contractors and/or miscellaneous job specific consumables such as travel expenses or the purchase of low value material.

In terms of estimating and costing of capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. In these cases, the cost of removal work is accounted for as depreciation, and customer contributions are netted against gross capital costs.

Capital work also receives a monthly charge for its share of corporate interest and overhead costs. The composition of these two cost categories and the annual calculation are explained in Exhibit D1, Tab 3, Schedule 1, Interest Capitalized and Exhibit C1, Tab 6, Schedule 2, Overhead Capitalization Rate.

2.5 Standard Rates

When using standard rates, residual costs naturally arise when actual costs incurred differ from the standards. These variances are accounted for on a monthly basis and assigned to both capital and maintenance programs. The monthly assignments of residual costs are made to OM&A and Capital based on the program and project cost activities responsible for generating the year-to-date variances.

3.0 FLEET MANAGEMENT SERVICES

Fleet Management Services provides centralized and turnkey services that include maintenance, administration, vehicle replacement and disposal. Vehicles are maintained to an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations, including, but not limited to; CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator’s Registration regulations. Fleet Management Services also ensures that environmental impacts are minimized and line-of-business productivity is optimized by minimizing downtime and travel time, and by optimizing technology and continuous improvement opportunities.

Fleet Management Services has adapted to the changing needs of its business by:

- Revising the Company's model for responding to internal customers from fixed zone service to a mobile and fire hall model, with maintenance garages strategically placed throughout the Province to facilitate a more rapid turnaround for vehicle servicing;
- Optimizing the number of geographical locations served through implementation of Garage hubs;
- Reducing equipment downtime and improving our equipment utilization;
- Providing more competitive and cost efficient fleet support, enhanced through the procurement of modern maintenance facilities;
- Adopting a flexible service delivery model that matches the nomadic and variable work program needs of Hydro One's lines of business with service delivery options that mirror private sector practices. Such options include shift work, extended hours of service and mobile service delivery;
- Developing more timely, strategic and cost-efficient processes for equipment procurement and disposal;
- Developing a long-range capital replacement program; and
- Adopting data collection and information management systems that match the nomadic requirements of the Company's business units.

3.1 Maintenance Model

Fleet Management Services has developed a balanced maintenance model for mobile service delivery and centralized facilities. This model provides for 38 provincial locations and balances geographical customer requirements, travel time, third party vendor support and response time. Mobile/satellite repair units minimize costs organizationally by providing timely on-site field support for various nomadic work programs, such as vegetation control, new construction and off-road tower maintenance. Services provided to the lines of business meet the rigorous requirements of Fleet Management Services' agreements and are structured as a mobile and fire hall operating model to meet customer requirements.

3.2 Managed Systems

Fleet Management System

The strategic alliance to implement a fleet management system (FMS), developed with Automotive Resources International (ARI) in 2003, was renewed in 2008. In 2013 the contract was extended to 2015 to allow pursuit of a potential amalgamation of a FMS with the Ontario Public Service. The implementation of the FMS created an automated web-based system that uses a single credit card for each vehicle to capture all operating costs including fuel, parts and repairs. The FMS also incorporates programs to manage contracts, such as tender agreements, and the system prescribes spending guidelines and negotiated discounts. The system measures a variety of targets that reconcile approved purchase orders, estimates versus actuals, and vendor-related expenditures, discounts and complaints.

The benefits of the FMS include:

- Improved scheduling of preventative maintenance, reduced repair times, travel time and reduced equipment downtime;
- Increased access to a number of vendors for fuel, repairs and parts, thus minimizing cost and downtime;
- Improved cost and efficiency, through carefully-considered procurement strategies and economies of scale, including improved volume discounts for fuel, parts and service;

- A 1-800 number for repairs, roadside assistance and towing and improved reporting and data collection; and
- Exposure to best practices for fleet management by similar sector organizations.

The FMS uses a variety of linked programs to manage the data and information for all facets of the business, including internal and external repairs. This takes advantage of both internal and external intelligence and technology.

The maintenance program minimizes avoidable and expensive repairs and minimizes equipment downtime, which results in improved equipment utilization. Both internal and external service providers have access to the appropriate information through state-of-the-art automated management systems, allowing for quality decision-making at all levels of the maintenance program. Examples of the information provided include:

- Real time vehicle history;
- Warranty criteria and warranty recovery;
- A work and resources scheduling tool;
- A pending and overdue work information alert system;
- Product information, including vendor-specific information;
- Repair and safe practices manuals;
- Process and policy information;
- Invoice and cost-management details;
- Monthly and ad-hoc reports; and
- Work order management.

Telematics

In 2009, Hydro One Fleet Services entered into a pilot program to install GPS (Global Positioning System) into 500 Transportation and Work Equipment (TWE) units as part of the Hydro One Environmental Plan. From this Pilot Project, Hydro One Fleet Services recorded a number of lessons learned. These lessons were incorporated in the tender for a new generation fleet telematics system for 2,700 fleet vehicles that will provide significant enhancements to operator safety, workplace efficiency and reduction of environmental impacts. This project is currently scheduled to be implemented by end of 2015. The Telematics initiative will allow for continuous improvements and permit implementation of best practices through:

- Improved operator safety through awareness and driver aids;
- Decreased kilometers driven through route optimization;
- Increased productivity/utilization of vehicles;
- Expanded environmental benefits, including increased fuel efficiency and reduction of greenhouse gases;
- Increased fleet response time;
- Providing acceptable data for Fuel Tax Credits;
- Tracking of vehicle condition, including fluid levels, pressures and temperatures; and
- Increased security of fleet vehicles.

3.3 Fleet Complement and Utilization

Fleet Management Services controls and manages approximately 7,300 vehicles and other equipment primarily for Transmission and Distribution work. Inventory levels are controlled and set by the Hydro One lines of business and Fleet Management Services within the guidelines set for staffing versus fleet ratio, type and volume of work programs, geographic locations and utilization targets. The increase in the fleet complement, therefore, is directly related to the increase in the Company’s work on system infrastructure and corresponding staffing levels. Fleet Management Services maintains 38 facilities to support 17 Forestry locations, 1,007 Distribution Stations, 287 Transmission Stations, and 54 Provincial Lines operational centers.

As capital and OM&A investments have been increasing, the options to meet increased equipment demand include the purchase of new equipment, rental of additional equipment or increased utilization of existing equipment. The optimum option is to increase utilization, which minimizes capital investment compared to the option of additional purchases. Simultaneously, it maximizes the advantage of owned core equipment versus the additional cost of external rentals, which is 30 percent higher than owned equipment rates. This assessment is based on an internal comparison of the actual costs of equipment rentals versus those of owned core equipment.
The benefits of improving utilization include:

- decreased long term capital requirements;
- improved ability to respond to fluctuations in work programs; and
- reduced rental costs, with a correspondingly lower impact on the Company's OM&A budget.

Equipment utilization averages have increased from approximately 65 percent in 2001 to approximately 80 percent in 2013. The 2013 average equipment rate is $20.77 per hour; this is established by averaging total annual fleet equipment costs over total annual fleet utilization hours.

3.4 Fleet Management Services Budget

Fleet Management Services’ annual budget is developed and managed based on the all-in costs of operating the fleet and the following criteria:

- Historical and forecast fixed and variable costs including fuel, depreciation, maintenance and repair, labour/staffing, and external rentals;
- Historical cost and mechanical fitness evaluations;
- Work program forecasts provided by the lines of business;
- Estimates provided by internal and external providers;
- The requirements of the capital/vehicle replacement program; and
- Projected escalators.

Table 3 provides total expenditures on the components comprising the fleet rate for historic, bridge and test years. These expenditures are distributed among each of the 59 classes of vehicles.

Table 3
Fleet Management Services Budget Expenditures
($ Million)

	Historic			Bridge	Test	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Operations & Repairs	51.5	55.3	57.8	60.5	62.7	63.7
Depreciation	34.9	35.3	35.3	37.3	38.3	39.3
Fuel	28.3	29.1	30.2	30.3	30.8	31.2
Subtotal	**114.7**	**119.7**	**123.3**	**128.1**	**131.8**	**134.2**
Rentals	1.9	1.1	0.9	2	2	2
Total	**116.6**	**120.7**	**124.2**	**130.1**	**133.8**	**136.2**

3.4.1 Operations and Repairs

This cost category primarily consists of repair costs (external and internal labour and parts). The budget is based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculations. Throughout the year, all repair costs are charged directly to each piece of equipment. Operations costs include administration staff and their allocated share of central service support costs (for example, work methods and safety training activities).

3.4.2 Depreciation

The depreciation for each class within the fleet is calculated based on the current depreciation policies in Hydro One, the current composition of the fleet, and annual forecast additions and deletions.

3.4.3 Fuel Cost

Fuel cost per class of equipment is calculated based on past history and current market projections as well as the current composition of the class. Throughout the year, fuel costs are charged directly to the particular piece of equipment consuming the fuel.

3.4.4 External Fleet Rentals

Due to the seasonal and fluctuating nature of the Company’s work program, Hydro One Transmission requires the use of externally-owned equipment to meet the peaks in its programs. Using a process similar to that used to cost Hydro One Transmission’s own fleet, standard rates are calculated and costs are distributed to the Company’s programs and projects.

3.5 Recent Productivity Improvements in Fleet Management Services

Hydro One Transmission supports continuous improvement. This section details current work in progress in fleet management that promotes workplace and operator safety, productivity, efficiency and environmental considerations.

Hydro One Transmission's fleet management system is an automated web-based system under which a single credit card captures all operating costs (including fuel, parts and repairs) for each vehicle. This system is used to measure a variety of targets which identify opportunities to reduce costs and increase productivity efficiencies through strategic procurement practices and economies of scale, including improved volume discounts for fuel, parts and service.

Hydro One Transmission has a maintenance program for its fleet of vehicles. Internal and external service providers are granted access to appropriate information through state-of-the-art management systems linked to Hydro One Transmissions fleet management system. This allows for improved work and resource scheduling tools, information alerts and invoice and cost management details, resulting in avoidable and expensive repairs and equipment downtime being minimized and improved fleet efficiency.

As discussed in section 3.2, the Telematics Initiative will allow Hydro One Transmission to continuously improve and implement best practices in operator safety, workplace efficiency and environmental impacts. Operator safety will be improved through awareness and driver aids. Improvements in productivity efficiencies will include decreased kilometers driven through route optimization, increased fleet response time and automated tracking of vehicle condition. Also, with the implementation of telematics, environmental benefits such as increased fuel efficiency and a reduction of greenhouse gases will be realized.

4.0 SUPPLY CHAIN SERVICES

Hydro One delivers end-to-end supply chain services for the Distribution, Transmission, Telecom and Remotes businesses. The focus is on the right product with the right quality, at the right place, right time and at the right cost.

The forecast 2015 costs for Supply Chain Services are expected to be $40.5 million and remain fairly flat through 2016. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials; demand planning, inspection services, transportation, inventory management, and investment recovery of disposed assets.

Supply Chain Services costs are allocated to work programs and projects through the material surcharge rate.

This section describes the budgeted cost levels, followed by a description of the components of Supply Chain Services.

Table 4
Supply Chain Services
($ Million)

	Historic			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Total	42.9	40.5	39.2	40.2	40.5	39.9

The decrease in supply chain costs between 2011 and 2013 reflects the decrease in costs related to transportation and outsourcing services.
Hydro One Transmission's Supply Chain is a service which has been largely outsourced to Inergi L.P. The components of Supply Chain Services performed by Inergi include

sourcing (purchase) of materials and services, execution of transportation contracts, and contract management.

4.1 Supply Chain Policies and Procedures

Hydro One Transmission operates a fair and transparent procurement process that gives all companies equal opportunity to do business consistent with its Procurement Policy and Principles.

Tenders and proposals are evaluated based on predefined evaluation criteria by cross-functional teams as required. The outcome of the evaluation is the foundation for awarding procurement contracts.

4.2 Sourcing of Materials and Services

The sourcing of materials and services, primarily carried out within Inergi, includes the following:

- Demand Management and Procurement – Market intelligence with respect to commodities, processing purchase transactions and inspecting and expediting services to ensure delivery to contract commitments.
- Sourcing and Vendor Management – Services to support sourcing all commodities and services which include managing the size and composition of the vendor base and resolving issues.

Hydro One Transmission manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a Company-wide basis using cross-functional teams to manage the supply base as a valued resource. The methodology's five-step process includes spending analysis, market analysis, development of a sourcing strategy, negotiation, award, and contract management.

4.3 Inspection Services

Inergi LP is engaged to provide timely inspection services to assure that products are manufactured in accordance to specifications established by Hydro One Transmission, and tracks costs and schedules on a product and project basis.

4.4 Storage and Distribution of Materials - Warehousing

Hydro One Transmission's central warehouse operation in Barrie is responsible for the storage and distribution of materials for the service centres and station locations. This warehouse services the Operations & Maintenance organization which is further serviced through 88 field service centres and 21 station locations. The field staff is responsible for receiving shipments and for storing and ordering material. Deliveries to the service centres are contracted to a third party transportation carrier.

The intent of a consolidated warehouse operation is to realize efficiencies through focusing on activities such as:

- Bar coding to improve operating efficiencies such as receipting, cycle counting, shipping and tracking inventory;

- Managing and coordinating the delivery of materials on the scheduled delivery date to the service centres to ensure that the field operation receives the right material at the right time; and
- Improving receipting efficiency by integrating with the contracted transportation company to provide visibility into the supply chain and scheduling the inbound shipment.

4.5 Transportation

Hydro One Transmission manages its inbound and outbound transportation of materials through contracts with third party companies. In 2013, Hydro One Transmission entered into a new transportation contract for material delivery in and out of the central warehouse.

4.6 Investment Recovery

The final step of the supply chain is the disposal and investment recovery of end-of-life assets. This recovery is typically in the range of $2.5 million to $4.4 million per year, and primarily involves vehicle sales and scrap metal. Hydro One Transmission continues to focus on extracting the maximum value possible from the sale of these assets.

A breakdown of the sale of assets is as follows:

Table 5

Breakdown of Sales of Assets through Investment Recovery Program

($ Million)

Type of Sale	**Recovery 2011**	**Recovery 2012**	**Recovery 2013**
Vehicle Sales	2.0	1.0	1.5
Scrap Metal	2.4	1.6	1.6
Total	**4.4**	**2.6**	**3.1**

Note: 2011 Vehicle Sales include a sale of a helicopter ($0.5M)

4.7 Cost Savings from Strategic Sourcing

Between 2008 and 2016, due to its collaborative planning and strategic sourcing initiative, Hydro One Networks estimates $158 million in cumulative savings in the purchase of major equipment, commodities and services such as power transformers, circuit breakers, wood poles, distribution transformers, wire and cable, and pole and line hardware. Strategic sourcing results vary from commodity to commodity or from one service to another.

The main benefits of sourcing strategies are described below:

- Active involvement of internal stakeholders to communicate their business needs for the products and services;
- Cost reduction by increased leverage of Company-wide expenditures – purchases are consolidated by commodity and/or service to ensure that the business receives maximum value. This eliminates the need to tender and purchase as requirements surface -- an added benefit of this approach;

- Reduced total life cycle cost for materials and services – when purchasing equipment, all aspects are identified to ensure that Hydro One Transmission acquires maximum value for the life cycle of the equipment. For example, specifications, maintenance requirements, installation services and warranty services are defined and reviewed to ensure that business needs will be met, and order and invoice processes, lead time and inventory requirements, etc. are evaluated to determine where greater efficiencies may be realized;
- Improved security of supply through longer-term agreements. To maximize value, longer-term agreements are established with fixed prices, or formula pricing is considered to ensure that Hydro One Transmission achieves best value; and
- Improved and/or consistent quality of material and services.

Collaborative planning and strategic sourcing will continue to be a major focus, as the Company emphasizes cost control and security of supply while demand in the global utility sector increases.

4.8 Recent Productivity Improvements in Supply Chain Services

Hydro One Transmission is interested in continuous improvement, and Supply Chain Services is one example. This section details some work in progress to provide effectiveness and efficiency gains.

Previously, procurement of material for projects usually occurred after the release of the project. The supply management process is evolving, however, to consider the broader work program over multiple years, and obtain quotes for materials required over multiple delivery dates. This approach assists vendors by allowing them to better plan their activities, and leads to lower costs and a stronger relationship between Hydro One

Transmission and the vendor – which has additional benefits if difficulties arise in the supply of materials.

Hydro One Transmission has also developed "outline agreements" with vendors to establish a standing order or relationship for critical materials, such as cable and autotransformers as well as material for day to day consumption. In addition, the Company involves some suppliers in its planning activities, and studies historical buying patterns to assist in planning purchases.

Streamlining standards is another way in which Hydro One Transmission is improving the strategic sourcing process. In addition to simplifying procurement, this also increases both the likelihood that spares will be available for use, and the ease of maintaining a lower inventory.

Society of Energy Professionals (SEP) INTERROGATORY #3

Interrogatory

With reference to Exhibit A, Tab 18, Schedule 1 "Cost Efficiencies/ Productivity":

a) Has Hydro One done a survey of actual annual productivity/cost efficiency savings included by other Ontario transmission companies and LDC's in their cost of service applications since 2010? This would be both OM&A and capital expenditures actual annual productivity/cost efficiency savings as absolute $ quantities and also expressed as a percentage of actual OM&A and capital expenditures spent and as a percentage of revenues earned.

b) Has Hydro One done a survey of forecast test year(s) annual productivity/cost efficiency savings included by other Ontario transmission companies and LDC's in their cost of service applications since 2010? This would be both OM&A and capital expenditures forecast annual productivity/cost efficiency savings as absolute $ quantities and also expressed as a percentage of approved test year(s) OM&A and capital expenditures and as a percentage of approved revenue requirement.

c) If Hydro One has not done a) and/or b) why not? Have Board staff provided either a) or b), and if not, does Hydro One know why not and why did Hydro One not request this information from Board staff?

Response

a) Hydro One has not performed a survey of other Ontario transmission companies and LDCs for their actual annual productivity/cost efficiency savings.

b) Hydro One has not performed a survey of other Ontario transmission companies and LDCs for their forecast test year(s) of annual productivity/cost efficiency savings.

c) Hydro One has not performed these surveys as given the size of Hydro One versus any other transmission companies or LDCs in Ontario a comparison would not provide any meaningful data. Hydro One has not received any surveys conducted by Board staff that include this information.

Society of Energy Professionals (SEP) INTERROGATORY #4

Interrogatory

With reference to Exhibit A, Tab 18, Schedule 1 “Cost Efficiencies/ Productivity”, page 2, Table 1 “Impact to Revenue Requirement Inclusive and Exclusive of Productivity Savings”:

a) What are the Total OM&A productivity savings for 2015 to 2016?

b) What is the average annual Total OM&A productivity savings for 2015 to 2016

c) What is the annual average percentage productivity savings of OM&A expenditure for 2015 to 2016?

d) Using the data provided in Exhibit E1, Tab 1, Schedule 1, page 1 Table 1, what is Hydro One’s average annual Revenue Requirement less External Revenue for the period 2015 to 2016?

e) What percentage is the average annual Total OM&A productivity savings for 2015 to 2016 of Hydro One’s average annual Revenue Requirement less External Revenue for the period 2015 to 2016 [ie the value provided in b) above expressed as a percentage of the value provided in d) above]?

f) How does the figure calculated in e) compare to the OEB’s productivity analyses for Ontario LDC's and Transmitters? How does this compare to the productivity target which the OEB requires LDC's to use in their IRM applications?

g) Please calculate the figures provided in a) and b) above for the Total Capital Expenditures productivity savings.

h) A general rule of thumb of is that Revenue Requirement increases by roughly 10% of capital expenditures placed into service in the prior year. Accepting that this rule of thumb is correct, recalculate the percentage calculated in e) above to include 10% of the average annual Total Capital Expenditures productivity savings for 2015 to 2016.

i) How does the figure calculated in h) compare to the OEB’s productivity analyses for Ontario LDC's and Transmitters? How does this compare to the productivity target which the OEB requires LDC's to use in their IRM applications?

Response

a) Total OM&A productivity savings for Tx is $95M.

b) Average annual OM&A productivity savings for Tx is $47.5.

c) The annual average percentage productivity savings of OM&A expenditure for Tx 2015 to 2016 is 10.4%.

d) Hydro One's average annual revenue requirement less external revenue for the period 2015-2016 is $1,625M.

e) The percentage for OM&A only is 2.9%.

f) In EB-2010-0379 Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors on page 17 it states "the Board has determined that… the productivity factor used in the rate-adjustment formula to set rates will be set to zero".

g) Total OM&A productivity savings for Tx is 42,908,556.
   - Capital productivity savings is $42.7M
   - Average capital savings is $21.4M

h) The percentage for OM&A and Capital is 3.1%

i) See response to f.

Society of Energy Professionals (SEP) INTERROGATORY #5

Interrogatory

With reference to Exhibit A, Tab 18, Schedule 1, "Cost Efficiencies/ Productivity" pg 4 Table 2:

a) In Exhibit C1, Tab 2, Schedule 1 "Summary of OM&A Expenditures", on page 5 Hydro One explains that the underage in 2013 OEB approved OM&A expenditures in "the Sustaining, Development, and Operations work program spend reflects Cornerstone savings (both are included in the Board Approved Shared Services and Other total in Table 2)". A similar explanation is provided on page 6 for the underage in 2014 OEB approved OM&A expenditures. Please show where in Exhibit A, Tab 18, Schedule 1, pg 4 Table 2 the Cornerstone savings are included and provide the annual Cornerstone savings for the period 2011 to 2016.

b) In Exhibit D1, Tab 1, Schedule 2 "In-Service Capital Additions", on page 2 ln 21-24, it is stated:

The Riverside Junction by Strachan TS underground cable replacement project [which will go into service in 2014], which is expected to be completed for less than the previously approved amount partly due to lower material costs through procurement savings (approximately $35 million)

Please show where in Exhibit A, Tab 18, Schedule 1, pg 4 Table 2 these procurement savings are included and provide these annual savings for the period 2011 to 2014.

c) Similar to b) above, provide a breakdown of annual procurement savings by major capital projects and programs, including Midtown Transmission Reinforcement, Circuit Breaker Replacements, Integrated DESN Replacements, Power Transformer Replacements and Integrated Station P&C Replacements. Show where these savings are included in Exhibit A, Tab 18, Schedule 1, pg 4 Table 2.

d) Similar to b) above, provide a breakdown of annual productivity savings resulting from Hydro One "continuing the shift towards completing more Sustaining capital work in an integrated manner in part to reduce the current problem of projects being delayed due to outage planning constraints" [as stated in Exhibit D1, Tab 1, Schedule 2 "In-Service Capital Additions", on page 3 ln22-22]. Show where these savings are included in Exhibit A, Tab 18, Schedule 1, pg 4 Table 2.

Response

a) Cornerstone savings are included in the Business Systems and Business Transformation buckets of savings. Please refer to Exhibit I, Tab 4, Schedule 4, Part d that includes the Cornerstone Benefits Realization Plan for savings in both Tx and Dx.

b) The procurement savings referenced in Exhibit D1, Tab 2, Schedule 1 associated with the Riverside Junction by Strachan TS underground cable replacement are not tracked annually and while they are included in the total savings in Table 2 from Exhibit A, Tab 18, Schedule 1.

c) Procurement savings for major capital projects and programs are included in Exhibit A, Tab 18, Schedule 1 are at the aggregate level across various initiatives. Supply Chain procurement savings are explained in Exhibit I, Tab 5, Schedule 2, Attachment 5, Section 4.0.

d) The quoted statement refers to Hydro One improving the ability to get projects in service on schedule by reducing the impact of outage cancellations and scheduling difficulties. Only some of the annual productivity savings related to outage cancellations and bundling of work is included in Exhibit A, Tab 18, Schedule 1. Additional savings would be incremental.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #1

Interrogatory

Reference: Exhibit 1/Tab 2/Schedule 1/p.4
EB-2012-0031, Exhibit 1/Tab 2/Schedule 1/p.3

The rationale given in the current materials for the decline in external revenues from Station Maintenance (i.e., "primarily due to the expected shift in resources to Hydro One Transmission's growing work programs") is the same as that in EB-2012-0031 for the then 2013 test year. However, actual revenues for 2013 remained at historic levels. What is different about the test years 2015 and 2016 that the decline will now actually occur?

Response

Hydro One has given clear direction to Station Services that we will not be continuing at the level of involvement with our external customers for Electrical Maintenance Department (EMD) work going forward. External companies have been advised that Hydro One will not be bidding on any transformer maintenance, Planning & Control (P&C) work or other potential planned EMD work for 2015.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2

Interrogatory

Reference: Exhibit G1/Tab 1/Schedule 1/p. 2-3
EB-2012-0031, Exhibit G2/Tab 5/Schedule 1/p.1-2

a) Please provide schedules similar to that set out in EB-2012-0031, G2/T5/S1, page 1-2 that detail the proposed revenue requirement by rate pool for 2015 and 2016. Please also include in the schedules gross book value and net book value for each rate pool.

Response

a) The requested information regarding revenue requirement is provided in the tables below. Please refer to response to VECC IR 10 at Exhibit I, Tab 6, Schedule 10, part (b) for gross book and net book values.

2015 DETAILED REVENUE REQUIREMENT BY RATE POOL

	Rate Pool Revenue Requirement ($ Million)				
	Network	**Line Connection**	**Transformation Connection**	**Wholesale Meter**	**Total**
OM&A	234.8	45.6	105.0	0.17	385.7
Taxes Other Than Income Taxes	41.8	9.2	15.3	0.01	66.3
Depreciation of Fixed Assets	213.3	43.9	98.8	0.03	356.0
Capitalized Depreciation	-4.0	-0.9	-1.5	0.00	-6.4
Asset Removal Costs	23.8	5.2	9.1	0.00	38.1
Other Amortization	4.1	0.9	1.5	0.00	6.5
Return on Debt	191.6	42.2	70.2	0.03	304.0
Return on Equity	249.2	54.8	91.2	0.04	395.3
Capital & Income Taxes	45.2	10.0	16.6	0.01	71.8
SUB-TOTAL	999.8	210.8	406.2	0.29	1,617.1
Less Non-Rate Revenue	-17.6	-3.7	-7.1	-0.01	-28.4
Less Regulatory Asset Credit	-3.8	-0.8	-1.5	0.00	-6.2
Less Export Revenue Variance	-11.5	0.0	0.0	0.00	-11.5
Less Export Revenues	-33.4	0.0	0.0	0.00	-33.4
Plus LVSG Credit	0.0	0.0	13.2	0.00	13.2

	Rate Pool Revenue Requirement ($ Million)				
	Network	**Line Connection**	**Transformation Connection**	**Wholesale Meter**	**Total**
TOTAL	**933.6**	**206.3**	**410.8**	**0.28**	**1,550.9**
Gross Book Value	**9,783.1**	**2,135.8**	**3,745.2**	**1.4**	**15,665.5**
Net Book Value	**6,398.9**	**1,408.0**	**2,342.1**	**0.9**	**10,149.9**

2016 DETAILED REVENUE REQUIREMENT BY RATE POOL

	Rate Pool Revenue Requirement ($ Million)				
	Network	**Line Connection**	**Transformation Connection**	**Wholesale Meter**	**Total**
OM&A	237.5	46.1	106.6	0.12	390.4
Taxes Other Than Income Taxes	42.0	9.4	15.7	0.00	67.0
Depreciation of Fixed Assets	220.9	46.7	103.3	0.02	370.9
Capitalized Depreciation	-4.2	-0.9	-1.6	0.00	-6.7
Asset Removal Costs	20.9	4.7	8.1	0.00	33.7
Other Amortization	3.8	0.9	1.4	0.00	6.1
Return on Debt	203.1	45.4	75.8	0.02	324.3
Return on Equity	263.4	58.9	98.4	0.03	420.6
Capital & Income Taxes	51.9	11.6	19.4	0.01	82.8
SUB-TOTAL	1,039.3	222.6	427.1	0.2	1,689.2
Less Non-Rate Revenue	-17.7	-3.8	-7.3	0.0	-28.8
Less Regulatory Asset Credit	-3.8	-0.8	-1.6	0.0	-6.2
Less Export Revenue Variance	-11.5	0.0	0.0	0.0	-11.5
Less Export Revenues	-34.3	0.0	0.0	0.0	-34.3
Plus LVSG Credit	0.0	0.0	13.9	0.0	13.9
TOTAL	**972.0**	**218.0**	**432.1**	**0.20**	**1,622.3**
Gross Book Value	**10,151.4**	**2,255.0**	**3,945.6**	**1.0**	**16,353.0**
Net Book Value	**6,595.8**	**1,474.5**	**2,462.8**	**0.7**	**10,533.7**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3

Interrogatory

Reference A/T15/S2, pg. 1

a) Are the values reported in Table 1 based "measured" as of the point of generation or the point of delivery?
b) Please provide the equivalent weather normalized values for the years 2011-2013.

Response

a) The values reported in Table 1 are measured at the delivery point level.

b) The equivalent weather-normalized values for the years 2011 to 2013 are provided in the following table.

	Ontario Demand	Hydro One Rate Categories (Charge Determinants)		
		Network Connection	Line Connection	Transformation Connection
2011	20,547	19,882	19,039	16,296
2012	20,348	19,747	18,941	16,191
2013	20,360	20,220	19,322	16,606

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4

Interrogatory

Reference A/T15/S2, pg. 14-15

a) Please provide a schedule that for 2015 and 2016 sets out the total transmission system load forecast based on each of the three models discussed.

Response

a) The requested information is provided below. Monthly econometric model is good for short-term forecasting for up to 2 years and as such was not used to produce a forecast for the year 2016.

Year	Annual Econometric Forecast	Monthly Econometric Forecast	Annual End-Use Forecast	Final Forecast
2015	20,464	20,523	20,184	20,595
2016	20,551	n.a.	20,292	20,814

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5

Interrogatory

Reference **A/T15/S2, pg. 20**
2013 LTEP, Module 1 (Demand Forecast), pg. 49

a) Are the values reported in Table 3 for 2013 forecast or actuals?

b) The housing forecast used in the 2013 LTEP shows higher levels of housing additions for each of the years 2014-2016 than the Hydro One Networks' forecast. Please reconcile and explain why Hydro One Networks' forecast is appropriate.

Response

a) In Table 3, Load Forecast after Deducting Embedded Generation and CDM as well as Embedded Generation values are actuals for 2013. The remaining values, CDM and Load Forecast before Deducting Impacts of Embedded Generation and CDM, for 2013 are estimates only.

b) The houshold forecast referenced in Page 49 in Module 1 of 2013 LTEP pertains to the number of households in Ontario. Hydro One uses the number of housing starts (not households) in its econometric models. This explains why the OPA has higher number of households forecast as compared to number of housing starts used by Hydro One. As explained in Exhibit A, Tab 15, Schedule 2, page 5, Hydro One uses the consensus forecast approach to estimate the forecast for housing starts. Based on our experience in load forecasting, this approach works well.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6

Interrogatory

Reference A/T15/S2, pg. 20
2013 LTEP, Module 1 (Demand Forecast), pg. 6

Preamble: The 2013 LTEP included the following forecast for Ontario peak demand (taken back to the generator) prior to adjustments for CDM.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Energy, TWh	143.6	145.0	144.1	143.9	144.6	146.9	146.9	149.1	152.4	155.0	157.1
Peak, MW	23,837	24,028	24,042	24,097	24,275	24,579	24,665	25,024	25,511	25,805	26,174

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy, TWh	158.2	159.7	162.0	163.8	166.0	168.7	171.3	173.5	176.1	178.7	181.3
Peak, MW	26,368	26,607	26,907	27,259	27,596	28,041	28,367	28,766	29,167	29,539	29,944

a) Are the values reported in Table 3 for 2013 forecast or actuals?

b) The OPA's forecast for Ontario demand (before deducting CDM) is materially higher than Hydro One Networks' forecast. Please explain the difference and why Hydro One Networks' forecast is the more appropriate on to use.

c) To the extent the difference is based on point of measurement (e.g. at generation vs. point of delivery), please restate the Hydro One Networks' forecast so it is reflective of the same point of measurement as the OPA's and indicate the loss factors used.

d) How are the forecasts for the various Charge Determinants derived from the forecast of Ontario Demand – per Table 3? For example, are they based on the historical relationship or is the post 2013 growth rate forecast for Ontario Demand applied to each of the actual 2013 value for each of the charge determinants?

Response

a) Please see the response to Exhibit I-06 VECC-05, Part (a).

b) The peak demand forecast presented in Module 1, page 6, 2013 LTEP, pertains to the maximum (summer) peak for use in capacity planning in the province. The load forecast presented in Table 3 in Exhibit A, Tab 15, Schedule 2, page 20, pertains to the 12-month average peak and, as such, the average peak values are lower compared to the maximum peak. The 12-month average peak is more appropriate for Hydro One to use in estimating the charge determinants in this rate application which are based on the twelve month average peak..

To make an apple-to-apple comparison, the weather-normal summer peak forecast of Hydro One before CDM and embedded generation deductions should be used, as presented in the following table (all peak numbers are presented in MW).

Forecast	2013	2014	2015	2016
LTEP	24,042	24,097	24,275	24,579
Hydro One	25,127	25,434	25,782	26,260

c) The difference is not due to point of measurement as explained (b) above.

d) The forecast for each charge determinant, before deducting CDM and embedded generation, is arrived at by applying the post 2013 growth rates of the Ontario Demand before deductions to the 2013 base-year forecast value of that charge determinant. Then for each charge determinant, the associated CDM and embedded generation is deducted to estimate the charge determinant forecast after deductions.

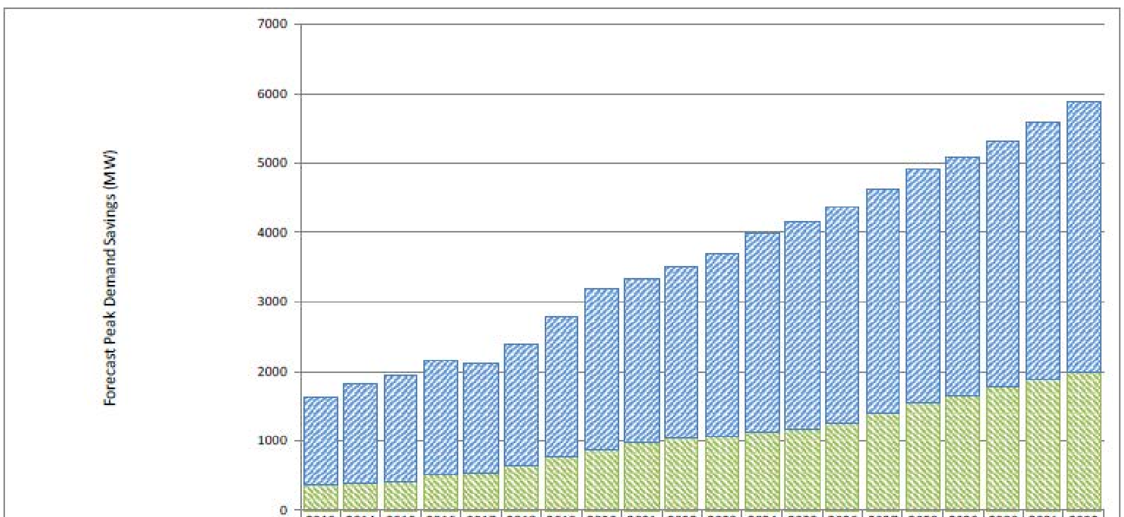
Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7

Interrogatory

Reference **A/T15/S2, pg. 7 and 20**
2013 LTEP, Module 2 (Conservation), pg. 11 and 21

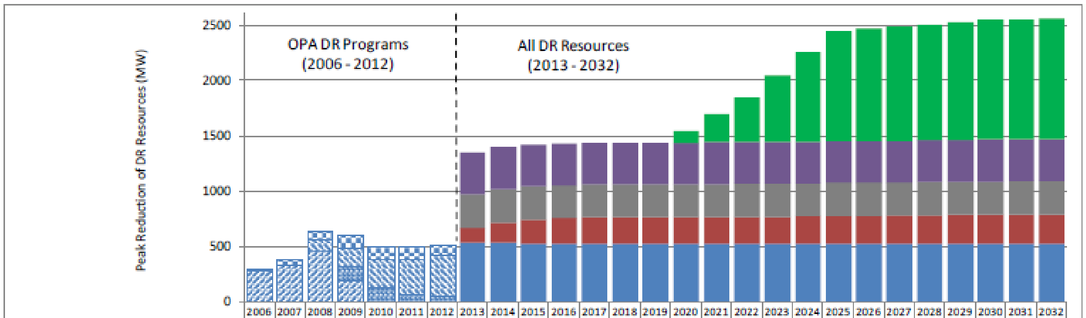
Preamble: The 2013 LTEP included the following forecasts for future demand reductions due to CDM.

Module 2, Page 11



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EE (historical and future programs)	1248	1435	1528	1662	1575	1752	2022	2321	2357	2470	2636	2865	2985	3125	3224	3378	3444	3556	3720	3880
Codes and Standards (existing and forecast)	373	386	413	505	525	639	777	876	984	1039	1056	1128	1176	1244	1398	1537	1647	1768	1879	1988
Total	1621	1820	1942	2167	2099	2391	2799	3197	3341	3509	3693	3993	4160	4369	4622	4915	5091	5324	5599	5868

Module 2, Page 21



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
New dispatchable DR														
Dispatchable load								377	377	377	377	377	377	377
Industrial Conservation Initiative								300	300	300	300	300	300	300
Time of Use rates								137	184	221	232	239	239	239
Existing DR programs (capacity maintained)								539	539	528	528	528	528	528
peaksaver and other direct load control	20	48	84	112	117	115	96							
DR3	0	0	91	182	264	315	367							
DR2	0	0	0	128	122	69	56							
DR1	285	340	471	188	0	0	0							
Total	305	388	646	609	504	498	519	1352	1399	1425	1437	1444	1444	1444

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
New dispatchable DR	100	250	400	600	800	990	1010	1030	1040	1060	1080	1080	1090
Dispatchable load	377	377	377	377	377	377	377	377	377	377	377	377	377
Industrial Conservation Initiative	300	300	300	300	300	300	300	300	300	300	300	300	300
Time of Use rates	239	241	243	245	248	250	253	256	259	262	265	268	268
Existing DR programs (capacity maintained)	528	528	528	528	528	528	528	528	528	528	528	528	528
peaksaver and other direct load control													
DR3													
DR2													
DR1													
Total	1544	1696	1848	2050	2253	2445	2468	2491	2504	2527	2550	2553	2563

a) Please reconcile Hydro One Networks' CDM adjustments to Ontario peak demand for 2013-2016 (per Table 2) with those forecast in the 2013 LTEP.

b) Please explain how the CDM impact on the 12 month average Peak Demand is derived from the forecast impact on the Ontario Peak Demand.

Response

a) The table below provides the reconciliation of peak saving assumptions for 2013-2016.

Category	Year	2013 LTEP in MW	Hydro One's Assumptions in MW	Notes
EE (historical and future programs)	2013	1248	1248	Hydro One's peak reduction due to EE is consistent with the OPA's 2013 LTEP
	2014	1435	1435	
	2015	1528	1528	
	2016	1662	1662	
Codes and Standards (existing and forecast)	2013	373	373	Hydro One's peak reduction due to C&S is consistent with the OPA's 2013 LTEP
	2014	386	386	
	2015	413	413	
	2016	505	505	
Dispatchable Load	2013	377	50	Hydro One analyzed the historical actual monthly peak
	2014	377	50	

Category	Year	2013 LTEP in MW	Hydro One's Assumptions in MW	Notes
Dispatchable Load (cont.)	2015	377	50	reduction due to dispatchable load for 2003-2013 to derive the peak saving for the forecast period.
	2016	377	50	
Industrial Conservation Initiative	2013	300	300	Hydro One's peak reduction due to Industrial Conservation Initiative is consistent with the OPA's 2013 LTEP
	2014	300	300	
	2015	300	300	
	2016	300	300	
Time-of-Use Rates	2013	137	137	Hydro One's peak reduction due to TOU is consistent with the OPA's 2013 LTEP
	2014	184	184	
	2015	221	221	
	2016	232	232	
Existing DR Programs (assume capacity maintained)	2013	539	511	Hydro One analyzed the actual peak reduction of DR1, DR2, DR3 and peaksaver programs for 2006-2012 and used the same ratio to derive the peak saving forecast for 2013-2016
	2014	539	511	
	2015	528	501	
	2016	528	500	
Total	2013	2974	2619	
	2014	3221	2865	
	2015	3367	3014	
	2016	3604	3250	

b) Hydro One derives the monthly peak savings by CDM categories including EE, C&S, dispatchable load, Industrial Conservation Initiative, TOU and DR programs (DR2, DR3, PeakSaver). The table below provides the detailed assumptions used for each CDM category.

Category	Method used to derive monthly saving
EE (historical and future programs)	Use monthly saving profile provided by the OPA
Codes and Standards (existing and forecast)	Use monthly saving profile provided by the OPA
Dispatchable Load	Use monthly saving profile provided by the IESO
Industrial Conservation Initiative	Assume the impact only for June and July
Time-of-Use Rates	Use monthly saving profile provided by the OPA

Category	Method used to derive monthly saving
Existing DR Programs (assume capacity maintained)	DR2: monthly saving profile based on 2009-2012 actual saving information from the OPA
	DR3: assume the impact only for June and July
	PeakSaver: assume the impact only for June and July

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8

Interrogatory

Reference: H1/T5/S1, Attachment 1, pg. 10

a) Did Elenchus undertake any further investigation as to the interruptible nature of exports (i.e., as to under what conditions they are interruptible)? If so, what were its findings?

Response

a) No. Elenchus did not undertake any further investigation as to the interruptible nature of exports.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9

Interrogatory

Reference: H1/T5/S1, Attachment 1, pg. 12-14

a)

b) Please provide a schedule that sets out the actual export sales (MWh) for 2010-2013 and the forecast values for 2014-2016. In the same schedule please include the forecast export sales for 2012-2014 per EB-2012-0031.

c) Please provide a schedule that sets out actual 2011-2013 export and domestic customer MWh volumes and the forecast domestic customer MWH volumes for 2015-2016.

Response

a)

b) The requested information is provided in the table below.

Year	Actual Exports (MWh)	Forecast Exports (MWh)*	Forecast Export per EB-2012-0031 (MWh)*
2010	15,165,494	N/A	N/A
2011	12,848,505	N/A	N/A
2012	14,627,403	N/A	15,800,000
2013	18,309,407	N/A	15,500,000
2014	N/A	16,000,000	15,000,000
2015	N/A	16,700,000	N/A
2016	N/A	17,200,000	N/A

*Forecast is for Hydro One only (excludes other transmitters).

c) The requested information is provided in the table below.

Year	Actual Exports (MWh)	Actual Domestic (MWh)	Forecast Domestic (MWh)
2011	12,848,505	141,473,805	N/A
2012	14,627,403	141,287,009	N/A
2013	18,309,407	140,736,784	N/A
2014	N/A	N/A	N/A
2015	N/A	N/A	139,922,990
2016	N/A	N/A	141,204,442

Note: All values provided in this table are for the Province (including other transmistters).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10

Interrogatory

Reference **H1/T5/S1, Attachment 1, pg. 10-11**
E1/T1/S1, pg. 1

a) Please provide schedules that breakdown the proposed revenue requirements for 2015 and 2016 by functional category, per EB-2012-0031, G1/T2/S1, pg. 2-8 (i.e. the totals should reconcile with the proposed revenue requirement for each year). In each schedule please identify the contribution of OM&A, Depreciation, Income Taxes, Property Taxes and Cost of Capital to the cost for each functional category. The totals should reconcile with the values shown in E1/T1/S1, pg. 1.

b) Please also include in the response to part a) the net book value and gross book value for each functional category.

Response

a) The requested information is provided in the tables below.

2015						
Functional Category	**OM&A**	**Property Taxes and Rights Payments**	**Depreciation**	**Income Taxes**	**Cost of Capital**	**Total Revenue Requirement**
Network	113.1	31.5	144.7	34.0	331.5	654.7
Line Connection	22.9	7.3	31.5	7.9	76.8	146.3
Transformation Connection	60.4	13.6	75.4	14.7	143.0	307.1
Wholesale Revenue Meter	0.2	0.0	0.0	0.0	0.1	0.3
Network Dual Function Line	15.4	3.9	14.0	4.3	41.5	79.1
Line Connection Dual Function Line	3.4	0.9	3.1	0.9	9.1	17.3
Generation Line Connection	4.5	1.4	6.5	1.5	15.1	29.0
Generation Transformation connection	2.0	0.2	1.4	0.3	2.5	6.4
Common	154.3	6.6	114.1	7.2	70.3	352.5
Other	9.5	0.9	3.6	1.0	9.4	24.4
Total	**385.7**	**66.3**	**394.2**	**71.8**	**699.3**	**1,617.1**

2016						
Functional Category	**OM&A**	**Property Taxes and Rights Payments**	**Depreciation**	**Income Taxes**	**Cost of Capital**	**Total Revenue Requirement**
Network	114.3	31.6	148.0	39.0	350.5	683.3
Line Connection	23.1	7.5	33.1	9.2	82.8	155.6
Transformation Connection	61.3	13.9	78.2	17.1	154.1	324.6
Wholesale Revenue Meter	0.1	0.0	0.0	0.0	0.0	0.2
Network Dual Function Line	15.6	3.9	14.1	4.8	43.2	81.6
Line Connection Dual Function Line	3.4	0.9	3.1	1.1	9.4	17.8
Generation Line Connection	4.5	1.4	6.7	1.8	16.1	30.5
Generation Transformation connection	2.1	0.3	1.5	0.3	2.8	7.0
Common	156.2	6.8	115.7	8.5	76.1	363.2
Other	9.7	0.9	3.7	1.1	9.9	25.3
Total	**390.4**	**67.0**	**404.0**	**82.8**	**744.9**	**1,689.2**

b) The requested information is provided in the table below.

Asset Value by Functional Categroy

Functional Category	**Gross Book Value ($ Million)**		**Net Book Value ($Million)**	
	2015	**2016**	**2015**	**2016**
Network	7,169.8	7,412.8	4,816.2	4,960.1
Line Connection	1,648.4	1,739.0	1,116.6	1,171.6
Transformation Connection	3,223.7	3,382.2	2,076.9	2,180.1
Wholesale Meter	1.4	1.0	0.9	0.7
Network - Dual Function Line	869.5	887.5	603.2	611.1
Line Connection - Dual Function Line	190.0	194.0	132.0	133.7
Generator Line Connection	325.0	339.1	218.9	227.8
Generator Station Connection	56.7	62.4	36.2	39.8
Common	1,980.0	2,126.8	1,013.0	1,068.8
Other	201.1	208.2	136.0	140.0
TOTAL	**15,665.5**	**16,353.0**	**10,149.9**	**10,533.7**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #11

Interrogatory

Reference: H1/T5/S1, Attachment 1, pg. 12

a) Does Hydro One Networks take into consideration transmission capacity needed for imports when planning the Network transmission system?

b) Has Hydro One Networks ever constructed facilities that would facilitate the import or export of electricity? If so, what facilities, were they just inter-jurisdiction interties or also intra-provincial network facilities and what was the basis for this activity (i.e., was it the result of an internal planning process, direction from the OPA/government or direction from the IESO)?

c) Does Hydro One Networks plan and construct network facilities so as to reduce/eliminate congestion on the transmission system? If so, is congestion assessed based just on domestic load?

Response

a) Yes, Hydro One considers the transmission capacity needed for imports where it's relevant to investments being planned or under consideration. For example, where firm purchases have been established, Hydro One will reflect the network capacity needed to support the purchases in its planning studies.

b) The following facilities were constructed by Hydro One to facilitate the exchange of power with other jurisdictions:

1. Ontario-Michigan Phase Shifters. This project involved adding phase shifters and additional autotransformation capability on the interties with Michigan at Lambton TS and Scott TS.

2. Ontario-Quebec High Capacity Intertie. This project involved building two new 230kV circuits from Hawthorne TS to the provincial border to connect with the TransEnergie 230kV circuits that connect to the Outaouais station in Quebec.

3. Niagara Reinforcement Project. This project involved building two new intra-provincial 230kV circuits from Allanburg TS to Middleport TS. This project has been partially completed but is on hold pending the resolution of the First Nation issues in the Caledonia area.

These three projects were initiated in response to Hydro One's transmission license requirement to "use its best efforts to expand inter-tie capacity to neighbouring jurisdictions by approximately 2000 MW by May 1, 2005". These projects also provide other key reliability benefits including mitigation of loop flows through Ontario, strengthening the transmission systems in eastern Ontario and the Niagara area, and greater access to renewable resources.

c) Yes, where appropriate Hydro One plans and constructs facilities to address congestion on the network. A recent example is the upgrade of the Lambton to Longwood circuits to address congestion of resources in the area west of London. As well as load levels and loading profiles, congestion is based on many other factors and assumptions including generation levels, operating characteristics and outage rates, network configuration and characteristics, system transfers and import/export transactions.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #12

Interrogatory

Reference H1/T5/S1, Attachment 1, pg. 12-16
H1/T2/S1, pg. 2

a) Why does Elenchus propose using 12-CP as the allocator when Hydro One Networks effectively allocates Network Costs to domestic customers (per EB-1999-0044) based on the higher of a) the monthly Coincident Peak and b) 85% of the monthly Non-Coincident Peak – averaged over 12 months?

b) Please explain more fully the basis for the "Net Shared Assets" allocator and provide the derivation of the values set out in Tables 6 and 7.

Response

a) Elenchus is of the view that in order to develop a simple cost allocation methodology to determine a cost-based export tariff, the allocators to be used should be commonly used allocators in cost allocation methodologies. Coincident peak ("CP") and non-coincident peak ("NCP") are the commonly used allocators used for demand related costs. It is Elenchus' understanding that using 85% of the monthly Non-Coincident Peak is not a commonly used allocator in cost allocation methodologies and introduces a level of complexity into the proposed methodology.

b) "Net Shared Assets" are the assets that are left over after deducting the assets exclusively dedicated to domestic customers and exclusively dedicated to interconnections.

On Tables 5, 6, and 7, the data shown as composite allocator for Net Shared Assets reflects the allocation of all assets, dedicated and shared to domestic and interconnections.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #13

Interrogatory

Reference: H1/T5/S1, Attachment 1, pg. 17 and pg. 19-21

a) Please explain why no asset related costs associated with shared assets are allocated to export customers for the Base Case ETS Rate (or any of the alternative scenarios except #6).
b) Please explain why export customers are not allocated a share of the costs associated with the Generation Line Connection and Generation Transformation Connection functional categories.
c) Do the Shared OM&A expenses allocated between domestic and export customers include OM&A associated with both the Common and Other functional categories? If not, why not?
d) Are export customers allocated a share of property taxes? If so, how is the allocation determined?
e) Are the ETS rates set out in Table 9 before or after the adjustment to account for the revenue requirements of the other transmitters?

Response

a) As stated in the Elenchus report on page 12, lines 1 to 6:
As export is considered to be interruptible service, no asset related costs associated with shared assets are proposed to be allocated to the export customer class.
This is considered appropriate because, as confirmed by Hydro One staff, HONI's planning of the Network transmission system does not take into consideration the capacity needed to supply export customers, transmission planning is only based on the capacity needs of domestic customers.

b) Export customers are allocated their share of costs associated with Generation Line Connection and Generation Transformation Connection functional categories.

c) Yes, shared OM&A expenses allocated between domestic and interconnections include OM&A associated with both the Common and Other functional categories.

d) Yes, interconnections are allocated a share of property taxes (Grants in Lieu). Revenue requirement for the Network rate pool is broken down between dedicated to interconnections, dedicated to domestic and shared based on 2013 actual GBV.

e) The ETS rates shown on Table 9 are before the adjustment to account for the revenue requirements of the other transmitters.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #14

Interrogatory

Reference: H1/T5/S1, Attachment 1, pg. 20

a) Please provide a schedule that, starting with Hydro One Networks' allocation of the various components (e.g. OM&A, Depreciation, Cost of Capital, etc.) of 2015 proposed revenue requirement to functional categories sets out the allocation of each cost component of each functional category as between export and domestic customers including the allocator used, the allocator's values and the resulting allocation of costs per the Base Case methodology.

b) Using the resulting export customer revenue requirement from part (a), please show the derivation of the $1.63/MWh ETS rate for 2015.

Response

a) The requested information is provided in the tables below.

Breakdown of Revenue Requirement by functional category (Dedicated to Interconnect/Dedicated to Domestic/Shared)

Revenue requirement		Network			Line Connection	Transformation Connection	Wholesale Revenue Meter	Network Dual Function Line	Line Connection Dual Function Line	Generation Line Connection	Generation Transformation connection
	2015 Rates Revenue Req ($M)	*Total*	Dedicated to Interconnect	Shared	Dedicated to Domestic	Dedicated to Domestic	Dedicated to Domestic	Shared	Dedicated to Domestic	Shared	Shared
OM&A	385.7	*196.69*	2.40	194.29	39.76	105.04	0.17	26.78	5.86	7.79	3.56
Other Taxes (Grants in Lieu)	66.3	*35.476*	0.43	35.04	8.225	15.299	0.006	4.443	0.972	1.613	0.266
Depreciation on fixed assets	356.0	*185.843*	2.26	183.58	40.079	98.829	0.030	17.321	3.782	8.336	1.792
Capitalized depreciation	(6.4)	*(3.408)*	(0.04)	(3.37)	(0.784)	(1.532)	(0.001)	(0.413)	(0.090)	(0.154)	(0.027)
Asset removal costs	38.1	*20.253*	0.25	20.01	4.656	9.106	0.004	2.456	0.537	0.918	0.160
OPEB amortization	-		-	-							
Other amortization	6.5	*3.458*	0.04	3.42	0.802	1.491	0.001	0.433	0.095	0.157	0.026
Return on debt	299.0	*159.993*	1.95	158.04	37.087	69.023	0.028	20.042	4.384	7.271	1.204
Return on equity	395.3	*211.476*	2.58	208.90	49.021	91.233	0.037	26.491	5.795	9.611	1.591
Income tax	71.8	*38.394*	0.47	37.93	8.900	16.564	0.007	4.809	1.052	1.745	0.289
Capital tax	-		-	-							
AFUDC	5.0	*2.661*	0.03	2.63	0.617	1.148	0.000	0.333	0.073	0.121	0.020
Revenue requirement	1,617.1	*$ 850.84*	10.37	840.47	$ 188.36	$ 406.20	$ 0.29	$ 102.70	$ 22.46	$ 37.41	$ 8.88

Group Revenue Requirement by Rate Pool

Rate Pool	Dedicated to Interconnect	Dedicated to Domestic	Shared	Total
Network	10.4		989.5	999.8
Line		210.8		210.8
Transformation		406.2		406.2
Meter		0.3		0.3

Revenue requirement for the Network Rate Pool is broken down between dedicated to interconnections, dedicated to domestic and shared based on 2013 actual GBV.

Expenses dedicated to interconnections were allocated 100% to interconnections. Expenses dedicated to domestic were allocated 100% to domestic. The allocator used for OM&A expenses associated with net shared assets was gross assets. Shared assets are allocated based on 12 CP 2013 data shown on Table 4 of Elenchus report.

Out of the $1.617B revenue requirement for 2015, $1.590B was allocated to domestic and $0.027B was allocated to interconnections.

b) $27,232,324 million divided by the forecast export volumes for 2015 of 16,700,000 MWh results in an ETS rate of $1.63/MWh.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #15

Interrogatory

Reference A/T18/S1, pg. 4

a) Please provide the actual and budget amounts for each of the categories shown in Table 2 (Total Annual Savings – Transmission)

Response

a) The productivity categories provide information on the types of savings that are occurring at Hydro One. Individual initiatives often have an impact on many different programs or divisions and as a result it is not possible to apply the productivity category approach to the business plan budgets or align these budgets to the categories without creating overlap and duplication.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #16

Interrogatory

Reference D1/T2/S1/pg. 47

a) For figures 8, 13, 19, 25, 31, 37 and 43 please revise to show the actual replacement levels for 2009 through 2014.

Response

Please see table below for the actual replacement levels for 2009 through 2013 and the forecast replacement level for 2014 for each key transmission asset outlined in Exhibit D1, Tab 2, Schedule 1.

Asset Replacements		Years					
		2009	**2010**	**2011**	**2012**	**2013**	**2014**
Transformer Replacements	# units	4	10	16	12	15	26
Circuit Breaker Replacements	# units	33	81	100	55	57	125
Protection System Replacements	# units	259	283	389	350	340	350
Conductor Replacements	# kms	30	30	37	22	75	113
Wood Pole Replacements	# units	811	880	862	763	830	850
Steel Structure Replacements/Refurbishments	# units	71	33	0	226	235	354
Underground Cable Replacements	# kms	0	0	0	0	5	5

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #17

Interrogatory

Reference D1/T2/S1/pg. 47

a) The Historical Replacement level for this chart is not shown. Please provide so as to be consistent with Figures 8, 13, 19, and 25.

Response

The historic and proposed replacement rate are the same, and as such can not be separately distinguished on Figure 31 of the reference.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #18

Interrogatory

Reference D1/T3/S2, pg. 3 Table 1

a) Please provide the sustaining capital as shown in Table 1 for the years 2008 through 2010.

b) Explain why 2011-2013 capital spending was significantly lower than that proposed for 2014 through 2016.

Response

a) Please see table below for the sustaining capital for the years 2008 through 2010.

Description	**Historic Year ($M)**		
	2008	**2009**	**2010**
Stations	211.0	216.6	271.2
Lines	56.5	76.0	71.6
Total	**267.4**	**292.3**	**342.8**

b) The proposed spending for Sustaining Capital over the 2014 to 2016 period is directionally focused on maintaining equipment reliability and overall system reliability, through continued Sustaining Capital expenditures, while containing the test year Sustaining OM&A expenditures increases to less than inflation as outlined in Exhibit D1, Tab 2, Schedule 1, page 2 lines 4 to 7.

The primary driver for the Stations capital expenditures being higher when compared to historic years is due to the on-going focus within Station Re-investment on replacing air blast circuit breakers at critical system stations and executing integrated station rebuilds at load delivery stations as outlined in Exhibit D1, Tab 3, Schedule 2, page 7 lines 12 to 15.

And similarly, the increasing Lines Sustaining capital expenditures reflect the need for an increase in the line refurbishment and underground cable replacements to address the number of these assets that are approaching end of life. A significant increase is also required in the refurbishment of steel towers in order to extend the life of these assets as outlined in Exhibit D1, Tab 3, Schedule 2, page 42 lines 12 to 16.

Power Workers' Union (PWU) INTERROGATORY #1

Interrogatory

Ref (a): Participant Information Package: Exhibit C1-2-1, Page 5 of 6, Table 2 (OM&A Expenditures)

Table 2: 2013 Board Approved versus 2013 Actual OM&A Expenditures

OM&A Categories	2013 Board Approved ($ million)	2013 Actuals ($ million)	Variance ($ million)
Sustaining	235.7	221.0	(14.8)
Development	13.7	8.6	(5.1)
Operations	57.7	56.7	(1.0)
Customer Care	4.9	5.3	0.4
Common Corporate & Other Costs	61.9	75.8	13.9
Taxes other than Income Taxes	66.0	21.2	(44.8)
Total OM&A	**440.3**	**388.4**	**(51.6)**

Ref (b): Exhibit C1-2-1, Page 5 of 6, Lines 4-8:

> **Hydro One Transmission's actual 2013 OM&A costs were $51.6 million lower than the $440.3 million approved by the Board in Proceeding EB-2012-0031. The reduction in the Sustaining, Development, and Operations work program spend reflects Cornerstone savings (both are included in the Board Approved Shared Services and Other total in Table 2).**

a) The actual sustaining OM&A spending in 2013 was less than the Board-approved amount by about $15M (Ref a). Is the variance fully attributable to Cornerstone savings? If not, please identify and describe any Board-approved planned sustaining work that was later cancelled, deferred or reduced in scope and explain why.

Response

a) The actual Sustaining OM&A expenditures in 2013 are lower than Board Approved amounts primarily for the following reasons:
   - Lower than anticipated cost of corrective work for both Lines and Stations assets, partially attributed to the capital replacement programs addressing end of life components;
   - Lower than anticipated costs to complete required work in Site Infrastructure Maintenance;
   - Lower than anticipated volume of work on Cyber Security partially associated with external delays in the approval of new standards; and

- Delays in the Engineering and Environmental Support category for Class EA process documentation updates due to slower than planned progress associated with on-going external stakeholder consultations.

Power Workers' Union (PWU) INTERROGATORY #2

Interrogatory

Ref (a): Participant Information Package. Exhibit C1-2-1, Page 6 of 6, Table 3 (OM&A Expenditures)

Table 3: 2014 Board Approved versus 2014 Projected OM&A Expenditures

OM&A Categories	2014 Board Approved ($ million)	2014 Projected ($ million)	Variance ($ million)
Sustaining	246.5	236.2	(10.3)
Development2	14.7	12.9	(1.8)
Operations	58.0	57.4	(1.6)
Customer Care	4.7	5.8	1.1
Common Corporate & Other Costs	59.0	70.6	11.6
Taxes other than Income Taxes	66.8	65.6	(1.2)
Total	**449.7**	**448.5**	**(1.2)**

Ref (b): Participant Information Package. Exhibit C1-2-1, Page 6 of 6, Lines 9-11:

> **The reduction in the Sustaining, Development, and Operations work program spend was driven by the need to stay within the overall Transmission business OM&A envelope approved in the Board's last Decision, and also reflects Cornerstone savings. These variances are partially offset by an increase in Common Corporate and Other Costs primarily in the Real Estate and Facilities area.**

a) The sustaining OM&A spending in 2014 is projected to be less than the Board-approved amount by about $10M (Ref b). Please identify and describe any planned sustaining work that was later cancelled, deferred or reduced in scope as a result of "the need to stay within the overall Transmission business OM&A envelope approved in the Board's last Decision" described in Ref b. What proportion of the $10M variance is attributable to Cornerstone savings?

Response

a) The actual Sustaining OM&A expenditures in 2014 are lower than Board Approved amounts primarily for the following reasons:
- Lower than anticipated costs to complete Power Equipment maintenance program;
- Lower than anticipated costs to complete the Ancillary Equipment maintenance program; and
- Lower than anticipated costs to complete the Site Infrastructure maintenance program.

Power Workers' Union (PWU) INTERROGATORY #3

Interrogatory

Ref (a): Participant Information Package. Exhibit C1-2-2, Page 39 of 51, Lines 20-22 (Vegetation Management):

> **In addition to the condition patrols, Hydro One Transmission will be required to inspect applicable lines annually as outlined in the recent revision to the NERC Vegetation Management Standard (FAC-003-2); which became enforceable in 2014.**

a) Please describe the new or additional requirements relating to vegetation management that are included in the revised NERC Vegetation Management Standard.

b) Please provide the NERC Vegetation Management Standard (FAC-003-2).

Response

a) Hydro One is now required to annually inspect vegetation on all circuits operating at 230kV and above by either helicopter or ground to comply with the NERC standard that states *"Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW [right of way]."*.

b) Please refer to the following link for the latest version (Version 3) of the NERC Transmission Vegetation Management standard. *http://www.nerc.com/files/FAC-003-3.pdf*

Power Workers' Union (PWU) INTERROGATORY #4

Interrogatory

Ref (a): Participant Information Package. Exhibit C1-2-2, Page 37 of 51, Table 11 (Vegetation Management)

Vegetation Management OM&A ($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Brush Control	17.0	15.5	19.8	18.3	18.6	19.0
Line Clearing	4.3	5.3	5.2	6.4	6.5	6.4
Property Owner Contact	1.2	1.3	1.2	1.8	1.8	1.8
Condition Patrols	1.3	1.4	1.6	1.6	1.6	1.6
Demand Maintenance	1.0	1.4	0.9	1.4	1.4	1.4
Grounds Maintenance	1.9	2.2	2.3	2.8	2.9	2.9
Total	**26.6**	**27.1**	**31.1**	**32.2**	**32.8**	**33.2**

a) Please provide the corresponding historic and planned levels of accomplishment for the test years for brush control (ha) and line clearing (km).

Response

The corresponding historic accomplishment and planned levels for brush control and line clearing are as follows:

	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Brush Control (ha)	11,580	11,048	11,687	13,000	13,000	13,000
Line Clearing (km)	2,878	2,704	2,864	3,400	3,400	3,300

Power Workers' Union (PWU) INTERROGATORY #5

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-3-1, Page 1, Lines 3-8.

> **1.0 SUMMARY OF CAPITAL BUDGET**
> **The proposed capital expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision-making to ensure that the appropriate, cost-effective solutions are put into place to meet Hydro One Transmission objectives. These processes are described in detail in Exhibit A, Tab 16, Schedules 1 to 7.**

Ref (b): EB-2013-0416. Exhibit D1-3-1, Page 1, Lines 3-8.

> **1.0 SUMMARY OF CAPITAL EXPENDITURES**
> **The requested capital expenditures result from the rigorous business planning and work prioritization processes described in detail at Exhibit A, Tab 17, Schedules 1 through 7. These processes reflect a risk-based decision-making approach to ensure appropriate and cost-effective investments.**

a) As per Ref (a), the business planning and work prioritization processes for this application are described in Exhibit A, Tab 16, Schedules 1 to 7 as provided in the Participant Information Package. As per Ref (b), the business planning and work prioritization processes for HONI's 2015-2019 Distribution Custom Rate Application are described EB-2013-0416, Exhibit A, Tab 17, Schedule 1 to 7. Please confirm that HONI's business planning and work prioritization processes outlined in the distribution and transmission applications are identical. If not, please provide Exhibit A, Tab 16, Schedule 1 to 7.

Response

HONI's business planning and work prioritization processes outlined in the distribution and transmission applications are identical.

Power Workers' Union (PWU) INTERROGATORY #6

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-2-1, Page 7, Lines 6-10.

> **4.0 TRANSMISSION ASSET RISK ANALYSIS**
> **The information presented below entails the asset risk analysis summaries for key transmission assets, based on the asset risk assessment process introduced in Exhibit A, Tab 16, Schedule 7.**

Ref (b): EB-2013-0416, Exhibit A-17-7. Asset Risk Assessment. Page 1, Lines 11-21.

> **2.0 ASSET RISK ASSESSMENT PROCESS**
> **Hydro One's Asset Risk Assessment methodology is built on the foundation of the Asset Condition Assessment approach previously filed in proceeding EB-2009-0096. Since then, Hydro One has completed an asset inventory of its key distribution assets that was collected during routine maintenance and inspections. This information is centralized in a repository and has been linked to other non-condition based information such as outage and customer data. This has enabled Hydro One to extended its assessment methodology to improve its focus on non-condition risk factors. This newly coined "Asset Risk Assessment" enables a holistic view of asset risk, and ultimately, improved decision making.**

Ref (c): EB-2012-0031. Exhibit C1-2-2. Transmission Assets and Sustaining Investment Overview.

a) The PWU notes that in the current application the condition of assets for a transmission asset class is assessed based on risk while in EB-2012-0031 it was based on the state of condition of the asset class. Is there equivalence between the two asset condition assessments? Specifically, is there equivalence or matching between levels of risk such as very low, low, fair, high and very high AND states of condition such as very poor, poor, fair, good and very good? What is Hydro One's recommendation to parties that wish to conduct a comparative trend analysis of the condition of Hydro One's transmission assets?

Response

Correct, Hydro One no longer uses the terminology "Very Good", "Good", "Fair", "Poor", and "Very Poor" of the Asset Condition Assessment applied in previous proceedings; rather Hydro One now utilizes an Asset Risk Assessment methodology that classifies equipment condition based on level of risk relative to the asset population. The overall asset risk assessment methodology is more comprehensive than the Asset Condition Assessment review in that it provides additional information on non-condition risk factors.

However for the condition risk factor of the asset risk assessment, the condition assessment scale used in the current application of Very Low Risk to Very High Risk is comparable to the Very Good to Very Poor condition assessment scale used in the EB-2012-0031 proceeding.

As such condition information presented for key transmission assets in Exhibit D1, Tab 2, Schedule 1 could be utilized to conduct a high level comparative analysis to the condition information presented in previous applications.

Power Workers' Union (PWU) INTERROGATORY #7

Interrogatory

Ref (a): EB-2012-0031. Exhibit I-5-8.15 PWU 16, Page 4.

Response

a) The table of values requested is provided below. References for the sources of data provided in the notes section below the table.

#	Asset Class	Transformers	Breakers	Protections	Cables	Towers	Conductors	Wood Poles
1	Fleet (# units)	719	4,490	11,013	291 circuit km	49,890	28,636	42,007
2	ESL (years)	50	40 - 55	25 - 40	50	80 - 100	70	40 - 50
3	Historic Replacement Rate (%/yr)	1.4	1.6	2.8	0	0	0.1	2
4	Proposed Replacement Rate (%/yr)	2.6	2.1	3.7	1.3	0.01	0.2	2
5	% of assets beyond ESL 2006	17	3		6			16
6	% of assets beyond ESL 2009	24	6		18			21
7a	% of assets beyond ESL 2012	21	8	31	19	15	16	27
7b	% of assets beyond ESL 2021 assuming historic rate	30	8	25	36	25	31	13
8	% of assets beyond ESL 2021 assuming proposed rate	18	2	16	23	19	30	13
9	% in "poor and very poor" 2006	3	1	10	0		2	10
10	% in "poor and very poor" 2009							
11	% in "poor and very poor" 2012	10	16	17	6	1	16	10
12	% in "poor and very poor" 2021 assuming historical rate							
13	% in "poor and very poor" 2021 assuming proposed rate							
14	Equipment Frequency of forced outages compared to CEA average	Worse	Worse	Worse	Worse	Better	Better	Worse

Notes:

1. The 2012 and future year data are from pre-filed evidence: Exhibit C1, Tab 2, Schedule 2; Exhibit D1, Tab 3, Schedule 2; Exhibit A, Tab 13, Schedule 2;
   The 2009 year data are from Appendix A of Exhibit C1, Tab 02, Schedule 2 of EB-2010-0002.
   The 2006 year data are from Appendix A of Exhibit D1, Tab 2, Schedule 1 of EB-2005-0501.
2. Table cells that are blank are data that are not readily available.
3. With the exception of Breakers and Cables, the "At a Glance Tables" in Exhibit C1, Tab 2, Schedule 2 were not updated as part of the August 15 update.

a) Based on the table provided in the reference, please update the following table with most recent data on a best effort basis:

#	Asset Class	Transformers	Breakers	Protection	Cables	Towers	Conductors	Wood Pole
1	Fleet Size (#units)							
2	ESL (years)							
3	Historic Replacement Rate (%/yr)							
4	Proposed Replace Rate (%/yr)							
5	% of assets beyond ESL 2006	17	3		6			16
6	% of assets beyond ESL 2009	24	6		18	15	16	27
7	% of assets beyond ESL 2012	21	8	31	19	15	16	27
8	% of assets beyond ESL 2014							
9a	% of assets beyond ESL 2024 assuming historic rate							
9b	% of assets beyond ESL 2024 assuming proposed rate							
10	% of assets in “poor and very poor” condition - 2006	3	1	10	0		2	10
11	% of assets in “poor and very poor” condition -2012	10	16	17	6	1	16	10
12	% of assets in “poor and very poor” condition - 2014							
13	% of assets in “very high and high “ risk							
14	Equipment Frequency of forced outages compared to CEA Average							

Notes:
1. The 2012 and future year data are from pre-filed evidence: Exhibit C1, Tab 2, Schedule 2; Exhibit D1, Tab 3, Schedule 2; Exhibit A, Tab 13, Schedule 2;
The 2009 year data are from Appendix A of Exhibit C1, Tab 02, Schedule 2 of EB-2010-0002.
The 2006 year data are from Appendix A of Exhibit D1, Tab 2, Schedule 1 of EB-2005-0501.
2. With the exception of Breakers and Cables, the “At a Glance Tables” in EB-2012-0031, Exhibit C1, Tab 2, Schedule 2 were not updated as part of the August 15 update filed in EB-2012-0031.

Response

a) Please see below for the updated table with most recent data on a best effort basis.

#	Asset Class	Transformers	Breakers	Protection Systems	U/G Cables	Steel Towers	Overhead Conductors	Wood Pole Structures
1	Fleet Size (#units)	722	4,537 [1]	12,135	290 km	50,000	30,000 km	42,000
2	ESL (years)	40 / 50 / 60 [2]	40 / 55 [3]	20 / 25 / 45 [4]	50	80-100 [5]	70	50
3	Historic Replacement Rate (%/yr)	2.0	1.5	3.1	0.5	0.3	0.2	2.0
4	Proposed Replace Rate (%/yr)	3.6	3.1	3.2	1.4	0.7	0.3	2.0
5	% of assets beyond ESL 2006	17	3	N/A	6	N/A	N/A	16
6	% of assets beyond ESL 2009	24	6	N/A	18	N/A	N/A	21
7	% of assets beyond ESL 2012	21	8	31	19	14	16	27
8	% of assets beyond ESL 2014	24	8	17	16	21	19	26
9a	% of assets beyond ESL 2024 assuming historic rate	35	13	25	30	24	37	18
9b	% of assets beyond ESL 2024 assuming proposed rate	19	10	22	20	18	35	18
10	% of assets in "poor and very poor" condition - 2006	3	1	10	0	N/A	2	10
11	% of assets in "poor and very poor" condition -2012	10	16	17	6	1	16	10
12	% of assets in "poor and very poor" condition - 2014	See Row 13 [6]						
13	% of assets with "very high and high" condition risk factors	8	16	26	2	1	4	9
14	Equipment Frequency of forced outages compared to CEA Average	Worse	Worse	Worse	Worse	Better	Better	Worse

<u>Notes:</u>
[1] As per Exhibit I, Tab 7, Schedule 10.
[2] ESL of 40 to 60 years is used for transformers based on the type of transformer; as outlined in Table 3 of Exhibit D1, Tab 2, Schedule 1, page 11.
[3] ESL of 40 years for all circuit breakers, with exception of oil circuit breakers which has an ESL of 55 years; as outlined in Exhibit D1, Tab 2, Schedule 1, page 19.
[4] ESL of 20 to 45 years is used for protection systems based on type of technology as outlined in Table 6of Exhibit D1, Tab 2, Schedule 1, page 29.
[5] ESL of 80 to 100 years is used for steel structures if the structures are not re-coated; as outlined in Exhibit D1, Tab 2, Schedule 1, page 54.
[6] Consistent with Exhibit I, Tab 7, Schedule 6, Hydro One now uses a condition risk factor ranging from Very Low to Very High risk.

Power Workers' Union (PWU) INTERROGATORY #8

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-2-1, Page 11. Figure 7: Demographics of the Transformer Fleet.

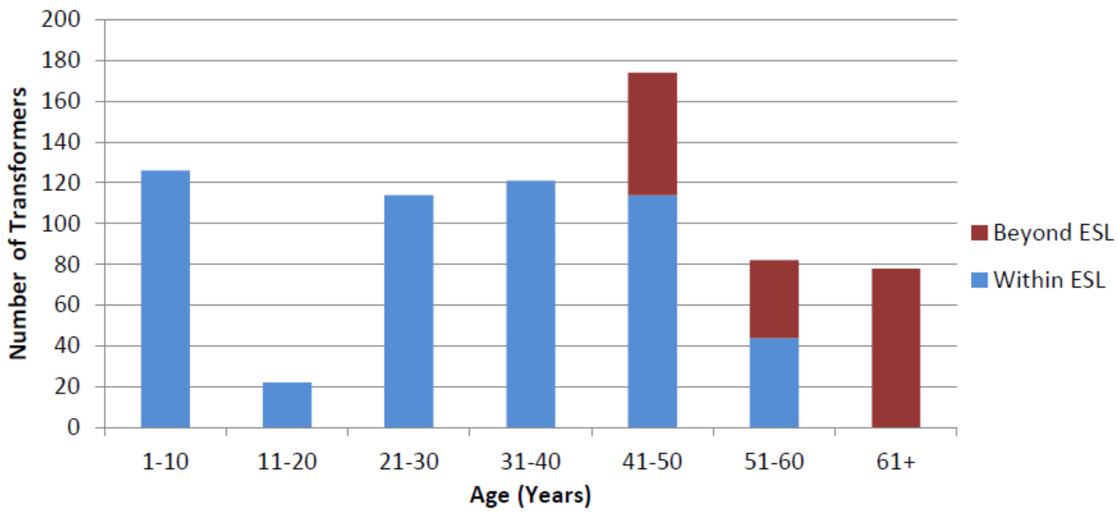


Figure 7: Demographics of the Transformer Fleet

a) Please provide a table showing the number and corresponding percentage of transformers by age group and voltage class.

Response

Please see table below for the transformer demographics in tabular form by voltage class.

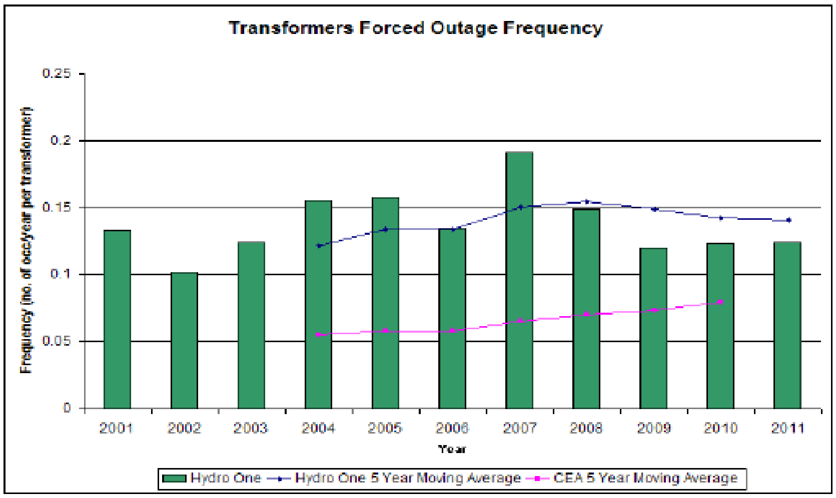
		Voltage Class					
		115 kV	**230 kV**	**345 kV**	**500 kV**	**Total**	**%**
Age Group (years)	**1-10**	52	73	-	10	**135**	**19%**
	11-20	10	8	-	3	**21**	**3%**
	21-30	21	81	2	10	**114**	**16%**
	31-40	33	76	1	9	**119**	**16%**
	41-50	40	123	1	10	**174**	**24%**
	> 50	129	30	-	-	**159**	**22%**
	Total	**285**	**391**	**4**	**42**	**722**	**100%**
	%	**39%**	**54%**	**1%**	**6%**	**100%**	

<u>Power Workers' Union (PWU) INTERROGATORY #9</u>

Interrogatory

Ref (a): EB-2012-0031. Exhibit C1-2-2. Transmission Assets and Sustaining Investment Overview. Page 24, Figure 10: Transformer Forced Outage Frequency and Comparison to CEA.

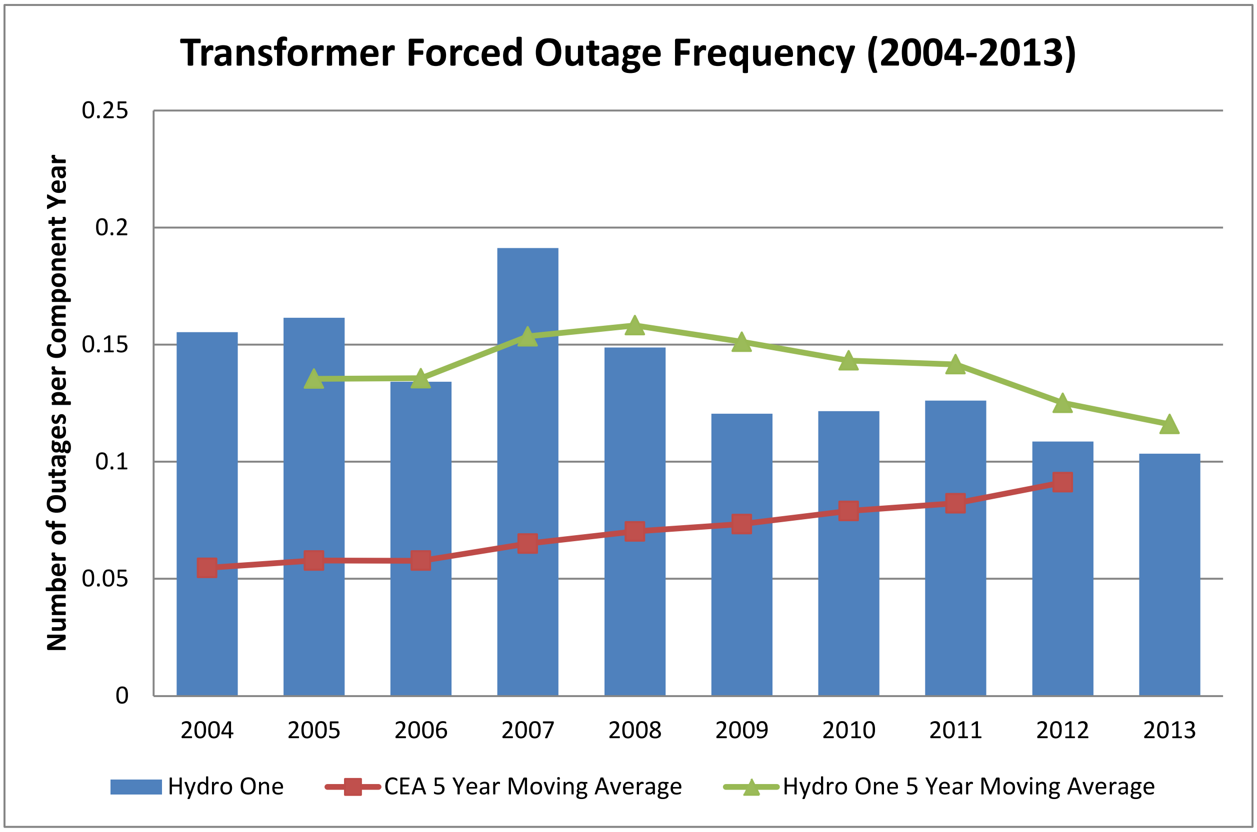
Figure 10
Transformer Forced Outage Frequency and Comparison to CEA



a) Please update Figure 10 from the reference by including most recent data.

Response

a) The figure below contains the most recent Transformer Forced Outage Frequency data and includes a comparison to CEA data.


Transformer Forced Outage Frequency (2004-2013)
Number of Outages per Component Year
0.25
0.2
0.15
0.1
0.05
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Hydro One
CEA 5 Year Moving Average
Hydro One 5 Year Moving Average

Power Workers' Union (PWU) INTERROGATORY #10

Interrogatory

Ref (a): EB-2012-0031. Exhibit C1-2-2, Page 11. Demographics of Circuit Breakers by Breaker Type.

The following table shows the demographics of the circuit breaker fleet by breaker type.

		Breaker Type							
		Air Blast	Oil	SF6	Metalclad	Vacuum	GIS	**Total**	**%**
Age Group (years)	0-10	0	20	614	216	15	22	**887**	**19.8%**
	11-20	0	348	377	156	11	10	**902**	**20.1%**
	21-30	13	93	364	265	10	14	**759**	**16.9%**
	31-40	89	664	15	133	0	53	**954**	**21.2%**
	41-50	88	609	5	76	0	0	**778**	**17.3%**
	> 50	0	189	1	20	0	0	**210**	**4.7%**
	Total	**190**	**1923**	**1376**	**866**	**36**	**99**	**4490**	**100.0%**
	%	**4.2%**	**42.8%**	**30.6%**	**19.3%**	**0.8%**	**2.2%**	**100.0%**	

a) Please update the demographics of the circuit breaker by breaker type using the same format of Ref (a).

Response

Please see table below for the circuit breaker demographics in tabular form by breaker type.

		Breaker Type							
		Air Blast	**Oil**	**SF6**	**Metalclad**	**Vacuum**	**GIS**	**Total**	**%**
Age Group (years)	**1 - 10**	0	3	744	209	16	34	**1006**	**22%**
	11 - 20	0	287	265	108	19	14	**693**	**15%**
	21 - 30	0	72	520	242	6	18	**858**	**19%**
	31 - 40	67	600	10	149	0	46	**872**	**19%**
	41 - 50	120	619	0	109	0	0	**848**	**19%**
	> 50	0	237	0	23	0	0	**260**	**6%**
	Total	**187**	**1818**	**1539**	**840**	**41**	**112**	**4537**	**100%**
	%	**4%**	**40%**	**34%**	**19%**	**1%**	**2%**	**100.0%**	

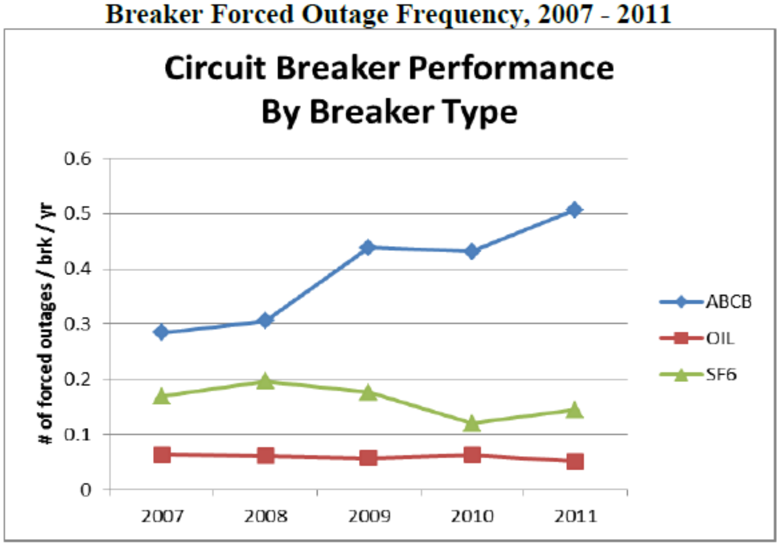
Note: due to typographical errors in Table 4 in Exhibit D1, Tab 2, Schedule 1, the total numbers in the table above are different in some categories.

Power Workers' Union (PWU) INTERROGATORY #11

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-2-1, Pages 16-25.4.1.2, Circuit Breakers.
Ref (b): EB-2012-0031. Exhibit C1-2-2, Page 13. Figure 5: Breaker Forced Outage Frequency 2007-2011.

Figure 5
Breaker Forced Outage Frequency, 2007 - 2011



	# forced outages	% of outages	# Installed TODS Breakers	% of installed TODS fleet	Forced outages per breaker per year 5-year average	Trend
AIR BLAST	410	27 %	193	7 %	0.39	**Degrading**
OIL	337	22 %	1102	40 %	0.06	Stable
SF6	634	41 %	899	33 %	0.16	**Improving**
VACUUM	15	1 %	15	0.6%	0.18	Stable
GIS	86	6 %	99	4 %	0.19	Stable
METALCLAD	62	4 %	418	15 %	0.03	Stable

a) Please provide the demographics of the circuit breaker fleet by breaker type and age group.

b) Has the trend on forced outages per breaker type as shown in Ref (b) been maintained over the last three years?

Response

a) Please see response Exhibit I, Tab 7, Schedule 10 for demographics of the circuit breaker fleet by breaker type.

b) An updated performance trend was provided in Exhibit D1, Tab 2, Schedule 1, Figure 15. The trends are generally the same, please refer to table below for the summary for each breaker type.

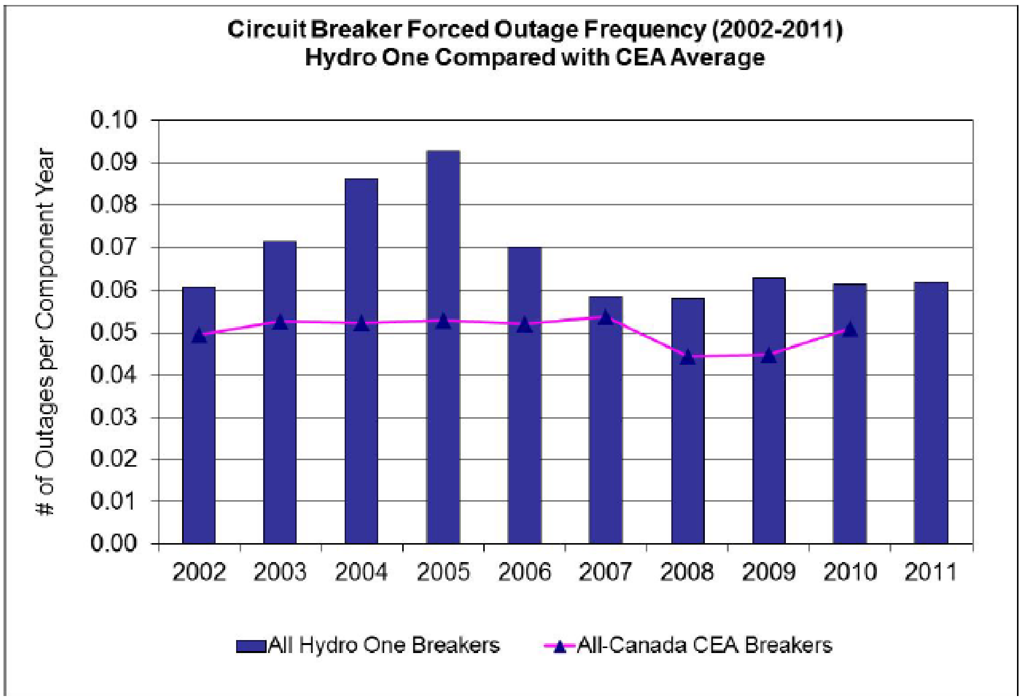
Breaker Type	Trend
AIR BLAST	Degrading
OIL	Stable
SF6	Improving
VACUUM	Degrading
GIS	Improving
METALCLAD	Stable

Power Workers' Union (PWU) INTERROGATORY #12

Interrogatory

Ref (a): EB-2012-0031. Exhibit C1-2-2, Page 12. Figure 4: Hydro One Circuit Breaker Performance, All Voltages vs. CEA Benchmark.

Figure 4
Hydro One Circuit Breaker Performance, All Voltages, vs. CEA Benchmark

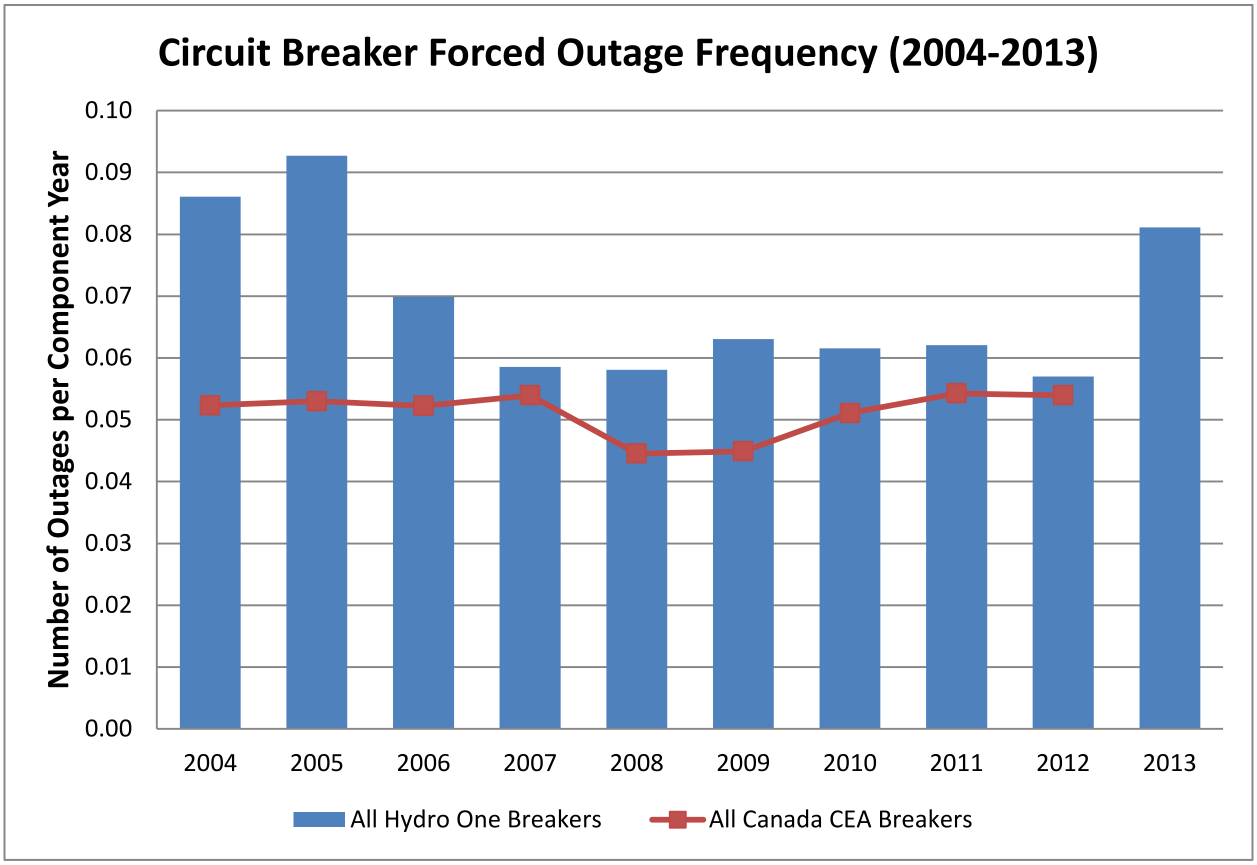


a) Please update Figure 4 from Ref (a) by including most recent data.

Response

a) The figure below contains updated Circuit Breaker Forced Outage Frequency data and includes a comparison to CEA data.

1


Circuit Breaker Forced Outage Frequency (2004-2013)
Number of Outages per Component Year
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
All Hydro One Breakers
All Canada CEA Breakers

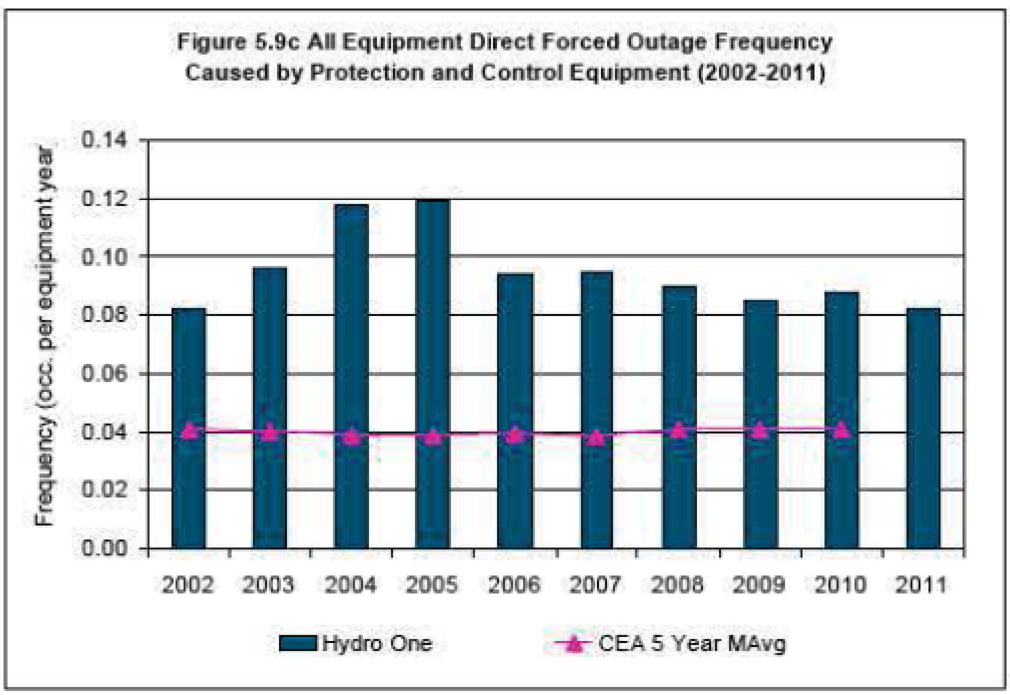
Power Workers' Union (PWU) INTERROGATORY #13

Interrogatory

Ref (a): EB-2012-0031. Exhibit A-13-2, Page 50, Figure 5.9c: All Equipment Direct Forced Outage Frequency Caused by Protection and Control Equipment (2002-2011)

Reliability Performance

Figure 5.9c provides the frequency of forced outages caused by P&C relay failures along with the corresponding average forced outage frequency derived from the Canadian Electricity Association's multi-utility database.



a) Please update Figure 5.9c from Ref (a) by including most recent data.

Response

a) Figure 5.9c from Ref (a) pooled transmission lines and station equipment together to calculate forced outage frequencies caused by protection and control equipment. In current rate filing, this figure was replaced by Figure 20 in Exhibit D1 Tab 2 Schedule 1 on Page 32. In the updated figure, protection and control equipment caused outage frequencies were split into two categories, one for station equipment and one for transmission lines. Station equipment outage frequency has been normalized by number of components. Transmission lines outage frequency has been normalized by number of terminals. Therefore, the station equipment outage frequency and the transmission line outage frequency cannot be added. Due to the change of methodology Figure 5.9c won't be updated.

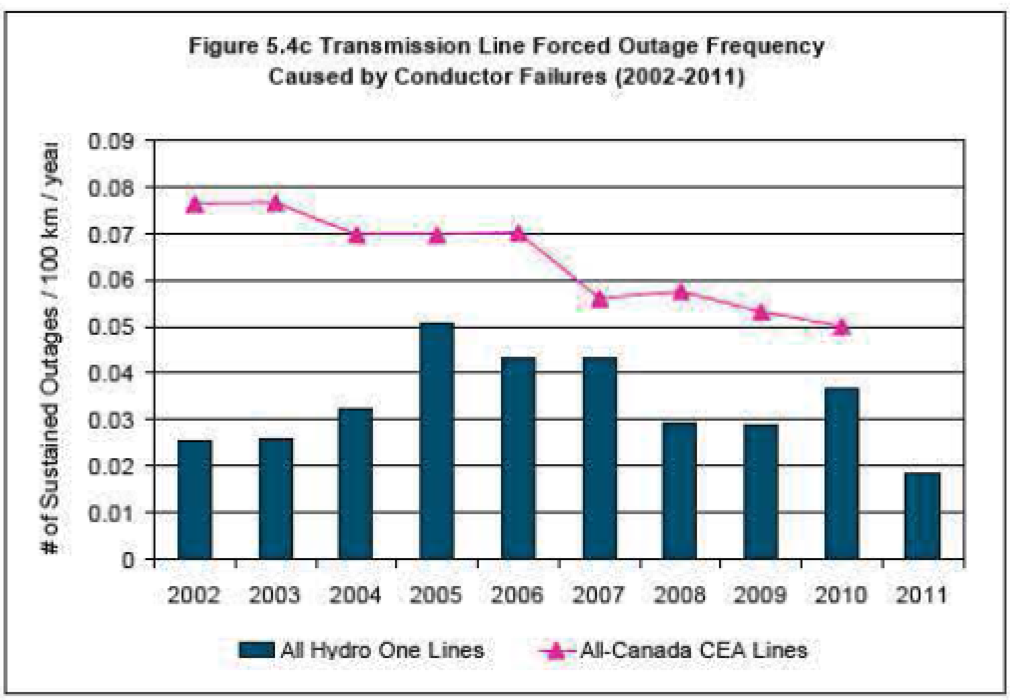
Power Workers' Union (PWU) INTERROGATORY #14

Interrogatory

Ref (a): EB-2012-0031. Exhibit A-13-2, Page 40, Figure 5.4c: Transmission Line forced Outage frequency Caused by Conductor Failures (2002-2011)

Reliability Performance

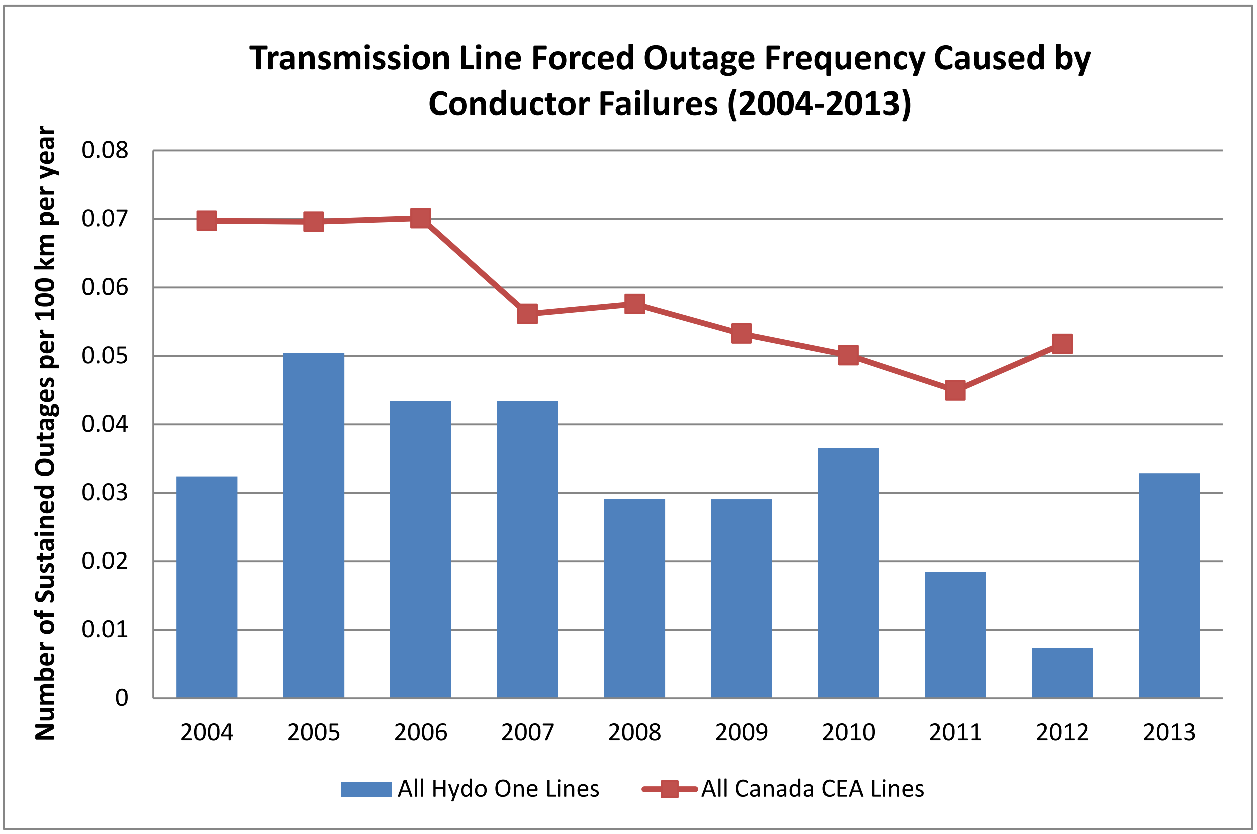
Figure 5.4c illustrates the overhead conductor forced outage frequency (number of sustained failures per 100 km of conductor per year) for the period 2002 to 2011. The corresponding average overhead conductor failure frequency for utilities in the Canadian Electricity Association is also shown for comparison purposes.



a) Please update Figure 5.4c from Ref (a) by including most recent data.

Response

a) Updated Transmission Line Forced Outage Frequency caused by conductor failures (2004-2013) figure is provided below.



Power Workers' Union (PWU) INTERROGATORY #15

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-2-1, Page 47, Figure 30: Demographics of the Wood Pole Fleet.

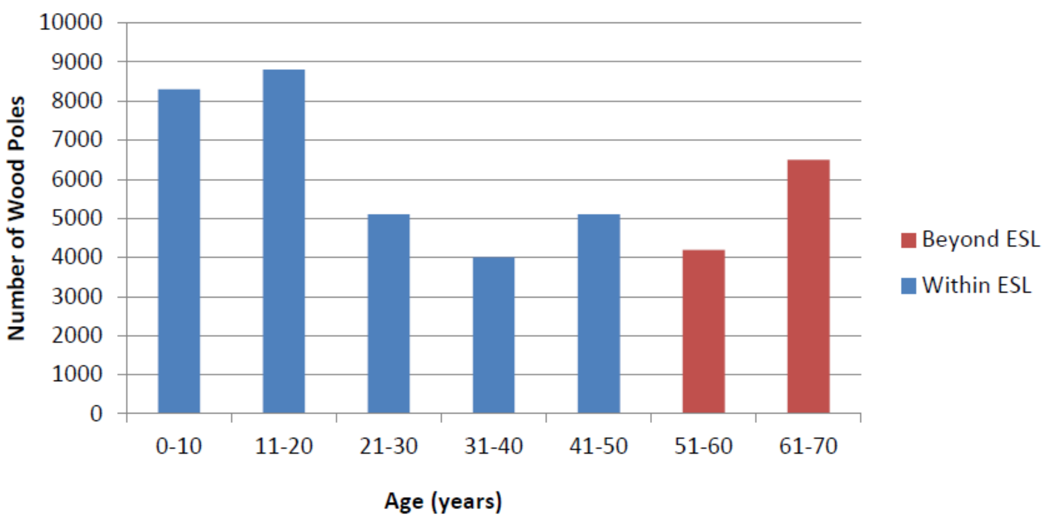


Figure 30: Demographics of the Wood Pole Fleet

a) Please provide a table showing the number and corresponding percentage of wood poles by pole type and age group.

Response

Please see table below for wood pole structure demographics in tabular form by circuit voltage.

		Voltage Class				
		<115 kV	**115 kV**	**230 kV**	**Total**	**%**
Age Group (years)	**1 - 10**	6	6,387	1,884	**8,277**	**20%**
	11 - 20	124	7,044	1,612	**8,780**	**21%**
	21 - 30	133	4,265	692	**5,090**	**12%**
	31 - 40	1	3,167	838	**4,006**	**10%**
	41 - 50	98	3,532	1,440	**5,070**	**12%**
	51 - 60	283	3,521	460	**4,264**	**10%**
	61 - 70	83	5,879	558	**6,520**	**16%**
	Total	**728**	**33,795**	**7,484**	**42,007**	**100%**
	%	**2%**	**80%**	**18%**	**100%**	

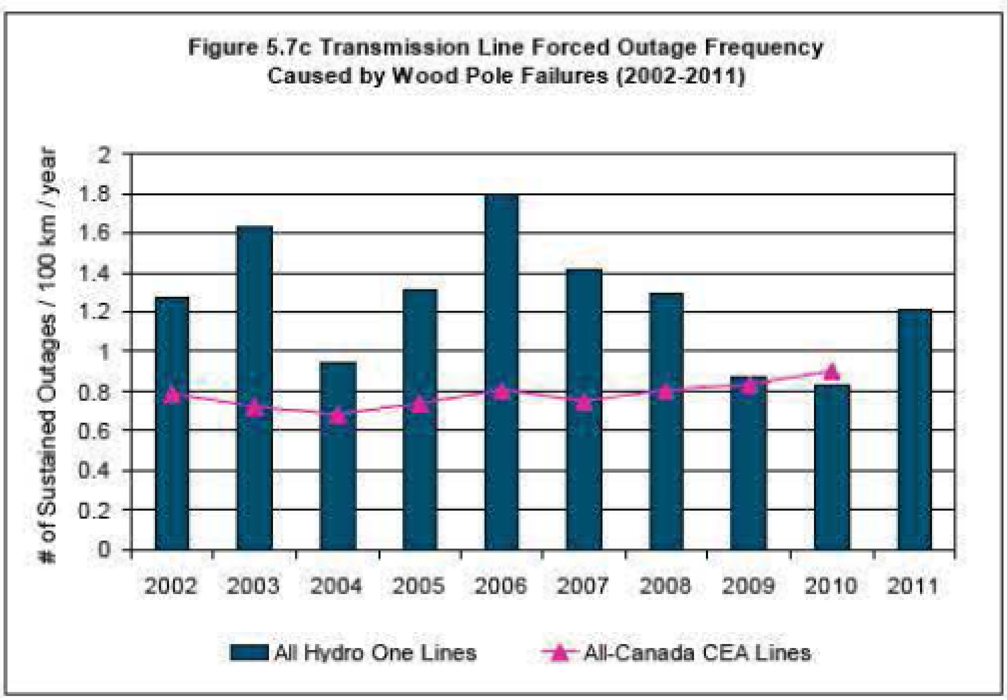
Power Workers' Union (PWU) INTERROGATORY #16

Interrogatory

Ref (a): EB-2012-0031, Exhibit A-13-2, Page 46, Figure 5.7c: Transmission Line Forced Outage Frequency Caused by Wood Pole Failures (2002-2011)

Reliability Performance

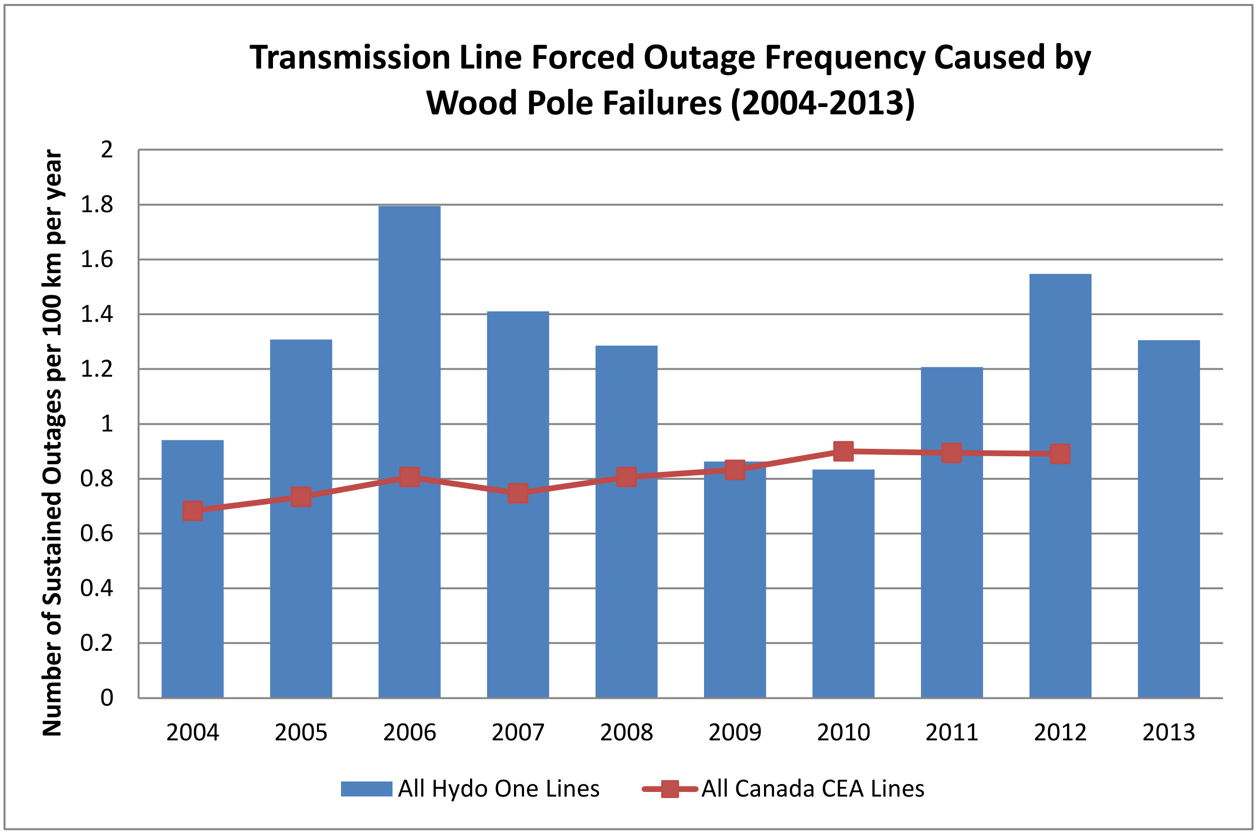
Figure 5.7c shows the annual frequency of forced outages caused by wood pole failures in the transmission system from 2002 to 2011 (number of occurrences per 100 km length of conductor-strung wooden poles). The average forced outage frequency due to wood pole failures in the Canadian Electricity Association's multi-utility database is provided as a comparator.



a) Please update Figure 5.7c from Ref (a) by including most recent data.

Response

a) An updated Transmission Line Forced Outage Frequency Caused by Wood Pole Failure figure is provided.



Power Workers' Union (PWU) INTERROGATORY #17

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-2-1, Page 54, Figure 36: Demographics of Steel Structure Fleet.

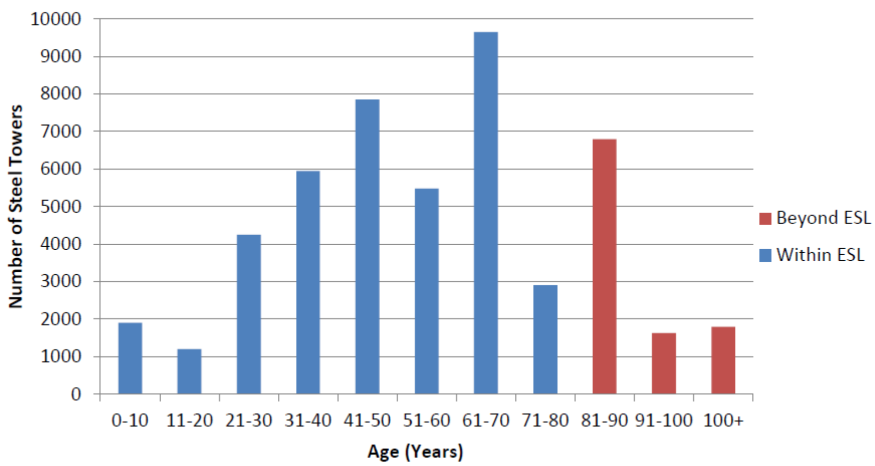


Figure 36: Demographics of Steel Structure Fleet

b) Please provide a table showing the number and corresponding percentage of steel structures by age group and voltage class.

Response

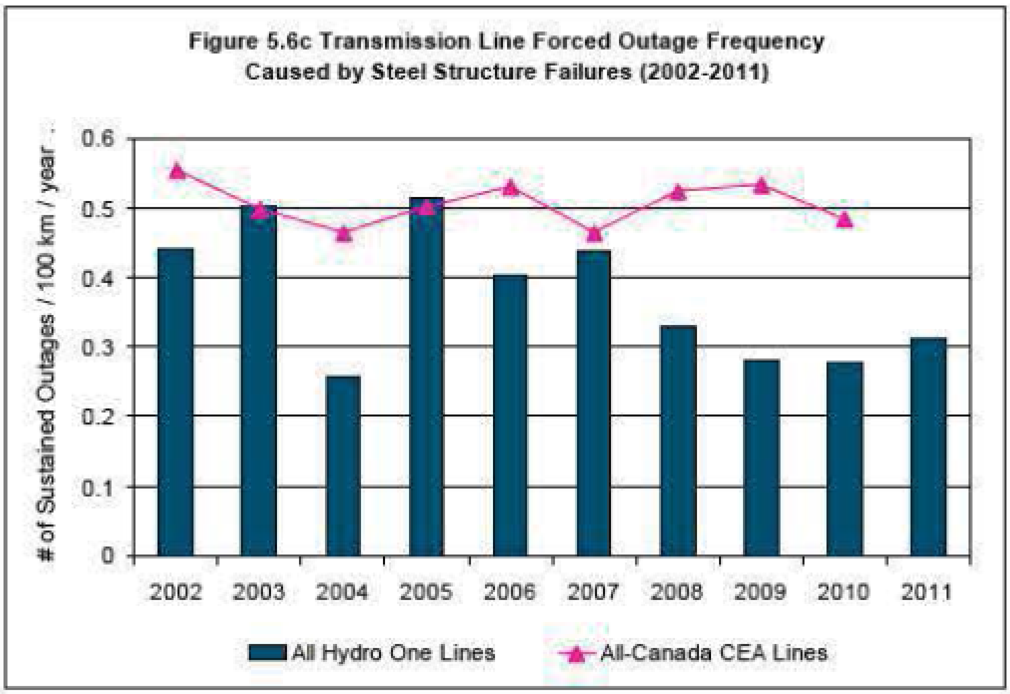
Please see table below for the steel structure demographics in tabular form by voltage class.

		Voltage Class						
		<115 kV	**115 kV**	**230 kV**	**345 kV**	**500 kV**	**Total**	**%**
Age Group (years)	**1 - 10**	0	203	976	0	725	**1,904**	**4%**
	11 - 20	0	417	125	0	712	**1,254**	**3%**
	21 - 30	0	63	1,085	0	3,121	**4,269**	**9%**
	31 - 40	0	64	2,958	3	2,952	**5,977**	**12%**
	41 - 50	0	203	5,641	15	2,024	**7,883**	**16%**
	51 - 60	22	1,551	3,100	0	863	**5,536**	**11%**
	61 - 70	246	3,259	6,259	0	0	**9,764**	**20%**
	71 - 80	109	1,907	963	0	0	**2,979**	**6%**
	81 - 90	0	2,171	4,729	0	0	**6,900**	**14%**
	91 - 100	530	1,154	2	0	0	**1,686**	**3%**
	100+	99	1,733	8	0	0	**1,840**	**4%**
	Total	**1,006**	**12,725**	**25,846**	**18**	**10,397**	**49,992**	**100%**
	%	**2%**	**25%**	**52%**	**0%**	**21%**	**100%**	

Power Workers' Union (PWU) INTERROGATORY #18

Interrogatory

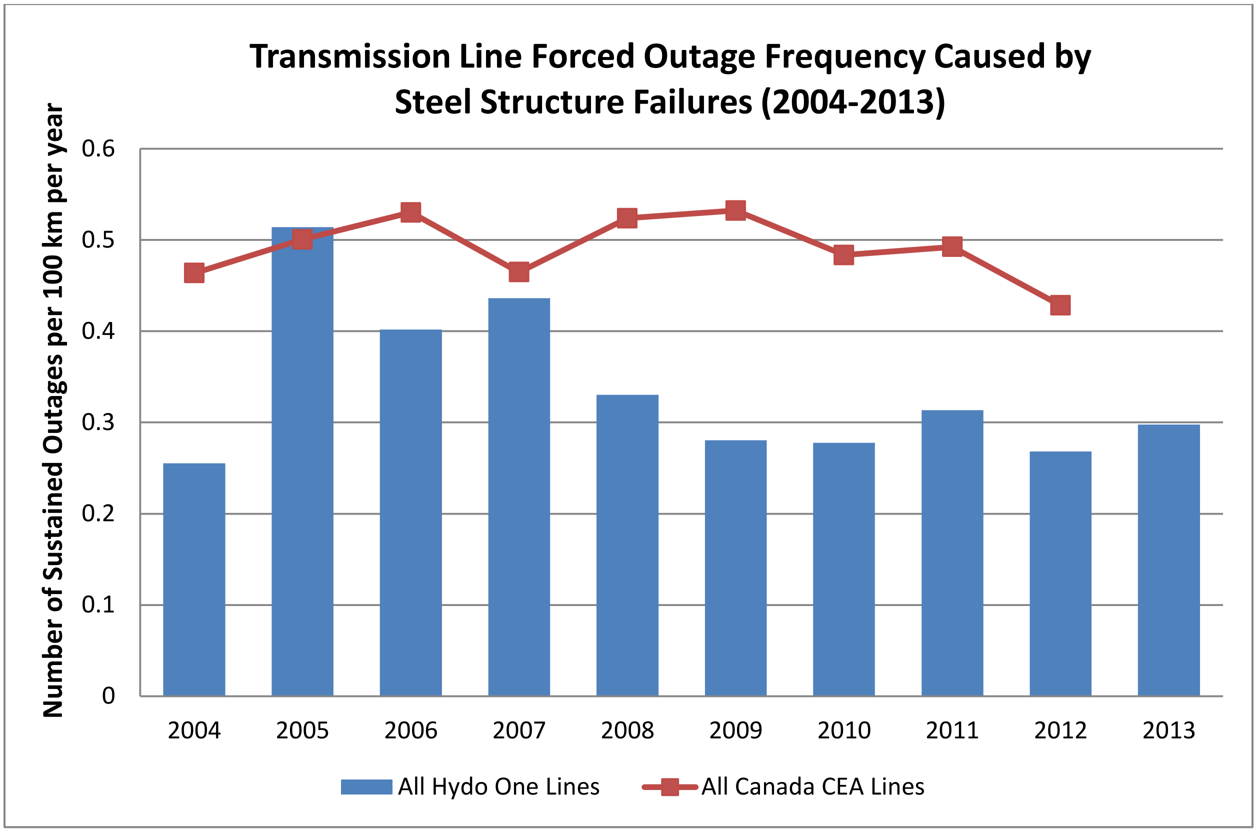
Ref (a): EB-2012-0031, Exhibit A-13-2, Page 44, Figure 5.6c: Transmission Line Forced Outage Frequency Caused by Steel Structure Failures (2002-2011)



a) Please update Figure 5.6c from Ref (a) by including most recent data.

Response

a) An updated Transmission Line Forced Outage Frequency Caused by Steel Structure Failure figure is provided.

1 
Transmission Line Forced Outage Frequency Caused by Steel Structure Failures (2004-2013)
Number of Sustained Outages per 100 km per year
0.6
0.5
0.4
0.3
0.2
0.1
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
All Hydo One Lines
All Canada CEA Lines

Power Workers' Union (PWU) INTERROGATORY #19

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-2-1, Page 62, Figure 42: Demographics of Underground Cables Fleet.

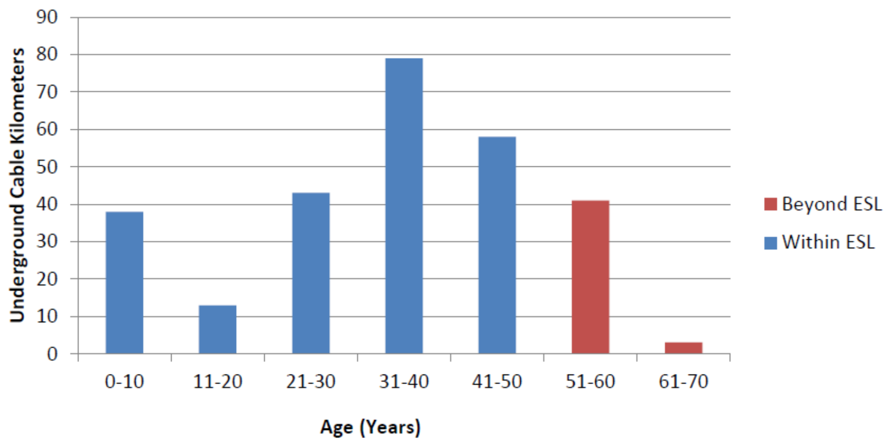


Figure 42: Demographics of Underground Cables Fleet

a) Please provide a table showing the length (km) and corresponding percentage of underground transmission cables by age group and voltage class.

Response

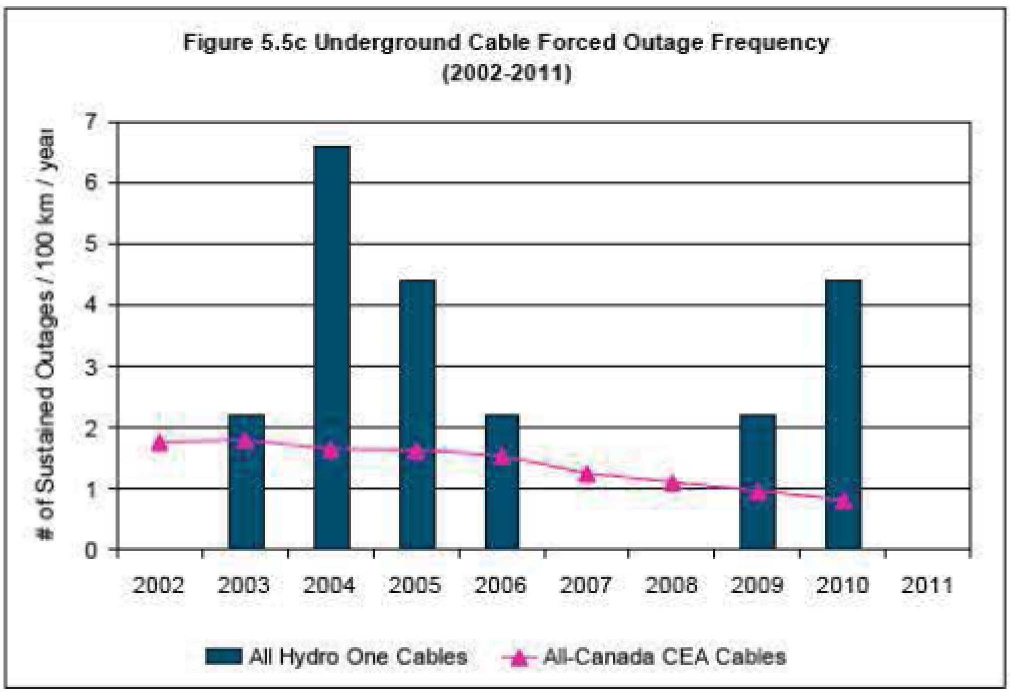
Please see table below for the underground cable demographics in tabular form by voltage class.

		Voltage Class			
		115 kV	**230 kV**	**Total**	**%**
Age Group (years)	**1 - 10**	19	20	**39**	**14%**
	11 - 20	14	0	**14**	**5%**
	21 - 30	29	16	**45**	**16%**
	31 - 40	57	25	**82**	**28%**
	41 - 50	60	0	**60**	**21%**
	51 - 60	44	0	**44**	**15%**
	61 - 70	3	0	**3**	**1%**
	Total	**226**	**61**	**287**	**100%**
	%	**79%**	**21%**	**100%**	

Power Workers' Union (PWU) INTERROGATORY #20

Interrogatory

Ref (a): EB-2012-0031, Exhibit A-13-2, Page 42, Figure 5.5c: Underground Cable Forced Outage Frequency (2002-2011)

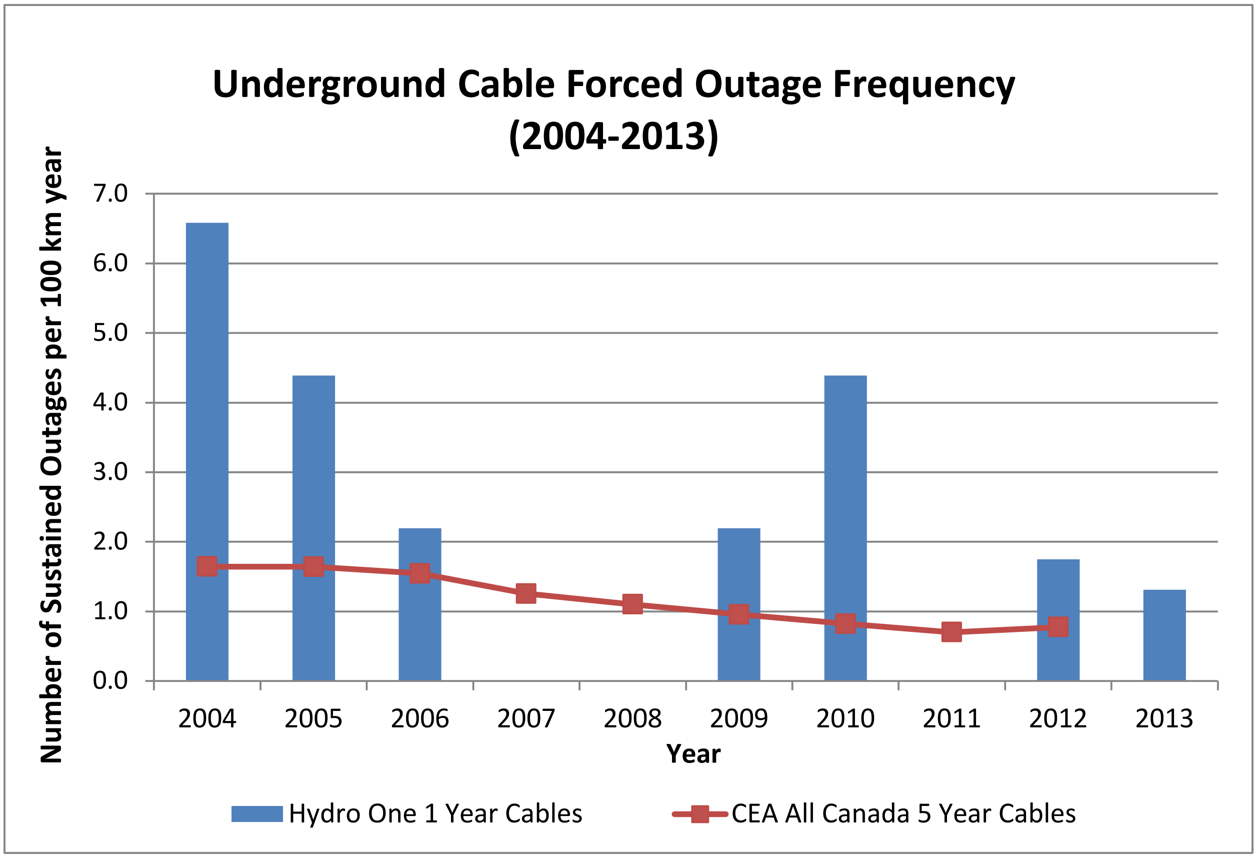


a) Please update Figure 5.5c from Ref (a) by including most recent data.

Response

a) An updated Underground Cable Forced Outage Frequency figure is provided.

1


Underground Cable Forced Outage Frequency
(2004-2013)
Number of Sustained Outages per 100 km year
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Year
Hydro One 1 Year Cables
CEA All Canada 5 Year Cables

Power Workers' Union (PWU) INTERROGATORY #21

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-3-1, Sustaining Capital, Page 3, Lines 4-5.

> **Investment Summary Documents in support of capital projects with cash flows in excess of $3.0 million in either 2015 or 2016 are filed at Exhibit D2, Tab 2, Schedule 3.**

a) The Participant Information Package does not include Exhibit D2, Tab 2, Schedule 3. Please provide that exhibit.

Response

a) Please refer to Exhibit I, Tab 10, Schedule 14.

Power Workers' Union (PWU) INTERROGATORY #22

Interrogatory

Ref (a): Participant Information Package. Exhibit D1-3-3, Development Capital, Page 13 of 36, Lines 25-27:

> **Funding levels for 2015 and 2016 for Inter-Area Network Transfer Capability projects, along with the spending levels for the bridge and historic years are provided in Table 2 of Appendix A to this exhibit.**

a) The Participant Information Package does not include Appendix A. Please provide that exhibit.

Response

a) Please refer to Exhibit I, Tab 10, Schedule 15 (SEC Interrogatory # 15).

Ontario Power Generation (OPG) INTERROGATORY #1

Interrogatory

Reference D1-T3-S2, Pages 5 and 6.
D1-T3-S2, pages 5 and 6 describes the eight categories of Stations Sustaining Capital expenditures (i.e., circuit breakers, station reinvestment, power transformers, other power equipment, ancillary services, station environment, protection control, monitoring and telecommunication, and site facilities and infrastructure). Please provide a table that sets out actual and forecast in-service amounts for these eight categories over the period 2009-2016.

Response

Please see table below for the in-service amounts for each of the eight categories over the 2010 to 2016 period.

Description	**Historic Years** *(Actual)*				**Bridge Year** *(Forecast)*	**Test Years** *(Forecast)*	
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Circuit Breakers	21.6	40.4	5.3	24.3	25.7	17.8	22.2
Station Re-investment	15.2	12.6	28.4	77.4	122.1	189.4	98.3
Power Transformers	72.9	113.1	76.7	66.2	95.3	50.9	67.4
Other Power Equipment	14.0	12.8	24.9	28.8	23.4	23.3	24.6
Ancillary Systems	8.3	7.3	21.7	7.7	25.9	22.3	21.0
Station Environment	4.3	6.0	7.8	0.6	10.3	10.8	10.8
Protection, Control, Monitoring, and Telecommunications	92.4	70.0	78.7	92.2	107.4	111.2	103.6
Site Facilities and Infrastructure	20.1	17.0	24.0	17.2	23.8	20.0	19.2
Total ($M)	**249.0**	**279.2**	**267.5**	**314.4**	**433.9**	**445.7**	**367.1**

Ontario Power Generation (OPG) INTERROGATORY #2

Interrogatory

Reference D1-T3-S2, page 13.
Please provide a copy of Investment Summary Document S02 and S05 referenced in D2-T3-S3.

Response

Please see response to Exhibit I, Tab 10, Schedule 14.

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

Interrogatory

Please provide a table with the results of ROE calculations for HONI's transmission network business for each of the years 2012-2014, compared to Board approved ROE.

Response

Please see Hydro One's reponse to SEC's interrogatory filed at Exhibit I, Tab 10, Schedule 5.

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

Interrogatory

Ref: A-15-2 Table 1

The table shows a forecast average monthly peak in Ontario Demand of 20,595MW and an Average Monthly Network Connection Charge Determinant of 20,457 MW. Does the difference between these two numbers represent Hydro One's share of Ontario demand or is there another cause? Please provide an explanatory and quantitative discussion if the latter is the case.

Response

The difference is not attributed to Hydro One's share of Ontario Demand. Ontario Demand (12-month average peak) forecast of 20,595 MW is a coincident peak measured at the generation level and it includes transmission losses of about 2.5% (515 MW). Ontario Demand also includes load transmitted to other transmitters in Ontario averaging about 554 MW over 12 months measured at the monthly coincident peak time. Hydro One 12-month average coincident peak forecast at the delivery point level is 19,526 MW (20,595 MW - 515 MW – 554 MW). Hydro One Network Connection charge is measured as the higher of the coincident peak during a month and 85% of the non-coincident peak between 7 a.m. and 7 p.m. during weekdays excluding holidays as defined by the IESO and it is greater than Hydro One 12-month coincident peak at the delivery point level by about 931 MW. The forecast of the 12-month average Hydro One Network Connection charge is 20,457 MW (19,526 MW+ 931 MW).

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

Interrogatory

Ref: A-15-2 Section 4.1.2

Preamble: The text of the first few paragraphs of this section appears to attempt justification of Hydro One's weather correction methodology by comparing with other utility practices. This may be useful for illustrative purposes, but does not address the statistical validity of traditional practices in an era of changing climate.

Is Hydro One aware of any studies by other utilities or research organizations in the recent past that have validated the 31 year average for weather correction or suggested any alternative adjustment for climate change effects? If so, please provide such study(s).

Response

Hydro One is not aware of any recent studies publicly released by other utilities or research organizations.

Hydro One conducted a load forecasting methodology survey of North American utilities in September of 2013 and received 31 responses. The results of the 3 questions pertaining to weather normalization are presented below.

1. Have you recently made changes to your methodology for weather normalization?

Response (N=24)	Percentage
Yes (increased number of years used)	0%
Yes (decreased number of years used)	4%
No	96%
Total	100%

2. How many years of historical weather data are used in your weather normalization?

Response (N=30)	Percentage
Less than 20 years	27%
20 years	23%
21 to 29 years	3%
30 years or more	47%
Total	100%

3. Do you consider the impacts of changing climate and/or extreme weather in your weather normalization?

Response (N=30)	**Percentage**
No	83%
Yes	17%
Total	100%

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

Interrogatory

Ref: EB-2012-0031Ex I/Tab 3/Sch 13.02 AMPCO 2

The reference is to an AMPCO interrogatory for Hydro One's previous transmission application. Please provide an updated version of Hydro One's response, for the year's 2012 and 2013.

Response

The requested information is provide below.

Comparison of Average Monthly Transmission Peak Demand Forecast with Actual
(Variance of forecast as percentage of actual)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Actual	Variance for Plan Year	Variance for Second Year	Variance for Third Year
1999	20,776															21,060	-1.35	-3.11	-2.76
2000	20,896	21,407														21,566	-0.74	-0.21	-3.87
2001	21,060	21,612	21,526													21,658	-0.61	-4.36	-1.27
2002		21,857	21,747	21,842												22,737	-3.94	-1.32	-1.08
2003			22,035	22,023	21,999											22,317	-1.42	-0.85	-2.79
2004				22,133	22,185	22,183										22,375	-0.86	-3.02	-2.55
2005					22,431	22,377	22,285									23,074	-3.42	-3.06	-5.67
2006						22,073	21,958	21,727								22,650	-4.08	-6.20	-0.98
2007							21,684	21,563	21,677							22,988	-5.71	-0.95	3.32
2008								21,606	21,613	21,492						21,820	-1.50	2.85	-3.88
2009									21,489	21,391	21,290					20,798	2.37	-4.96	-3.74
2010										20,734	20,503	20,891				21,572	-3.15	-2.62	-3.97
2011											20,376	20,613	20,465			21,168	-3.32	-5.01	-7.72
2012												20,292	20,073	20,339		21,132	-3.75	-5.47	n.a.
2013													19,834	20,319	20,316	21,494	-5.48	n.a.	n.a.
Mean																	-2.46	-2.73	-2.84
One standard deviation (+/-)																	2.61	3.44	3.61

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

<u>Interrogatory</u>

Ref: A-15-Sch 1 Page 6

Ref: C1/3/3/para 2.3.4

The first reference states that all incentive plans have been discontinued. The second reference states that part of the Compensation and Benefits function is to manage the short term management incentive plan. Please address this apparent discrepancy.

<u>Response</u>

a) Exhibit A, Tab 15, Schedule 1, page 6 states "All incentive plans have been discontinued, with the exception of the MCP Short Term Incentive Plan". Exhibit C1, Tab 3, Schedule 3, paragraph 2.3.4 states "The same group also manages the Short Term Incentive for management's compensation". Both references refer to the same Short Term Incentive Plan for management (MCP) staff.

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

Interrogatory

Ref: No documentation provided

Please provide a table or chart illustrating the proportion of total compensation paid out as premium/overtime pay for those employee groups entitled to premium pay when working overtime or outside of regular working hours.

Response

Please see Exhibit I-04 EP-3, Attachment 1.

Note: MCP (non represented staff) do not receive overtime pay. Any dollar amount shown for MCP staff reflects overtime for employees earned while working in a represented position during the year.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #7

Interrogatory

Ref: Slide 21 of Transmission Information Presentation

Has the purchase of 34% of the Bruce-Milton line been reflected in the rate base projections for 2015 and 2016 shown on slide 10 in this information package? If not and if possible, please provide rate base projections post-transaction.

Response

The proposed Bruce to Milton partnership has not yet been completed. Therefore, the Hydro One Transmission Rate Base projections for 2015 and 2016 included in the package sent on June 27 continue to include the project assets contemplated in the Bruce to Milton partnership. Due to the uncertainty of the timing of execution and potential closing adjustments, an exact rate base estimate is not available. However, the Rate Base amount is expected to be in the range of $520 million to $535 million.

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

Interrogatory

Ref: Page 31 of 500 : Capital Development Projects

Supply to Essex County Transmission Reinforcement. Has the OPA or Hydro One reviewed this project justification with respect to timing in light of current data?

Response

Please refer to Hydro One’s Section 92 Application for this projerct, EB-2013-0421 - Supply to Essex County Transmission Reinforcement Project which provides details of the Hydro One and OPA studies showing the need and justification for the project.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #9

Interrogatory

Ref: Ex H1-5-1 Attachment 1 (ETS rate Study)

Please provide the Terms of Reference given by Hydro One to Elenchus for the performance of this study.

Response

The Terms of Reference has been included as Attachment 1 to this interrogatory.

REQUEST to ELENCHUS – ETS Rate Study

1.0 Introduction

In its Decision with Reasons on 2013 Export Transmission Service Rates (EB-2012-0031, Decision and Order, page 10), the Ontario Energy Board ("OEB") directed Hydro One to prepare a cost allocation study involving the network assets utilized by export transmission customers. The OEB directed Hydro One to include a proposal of the appropriate cost based ETS rate, with supporting rationale, to the Board at its next transmission rates application.

Hydro One plans to use the Outline Agreement that is currently in place with Elenchus to engage Elenchus to complete this study.

2.0 Background

In 1999, when Ontario's electricity market opened, the OEB set an ETS rate of $1.00/MWh as a "placeholder" with the acknowledgment that the rate was "not the product of an objective, principled or pragmatic study."

The OEB next considered changes to the ETS rate in 2010 as part of its decision concerning Hydro One's 2011 and 2012 Transmission Rates (EB-2010-0002) and increased the rate to $2.00/MWh. However, the OEB concluded that, "…the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application." The Board directed the IESO to undertake this comprehensive study.

The OEB considered the following alternatives:

- Setting the ETS rate to the equivalent average network charge.
- Eliminating the ETS rate.
- Setting a two-tiered ETS rate.
- Retaining the $2.00 ETS rate.

The OEB found that absent an analysis of cost causality (through a cost allocation study), there is insufficient basis for the OEB to conclude that any change to the ETS rate is just and reasonable. The OEB concluded, therefore, that the rate should remain unchanged.

The OEB requires that Hydro One perform a cost allocation study to establish a cost basis for the ETS rate. Some parties to the EB-2012-0031 proceeding suggested that such a study would be prohibitively costly. However, the OEB accepted the Elenchus testimony that a study could be properly scaled to address the magnitude of the issue and could be completed for a reasonable cost.

The OEB expects that this study will be completed in time for Hydro One's next cost of service transmission rate application. The OEB stated that while Hydro One has the responsibility for completing this study, the Board expects that the IESO will assist Hydro One as required to fully address the ETS rate issue.

3.0 Scope of Work

The work will be divided into two distinct phases: Phase 1: Develop the Study Methodology and Model and Complete the Study, and Phase 2: Regulatory Support of Study. It is expected that Elenchus will provide a preliminary study methodology as part of their response to this request including an estimate of the time and type of support required by Hydro One staff and the IESO to complete this study.

It is expected that Elenchus will provide a fixed price for Phase 1 work. It is expected that any required Phase 2 work will be priced on a time and material basis.

3.1 Phase 1: Develop the Study Methodology and Model and Complete the Study

Phase 1 will include the following key activities:

- Prepare a detailed model to perform a cost allocation study to establish a cost basis for the ETS rate.
- Review detailed model with Hydro One staff.
- Review model with IESO and solicit any comments they may have.
- Elenchus and Hydro One staff work together to gather the information required to populate Elenchus' model.
- Elenchus populates model and completes the study.
- Elenchus prepares a final report that will be filed with the OEB at Hydro One's next Transmission Cost of Service proceeding documenting the work undertaken and conclusions with supporting rationale.

3.2 Phase 2: Regulatory Support of Study

- As required, prepare and deliver presentations at stakeholder sessions for Hydro One Transmission's next Cost of Service Application summarizing the work completed and results of the study.
- As required, defend the study methodology, findings and conclusions within a regulatory proceeding. This could include work associated with all phases of a full hearing, such as: responding to written interrogatories, participating in other discovery processes defined by the OEB (e.g. technical conference), testifying at oral hearing and preparing undertaking responses.

4.0 Deliverables

- A well-documented and populated cost allocation model to establish a cost basis for the ETS rate.

- Make presentations to external stakeholders and refine study methodology as appropriate.
- Prepare a final report documenting the work undertaken and conclusions with supporting rationale.
- Present the study findings to external stakeholders and provide regulatory support to Hydro One's next Transmission Cost-of-Service application.

5.0 Proposed Schedule

- Hydro One issues request to Elenchus: *September 2013*
- Elenchus provides a preliminary study methodology including a fixed price commitment for completing Phase 1 of this engagement: *September 2013*
- Develop detailed study methodology and model: *October to November 2013*
- Gather Data and Populate Model: *November to December 2013*
- Final report: *December 2013*
- Present and defend study: *Hydro One's next Transmission Cost-of-Service Rate Application*

Appendix A: Selected Reference Material

- EB-2012-0031 Hearing Information: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2012-0031&sortd1=rs_dateregistered&rows=200

- Hydro One's 2011 and 2012 Transmission Rates (EB-2010-0002) Hearing Information: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2010-0002&sortd1=rs_dateregistered&rows=200

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

Interrogatory

In the Executive Summary, it is stated that only dedicated assets should be used to allocate costs to the Export Customer Class.

a) Is it Elenchus' view that the export customer class use of the transmission system drives no costs whatsoever when using non-dedicated transmission assets, such as control room costs, energy losses, transformer ageing, etc.?
b) Are there other customer classes that Elenchus believes should be allocated only costs based on their use of dedicated assets, either in distribution or transmission cost allocation?
c) Did Elenchus review methodologies used for establishing ETS rates in other jurisdictions to determine if it was following commonly applied cost allocation principles for this customer class?

Response

a) Elenchus is of the view that the assets that are shared or are used exclusively by domestic customers should not be allocated to interconnections. That is, the associated depreciation, return, etc. costs in Rate Base associated with these assets should not be allocated to export customers.

   The depreciation, return, etc. in Rate Base associated with assets dedicated to interconnections are included in the Elenchus' proposed methodology.

   In the Elenchus' proposed methodology, interconnections are allocated the expenses (OM&A costs included in the revenue requirement) associated with all shared assets in addition to the OM&A expenses associated with the assets dedicated to interconnections.

b) Elenchus did not review how assets are allocated to other customer classes either in distribution or transmission cost allocation. Elenchus is aware that the OEB's Cost Allocation Methodology used by distributors in Ontario includes Sheet 9 "Direct Allocation", that allows distributors to directly allocate assets and/or expenses to customer classes if there are circumstances that meet the criteria of assets and/or expenses being associated with only one customer class and not shared with other customer classes.

c) No.

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

Interrogatory

Previous ETS studies have revealed that neighbouring jurisdictions such as Quebec or New York appear to apply substantially higher ETS rates than are being proposed for Ontario in this report. Please comment on whether the differences are methodological/policy based in nature, or whether the differences are due to significantly different cost drivers in Ontario relative to the other jurisdictions.

Response

Elenchus did not review how ETS rates are established in other jurisdictions.

Elenchus was retained by Hydro One to respond to the OEB's direction in Proceeding EB-2012-0031 of developing: "*... a cost allocation study to establish a cost basis for the ETS rate.*"

School Energy Coalition (SEC) INTERROGATORY #1

Interrogatory

Please indicate what parts of the evidence from HONI's EB-2013-0416 Distribution application is wholly applicable to HONI Transmission request for 2015-2016 rates.

Response

The evidence from the EB-2013-0416 Distribution application is wholly applicable to Hydro One's request for its 2015-2019 distribution rates.

However, the following list of exhibits (in EB-2013-0416) do have components that are related to Hydro One's request for its 2015-2016 Transmission rates:

- Exhibit C1, Tab 2, Schedule 6 – Summary of Common Corporate Costs OM&A
- Exhibit C1, Tab 2, Schedule 8 – Common Corporate Functions and Services and Other OM&A
- Exhibit D1, Tab 3, Schedule 6 – Summary of Common Corporate Costs Capital

There are other exhibits in EB-2013-0416 that contain further breakdown of certain cost components in the above three exhibits. Some of these detailed cost components may also have allocations to Hydro One Transmission.

School Energy Coalition (SEC) INTERROGATORY #2

Interrogatory

Reference: Ex.A-15-1/p.2-4

Please update Tables 2-3 to provide the most recent Global Insight Forecast. What would be the revenue requirement impact of using the most recent Global Insight cost escalation, inflation and exchange rate forecasts?

Response

Please refer to Interrogatory response I-03-01 for updated Global Insight forecasts.

Updating the revenue requirement impact of using the most recent forecasts would be complex and we expect that the change would be immaterial.

School Energy Coalition (SEC) INTERROGATORY #3

Interrogatory

Reference: Ex.A-16-8/p.3

Please revise Table 1 to include 2010-2013 Board-approved information.

Response

Please see the response to CME's interrogatory 6 part a, at Exhibit I, Tab 2, Schedule 6, for the requested information.

School Energy Coalition (SEC) INTERROGATORY #4

Interrogatory

Reference: [Ex.A-18-1/p.4]

Please provide the transmission version of IR response VECC No. 42 (EB-2013-0416, Ex. I, Tab 2.03, Schedule 6 VECC 42).

Response

Please refer to the table below showing Tx productivity savings.

Transmission Productivity Initiatives 2013-2016

Initiative Name	LOB	Category	OMA	CAP	Sus	Dev	Oper	Cus	Com	Tx 2013 Actual	Tx 2014 Forecast	Tx 2015 Forecast	Tx 2016 Forecast
E3 - Eng Design	Engineering & Construction	Business Transformations	0%	100%					100%	0	300,000	877,200	894,744
Air Stair Increased Usage	Engineering & Construction	Leveraging Technology	0%	100%	100%					0	97,240	100,000	0
Form Jacks for Tower Footings	Engineering & Construction	Leveraging Technology	0%	100%		100%				43,500	381,000	388,620	396,392
Vibro Hammer for tower footings	Engineering & Construction	Leveraging Technology	0%	100%		100%				0	50,000	81,600	52,020
Reduced Unit Cost - Structure Replacement	Engineering & Construction	Process Improvement	0%	100%	100%					939,250	1,905,892	1,821,932	1,821,932
Camera Cable Vault Inspections	Stations Services	Leveraging Technology	100%	0%	100%					33,537	170,000	173,400	176,868
AIP - Asset Investment Planning	Planning and Operating	Business Transformations	100%	0%					100%	213,504	216,840	222,511	228,218
Regular Head Count Reduction	Corporate	Centralized Operations	100%	0%					100%	6,078,018	6,078,018	6,381,056	6,508,677
Admin Spend Controls	Corporate	Miscellaneous Admin	100%	0%					100%	6,410,733	6,549,733	6,688,733	6,827,733
Initial Training: union pays for basic	Engineering & Construction	Staff Flexibility	100%	0%	63%	35%	2%	0%	0%	188,851	159,550	162,510	166,589
Outsourcing Drawing Backlog	Engineering & Construction	Staff Flexibility	100%	0%	63%	35%	2%	0%	0%	792,689	147,340	147,340	147,340
Electrical Safety Awareness available online	Health, Safety & Environment	Centralized Operations	100%	0%					100%	0	83,400	85,068	86,769
Make Spills Management training available via E Learning	Health, Safety & Environment	Centralized Operations	100%	0%					100%	48,122	49,084	50,066	51,067
Workflow of the Future	ISD	Business Transformations	100%	0%					100%	0	0	0	1,653,989
Cell Contracts	ISD	Telephony	100%	0%					100%	915,322	1,187,085	1,428,970	1,525,724
Telecom Expense Management (TEM)	ISD/AM	Telephony	100%	0%					100%	333,028	696,432	908,239	1,112,000
Process Improvements & BPC	Shared Services	Business Transformations	100%	0%					100%	266,880	266,880	272,218	277,662
HR Pay Project	Shared Services	Business Transformations	100%	0%					100%	0	387,300	1,515,515	1,545,825
Vendor Rebates	Shared Services	Centralized Operations	100%	0%	73%	23%	2%	2%		75,616	111,200	111,200	111,200
Facilities Energy Efficiency Retrofits	Shared Services	Leveraging Technology	100%	0%	100%					14,176	13,900	13,900	13,900
Employee Travel Policy	Shared Services	Leveraging Technology	100%	0%					100%	31,603	30,580	0	0
Project Trailer Purchase	Shared Services	Process Improvement	100%	0%					100%	0	88,960	88,960	88,960
Manage Stations Work for Facilities	Shared Services	Staff Flexibility	100%	0%	100%					2,176,740	2,176,740	0	0
Fleet Mechanic Reduction	Shared Services	Staff Flexibility	100%	0%	73%	23%	2%	2%		558,224	834,000	834,000	834,000
Work Program Optimization (TSOGs)	Stations Services	Leveraging Technology	100%	0%	96%	1%	3%	0%		0	1,219,651	1,209,048	1,795,297
SMNO - Smart Meter Network Operating	Stations Services	Leveraging Technology	100%	0%	95%	0%	4%	0%		0	0	0	277,662
Maintain Stock of Regularly Used Items	Stations Services	Process Improvement	100%	0%	95%	0%	4%	0%		142,102	194,600	198,492	202,462
TWHQ - Stations	Stations Services	Staff Flexibility	100%	0%	95%	0%	4%	0%		1,193,195	222,400	226,848	231,385
Inhouse Retorques on Light Vehicles	Stations Services	Staff Flexibility	100%	0%	95%	0%	4%	0%		52,453	50,040	50,040	50,040
Cornerstone Ph1, 2	Corporate	Business Systems	42%	58%					100%	27,490,411	28,098,563	28,267,122	28,439,052
Standards Development for Design	Engineering & Construction	Leveraging Technology	0%	100%	63%	35%	2%	0%	0%	105,750	105,750	105,750	105,750
Smart MFA spend	Engineering & Construction	Process Improvement	0%	100%	63%	35%	2%	0%	0%	65,208	88,188	88,188	88,188
AA	Planning and Operating	Business Transformations	44%	56%					100%	0	1,877,255	2,791,752	2,916,569
Facilities & Real Estate Outsourcing	Shared Services	Staff Flexibility	100%	0%					100%	0	0	2,400,000	2,400,000
Inergi Contract Extension	Shared Services	Back Office	100%	0%					100%	6,396,000	8,294,000	0	0
Contract Replacement	Shared Services	Back Office	100%	0%					100%	0	0	9,516,000	9,516,000
Total										54,564,912	62,131,621	67,206,277	70,544,014

School Energy Coalition (SEC) INTERROGATORY #5

Interrogatory

Reference: Ex.B1

Please provide the actual regulated ROE for 2010-2014.

Response

The actual regulated ROE for the years 2010 to 2013, found in the table below, have been calculated using the revised template for reporting regulatory return (ROE) under the Reporting & Record Keeping Requirements for Electricity issued by the Board on March 14, 2014. The actual results for 2014 are not available before December 31, 2014.

Year	Actual Regulated ROE
2010	11.5%
2011	10.9%
2012	12.4%
2013	13.2%

School Energy Coalition (SEC) INTERROGATORY #6

Interrogatory

Reference: Ex.C1-2-1-/p.5

Why was the reduction due to 'Cornerstone savings' not forecasted in HONI's EB-2012-0031 application?

Response

The expected reduction in 2013 due to "Cornerstone savings" was included in Hydro One's EB-2012-0031 application.

The actual savings due to Cornerstone in 2013 were higher than the forecasted figures used in EB-2012-0031.

The revised Cornerstone savings (slightly higher, which are based on the latest available information) have been incorporated in Hydro One's proposed 2015/16 Transmission Rate Application.

School Energy Coalition (SEC) INTERROGATORY #7

Interrogatory

[Ex.C1-3-3/p.1] Please revise Table 1 to show the Tx allocation for each year between 2010-2016.

Response

Please refer to the tables below:

Tables 1(a), 2(a), 3(a) and 4(a) of this response include the allocation of actuals for the period 2010-2013 between the Transmission and Distribution businesses. The allocation to, and recoveries from, affiliates for the same period are reflected in Tables 1(b), 2(b), 3(b) and 4(b). These amounts are incorporated as part of Common Corporate Costs and Other OM&A (see Exhibit C1, Tab 3, Schedule 3).

Table 5 provides an allocation for 2014 in a manner similar to how the allocations for the test years were created.

The test year allocations are provided in Exhibit C1, Tab 6, Schedule 1, Page 3, Tables 1 and 2.

Table 1(a) - 2010 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution
Corporate Management	5.0	2.9	2.1
Finance	31.4	18.1	13.3
Human Resources	16.4	9.5	7.0
Corporate Communications & Services	9.6	5.6	4.1
General Counsel & Secretariat	7.5	4.3	3.2
Regulatory Affairs	21.3	9.8	11.5
Corporate Security	2.4	1.4	1.0
Internal Audit	2.8	1.6	1.2
Real Estate & Facilities	49.9	23.5	26.3
Total CCF&S Costs	**146.3**	**76.7**	**69.7**

Table 1(b) - 2010 Allocation and Recoveries from Affiliates ($ Millions)

Description	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	0.1	0.1	0.0	0.1
Finance	0.8	0.3	0.3	0.0
Human Resources	0.2	0.0	0.1	0.0
Corporate Communications & Services	0.0	0.0	0.1	0.0
General Counsel & Secretariat	0.1	0.2	0.2	0.1
Regulatory Affairs	0.0	0.0	0.1	0.0
Corporate Security	0.0	0.0	0.0	0.0
Internal Audit	0.0	0.1	0.1	0.0
Real Estate & Facilities	0.0	0.0	0.0	0.0
Total CCF&S Costs	**1.2**	**0.7**	**0.9**	**0.2**

Table 2(a) - 2011 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution
Corporate Management	5.1	2.2	2.9
Finance	31.9	17.6	14.2
Human Resources	11.0	6.6	4.4
Corporate Communications & Services	8.7	3.8	4.9
General Counsel & Secretariat	7.4	4.2	3.2
Regulatory Affairs	20.1	8.9	11.3
Corporate Security	3.0	1.5	1.5
Internal Audit	3.1	2.0	1.1
Real Estate & Facilities	51.6	26.7	25.0
Total CCF&S Costs	**141.9**	**73.5**	**68.5**

Table 2(b) - 2011 Allocation and Recoveries from Affiliates ($ Millions)

Description	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	0.1	0.1	0.0	0.1
Finance	0.6	0.2	0.3	0.0
Human Resources	0.2	0.0	0.1	0.0
Corporate Communications & Services	0.0	0.0	0.1	0.0
General Counsel & Secretariat	0.1	0.2	0.2	0.1
Regulatory Affairs	0.0	0.0	0.1	0.0
Corporate Security	0.0	0.0	0.0	0.0
Internal Audit	0.1	0.2	0.1	0.0
Real Estate & Facilities	0.0	0.0	0.0	0.0
Total CCF&S Costs	**1.1**	**0.7**	**0.9**	**0.2**

Table 3(a) - 2012 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution
Corporate Management	5.0	2.5	2.4
Finance	35.2	20.7	14.5
Human Resources	9.9	6.0	4.0
Corporate Communications & Services	11.3	5.3	6.0
General Counsel & Secretariat	8.8	4.9	3.8
Regulatory Affairs	20.6	9.0	11.6
Corporate Security	3.1	1.5	1.6
Internal Audit	3.5	2.3	1.2
Real Estate & Facilities	54.6	28.3	26.3
Total CCF&S Costs	**152.0**	**80.5**	**71.4**

Table 3(b) - 2012 Allocation and Recoveries from Affiliates ($ Millions)

Description	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	0.1	0.1	0.0	0.1
Finance	0.5	0.2	0.2	0.1
Human Resources	0.2	0.0	0.1	0.0
Corporate Communications & Services	0.0	0.0	0.1	0.0
General Counsel & Secretariat	0.1	0.2	0.2	0.1
Regulatory Affairs	0.0	0.0	0.1	0.0
Corporate Security	0.0	0.0	0.0	0.0
Internal Audit	0.1	0.2	0.1	0.0
Real Estate & Facilities	0.0	0.0	0.0	0.0
Total CCF&S Costs	**1.0**	**0.7**	**0.8**	**0.3**

Table 4(a) - 2013 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution
Corporate Management	4.9	2.1	2.8
Finance	41.9	25.1	16.9
Human Resources	11.1	6.5	4.6
Corporate Communications & Services	15.0	6.5	8.5
General Counsel & Secretariat	9.6	5.4	4.1
Regulatory Affairs	20.6	10.3	10.3
Corporate Security	3.4	1.6	1.8
Internal Audit	3.4	2.1	1.3
Real Estate & Facilities	54.1	28.0	26.0
Total CCF&S Costs	**164.0**	**87.6**	**76.3**

Table 4(b) - 2013 Allocation and Recoveries from Affiliates ($ Millions)

Description	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	0.1	0.1	0.0	0.1
Finance	0.6	0.2	0.2	0.1
Human Resources	0.2	0.0	0.1	0.0
Corporate Communications & Services	0.0	0.0	0.0	0.0
General Counsel & Secretariat	0.1	0.2	0.2	0.1
Regulatory Affairs	0.0	0.0	0.1	0.0
Corporate Security	0.0	0.0	0.0	0.0
Internal Audit	0.1	0.0	0.0	0.0
Real Estate & Facilities	0.0	0.0	0.0	0.0
Total CCF&S Costs	**1.1**	**0.5**	**0.6**	**0.3**

Table 5 - 2014 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.3	2.7	2.4	0.1	0.1	0.0	0.1
Finance	45.0	25.5	18.2	0.8	0.2	0.3	0.0
Human Resources	13.1	7.0	5.8	0.2	0.0	0.1	0.0
Corporate Communications & Services	13.9	6.6	7.2	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.1	5.4	4.1	0.1	0.2	0.3	0.1
Regulatory Affairs	24.1	10.3	13.6	0.0	0.0	0.1	0.2
Corporate Security	4.8	2.2	2.5	0.0	0.0	0.0	0.0
Internal Audit	3.6	2.4	1.1	0.0	0.0	0.0	0.0
Real Estate & Facilities	60.2	36.0	24.3	0.0	0.0	0.0	0.0
Total CCF&S Costs	**180.1**	**98.1**	**79.2**	**1.2**	**0.5**	**0.9**	**0.4**

School Energy Coalition (SEC) INTERROGATORY #8

Interrogatory

[Ex.C1-6-2/p.1] Please provide a copy of the Black & Veatch report reviewing and updating HONI's overhead methodology.

Response

Please see Attachment 1 for the report requested.

REVIEW OF OVERHEAD CAPITALIZATION RATES (TRANSMISSION)– 2015-2016

PREPARED FOR

Hydro One Networks Inc.

17 MARCH 2014

BLACK & VEATCH
Building a world of difference.

Table of Contents

List of Appendices

I. Overview

A. INTRODUCTION

Black & Veatch ("B&V" or "we") is pleased to provide this Report to Hydro One on our *Review of Overhead Capitalization Rates (Transmission)– 2015-2016*. The Overhead Capitalization Rates ("OH Cap Rates") developed by Hydro One are percentages that are applied to the cost of Transmission and Distribution capital expenditures; the results are the amounts of Common Corporate Costs that are capitalized to those capital expenditures for the year.

The methodology was developed for Hydro One by B&V, first presented in our report *Distribution Overhead Capitalization Rate Method* report dated May 20, 2005 and accepted by the Ontario Energy Board ("OEB").

The OEB-accepted methodology for development of the OH Cap Rates has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW / ASSET VALUES	HYDRO ONE FILING	B&V REPORT
2006 Review	2006 Transmission Rates	*Transmission Overhead Capitalization Rate Method* dated April 30, 2006
2008 Review	2008 Transmission Rates	*Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010* dated September 10, 2008
2009 Review (Distribution)	2010/2011 Distribution Rates	*Review of Overhead Capitalization Rates* dated June 29, 2009
2009 Review (Transmission)	2011/2012 Transmission Rates	*Review of Overhead Capitalization Rates (Transmission) – 2011/2012* dated February 26, 2010
2011 Review (Transmission)	2013/2014 Transmission Rates	*Review of Overhead Capitalization Rates (Transmission)– 2013-2014* dated February 1, 2012
2013 Review (Distribution)	2015-2019 Distribution Rates	*Review of Overhead Capitalization Rates (Distribution)– 2015-2019* dated September 19, 2013

Hydro One computed the **Transmission OH Cap Rate to be 14% for 2015 and 15% for 2016** (*Appendix A, row 90*). The calculation of the rates is described in Section II of this report and shown in Appendix A.

Based on the work we performed, B&V believes that Hydro One's implementation of the Overhead Capitalization Rate methodology and computation of the Transmission OH Cap Rates for 2015-2016 are appropriate and conform to the OEB-accepted methodology.

B. BACKGROUND

Hydro One's capital spending program is a major focus for the utility in terms of time and cost. Transmission Capital spending is budgeted to be approximately $880M annually in 2015-2016, each year representing approximately 9% of Transmission Net utility plant.

Most of Hydro One's capital program is performed by Hydro One employees, and not contracted out. Hydro One's capital program requires significant support from all areas of the utility, including engineering, management, administration and infrastructure resources. These resources support Transmission Operations and Maintenance ("Tx OMA") and Transmission Capital Expenditures work.

C. CRITERIA FOR COST ALLOCATION METHODS

The portion of Common Corporate Costs attributed to Transmission was determined based on the OEB-accepted methodology, as described in the B&V's *Review of Allocation of Common Corporate Costs (Transmission)*- 2014 dated March 17, 2014**.** The Transmission OH Cap Rate is used to distribute the Transmission portion of Common Corporate Costs, between Transmission OMA and Transmission Capital Expenditures. Following are the criteria that B&V used in selecting and evaluating methods to develop the OH Cap Rates methodology:

- The method should be based on *cost causation*. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the costs that has been incurred.
- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is *benefits received* (i.e., allocated to the business that received the benefits).
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- If the method uses estimates, results should be unbiased and reasonably consistent with the results that would be obtained from using actual data.

D. DESCRIPTION OF OH CAP RATE METHOD

Ideally, the amount of Common Corporate Costs to be capitalized would be based entirely on time studies for labor costs, and additional analyses for other costs, for each activity include in Common Corporate Costs.

Approximately $115 million of labour costs (for the departments in the study), representing approximately 28% of the annual total Common Corporate Costs (and approximately 50% of annual labour costs), were directly assigned between OMA and capital based on a time study performed for the four-weeks ending May 31, 2013 ("2013 Time Study"). The 2013 Time Study included the following departments in the Operations group: Distribution Business Development; Transmission Projects Development; Asset Strategy; Network Operations; Transmission Asset Management; and SVP Planning & Operating; and the following departments in the Customer Service group: Customer Care Services; Strategy and Conservation; Distributed Generation; Customer Business Relations; TxDx Settlements; Account Management Director; Advanced Distribution; Pricing; VP Customer Service; SVP Customer Operations.

A properly performed time study measures cost causation, and is widely accepted as a basis for allocating costs. B&V participated in the design, administration and supervision of the 2013 Time Study. The methodology was the same as for prior time studies conducted by B&V for Hydro One. B&V found that the 2013 Time Study was properly conducted, and therefore is a proper basis to determine the portion of the costs of the participating departments to be capitalized to Transmission capital expenditures.

While the remaining Common Corporate Costs departments can determine with reasonable accuracy the portions of time spent on Transmission, Distribution and the other business units, they are unable to determine with reasonable accuracy the time spent on OMA versus capital projects. Therefore, the amount of costs to be capitalized must be computed using allocators based on cost causation or benefits received.

In traditional utility cost allocation studies, administrative and general costs are allocated based on one or more factors such as Labor costs, OMA, Investment in Plant or a weighted combination of two or more. B&V considered the following two bases for allocating Common Corporate Costs costs between OMA and capital projects:

- **Labor Content Method-** Labor Content of Transmission (Tx) OMA versus Tx capital expenditures
- **Total Spending Method-** Total Spending on Tx OMA versus Tx capital expenditures

The Common Corporate Costs to be allocated are causally related to both Labor content and Total spending. Therefore the OH Cap Rate method for Common Corporate Costs recommended by B&V uses a weighting of 50% Labor Content and 50% Total Spending, as there is no evidence that either the Labor Content method or the Total Spending method is meaningfully more appropriate.

- The formula for Transmission (Tx) Labor Content is:

Tx Labor Content = Tx Labor $ in Tx Capital Expenditures / (Labor $ in Tx Capital Expenditures + Labor $ in Tx OMA)

- The formula for Tx Total Spending is:

Tx Total Spending = Tx Capital Expenditures / (Tx Capital Expenditures + Tx OMA)

The table below shows the results of the computations for 2015-2016.

PORTION OF COMMON CORPORATE COSTS SERVICES CAPITALIZED- TRANSMISSION	2015	2016
Labor Content- Capital	60.5%	59.9%
Total Spending- Capital	70.5%	68.9%
50/50 Average	65.5%	64.4%

Sensitivity Analysis

As a sensitivity analysis, B&V analyzed two sensitivity cases- the highest Labor Content weight considered (75%) and the lowest Labor Content weight considered (25%). The results, shown below, indicate the total OH Cap Rates would not change materially.

CASES	LABOR CONTENT / TOTAL SPENDING	TRANSMISSION-2015		TRANSMISSION-2016	
		% costs Capitalized	2015 OH Cap Rate	% costs Capitalized	2016 OH Cap Rate
Recommended	50%/50%	65.5%	14.3%	64.4%	14.8%
High Labor Case	75%/25%	63.0%	13.6%	62.1%	14.4%
Low Labor Case	25%/75%	68.0%	14.7%	66.7%	15.2%

Note- In all cases Tx Labor Content-Capital and Tx Total Spending-Capital were the ratios in the table above.

B&V also considered the following:

1. The same rate is applied to capitalized assets regardless of their actual usage of Common Corporate Costs services. For example, a transformer that is purchased for use in a capital project from a pre-approved vendor requires very little of these services, but receives the same rate of overhead capitalization as a project requiring substantial support. In applying the OH Cap Rates, there will be differences compared to performing a specific analysis for each project. However, the B&V method is appropriate because:

- B&V's recommended Labor / Total Content method correctly computes the total Common Corporate Costs dollars to be capitalized, and the amount charged to specific expenditures has virtually no effect on the financial statements or on ratepayers.
- Most assets purchased for stand-alone use are Minor Fixed Assets and the OH Cap Rates are computed without them, and not applied to them. Other assets (i.e., non- Minor Fixed Assets) are usually parts of larger projects, therefore the use of average OH Cap Rates is appropriate, because larger expenditures are more likely to have an average usage of Shared Services.
- It is impractical to perform an analysis for each project.

2. The OH Cap Rates are developed based on the weighted Labor Content and Total Spending, but are applied to Total Capital Cost.

It is appropriate to compute the total costs to be capitalized based on the weighted Labor Content / Total Spending. Once the amount to be capitalized is computed, it can be applied based on either Total Cost or Labor Content. B&V recommends stating the capitalization rate based on Total cost, and applying it to Total cost dollars, as Hydro One has done, because it is easier to plan and implement based on Total cost than Labor content.

B&V believes that allocating Common Corporate Costs to capital expenditures based on 50% Labor Content / 50% Total Spending is the most appropriate method for Hydro One, and is consistent with industry practice and with the nature of the costs being capitalized.

E. USE OF BUDGETED NUMBERS

The OH Cap Rates are developed based on Business Plan numbers and other estimates. Hydro One reviews and adjusts the OH Cap Rates quarterly to reflect changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up (in-year) to reflect actual results. Therefore, no adjustment is needed in subsequent years.

II. Computation of Transmission OH Cap Rate

This Section presents, as an example, the computation of the Transmission OH Cap Rate for 2015. The calculation of the rate uses the same method for all years in BP 2015-2019.

A. FORMULA

The following formula is used to compute the 2015-2016 Transmission OH Cap Rates:

a. *Transmission OH Cap Rate*= (Capitalized Transmission CCC-A&G Costs + Capitalized Transmission CCC-Operating Costs) / Transmission Capital Expenditures

Note: A&G = Administrative & General

Where

b. *Capitalized Transmission CCC-A&G Costs* = Transmission CCC-A&G Costs capitalized = (Transmission Labor Content Ratio X 50% + Transmission Total Spending Ratio X 50%) X Transmission CCC-A&G Costs

c. *Transmission CCC-A&G Costs* = Total Transmission CCC Costs less Transmission CCC-Operating Costs departments

d. *Capitalized Transmission CCC-Operating Costs* = Transmission CCC-Operating Costs capitalized, based on the results of the 2013 Time Study

e. *Transmission CCC-Operating Costs* = The budgets for the following departments, included in the 2013 Time Study:

- Asset Development and Management, comprising the following departments in the Operations group: Distribution Business Development; Transmission Projects Development; Asset Strategy; Transmission Asset Management; and SVP Planning & Operating, plus
- Network Operating department (part of the Operations group), plus
- Customer Care, comprising the following departments in the Customer Care group: Care Services; Strategy and Conservation; Distributed Generation; Customer Business Relations; TxDx Settlements; Account Management Director; Advanced Distribution; Pricing; VP Customer Service; SVP Customer Operations.

f. *Transmission Capital* = Cost of Transmission capital expenditures supported by Common Corporate Costs (i.e., CCC-A&G Costs plus CCC-Operating Costs); also, total cost of Transmission capital expenditures to which the Transmission OH Cap Rate is applied

g. *Transmission Labor Content Ratio* = Transmission Labor $ in Transmission Capital Expenditures / (Labor $ in Transmission Capital Expenditures + Labor $ in Transmission OMA)

h. *Transmission Total Spending Ratio* = Transmission Capital Expenditures / (Transmission Capital Expenditures + Transmission OMA)

These terms are further discussed below.

B. RECOMMENDED METHOD

This section discusses the method recommended by B&V to compute the Transmission OH Cap Rate. References below are to Appendix A, and the amounts and percentages cited are for 2015. The calculations use projected data. Because the methodology includes a true-up at the end of the year (Section I.E), the amounts recorded by Hydro One reflect actual data.

1. TRANSMISSION CAPITAL

(Appendix A, rows 1-8)

Transmission Capital (Formula f in Section II.A) represents the cost of Transmission business Capital Expenditures that are supported by Transmission business CCC activities (CCC-A&G activities and CCC-Operating activities), and is the total cost of Transmission business Capital Expenditures to which the Transmission OH Cap Rate is applied. Transmission Capital equals total spending for Transmission Capital Expenditures reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little CCC-A&G or CCC-Operating support.
- Capitalized Overhead is removed to avoid redundancy.
- Capital Contributions by Customers are added because the CCC-A&G and CCC-Operating effort required is related to gross capital cost, not net capital cost.
- Removal Costs are added because removal of capital assets requires support from CCC-A&G and CCC-Operating.

2. TRANSMISSION SPENDING FOR OMA

(Appendix A, rows 10-16)

Transmission Spending for OMA is used in computing the portion of Total Spending (capital plus OMA) related to capital (rows 42-46). The amounts are based on the BP 2015-2019, with adjustments to remove those costs which are included in Applicable CCC-A&G costs (row 34).

3. APPLICABLE TRANSMISSION CCC-A&G COSTS

(Appendix A, rows 18-34)

Applicable Transmission CCC-A&G Costs (Formula c) (row 34) represents the Transmission CCC-A&G Costs subject to capitalization, and equals total Common Corporate Costs distributed to the Transmission Business in the Common Corporate Costs Model, adjusted as follows:

- Transmission CCC-Operating Costs (Formula e) are removed because the capitalization ratios for those departments were determined in the 2013 Time Study.
- Transmission Facilities costs that are removed from the CCC-A&G Costs, relating to Operations facilities, are added back, because they are used to support activities that support Capital Expenditures.
- Transmission CCC-A&G Costs for the following departments that do not support capital expenditures are removed: Inergi- Customer Support Operations (CSO), Inergi-ETS to support CSO Applications, Inergi-ETS to support market transition costs and Inergi- Settlements (Note-No costs of CSO or Inergi-ETS-CSO were allocated to Transmission in the Corporate Common Costs model.)

4. TRANSMISSION LABOR CONTENT- CAPITAL RATIO

(Appendix A, rows 36-40)

Transmission Labor Content-Capital Ratio is the portion of total Transmission labor costs included in Transmission Capital Expenditures (Formula g). The Labor $ on Rows 37-38 were developed by Hydro One. The Labor $ are fully burdened labor costs (salary plus benefits).

5. TRANSMISSION TOTAL SPENDING- CAPITAL RATIO

(Appendix A, rows 37-41)

Transmission Total Spending-Capital Ratio is the portion of Transmission total spending included in Transmission Capital Expenditures (Formula h). In the formula, Transmission spending for OMA (row 43) is from row 16 and Transmission spending for capital expenditures (row 44) is from row 8.

6. CAPITALIZED TRANSMISSION CCC-A&G

Capitalized CCC-A&G Costs (Formula b) is the portion of Transmission CCC-A&G Costs to be capitalized. The portion of Transmission CCC-A&G Costs to be capitalized (row 52) is the average of Transmission Labor Content-Capital Ratio (from row 40) and Total Spending Capital Ratio (from row 46), using the appropriate weights (rows 49-50),. This portion is multiplied by the Applicable CCC-A&G Costs (row 34) to compute Capitalized CCC-A&G Costs (row 54).

7. CAPITALIZED TRANSMISSION CCC-OPERATING

(Appendix A, rows 56-83)

Capitalized Transmission CCC-Operating Costs (Formula d) represents the amount of Transmission CCC- Operating Costs capitalized to Transmission Capital Expenditures. The 2013 Time Study showed that 34.3% of Asset Development and Management time, 21.3% of Network Operations time and 0.2% of Customer Care time, are related to Transmission Capital Expenditures. These percentages are applied to the BP 2015-2019 annual budgeted amounts for those groups, and the results are the amounts of CCC-Operating Costs to be capitalized (rows 73-77).

8. TRANSMISSION OH CAP RATE

(Appendix A, rows 85-90)

The Transmission OH Cap Rate (Formula a) equals A) the sum of items 6 and 7 above, divided by B) Capital spending. The Transmission OH Cap Rates for 2015-2016 (row 90) are in the table below.

TRANSMISSION OVERHEAD CAPITALIZATION RATE	2015	2016
Rate	14.0%	15.0%

School Energy Coalition (SEC) INTERROGATORY #9

Interrogatory

[Ex.C1-7-1/p.2-3] Please provide a copy of the detailed depreciation and amortization schedules.

Response

Please see Attachment 1 for the schedules requested.

C2-04-01 - DEPRECIATION & AMORTIZATION EXPENSES

HYDRO ONE NETWORKS INC.
TRANSMISSION
Depreciation & Amortization Expenses
Historical Years (2011, 2012 and 2013)
Year Ending December 31
($ Millions)

		2011		**2012**		**2013**	
Line No.	**Particulars**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision**
		(a)	(b)	(c)	(d)	(e)	(f)
	Depreciation Expenses						
1	Major Fixed Assets	2.22%	263.5	2.20%	281.6	2.04%	278.8
2	Minor Fixed Assets	10.87%	18.8	10.77%	19.8	13.20%	25.6
4	Depreciation on Fixed Assets		282.3		301.4		304.3
4	Less Capitalized Depreciation		(9.6)		(9.3)		(9.7)
5	Asset Removal Costs		19.7		22.1		25.4
6	Losses/(Gains) on Asset Disposition		(0.1)		(0.1)		0.2
7	Total Depreciation Expenses		292.3		314.1		320.2
	Amortization Expenses						
8	OPEB		0.0		0.0		0.0
9	Environmental Costs		6.9		5.9		6.1
10	Other Regulatory Amortization		2.0		0.0		0.0
11	Other Amortization		0.0		0.0		0.0
12	Total Amortization Expenses		8.9		5.9		6.1
13	Total Deprn & Amor Expenses		301.2		320.0		326.3
12	Exclude Other Reg Amort		2.0		0.0		0.0
13	Deprn & Amort for recovery		299.2		320.0		326.3

HYDRO ONE NETWORKS INC.
TRANSMISSION
Depreciation & Amortization Expenses
Bridge Year (2014) and Test Years (2015 and 2016)
Year Ending December 31
($ Millions)

		2014		2015		2016	
Line No.	**Particulars**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision**
		(a)	(b)	(c)	(d)	(e)	(f)
	Depreciation Expenses						
1	Major Fixed Assets	2.01%	288.3	2.13%	321.8	2.13%	336.6
2	Minor Fixed Assets	10.28%	32.9	10.00%	34.3	9.55%	34.3
3	Depreciation on Fixed Assets		321.2		356.0		370.9
4	Less Capitalized Depreciation		(6.2)		(6.4)		(6.7)
5	Asset Removal Costs		44.9		38.1		33.7
6	Total Depreciation Expenses		360.0		387.7		397.9
	Amortization Expenses						
7	Environmental Costs		6.3		6.3		6.0
8	Other Regulatory Amortization		4.7		0.0		0.0
9	Other Amortization		0.2		0.2		0.2
10	Total Amortization Expenses		11.2		6.5		6.1
11	Total Depreciation & Amortization Expenses		371.2		394.2		404.0
12	Exclude Other Reg Amort		4.7		0.0		0.0
13	Depreciation & Amortization for recovery		366.5		394.2		404.0

School Energy Coalition (SEC) INTERROGATORY #10

Interrogatory

[EB-2013-0416] If any of the evidence in EB-2013-0416 regarding corporate staffing, compensation, and pensions (Ex. C1-2-3), is not the same as would be filed in any HONI Transmission application for 2015-2016, please identify, and provide necessary modifications.

Response

Please see response to SEP IR #1, Exhibit I, Tab 5, Schedule 1.

School Energy Coalition (SEC) INTERROGATORY #11

Interrogatory

[EB-2012-0031 Ex.I-11-9.01 SEC 24] Please update the table and add columns showing the actual net total cost, and in-service year and month. Please explain all material variances.

Response

Please see below for an update on all major projects identified in EB-2012-0031 Exhibit I, Tab 11, Schedule 9.01 SEC 24 and explanation of material variances.

SUSTAINING

ISD#	Investment Summary Description	Forecast as per EB-2012-0031 I-11-9.01 SEC 24			Update		
		Net Total Cost ($M)	I/S (Year)	I/S (Month)	Net Total Cost($M)	I/S (Year)	I/S (Month)
S06	Hanmer TS – 500kV ABCB	26.1	2013	September	27.6	2014	October
S07	Orangeville TS – 230kV ABCB	28.1	2014	March	30.2	2014	August
S08	Pickering A SS – 230kV ABCB	5.8	2014	December	5.8	2016	December
S11	Bruce A TS- 230kV ABCB	35.0	2014	December	74.6	2018	June
S12	Burlington TS – 230kV ABCB	8.1	2014	August	18.5	2015	December
S13	Abitibi Canyon SS / Pinard TS: Reconfigure and Demerge	46.0	2013	August	39.6	2014	June
S15	Wallaceburg: TS – Reconfigure to Address Failed Transformers	26.4	2013	October	25.2	2014	January
S17	Merivale GIS Bus Replacement	11.0	2013	December	11.7	2014	July
S19	Integrated DESN Investments	152.1*	2014+	Various	103.0 *	2014+	Various
S63	Claireville T14 Replacement	25.0	2013	October	20.5	2013	October
S30	BSPS Replacement of End-of-Life Equipment	34.6	2014	December	28.3	2015	January
S39	ITMC Refreshment	4.4	2014	October	Project Cancelled		
S40	TDCN Cyber Security	10.4	2013	November	8.3	2014	December
S50	S2B Steel Structure Replacements	7.2	2013	August	6.5	2013	August
S53	D1A Line Refurbishment	3.2	2013	December	4.2	2013	December
S54	H27H Line Refurbishment	14.5	2014	October	9.2	2014	May
S55	V73R/V74R Self Damping Conductor Replacement	9.0	2014	November	Project Cancelled		
S56	H24C Line Refurbishment	25.7	2014	October	21.7	2016	December
S57	C27P Line Refurbishment	6.2	2013	December	4.3	2014	September
S62	H2JK/K6J Underground Cable Replacement	89.7	2014	December	62.0	2015	June

**This figure represents the summation of the forecasted 2013 and 2014 net capital costs for all integrated DESN investments, not net total costs of the projects.*

- The Bruce A TS 230kV ABCB project variance is explained in Exhibit D2, Tab 2, Schedule 3, Reference # S-06 which has been filed as part of Exhibit I, Tab 10, Schedule 14.

- The Burlington TS 230kV ABCB project variance is explained in Exhibit D2, Tab 2, Schedule 3, Reference # S-07 which has been filed as part of Exhibit I, Tab 10, Schedule 14.

- The Integrated DESN Refurbishment projects variance is a result of some projects being deferred following the EB-2012-0031 Decision.

- The ITMC Refreshment project was cancelled as the existing systems were determined to be operating at an acceptable level.

- The V73R/V74R self damping conductor replacement project was cancelled after detailed project planning identified an opportunity to defer the replacement. Short-term risk was managed through completion of some corrective maintenance and establishment of an enhanced inspection program to monitor for degradation.

- The H2JK/K6J Underground Cable Replacement project has decreased in total cost from the previous application as the project underwent further competitive bidding prior to award of external contracts that resulted in a reduction in the original forecasted costs for the project.

DEVELOPMENT

		Forecast as per EB-2012-0031 I-11-9.01 SEC 24			Update		
ISD#	**Investment Summary Description**	**Net Total Cost ($M)**	**I/S (Year)**	**I/S (Month)**	**Net Total Cost($M)**	**I/S (Year)**	**I/S (Month)**
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	709.0	2012	May	709.0	2012	May
D34	Northwest Reactors for Area Voltage Control	11.2	2014	November	11.8	2014	November
D02	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 1	7.3	2014	October	7.0	2018	June
D06	Reconductor the Lambton TS to Longwood TS 230kV Circuits	40.0	2014	December	30.2	2014	December
D07	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	26.6	2014	December	21.3	2014	December
D08	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	17.5	2014	November	23.6	2016	June
D09	Toronto Area Station Upgrades for Short Circuit Capability: Re-build Hearn SS	103.9	2013	December	99.1	2014	January

ISD#	Investment Summary Description	Forecast as per EB-2012-0031 I-11-9.01 SEC 24			Update		
		Net Total Cost ($M)	I/S (Year)	I/S (Month)	Net Total Cost($M)	I/S (Year)	I/S (Month)
D10	Midtown Transmission Reinforcement Plan **	68.6	2014	August	69.9	2015	December
D13	Tremaine TS: Build New Transformer Station **	18.8	2013	March	18.4	2013	January
D14	Barwick TS: Build new Transformer Station	23.8	2013	October	23.5	2014	August
D15	Nebo TS: Increase Capacity of 230/27.6kV DESN **	10.0	2013	October	11.3	2013	October
D16	Orleans TS: Build new Transformer Station **	13.2	2014	May	9.9	2015	May
D17	Bremner TS: Build Line Connection for Toronto Hydro *	0.0	2014	December	0.0	2015	September
D18	Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station *	0.0	2014	May	Project Cancelled		
D19	Nelson TS: Replace T1/T2 DESN with new DESN **	15.0	2014	October	Project Cancelled		
D20	Samsung South Kent Wind Farm (270 MW) *	0.0	2013	June	0.0	2014	February
D21	Lower Mattagami Generation Connections **	1.7	2013	December	0.7	2015	December
D22	Niagara Region Wind Corporation Generation Connection (230MW)*	0.0	2014	June	0.0	2015	September
D23	Armow Wind Generation Connection (180 MW) *	0.0	2014	June	0.0	2015	September
D24	K2 Wind Generator Connection (270 MW) *	0.0	2014	November	0.0	2014	November
D25	Adelaide/Bornish/Jericho Wind Energy Centres (284 MW) *	0.0	2014	October	0.0	2014	July
D30	Hawthorne TS: Uprate Short Circuit Capability	11.8	2013	December	11.9	2015	July
D31	Allanburg TS: Uprate Short Circuit Capability	19.0	2013	December	32.2	2014	December
D32	Basin TS: Add Reactors	6.0	2013	December	8.6	2014	November
D33	Main TS: Add Breakers	6.7	2013	December	7.7	2014	May
D35	Summerhaven SS: Build New In-Line Breaker Station	20.4	2013	July	19.7	2013	June
D36	Sandusk SS: Build New In-Line Breaker Station	21.9	2013	October	18.9	2013	October

**Represents a project that is fully funded by the customer, and hence Net Cost = 0 and does not impact rate base.*
***Represents a project that is partially funded by the customer.*

- The Reconductor the Lambton TS to Longwood TS 230kV Circuits project cost was less than initially estimated due to lower cost of transmission line conductor and a substantial reduction in the number of access roads required to work on the line. In addition, access road removal and clean up costs were also greatly reduced as a number of communities wanted the roads left in place.

- The Allanburg TS: Uprate Short Circuit Capability project cost was higher than initially estimated as additional work was added to the scope of the project. A switchyard structure upgrade, control cable replacement and a need to provide temporary bus and line facilities was identified during the detailed engineering stage to facilitate uninterrupted supply to area customers during this major refurbishment.

- The Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station project was cancelled by the customer following the EB-2012-0031 Decision.

- The Nelson TS: Replace T1/T2 DESN with new DESN project was cancelled by the customer following the EB-2012-0031 Decision.

OPERATING

ISD#	Investment Summary Description	Forecast as per EB-2012-0031 I-11-9.01 SEC 24 Net Total Cost ($M)	Forecast I/S (Year)	Forecast I/S (Month)	Update Net Total Cost($M)	Update I/S (Year)	Update I/S (Month)
O1	NMS Upgrade	28.0	2015	September	34.5	2015	September
O4	Wide Area Network Project	55.5	2015	December	Project Cancelled		
O5	Frame Relay Replacement Project	10.4	2015	December	5.8	2014	December
N/A	Richview BUCC Flood Restoration	N/A	N/A	N/A	3.5	2014	February

- The Wide Area Network (WAN) Project was cancelled as substation bandwidth requirements expected to be achieved via consolidation did not materialize therefore WAN expansion objectives could not be met and hence the project has been cancelled.

- The Richview Backup Control Centre (BUCC) Flood Restorations were required due to severe flooding that occurred which caused a large amount of critical equipment damage.

School Energy Coalition (SEC) INTERROGATORY #12

Interrogatory

[EB-2012-0031 Ex.I-11-9.01 SEC 24] Please provide a similar table for in-service additions for 2014-2016.

Response

Please see table below for the expected in-service additions for all of the major projects to be in-service in the 2015 to 2016 period. The details on the major projects for 2014 can be found in Exhibit I, Tab 10, Schedule 11.

SUSTAINING

ISD#	Investment Summary Description	I/S Additions ($M)	I/S (Year)	I/S (Month)
S05	Air Blast Circuit Breaker Replacement - Beck #2 TS	32.7	2016	December
S07	Air Blast Circuit Breaker Replacement - Burlington TS	18.5	2015	December
S09	End of Life Station Reconfiguration – Timmins TS	10.7	2015	December
S10	End of Life Station Reconfiguration - Hanmer TS	16.0	2015	December
S11	Integrated DESN Replacement - Dunnville TS	18.3	2015	June
S12	Integrated DESN Replacement – National Research Council	22.1	2015	October
S13	Integrated DESN Replacement - Espanola TS	18.8	2016	December
S16	Integrated DESN Replacement - Gerrard TS	25.6	2015	December
S17	Integrated DESN Replacement – Chenaux TS	20.1	2016	December
S18	Integrated DESN Replacement - Overbrook TS	16.0	2015	December
S19	Integrated DESN Replacement – Ear Falls TS	9.2	2016	January
S20	Integrated DESN Replacement - Wiltshire TS	12.6	2016	December
S21	Integrated DESN Replacement - Bridgman TS	9.4	2015	October
S22	Integrated DESN Replacement – Dundas TS	15.6	2015	November
S40	Cyber Security NERC CIP V5 Readiness	15.6	2016	April
S51	C25H Line Refurbishment	52.4	2015	December
S52	H24C Line Refurbishment	21.7	2016	December
S53	D10S/D9HS Line Refurbishment	4.8	2015	December
S54	Q11S/Q12S Line Refurbishment	17.1	2016	December
S56	H2JK/K6J Cable Replacement	62.0	2015	June
S57	H7L/H11L Cable Replacement	28.8	2016	December

DEVELOPMENT

ISD#	Investment Summary Description	I/S Additions ($M)	I/S (Year)	I/S (Month)
D04	Midtown Transmission Reinforcement Plan	69.9	2015	December
D05	Guelph Area Transmission Reinforcement	94.3	2016	June
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate *	23.6	2016	June
D10	Copeland MTS: Build line connection for Toronto Hydro**	0.0	2015	September

ISD#	Investment Summary Description	I/S Additions ($M)	I/S (Year)	I/S (Month)
D14	Transmission Station P&C Upgrades for DG **	0.0	2016	December

**As per Exhibit I, Tab 4, Schedule 20, Table 2 the in-service additions per year are shown. This exhibit also shows the in-service additions in 2015 and 2016 for project D1- New 500kV Bruce to Milton Double Circuit Transmission Line.*
***Represents a project that is fully funded by the customer, and hence Net Cost = 0 and does not impact rate base*

OPERATING

ISD#	Investment Summary Description	I/S Additions ($M)	I/S (Year)	I/S (Month)
O1	NMS Capital Sustainment	35.2	2015	September

School Energy Coalition (SEC) INTERROGATORY #13

Interrogatory

[Ex.D1-3-2/p.2] Please provide referenced Exhibit A, Tab 16, Schedules 1-5 and 7.

Response

Exhibit A, Tab 16, Schedules 1-5 and 7 are included in Attachment 1.

SEC-13-ATTACHMENT 1A

1.0 INTRODUCTION

Business planning is performed annually and focuses on the development of a five year plan which comprises a detailed plan for the first three years in the planning cycle and a less detailed outlook for the remaining two-year period. The planning cycle in 2013 actually covered a six year period pertaining to the 2014-2019 period. The results as they apply to 2015 and 2016 (the test years) form the basis for the rate submission.

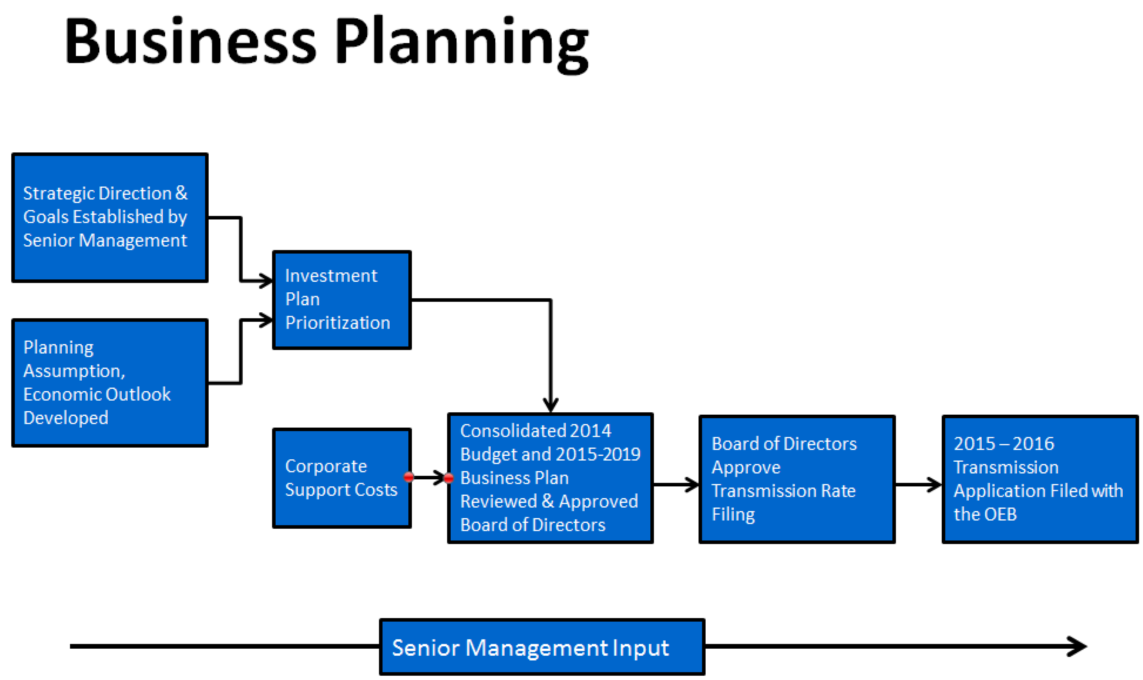
In 2013 Hydro One implemented a new Business Planning and Consolidation (BPC) tool. This tool delivers an integrated financial model to support business planning, budgeting and forecasting enabling a robust, transparent, streamlined, repeatable Business Planning process.

The typical annual business planning process consists of five stages:

1. Establishment of Strategic direction and goals;
2. Development of economic outlook and forecast assumptions;
3. Investment proposals developed;
4. Prioritization and selection of investment plan; and
5. Development of business plans and work programs;

Figure 1 provides an overview of the planning process:

Figure 1 – Business Planning Process



The key dates applicable to the 2014-2019 planning cycle included:

Date	**Action**
April 2013	Strategic direction and goals established by Senior Management
May 2013	Business plan instructions issued
June 2013	Investment proposals developed
July 2013	Investment plan prioritized and selected
November 2013	Hydro One Inc. Board approval of business plan

1.1 Establishment of Strategic Direction and Goals

Hydro One Transmission's strategic direction and goals are reviewed and established by the CEO and other members of the senior management team. The strategic goals are included in the business planning instructions for reference by planners as the business plan is being developed. Hydro One's corporate vision and strategic objectives are shown in Exhibit A, Tab 5, Schedule 1.

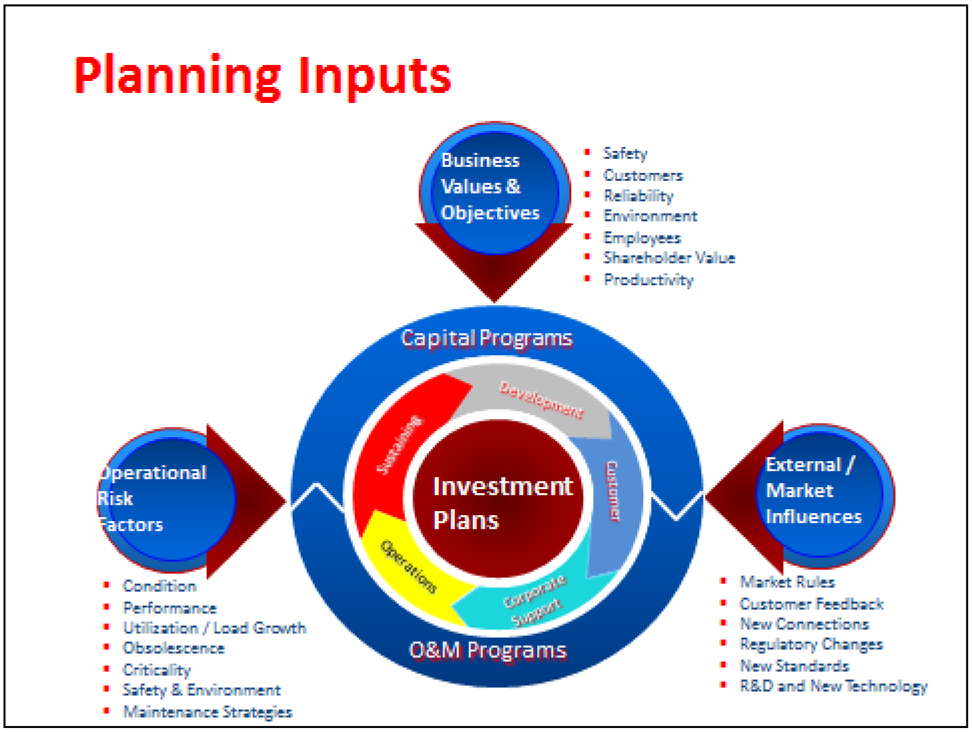
1.2 Development of Economic Outlook and Forecast Assumptions

To facilitate the preparation of the business plan, an economic outlook and customer load forecast is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, and cost rates for benefits. A detailed discussion of these variables is filed at Exhibit A, Tab 15, Schedule 1. Cost of Capital assumptions can be found in Exhibit B1, Tab 1, Schedule 1.

1.3 Investment Plan Development

As part of the investment plan development phase, inputs including customers' needs (including anticipated load growth and generator connections), criticality of asset, operational performance, and asset age and asset condition are examined as outlined in Figure 2. Data collected is assessed in the context of risk, risk mitigation and to address customers', business and transmission system needs. Exhibit A, Tab 16, Schedule 3 provides a detailed discussion of the Company's investment planning process.

Figure 2 – Planning Inputs



1.4 Prioritization and Selection of Investment Plan

The individual investments resulting from the planning process go through a risk-based prioritization process. The outcome of the risk-based prioritization process is a list of investments that is consistent with Hydro One Transmission's strategic goals and reflects financial, operational, environmental, safety, regulatory and legal considerations. A final investment plan is then endorsed and confirmed by the Hydro One senior management team. See Exhibit A, Tab 16, Schedule 4 for a more detailed description of the work prioritization and selection process.

1.5 Development of Business Plans and Work Programs

During the planning process, plans and work programs are further refined consistent with the economic and forecast assumptions and constraints. As part of this process, sufficient detail is provided to facilitate preparation of the 2015 and 2016 Transmission Rate Application. At the end of this process, the Hydro One senior management team provides direction to balance the various factors under consideration including customer service levels, rate impacts and economic considerations.

The operations, maintenance and administration ("OM&A") budget and the capital budget that result from this planning process are discussed at Exhibit C1, Tab 2 and Exhibit D1, Tab 3 respectively. Refer to Exhibit A, Tab 16, Schedule 5 for an overview of the project and program approval and control process for Hydro One Transmission.

The financial plan is prepared, incorporating OM&A and capital work program levels consistent with the investment plan, as well as forecasts of revenue, cost of power, depreciation and amortization expense, financing charges, income tax, and working capital.

The resulting plan and underlying assumptions are finalized and presented for approval to the Hydro One Inc. Board of Directors. The 2014-2019 Budget and Outlook was approved by the Board of Directors at its November 2013 meeting.

SEC-13-ATTACHMENT1B

1.0 INTRODUCTION

Hydro One's Asset Management Plan is a systematic approach to determine and optimize on-going operating and maintenance expenditures and capital investments in its distribution system and general plant. Hydro One has adopted an Asset Management model since its inception. The objective of this plan is to ensure all funding is spent in the most effective manner to realize the best value for Hydro One stakeholders and customers. To accomplish this objective, Hydro One applies a consistent approach to assess the relative asset risk impacts on business values and strategic objectives by considering and balancing asset performance (including physical condition), costs and risks, lifecycle management from an overall power system perspective and assigning asset risk scores to the corresponding investment planning actions for in-service assets. Hydro One's mission and vision is "We will be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers". The asset management process at Hydro One supports the corporate mission and vision.

2.0 THE ASSET MANAGEMENT PLAN OVERVIEW

The Hydro One Asset Management Plan for Transmission is incorporated throughout the evidence as documented below:

- Voice of the Customer (Exhibit A, Tab 4, Schedule 1)
- Summary of Transmission Business (Exhibit A, Tab 5, Schedule 1)
- Planning Process (Exhibit A, Tab 16, Schedule 1)
- Investment Plan Development (Exhibit A, Tab 16, Schedule 3)
- Investment Prioritization Process (Exhibit A, Tab 16, Schedule 4)

- Project/Program Approval and Control (Exhibit A, Tab 16, Schedule 5)
- Work Execution Strategy (Exhibit A, Tab 16, Schedule 6)
- Asset Risk Assessment (Exhibit A, Tab 16, Schedule 7)
- Regional Planning Process (Exhibit A, Tab 16, Schedule 9)
- Common Corporate Costs OM&A – Asset Management (Exhibit C1, Tab 3, Schedule 4)
- Transmission Assets Investment Overview (Exhibit D1, Tab 2, Schedule 1)

The result of this process is the five year capital and OM&A investment plan filed at and Exhibit D1, Tab 3 and Exhibit C1, Tab 2.

3.0 THE ASSET MANAGEMENT PLAN

This section provides more detailed descriptions of the aspects of the Asset Management Plan.

3.1 Voice of the Customer

Customers are a major driver of long-term success. Hydro One listens to its customers analyzes their needs and then modifies its work activities and work programs to address those needs. The many channels through which Hydro One listens to its customer's needs are discussed in Exhibit A, Tab 4, Schedule 1.

3.2 Summary of Transmission Business

The Summary of Transmission Business (Exhibit A, Tab 5, Schedule 1) provides an overview of the Hydro One transmission system including the evolution of the system, transmission system assets and asset performance. This exhibit also discusses the Corporate values, strategic goals and performance targets. All of these factors are considered to inform the Asset Management model and work plan.

3.3 Planning Process

Business planning is performed annually and focuses on the development of a detailed plan for each year in the plan (Exhibit A, Tab 16, Schedule 1). The results as they apply to the test years form the basis for this Transmission Rate Application.

3.4 Investment Plan Development

Hydro One utilizes a systematic investment approach to plan and optimize on-going capital, operating and maintenance expenditures. Four investment categories; sustaining, development, operations, and common corporate costs, follow a common investment plan development process described in Exhibit A, Tab 16, Schedule 3.

3.5 Investment Prioritization Process

The investment prioritization process is part of the overall company risk-based asset management planning process (see Exhibit A, Tab 16, Schedule 4). The prioritization process converts Hydro One Transmission's business values and key performance indicators into investment criteria and guidelines that are used for managing risk and facilitating trade-offs between investments to achieve the optimal balance of cost effectiveness, customer expectations, asset and business needs within the constraints and criteria imposed.

3.6 Project / Program Approval and Control

Once the preliminary investment plans have been accepted at the proof-of-concept stage and have gone through the investment prioritization process, a detailed analysis of the preferred alternatives and costs is completed for individual projects, programs and business cases. Based on the detailed analysis, cost estimates are prepared for review and approval by senior management and ultimately the Hydro One Board of Directors. See Exhibit A, Tab 16, Schedule 5 for more details.

3.7 Work Execution Strategy

Hydro One Transmission's Work Execution Strategy provides increased work execution capacity and necessary flexibility to accommodate the planned transmission work programs. The strategy will also address the continuing global business challenges such as the uncertainty regarding material availability and qualified personnel to undertake the work. A focus on efficiency continues throughout Hydro One's work planning and execution activities and processes. See Exhibit A, Tab 16, Schedule 6 for more details.

3.8 Asset Risk Assessment

Hydro One's Asset Risk Assessment methodology is built on the Asset Condition Assessment approach previously filed in proceeding EB-2009-0096. Since then, Hydro One has completed an asset inventory of its key distribution assets that has been linked to other non-condition based information such as outage and customer data. This has enabled Hydro One to extend its assessment methodology to improve its focus on non-condition risk factors. More details are found in Exhibit A, Tab 16, Schedule 7.

3.9 Regional Planning Process

In accordance with the Ontario Energy Board report, “Renewed Regulatory Framework for Electricity Transmitters: A Performance Based Approach (“RRFE”), all transmitters are required to participate in the regional planning process and activities to ensure the development of the provinces’ electricity infrastructure is completed in a cost-effective manner. Hydro One is the lead transmitter in nineteen of the twenty-one planning regions. Exhibit A, Tab 16, Schedule 9 describes Hydro Ones participation in the regional planning process.

3.10 Common Corporate Costs OM&A – Asset Management

The Hydro One Transmission and Distribution businesses are operated using the Asset Management model. The model separates the asset management functions of planning, decision-making and approvals from the services functions of engineering, construction, customer service and grid operations which execute approved plans. The Asset Management organization focuses on ensuring that the necessary transmission and distribution assets are planned, acquired, constructed, maintained and operated such that they deliver the required function and level of performance expected by customers in a sustainable manner over the long term. See Exhibit C1, Tab 3, Schedule 4 for more detail.

3.11 Transmission Assets Investment Overview

The Transmission Asset Investment Overview (Exhibit D1, Tab 2, Schedule 1) provides asset-centric information to support the test-year Sustaining OM&A and Capital expenditures. Information within this exhibit provides a summarized view of the key transmission assets and an outline of risk factors such as: demographic, performance, and condition information at an asset level. These results are utilized in the identification and prioritization of asset needs to assist in the investment plan development of both the capital and operating and maintenance work programs to ensure

an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One and its customers.

SEC-13-ATTACHMENT1C

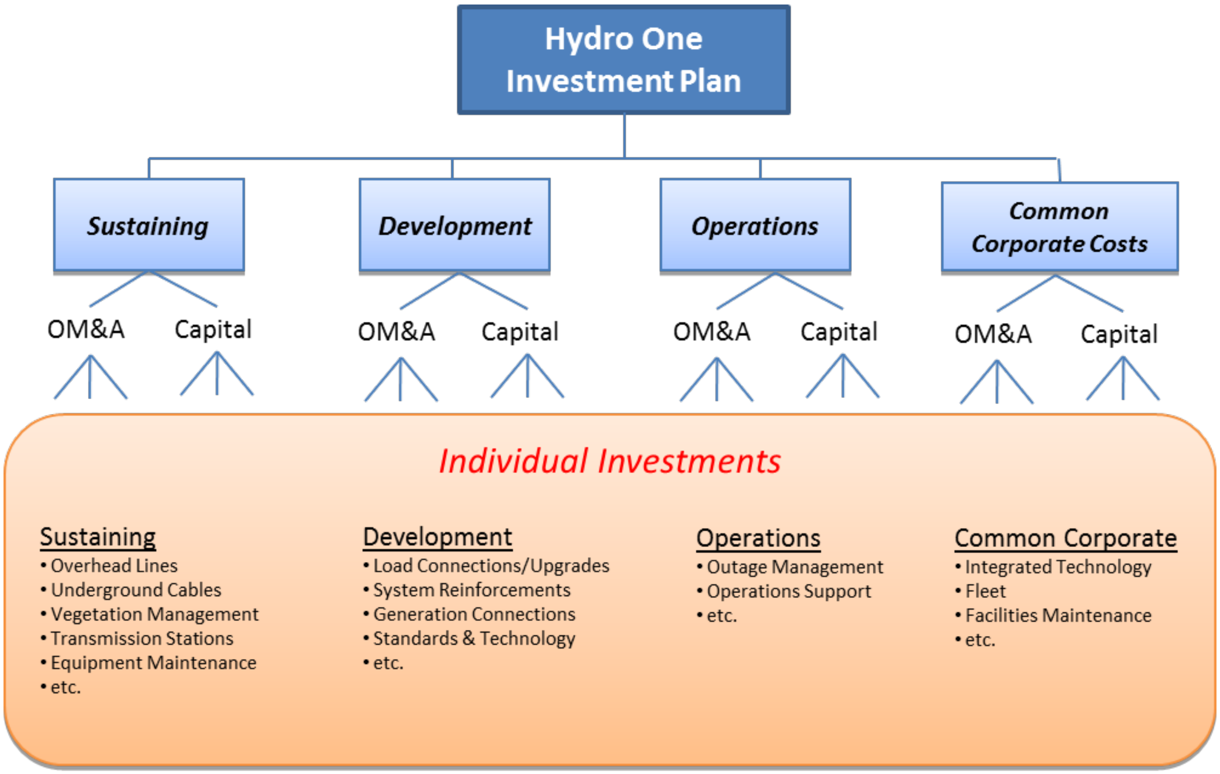
1.0 OVERVIEW

The development of Hydro One Transmission's Investment Plan consists of four major investment categories as outlined below.

- **Sustaining –** investments required to maintain the existing capability of transmission system assets to ensure that they will continue to function as originally designed.
- **Development –** investments required to ensure the transmission system capability to provide a secure and reliable supply of electricity in response to system demand and performance changes, new load and generator customer connections, system changes including generation retirements and changes to standards, codes and market rules.
- **Operations –** investments required to monitor the transmission system assets for power quality issues, faults and interruptions. Operations also manage the dispatch function, system reconfiguration, isolation and/or de-energization of equipment for work.
- **Common Corporate Investments -** investment projects that are common to both Hydro One's Transmission and Distribution businesses. These projects are a subset of the Common Corporate costs and include the expenditures for minor fixed assets (MFA), service equipment, projects and programs for Facilities and Real Estate and Integrated Technology (IT) projects.

The investments for each category pyramid up to an overall Investment Plan for Hydro One Transmission as shown in Figure 1.

Figure 1: Investment Plan



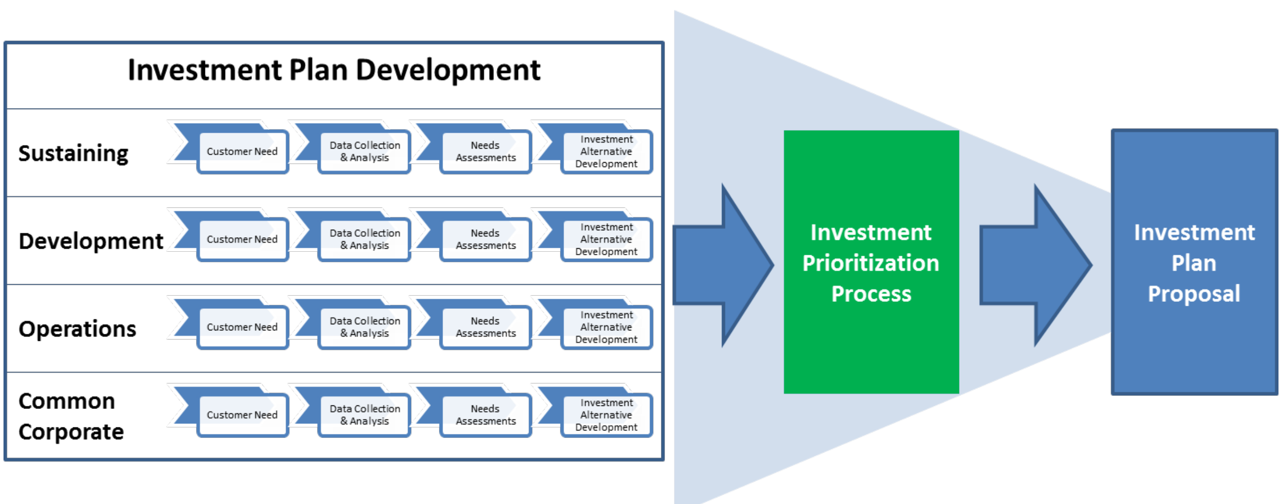
As discussed in Exhibit A, Tab 16, Schedule 1, the investment plan development process is part of Hydro One Transmission's corporate business planning process. During this phase of the business planning process, information is collected, needs are assessed, and potential investments are identified for the five major investment categories. The individual investments are then evaluated taking into consideration the other investments within a category. The proposed levels of investment for each category are submitted for further evaluation against all other investments proposed, using the investment prioritization process described in Exhibit A, Tab 16, Schedule 4.

2.0 INVESTMENT PLAN DEVELOPMENT PROCESS

The investment plan development process consists of four steps that are common to each of the investment categories Sustaining, Development, Operations and Common Corporate Cost. The steps in the investment planning process include;

(i) the determination of customer needs;
(ii) collection and analysis of data;
(iii)assessment of needs; and
(iv)identification of investments alternatives as outlined in Figure 2.

Figure 2: Investment Plan Development Process



The details of each step of the Investment Development process are outlined in the following sections.

2.1 Customer Need

Customer satisfaction research is conducted throughout the year across various customer segments to gain an understanding of the key drivers impacting customer satisfaction. This research guides the development of investment strategies and addresses satisfaction gaps.

Recent results identified the following customer's business needs:

- reliability, line maintenance and power quality;
- responsiveness, follow-up;
- outage planning and notification; and
- customer service communication.

Based on these customer needs and customer satisfaction strategies, investment alternatives are developed and included in this process. Specific investments are also evaluated in conjunction with asset and business needs.

2.2 Data Collection and Analysis

Data to guide and support the development of the investment plan is collected through a number of methods depending on the type of investment. Data requirements and decision criteria tend to be unique for each of the investment categories summarized in this section.

2.2.1 Asset Analytics

The new tools Hydro One uses in its corporate business planning process is Asset Analytics. The Asset Analytics support tools focus on asset risk prioritization to enable planners to make optimal asset decisions at any point in time (30+ year timeline). The tool provides an integrated technology solution, leveraging existing SAP investments to provide an integrated asset view and line of sight to future asset sustainment needs using asset information that is continually updated any time any maintenance, refurbishment, replacement or new construction occurs. This ensures planners have constant up to date information to determine the most effective business plan to meet the customer, business and corporate requirements.

The Asset Analytics solution provides a common understanding of asset health and comparability across asset types along with standardized reports and dashboards. Asset Analytics also provides:

1. A cascading information view of asset risk/priorities based on demographics, condition, economics, utilization, performance and criticality/customer
2. Geo-spatial bundling opportunities
3. Integrated data to support asset decision-making and the ability to format, filter and present data on demand
4. Documented, consistent and reliable processes that support the understanding of asset needs
5. A method of institutionalizing knowledge within the system to maximize value and facilitate knowledge transfer.

Hydro One will realize optimal functionality of Asset Analytics over time and with use of the tools resulting in a more efficient business planning process.

2.2.2 Sustaining

For Sustaining investments, condition data collected during routine maintenance, inspections and testing, performance history, equipment utilization, criticality and other non-condition information is assessed as described in Exhibit A, Tab 16, Schedule 7.

The information is compiled for each specific asset and may be grouped with the information of other like assets for the purpose of developing integrated investments (i.e. station refurbishments). In other cases, due to the variable nature of the work (i.e. demand work), investment levels are based on forecast volumes and costs using observed historical averages rather than specific asset data.

2.2.3 Development

Development investments are largely driven by system changes that include demand, performance and configuration, and changes to standards, codes and market rules. These investments include new customer connections (load and generation connections), enhanced system capacity to meet growing customer demand (Local Area Supply, Performance Enhancement and Risk Mitigation), and increasing network transfer capability to enable customers access to electricity supply (Network Upgrades).

The Development investment plan is produced using the best currently available information. For further discussion of Development Capital refer to Exhibit D1, Tab 3, Schedule 3. Subsequent needs and changes driven by customers, government directives, OPA and other resource procurement programs, regional planning studies and changes in codes and standards are managed through the redirection process described in Exhibit A, Tab 16 , Schedule, 4.

2.2.4 Operations

For Operations investments, the lifecycle of operating facilities and infrastructure is used as an input to developing investments. Other inputs include the requirements from reliability authorities, operating agreements, and the facilitation of renewable generation and conservation initiatives.

2.2.5 Common Corporate

Common Corporate investments support the Sustaining, Development, Operations and Customer Service work programs. Investments are based on organizational needs, optimized for facility and fleet requirements and include cost savings from IT productivity enablers and utilization assessments.

2.3 Needs Assessment

The next step in the investment plan development process is the assessment of needs. Based on the data collected, an assessment of the transmission system and assets is undertaken. Investment needs are derived by focusing on mitigating risk associated with the likelihood and consequences of asset failure as well as maintaining system performance and satisfying customer expectations.

Changes in provincial regulations, legislative and environmental law requirements, or technical standards, are also factored into the determination of investment needs.

2.4 Investment Alternative Development

Developing the alternatives is the final step in the process and is guided by the results from the needs assessments. In each of the categories there are investments that are demand in nature. For these one alternative is included in the plan which is based on a historic average with future considerations.

2.4.1 Sustaining

For Sustaining investments, alternative levels of sustainment effort are defined for each asset considering asset lifecycle cost and risks. Emphasis is placed on defining best value alternatives to address aging assets, maintain reliability and minimize customer disruption.

The planning process also involves reviewing the potential investments and "bundling" of work where there are synergies and efficiencies to be realized and it is practical to do so. For example, when replacing a transformer at a Transformer Station and work is required on the breakers in the future, this work will be advanced and bundled to realize efficiencies in the mobilization of crews, usage of resources and timing of outages. For a more fulsome discussion on work bundling please see the Work Executive Strategy, Exhibit A, Tab 16, Schedule 6.

Details on the Sustaining Capital and OM&A investments developed and included in the Investment Plan can be found in: Exhibit D1, Tab 3, Schedule 2 and Exhibit C1, Tab 2, Schedule 2.

2.4.2 Development

When looking at alternatives for Development investments, detailed planning studies (i.e. load flow study, short circuit study, transient stability study, etc.) are undertaken to identify, assess and compare the alternatives to determine the most effective transmission solution for implementation. In the case of Network upgrade investments, the inputs of the OPA and IESO are reflected in the development and selection of the recommended alternatives. In the case of some local area supply and load connection plans, joint studies are carried out with the OPA and/or the Local Distribution Companies in accordance with the Regional Planning Process which is further described in Exhibit A, Tab 16, Schedule 9. Theses joint studies assess alternatives and can recommend transmission investments to address needs at a regional level.

Details on the Development Capital and OM&A investments developed and included in the Investment Plan can be found in Exhibit D1, Tab 3, Schedule 3 and Exhibit C1, Tab 2, Schedule 3.

2.4.3 Operations

For Operations investments, alternatives are developed with emphasis placed on defining best value that strikes a balance between sustaining existing Operations facilities and developing new facilities. Many of the Operations investments pertain to the improvement of customer facing communication systems and tools in order to improve the information regarding service impacts and timelines and additional options on mediums the customer can use to receive this information.

Details on Operations Capital and OM&A investments developed and included in the Investment Plan can be found in Exhibit D1, Tab 3, Schedule 4 and Exhibit C1, Tab 2, Schedule 4.

2.4.4 Common Corporate

For Common Corporate investments, alternatives are developed to address the identified needs. In the case of information technology, for example, needs are assessed with regards to hardware, software and application required to support business processes throughout Hydro One focusing on:

- leveraging enhanced capabilities that are already inherent in the existing tool set;
- making better use of existing data;
- adjusting existing processes; or
- upgrading hardware and software in anticipation of its end-of-life.

Details on Common Corporate Capital and OM&A investments developed and included in the Investment Plan can be found in Exhibit D1, Tab 4, Schedule 1 and Exhibit C1, Tab 3, Schedule 1.

3.0 SUMMARY

Investment alternatives are developed to address asset needs and risks while maintaining reliability and satisfying customer expectations. These alternatives are then further evaluated applying the investment prioritization process outlined in Exhibit A, Tab 16, Schedule 4 to create an Investment Plan Proposal (IPP). The IPP is then recommended to the Hydro One Board of Directors for approval as part of the corporate Business Plan.

SEC-13-ATTACHMENT1D

1.0 OVERVIEW

The investment prioritization process is part of the overall company risk-based asset management planning process outlined at Exhibit A, Tab 16, Schedule 2. The prioritization process converts Hydro One Transmission's business values and key performance indicators shown in Table 1 into investment criteria and guidelines that are used for managing risk and facilitating trade-offs between investments. At the core of the process is a multi-criteria analysis, which is used to help decision-makers understand and quantify business risks and uncertainties, so that objective decisions can be made respecting priorities. This process requires several steps to obtain the best portfolio of investments that achieves the optimal balance of cost effectiveness, customer expectations, asset and business needs within the constraints and criteria imposed. The process also considers resource, material and outage availability and minimizing customer rate impacts.

Hydro One takes an enterprise engagement approach whereby each line of business (Planning, Executing and Finance) is represented at review meetings to discuss the output of the Asset Investment Planning (AIP) tool. Management discretion is required to adjust the plan to ensure we have the appropriate resources to achieve the plan, our financial objectives are met and the level of risk the plan imposes is acceptable. The objective of this exercise is to maximize risk mitigation and savings within the constraints defined.

Capital and OM&A investments are prioritized annually within the context of a multi-year planning period, with a view to the long term investment horizon. The output of the prioritization process is an Investment Plan Proposal (IPP). The IPP is comprised of a list of investments, both capital and OM&A, developed in response to customer needs, asset requirements and business needs. Once approved, within the corporate Business Plan, the IPP defines the work programs going forward.

The implementation of the IPP is subject to adjustments as new risks and/or opportunities emerge, including new customer requirements, changes in asset condition, emerging regulations/legislations or a shift in corporate priorities throughout the year. A redirection process described in Section 2.5 of this exhibit, monitors and approves the incorporation of such modifications.

2.0 INVESTMENT PRIORITIZATION PROCESS

The investment prioritization process responds to factors such as aging infrastructure, demand for reliable service and power quality, changing regulations, funding and resource constraints. There have been continuous improvements to the process using the experience gained each planning cycle.

In 2013, Hydro One implemented a new Asset Investment Planning (AIP) solution which builds on the existing processes and provides an enterprise-wide investment planning repository. The AIP solution provides an enhanced platform to:

- consider risk and financial impacts of investments;
- evaluate various investment alternatives; and
- coordinate competing investment plans to achieve a single, optimized long-term plan.

Although Hydro One has introduced new tools and a new naming convention of its levels of investment to improve clarity, the prioritization methodology has remained the same and continues to address the broad scope of investment areas required to expand, operate and maintain the transmission system. Work execution considerations such as resources, materials and outage availability, and effective work bundling are also accounted for in the development of the proposed expenditures. This results in investment proposals that balance the Company's asset needs and customer expectations within the various implementation constraints.

The investment prioritization process consists of the following steps:

- Refine/validate business values in line with the corporate strategy;
- Develop multiple investment alternatives to incrementally mitigate risks;
- Determine and evaluate the cost, benefits and risks for each level;
- Prioritize the levels across all functional areas of the corporation; and
- Assess the results and build the Investment Plan Proposal.

These steps are described in the remainder of this exhibit.

2.1 Business Values

Business Values (BVs) are utilized by Hydro One to enable the achievement of the Company's strategic goals, by forming the criteria against which: investments are developed; risks are managed; and trade-offs are facilitated between investments. The Business Values are measured by a set of key performance indicators (KPIs). The BVs represent the objectives that are factored into the decision-making process, while the KPIs represent how the impact on the BVs is to be measured.

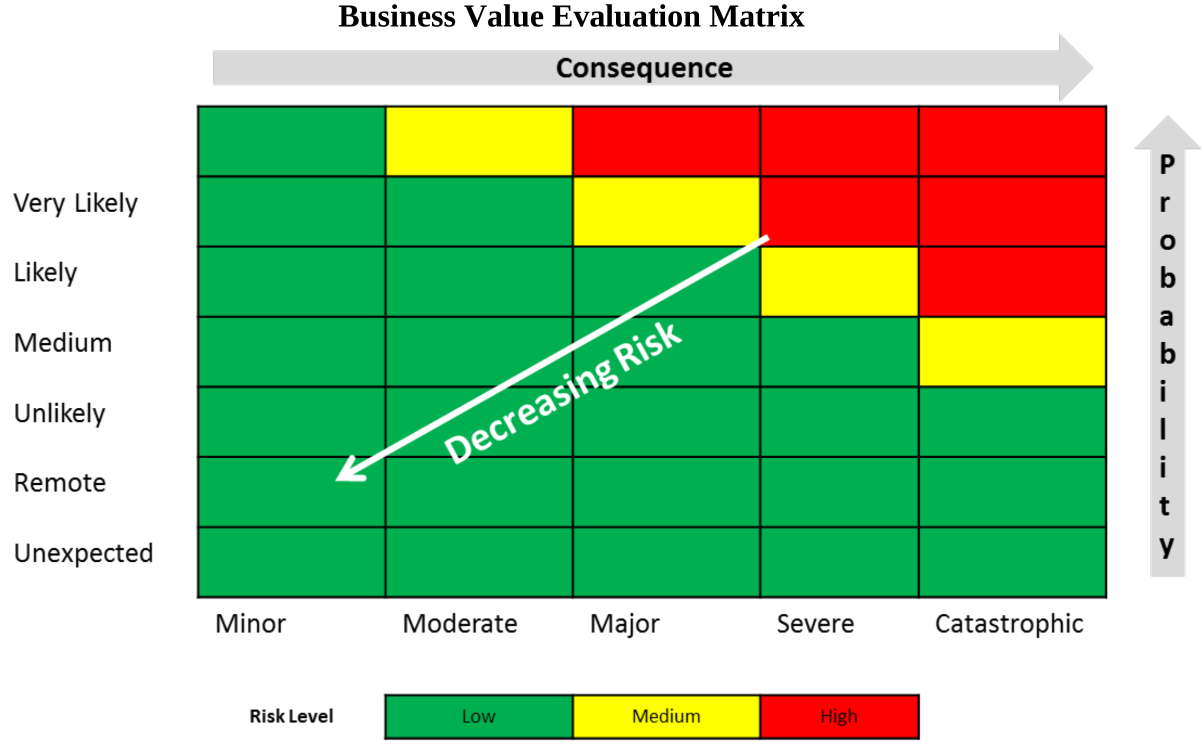
Table 1, shows the BVs and KPIs used in 2013 in the establishment of the 2014 - 2019 Investment Plan Proposal.

Table 1
2013 Business Values and Key Performance Indicators

Business Value	Measure/Key Performance Indicator
Safety	• Employee/contractor workforce health and safety • Public safety
Satisfying our Customers	• OEB service quality index • Customer satisfaction: large and mid-size customers (industrials, LDCs and Tx /Dx generators) • Customer satisfaction: residential and small business customers • Public profile and confidence: effective stewardship of assets
Reliability	• Reliable delivery of electricity • System security
Environment	• Environmental performance
Employee	• Employee skills: developing, retaining, attracting and competencies
Shareholder Value	• Shareholder confidence • Meet license conditions and maintain credibility with regulators • Get required approvals from regulators • Net income • Credit worthiness • Value of the enterprise
Productivity	• Productivity • Work Program accomplishment, including Dx plan short-term initiatives

The KPIs form the basis of the multi-criteria analysis used to prioritize investments by providing the dimensions for consideration when assessing the degrees of risk and the risk mitigation that each proposed investment level provides against each of the BVs. The process incorporates a probability and severity-of-outcome risk matrix to determine the impact ratings for each BV. The Probability scale ranges from Unexpected to Very Likely and Severity of Outcome scale ranges from Minor to Catastrophic (See Table 3).

Table 3:
Business Value Evaluation Matrix



2.2 Multiple Investment Levels

Customer, asset and business needs, risks and objectives guide the ongoing planning activities. Investment proposals are developed to address these needs, risks and objectives, and then are incorporated into the prioritization process. The scope and levels of the investment and the accomplishments those levels of investment deliver varies depending on the level of risk mitigated.

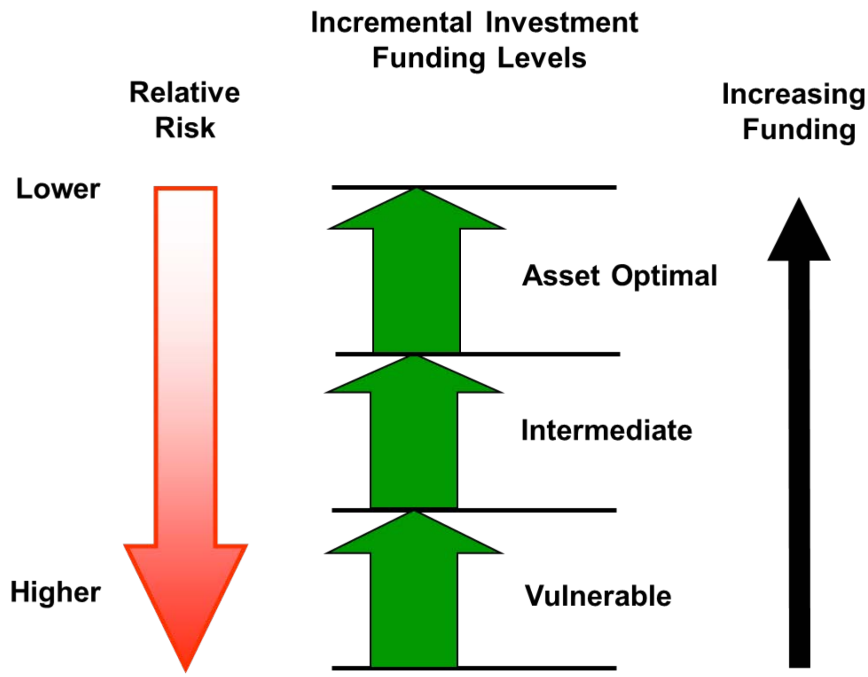
Hydro One's investment prioritization process is based on a risk mitigation approach and begins with the output from the Investment Plan Development process. A description of Hydro One Transmission Investment Plan Development is provided in Exhibit A, Tab 16, Schedule 3.

Incremental investment funding levels are established and evaluated for a period of five years but within a longer-term view of asset demographics, particularly in Sustainment, to ensure the appropriate management of overall life cycle requirements and resources. However, short-term constraints, such as scheduling of skilled staff, availability of materials, availability of outages and customer rate impacts are also considered when establishing the investment alternatives.

In the short term, the investment required to mitigate risk to a prudent residual level, may not be achievable because of factors such as shortages of critical work execution resources or financial constraints put in place to mitigate the impact to the customer bill. As a result, a lower investment plan may need to be undertaken over the short term while additional resources are secured and brought to bear on the overall investment requirement.

This approach is illustrated in Figure 1.

Figure 1
Accomplishment Levels versus Risk



As demonstrated in Figure 1, there are three investment funding levels.

"Vulnerable" Investment Level: (previously entitled Deteriorating) – This level of investment is tolerable for only brief periods and exposes the company to possible risk of asset failure. Under this level of funding, asset maintenance and/or replacement needs are not fully met and the future performance of the asset is uncertain. This level of investment includes non-discretionary investments required to ensure regulatory compliance and safety in the short term. The Vulnerable Level of investment is neither a sustainable level of investment nor a desirable target level of investment and the residual risk at the end of the five year planning period is just outside the "red zone" shown in Table 3.

“Intermediate” Investment Level (previously entitled Maintaining): This level of investment represents materially less risk exposure and materially more cost than “Vulnerable” but remains below “Asset Optimal”. Under this level of funding, asset performance and risk are held at current levels. Where appropriate there may be several intermediate investment levels to provide appropriate granularity between the Vulnerable and Asset Optimal alternatives.

“Asset Optimal” Investment Level (previously entitled Optimized): This level of investment represents a balancing point where total lifecycle costs of the asset are minimized and risk is low. This level of investment will ensure customer and asset needs are fully met and there is a high degree of confidence that the assets will perform as aligned with the Corporate Strategy.

2.3 Investment Costs, Benefits and Risks

Total funding requirements to carry out the accomplishments established for each level of investment are determined using current year costs as the basis for comparison. Where appropriate, links between investment areas are considered. For example, as Hydro One ramps up the PCB testing program, the budgets for investments to replace assets that were found to have unacceptable levels of PCB contaminants will also need to be ramped up. These links are factored into the plans to determine the total net cost of the resulting Investment Plan.

The benefits of each investment are determined by its ability to mitigate risk to the BVs. The KPIs provide a common set of criteria to measure the impact, or consequence, of the investment for the BV. However, risk is the product of the consequence and the probability of occurrence, so this probability of occurrence also has to be established. BV risk is identified in a two-dimensional table as shown in Table 3. Using this approach, the change in risk for each BV as a result of the investment is established.

The following is an example of the prioritization process using the Transmission Transformer Replacement program. This example is provided for illustrative purposes only.

Hydro One Transmission manages a fleet of 722 transmission power transformers. Currently 24% of the fleet is older than the typical expected service life for transmission transformers. Transformers approaching their end of service life are prone to demonstrating signs of degradation including leaks from failing/worn gaskets and fittings, deteriorating winding insulation, degrading insulating oil due to contaminants or worn tapchanger parts.

As a greater proportion of the fleet reaches the end of its expected service life, the probability of failure is expected to increase as transformer condition continues to degrade with age. Transformer failures can have significant reliability impact to the transmission system and the local customers; as well as environmental and safety concerns.

To address the risks associated with an aging fleet with a deteriorating condition, incremental levels of accomplishment are developed for the multi-year plan. Table 2 illustrates the Transmission Station Transformer Replacement example.

Table 2:
Transmission Transformer Replacement Levels

	Avg # Replacement per year	Avg % Replacement per year	# Replaced (over 5 yr plan)
Vulnerable	10	1.4%	50
Intermediate	16	2.2%	80
Asset Optimal	26	3.6%	130

The **Asset Optimal Level** is currently being proposed to address aged transformers and allow for the sustainment of the condition, demographics and reliability of the transformer fleet. At this replacement rate, the percentage of transformers beyond their expected service life will decrease from 24% to 19% by year 2024. This level of funding will address many of the transformers in poor and very poor condition, maintain or enhance customer reliability and reduce corrective maintenance.

The **Intermediate Level** would result in 50 fewer transformers replacements over the five years than the Asset Optimal Level of investment. At this rate of replacement, the percentage of transformers beyond their expected service life will slightly increase from 24% to 32% by year 2024. At this level the number of transformers that are at high risk is expected to increase. Customer reliability is also expected to degrade slightly compared to past performance.

The **Vulnerable Level** would result in about 80 fewer transformers being replaced over the five years than the Asset Optimal Level of investment. At this rate of replacement, the percentage of transformers beyond their expected service life will increase from 24% to 41% by year 2024. A replacement deficiency of this magnitude would increase the number of transformers that are high risk and reliability would significantly decrease as this accomplishment rate will not keep pace with the aging demographics and resulting deterioration of condition.

The Vulnerable Level of investment will result in a level of unacceptable risk over the five year planning horizon. Prolonged funding at the Vulnerable level is not sustainable and does not conform to good utility practice as refurbishment activities will not keep pace with asset condition requirements.

The risk-based prioritization process is used by Hydro One to quantify risks, and to identify the appropriate level of investments that will ensure the achievement of customer commitments, maintain safety and reliability while minimizing customer bill increases.

Reducing investments to the Vulnerable Level of investment over the planning period can create longer term sustainability issues, resulting in higher long-term customer costs. If the accomplishments fall below a certain level in a given area, meeting the appropriate safety, regulatory and/or legal requirements may be at risk.

2.4 Investment Prioritization

The needs, objectives, accomplishments, costs, and risk assessment for each level of accomplishment are documented. This information is then reviewed by asset managers, business analysts and other stakeholders within Hydro One. The quality control review ensures the full integration of the numerous investments and uniformity in the use of the risk assessment model.

The information provides the necessary cost and risk mitigation data required to conduct the risk-based prioritization process. The prioritization process selects one of several levels of investment for each investment area based on that level's ability to mitigate risk to an acceptable level to the BVs as discussed in sections 2.1 and 2.2. The aggregation of work programs and projects that define the various selected level yields the Preliminary IPP.

The Preliminary IPP is reviewed by Senior Management before the final Investment Plan and associated funding requirements are established. Senior Management's review takes into consideration the associated impacts on customer rates, the ability to accomplish the proposed work in light of known constraints (e.g. labour, material, engineering resources), the financial health of the company, as well as the residual risk to the business (i.e. the risk to the BVs that remains after the investments are made).

The end product is an Investment Plan that represents an effective balance between these considerations.

2.5 Investment Plan and Redirection

While the Investment Plan is the product of extensive planning and analysis, implementation of the plan must be done in a manner that is dynamic and flexible. Redirection of approved investments may be required as new risks or opportunities emerge, including;

- changing customer needs and requirements (e.g. new Regional Plans, unexpected load growth, etc.);
- changing asset priorities based on new information;
- changing external requirements (e.g. new Government mandates, new technical standards, Transmission or Transmission System Code changes, etc.); and
- major events (e.g. extensive storms and equipment failures).

This redirection of work allows appropriate and prudent adjustments to be made to the work originally identified in the Investment Plan. As an example, transmission line emergency restoration work required to repair damage caused by storms or equipment failures can be significant in a given year and may necessitate the redirection of funds and field resources from other investment areas to correct the unexpected and significant damage. On a monthly basis, the changes from plan are identified and corrective action is recommended for approval to senior management; they in turn balance the emerging needs, financial impacts, resource impacts and the changing risk profile, when making a decision to approve the changes to plan.

SEC-13-ATTACHMENT1E

1.0 INTRODUCTION

As described in Exhibit A, Tab 16, Schedule 1, Planning Process, there are a number of key steps within the overall business planning cycle which are typically completed prior to the development of the detailed project and program assessments. These prerequisite steps include: needs identification, project/program prioritization and the development of preliminary work programs, based on estimates of project and program costs and benefits. Once the preliminary plans have been accepted at the proof-of-concept stage and have gone through the investment prioritization process described in Exhibit A, Tab 16, Schedule 4, detailed analysis of the preferred alternatives and costs is completed for individual projects, programs and business cases. Based on the detailed analysis, cost estimates are prepared for review and approval by senior management and ultimately the Hydro One Board of Directors.

2.0 PROJECT AND PROGRAM APPROVAL

Once the overall investment plan has been prioritized and reviewed and the business plan approved, individual project and program proposals are developed and assessed. Factors considered in the assessment process include:

- the need for the investment;
- the implications of not doing the work and possible risk;
- the anticipated results;
- the recommended solution; and
- cost.

In determining the recommended solution, alternative approaches and project risks are considered. The proposals are then reviewed in a series of steps at the senior management and executive levels, depending on the dollar limit and the significance of the investment. The proposals are then approved consistent with the provisions of the Organizational Authority Register ("OAR") described in Exhibit A, Tab 9, Schedule 2. Strategic investments are reviewed and approved by the Hydro One Board of Directors. The Investment Summary Documents provided in Exhibit D2, Tab 2, Schedule 3 summarize the proposed projects and programs with expenditures exceeding $3 million in any of the test years.

3.0 MONITORING AND CONTROL

Each month, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures. Deviations from plans are identified and corrective action taken. In the event that spending on a project is expected to be materially different from the amount originally approved, an Interim Review of Variance (IROV) is prepared. An IROV is essentially an amended business case that is reviewed and approved based on the revised set of circumstances (cost, scope and schedule). The IROV is approved in accordance with the limits set out in the OAR. Projects which cannot be re-justified are either re-prioritized, cancelled or otherwise adjusted to conform to the new condition. Variances on programs are reviewed at the monthly Operations meeting. Any variances resulting re-direction of resources is approved by the Chief Financial Officer and the Chief Operating Officer.

SEC-13-ATTACHMENT1F

1.0 INTRODUCTION

This exhibit summarizes the process Hydro One Transmission uses to perform Asset Risk Assessments ("ARA") on transmission system assets. The result of these assessments are utilized in the planning process for sustaining investments. The assessment conveys the state of the transmission system; identifying current asset needs, and creating a line of sight to future needs.

2.0 ASSET RISK ASSESSMENT PROCESS

Hydro One's Asset Risk Assessment methodology is built on the foundation of the Asset Condition Assessment approach utilized in previous transmission rate filings. Hydro One has completed an asset inventory of its key transmission assets, this information is centralized in a repository and has been linked to other non-condition based information such as outage and customer data. This has enabled Hydro One to extended its assessment methodology to improve its focus on non-condition risk factors. This newly coined "Asset Risk Assessment" enables a holistic view of asset risk, and ultimately, improved decision making.

When considering the risk that an asset poses to Hydro One's strategic objectives as stated in Exhibit A, Tab 5, Schedule 1, it is useful to organize the various sources of this risk into logical groupings. Individually, these groupings, or "risk factors", relate to specific aspects of the risk associated with an asset. Taken together, the risk factors form a "composite risk" score that allows for a multi-faceted picture of asset risk. The primary factors Hydro One Transmission considers when evaluating risk are shown in Figure 1:

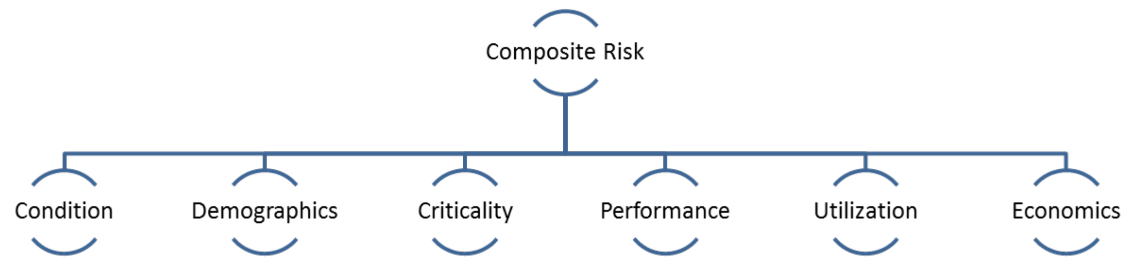


Figure 1: Factors used to evaluate asset risk

Each of the above factors is considered individually for all assets, after which the composite risk score is computed. The composite risk score allows for identification of assets that may require remedial action. The specific remedial action to be taken can be determined by detailed analysis of the individual risk factors. The following section describes each of these individual factors.

Hydro One Transmission also assesses the risks of technology obsolescence and potential of environment impacts and safety hazards of employees and the public when prioritizing the investments to address the assets in need of remedial action.

3.0 RISK FACTOR OVERVIEW

3.1 Asset Condition Risk

Asset condition risk relates to the increased probability of failure that assets experience when their condition degrades over time. Asset condition is defined in a number of ways, depending on the asset type in question. For example, the condition of a transmission station transformer is measured by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test, and if required, a boring test.

While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type are evaluated consistently. Assets of a given type that have a relatively high condition risk are candidates for refurbishment or replacement.

3.2 Asset Demographic Risk

Asset demographic risk relates to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages.

At times, specific asset makes or models are observed to deteriorate at a markedly different rate than other assets of the same type. For example, Hydro One Transmission has observed increased deterioration rates in Gulfport type wood structures. These wood pole structures therefore carry a higher asset demographic risk than other wood poles of the same age.

Assets with relatively high demographic risk are candidates for refurbishment or replacement.

3.3 Asset Criticality

Asset criticality represents the impact that the failure of a specific asset has on the transmission system. Primarily, it is defined by the number, type and size of customers impacted by the failure of a given asset. Assets whose failure would result in an interruption to a higher number of customers or in a larger amount of load would have an asset criticality that is higher than assets whose failure would have a smaller customer impact.

Asset criticality does not directly drive a decision to refurbish or replace an asset. However, it is used to prioritize the refurbishment or replacement of assets whose condition, demographic, performance, utilization or economic risk has already resulted in the asset being considered a candidate for refurbishment or replacement.

3.4 Asset Performance Risk

Asset performance risk is a reflection of the historical performance of an asset. An asset's performance is defined by any power interruptions that are caused by its failure. This risk factor considers the frequency and duration of these interruptions, as well as whether the interruptions are getting more or less frequent over time.

The asset performance risk does not directly project future performance; however past performance can be utilized as a good indicator of expected future performance. Therefore, assets with a relatively high performance risk can be considered candidates for refurbishment or replacement.

3.5 Asset Utilization Risk

Asset utilization risk represents the increased rate of deterioration exhibited by an asset that is highly utilized. While not all assets exhibit this increased rate, the deterioration of some assets is highly dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded relative to their nameplate rating deteriorate more quickly than those that are lightly loaded. Similarly circuit breakers utilized for capacitor and reactor switching which are subject to significant operations, results in accelerated mechanical and electrical wear-out of the breaker. Therefore, the asset utilization risk for transformers and circuit breakers attempts to consider their relative deterioration based on available loading and operation history, respectively.

Assets that exhibit a utilization risk that is high compared to other assets of the same type are considered candidates for upgrade, especially if they also carry a relatively high asset criticality or are deemed candidates for refurbishment or replacement based on other risk factors.

3.6 Asset Economic Risk

An asset economic risk is based on the economic evaluation of the ongoing costs associated with the operation of an asset. Depending on the asset type, this evaluation may be as simple as determining the replacement cost of the asset, or as complex as comparing the net present value of ongoing maintenance to complete refurbishment or replacement.

While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement.

4.0 SUMMARY

The Asset Risk Assessment is a valuable input to the investment planning process. It allows for a systematic evaluation of the risk associated with transmission assets. Since the asset risk assessment methodology is consistently applied, it provides a means of comparing risk between assets of the same type to prioritize investments and optimize asset life. For a detailed breakdown of how risk is assessed for specific assets, refer to Exhibit D1, Tab 2, Schedule 1.

School Energy Coalition (SEC) INTERROGATORY #14

Interrogatory

Reference: [Ex.D1-3-2]

Please provide all Investment Summary Documents for 2015-2016 projects.

Response

All Investment Summary Documents for 2015-2016 projects are included in Attachment 1.

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2015 OR 2016

1.0 SUSTAINING CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 2)

1.1 Stations

		2015	2016
S01	Oil Circuit Breaker Replacements	2.6	10.8
S02	SF6 Circuit Breaker Replacements	8.0	11.2
S03	GTA Metalclad Switchgear Replacements	10.3	10.9
S04	Air Blast Circuit Breaker Replacement - Richview TS	23.5	22.1
S05	Air Blast Circuit Breaker Replacement - Beck #2 TS	15.4	9.9
S06	Air Blast Circuit Breaker Replacement - Bruce A TS	22.1	26.4
S07	Air Blast Circuit Breaker Replacement - Burlington TS	11.3	0.0
S08	End of Life Station Reconfiguration - Gage TS	26.9	26.9
S09	End of Life Station Reconfiguration – Timmins TS	5.2	0.0
S10	End of Life Station Reconfiguration - Hanmer TS	8.0	0.0
S11	Integrated DESN Replacement - Dunnville TS	4.6	0.0
S12	Integrated DESN Replacement – National Research Council TS	15.5	0.0
S13	Integrated DESN Replacement - Espanola TS	0.9	17.9
S14	Integrated DESN Replacement - Strathroy TS	0.0	4.7
S15	Integrated DESN Replacement - Elgin TS	18.8	11.3
S16	Integrated DESN Replacement - Gerrard TS	18.8	0.0
S17	Integrated DESN Replacement – Chenaux TS	14.0	5.9
S18	Integrated DESN Replacement - Overbrook TS	11.3	0.0
S19	Integrated DESN Replacement – Ear Falls TS	5.4	0.0
S20	Integrated DESN Replacement - Wiltshire TS	5.1	5.2
S21	Integrated DESN Replacement - Bridgman TS	4.5	0.0

		2015	**2016**
S22	Integrated DESN Replacement – Dundas TS	3.4	0.0
S23	Integrated DESN Replacement - Goderich TS	0.9	6.6
S24	Integrated DESN Replacement - Leaside TS	1.9	9.7
S25	Integrated Station Component Replacements	15.4	0.9
S26	Power Transformer Replacements	20.7	60.1
S27	Operating Spare Transformer Purchases	3.2	8.4
S28	Disconnect Switch Replacements	5.4	7.8
S29	Capacitor Bank Replacements	6.3	6.5
S30	Instrument Transformer Replacements	4.5	3.9
S31	Insulator Replacements	4.4	4.5
S32	Station Service Replacements	12.0	12.3
S33	Spill Containment	11.3	10.8
S34	Integrated Station P&C Replacements	28.7	31.4
S35	Protection Replacements	18.4	21.6
S36	RTU and SER Replacements	4.3	8.2
S37	DC Signaling (Remote Trip) Replacements	6.7	4.6
S38	Protection Tone Channel Replacements	4.2	4.2
S39	PLC Device Replacements	4.6	4.7
S40	Cyber Security NERC CIP V5 Readiness	9.9	1.5
S41	Cyber Security of Load Stations	1.5	4.5
S42	Station Building Infrastructure	8.5	8.6
S43	Station Civil Infrastructure	7.6	7.9

1.2 Lines

		2015	2016
S44	Wood Pole Replacements	27.7	28.2
S45	Steel Structure Coating	8.8	10.3
S46	Steel Structure Replacements	1.9	5.7
S47	Steel Structure Foundation Refurbishments	4.7	5.5
S48	Shieldwire Replacements	4.4	4.4
S49	Insulator Replacements	3.6	3.7
S50	Transmission Lines Emergency Restoration	10.9	11.1
S51	C25H Line Refurbishment	27.1	0.0
S52	H24C Line Refurbishment	4.9	12.0
S53	D10S/D9HS Line Refurbishment	4.8	0.0
S54	Q11S/Q12S Line Refurbishment	0.0	17.1
S55	Secondary Land Use and Recoverable Projects	44.8	25.6
S56	H2JK/K6J Cable Replacement	12.1	0.0
S57	H7L/H11L Cable Replacement	14.3	14.5

Summary – Sustaining Capital	**2015**	**2016**
Total Sustaining Capital Projects & Programs Listed Above	**586.0**	**530.0**
Sustaining Capital Projects & Programs Less than $3M	**49.1**	**52.9**
Total Gross Sustaining Capital (per Exhibit D1-3-2)	**635.1**	**582.9**
Less Capital Contribution	**(53.2)**	**(34.3)**
Total Net Sustaining Capital (per Exhibit D1-3-2)	**581.9**	**548.6**

2.0 DEVELOPMENT CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 3)

2.1 Inter-Area Network Transfer Capability

		2015	2016
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	3.3	3.2
D02	Clarington TS: Build new 500/230kV Station	91.7	101.1
D03	Installation of Shunt Capacitor Banks at Cherrywood TS	0.1	3.4

2.2 Local Area Supply Adequacy

		2015	2016
D04	Midtown Transmission Reinforcement Plan	21.6	0.0
D05	Guelph Area Transmission Reinforcement	48.3	29.9
D06	Preston TS Transformation	10.0	4.6
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	5.7	3.9
D08	Hawthorne TS: Replace two existing Transformers	1.0	7.0
D09	York Region – Increase Transmission Capability for B82V/B83V Circuits	5.0	7.0

2.3 Load Customer Connection

		2015	2016
D10	Copeland MTS: Build line connection for Toronto Hydro	9.5	0.0
D11	Seaton TS: Build New 230-28kV Transformer Station	11.0	11.0
D12	Supply to Essex County Transmission Reinforcement	25.0	37.5

2.4 Generation Customer Connection

		2015	2016
D13	Napanee Gas Generation Connection	1.0	4.5

2.5 Protection and Control for Enablement of Distribution Connected Generation

		2015	2016
D14	Transmission Station P&C Upgrades for DG	17.5	18.0

Summary – Development	2015	2016
Total Development Projects & Programs Listed Above	**250.7**	**231.1**
Development Projects & Programs Less than $3 M	**36.4**	**50.0**
Total Gross Development Capital (per Exhibit D1-3-3)	**287.1**	**281.1**
Less Capital Contribution	**(77.4)**	**(69.3)**
Total Net Development Capital (per Exhibit D1-3-3)	**209.7**	**211.8**

3.0 OPERATIONS CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 4)

3.1 Grid Operations Control Facilities

		2015	2016
O1	NMS Capital Sustainment	12.6	0.0
O2	BUCC New Facility Development	0.5	11.0

3.2 Operating Infrastructure

		2015	2016
O3	Wide Area Network Outreach Program	4.0	4.0
O4	Station LAN Infrastructure Program	4.0	4.9
O5	Fault Locating Program	3.0	3.0
O6	Grid Control Network Sustainment	3.0	2.0
O7	Hub Site Management Program	2.0	3.0

Summary – Operations	2015	2016
Total Operations Projects & Programs Listed Above	**29.1**	**27.9**
Operations Projects & Programs Less than $3 M	**9.3**	**9.5**
Total Operations Capital (per Exhibit D1-3-4)	**38.4**	**37.4**

4.0 CAPITAL COMMON CORPORATE COSTS AND OTHER COSTS (EXHIBIT D1, TAB 4, SCHEDULES 1-4)

4.1 Information Technology

		2015	2016
IT1	Hardware/Software Refresh and Maintenance	12.0	11.2
IT2	MFA Servers and Storage	7.1	9.3
IT3	MFA PC and Printer Hardware	5.6	5.3
IT4	Field Workforce Optimization and Mobile IT	5.0	5.0
IT5	Customer Experience	5.0	1.0
IT6	Corporate Support Optimization	0.0	3.0

4.2 Other

		2015	2016
C1	Real Estate Head Office & GTA Facilities Capital for 2015	13.1	0.0
C2	Real Estate Field Facilities Capital	34.8	40.0
C3	Transport & Work Equipment	54.5	62.5
C4	Service Equipment	9.1	7.9

Summary - Capital Common Corporate Costs & Other Costs	**2015**	**2016**
Total Capital Common Corporate Costs & Other Costs Projects & Programs listed above	**146.2**	**145.2**
Capital Common Corporate Costs & Other Costs Projects & Programs less than $3 M	**8.6**	**7.9**
Total Capital Common Corporate Costs & Other Costs (per Exhibit D1-4-1)	**154.8**	**153.1**
Transmission allocation of Capital Common Corporate Costs & Other Costs (per Exhibit D1-4-1)	**69.4**	**68.5**

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Oil Circuit Breaker Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address end of life issues of the aging population of oil circuit breakers ("OCBs") by proactively replacing those that represent the highest risk to system security and customer connection reliability.

Implications of not proactively managing this population of breakers will result in a trend of equipment unavailability, and an increase in probability of failure and equipment outages (both customer and network connected) due to declining condition of the OCB population. It will also increase the likelihood of inadequate equipment fault ratings and increased risk to employee safety.

Investment Summary:
Hydro One Transmission currently owns and manages 1,818 OCBs, which accounts for approximately 40% of the total circuit breaker population. These OCBs are no longer commercially available with replacement parts becoming increasingly expensive and harder to source and in many cases the circuit breakers are not economically repairable. Therefore OCBs that reach end of life need to be proactively replaced on an ongoing basis.

Many factors are utilized in the determination of asset replacement needs. The criteria used to assess the OCB population includes: the age demographic, physical condition, recorded equipment defects, parts obsolescence, and equipment ratings such as switching duty-cycle requirements.

Approximately 7% of these circuit breakers are beyond their expected service life. As OCBs age, the condition of the circuit breaker will further deteriorate, creating untenable conditions in keeping this class of equipment in service in a reliable condition. Degraded condition leads to poor performance, where forced breaker outages can result in interruptions to customers or impact to the bulk electricity system. By replacing end of life OCBs before failure, these situations can be avoided.

The OCB's scheduled for replacement in the test years will be replaced with new SF6 circuit breaker technology to maintain a reliable supply of electricity. The proposed plan will replace 7 OCBs and 20 OCBs in the 2015 and 2016 test years respectively. This represents an average annual rate of replacement of approximately 1% of the OCB fleet over the test years. The execution of fewer units in 2015 compared to 2016 is a result of OCB's identified as replacement candidates being replaced as part of the Integrated DESN Investment category within the Station Re-investment program rather than on an individual component basis to improve work efficiency. Additional information on Integrated DESN Investments is provided in Exhibit D2, Tab 2, Schedule 3 Reference # S11 to S24.

Result:
This plan will replace a total of 27 OCBs over the test years to mitigate the risk of equipment unavailability thereby maintaining system security and customer connection reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	2.6	10.8	13.4
Operations, Maintenance & Administration and Removals (B)	0.1	0.4	0.5
Gross Investment Cost (A+B)	2.7	11.2	13.9
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	2.6	10.8	13.4

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: SF6 Circuit Breaker Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of SF6 breakers at end of life, by proactively replacing those that represent the highest risk to system security and customer connection reliability.

Implications of not proactively managing this population of breakers will result in a trend of equipment unavailability and an increase in probability of failure and equipment outages (both customer and network connected) due to declining condition of the SF6 circuit breaker population. It will also increase the likelihood of inadequate equipment fault ratings and an increased risk to safety and the environment.

Investment Summary:
Hydro One Transmission currently owns and manages 1,579 SF6 circuit breakers, which accounts for approximately 34% of the total circuit breaker population. There are two factors primarily driving the SF6 circuit breaker replacement program. Firstly, there is a population of the end of life breakers that were originally designed as low voltage SF6 circuit breakers built in early 1980's which have several major design flaws that require frequent repair and maintenance. Secondly, there is a large population of breakers (about 30%) that are utilized for the most onerous, special purpose duties, such as reactor and capacitor bank switching. These breakers experience several hundred operations per year thus accelerating the mechanical and electrical wear-out of the breaker. Most of these very poor performing breakers have reached or surpassed their mechanical design life; with the early breaker vintages also experiencing high leakage rates, operational problems due to the complex control and operating mechanisms, and technical obsolescence resulting in significant maintenance and refurbishment expenditures.

Many factors are utilized in the determination of asset replacement needs. The criteria used to assess the SF6 circuit breaker population includes: the age demographic, physical condition, performance statistics, recorded equipment defects and equipment ratings such as switching duty-cycle requirements.

As SF6 circuit breakers age, the condition of the circuit breaker will further deteriorate, resulting in degraded reliability due to electrical and mechanical defects, as well as negative environmental impacts as SF6 gas leaks through aged gaskets and sealing systems. By replacing end of life SF6 circuit breakers before failure, these situations can be avoided.

The SF6 circuit breakers scheduled for replacement in the test years will be replaced with newer SF6 circuit breaker designs; which remain as one of the utility standards for circuit breaker installations. The proposed plan will be to replace 16 and 19 SF6 breakers in the 2015 and 2016 test years respectively. This represents an annual replacement rate of approximately 1% of the SF6 breaker fleet over the test years, which is in line with the bridge and historic year. The year over year variation in expenditures is attributable to the mix of units being replaced.

Result:
This plan will replace in total 35 SF6 circuit breakers over the test years to mitigate the risk of equipment unavailability and environmental liability associated with end of life SF6 equipment thereby maintaining system security and customer connection reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	8.0	11.2	19.2
Operations, Maintenance & Administration and Removals (B)	0.3	0.3	0.6
Gross Investment Cost (A+B)	8.3	11.5	19.8
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	8.0	11.2	19.2

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: GTA Metalclad Switchgear Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address end of life issues of the aging population of the low-voltage metalclad switchgear in the Greater Toronto Area ("GTA") that represent the highest risk to system security and customer connection reliability.

Implications of not proactively managing this population of metalclad switchgear will result in a reliability reduction to Toronto Hydro Electric System Limited ("THESL") and its customers, and an increased in maintenance expenditures due to the difficulty in obtaining or fabricating technically obsolete spare parts. It would also increase the safety hazard risk in the event of failure, as the GTA metalclad switchgear equipment are not arc proofed.

Investment Summary:
Hydro One Transmission currently owns and manages 845 metalclad switchgear installations, of which 21% are installed in the GTA. Approximately 25% of the metalclad switchgear installations currently operating in the GTA are beyond their expected service life. THESL and Hydro One Transmission have identified three stations in the GTA where the metalclad switchgear is end of life and requires replacement over the test years.

Many factors are utilized in the determination of asset replacement needs. The criteria used to assess the metalclad breaker population includes: the age demographic, physical condition based on diagnostics and inspections, parts obsolescence, reliability and safety considerations.

This existing metalclad switchgear is not built to present day arc proof type C standards which results in safety and reliability concerns. Hydro One Transmission has experienced, on average, two major faults per year with inadequate metalclad arc proofing design. This can result in damages to the adjacent feeders and a potentially hazardous situation for personnel. By replacing end of life metalclad switchgear before failure, these situations can be avoided.

The replacement program includes the new metalclad circuit breakers along with new protections and the cables that supply the switchgear. This multiyear program is currently underway in coordination with THESL to replace the aged infrastructure. Prioritization is being done with THESL to allow both utilities to leverage resources and constructions outages. Work will continue on metalclad replacements at Duplex TS, Strachan TS, and Wiltshire TS over the test years, with a portion being recoverable from THESL.

Result:
This plan will replace metalclad switchgear at three stations in the GTA in order to maintain customer reliability, and mitigate safety hazards associated with substandard equipment.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	10.3	10.9	21.2
Operations, Maintenance & Administration and Removals (B)	0.7	0.7	1.4
Gross Investment Cost (A+B)	11.0	11.6	22.6
Recoverable (C)	(5.5)	(5.8)	(11.3)
Net Investment Cost (A+C)	4.8	5.1	9.9

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Air Blast Circuit Breaker Replacement - Richview TS
Work Execution Period: January 2013 to September 2017

Need:
This investment is required to replace Air Blast Circuit Breakers ("ABCBs") and their auxiliary systems at Richview TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence; which are negatively impacting the operability and reliability of the transmission system.

Implications of not completing this work will result in a significant risk of switchyard equipment failing which would degrade system reliability on the Western Greater Toronto Area (GTA).

Investment Summary:
Richview TS is a critical network station that facilitates bulk power transfers on the 230 kV network and transforms 230kV to 44 kV for load delivery within the GTA. The focus of this investment is on the 230 kV network. The Richview TS 230 kV switchyard was originally placed in-service in 1957 and many assets are approaching end of life.

Assessments and site inspections have identified end of life issues with the ABCBs, as well as with the associated free standing current transformers, high pressure air system, disconnect switches, station service system, protection and control systems, and insulators in the switchyard. There are twenty-four 230kV ABCBs at Richview TS. These breakers manufactured by Brown Boveri (type DMVF) are beyond their expected service life and are technically obsolete with vendor support for parts and service no longer available. ABCBs are the poorest performing breakers in the Hydro One transmission system. As ABCBs and their auxiliary systems age, the condition of components degrade, forced outages increase and maintenance costs increase.

The project will result in the complete rebuild of the entire Richview TS 230 kV switchyard, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be addressed within this project includes the replacement of twenty-four circuit breakers and associated high pressure air systems with new SF6 breakers, as well as the replacement of 108 switches, 108 protection and control systems, and other associated auxiliary components. The functionality and electrical configuration of the switchyard will remain unchanged and is planned to meet the foreseeable system requirements.

The project is in progress and continues to be on track for a planned in-service date of 2017 as originally outlined in the previous transmission rate filing (EB-2012-0031).

Result:
This project to completely rebuild the 230 kV switchyard at Richview TS will result in eliminating operational risks associated with the failure of end of life equipment and will preserve the reliability of the bulk electricity system in the Western GTA. It will also minimize ongoing life cycle costs due to the conversion of ABCBs to SF6 breakers and satisfy regulatory requirements with the upgrade of protection and control systems to meet current NPCC requirements.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	23.5	22.1	67.7
Operations, Maintenance & Administration and Removals (B)	1.5	1.4	4.3
Gross Investment Cost (A+B)	25.0	23.5	72.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	23.5	22.1	67.7

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Air Blast Circuit Breaker Replacement - Beck #2 TS
Work Execution Period: January 2013 to December 2016

Need:
This investment is required to replace Air Blast Circuit Breakers ("ABCBs") and their auxiliary systems at Beck #2 TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence; which are negatively impacting the operability and reliability of the transmission system.

Implications of not completing this work will result in significant risk of further equipment deterioration and declining reliability to the system and generation customers in the area.

Investment Summary:
Beck #2 TS is a critical network station that connects hydraulic generation from OPG to the 230 kV network. The Beck #2 TS 230 kV switchyard was originally placed in-service in 1955 and many assets are approaching end of life and are in need of major work to sustain their functionality. Assessments and site inspections have identified end of life issues with the ABCBs, as well as with the free standing current transformers, high pressure air system, disconnect switches, station service systems, and insulators in the switchyard. There are twenty 230kV ABCBs at Beck #2 TS. These breakers manufactured by either Brown Boveri (eight - type DMVF) or Delle (twelve - type PK4PB) are beyond their expected service life and are technically obsolete with vendor support for parts and service no longer available. ABCBs are the poorest performing breakers in the Hydro One transmission system. As ABCBs and their auxiliary systems age, the condition of components degrade, forced outages increase and maintenance costs increase.

This project will result in the partial rebuild of the Beck #2 TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be addressed within this project includes the replacement of all twenty 230 kV ABCBs and associated high pressure air systems with new SF6 breakers, as well as the replacement of forty-six disconnect switches, thirty-eight protection and control systems, and other associated auxiliary components.

The project is under development and continues to be on track for a planned in-service date of 2016 as originally outlined in the previous transmission rate filing (EB-2012-0031).

Result:
This project to partially rebuild the 230kV switchyard at Beck #2 TS will result in eliminating operational risks associated with the failure of end of life equipment and will maintain reliability of the bulk electricity system in the Niagara area. It will also minimize ongoing life cycle costs due to the conversion of ABCBs to SF6 breakers and satisfy regulatory requirements with the upgrade of protection and control systems to meet current NPCC requirements.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	15.4	9.9	32.7
Operations, Maintenance & Administration and Removals (B)	1.0	0.6	2.2
Gross Investment Cost (A+B)	16.4	10.5	34.9
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	15.4	9.9	32.7

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Air Blast Circuit Breaker Replacement - Bruce A TS
Work Execution Period: January 2012 to June 2018

Need:
This investment is required to replace Air Blast Circuit Breakers ("ABCBs") and their auxiliary systems at Bruce A TS that are in need of replacement due to deteriorated condition, asset demographics, fault duty requirements, and equipment obsolescence; which are negatively impacting the operability and reliability of the transmission system.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Investment Summary:
Bruce A TS is a critical network station that facilitates bulk power transfers from the Bruce Power nuclear generators to the 500kV and 230kV networks. The focus of this investment is on the 230 kV network. The Bruce A TS 230 kV switchyard was originally placed in-service in the 1970s and many assets are approaching end of life.

Assessments and site inspections have identified end of life issues with the ABCBs, as well as with the associated free standing current transformers, high pressure air system, disconnect switches, station service systems, protection and control systems and insulators in the switchyard. There are sixteen 230 kV ABCBs at Bruce A TS. These breakers are beyond their expected service life and are technically obsolete with vendor support for parts and service no longer available. ABCBs are the poorest performing breakers in the Hydro One transmission system. As ABCBs and their auxiliary systems age, the condition of components degrade, forced outages increase and maintenance costs increase.

In addition to the equipment end of life concerns, the fault duty (short circuit interrupting capability) of these breakers has been exceeded due to renewable and nuclear generation and transmission work that has recently come into service in the Bruce area. To manage the increased short circuit to acceptable levels temporary operating restrictions have been imposed until the breakers are replaced. Additional station upgrades are also required to return to the normal operating configuration.

The project will result in the complete rebuild of Bruce A TS 230 kV switchyard, replacing existing aged, degraded, and under-rated infrastructure with new equipment built to current standards. Equipment to be addressed within this project includes the replacement of sixteen circuit breakers and associated high pressure air systems with new 80 kA SF6 circuit breakers; as well as the replacement of disconnect switches, instrument transformers, protection and control systems, and other associated auxiliary components.

Additionally to address the short circuit interrupting capability the station strain buses withstand capability will be uprated and supporting structures will be reinforced or replaced, as required, to withstand the mechanical and thermal effects of the higher short circuit current.

The project is in progress with a planned in-service date of 2018; which is a delay from the original planned in-service date of 2014 outlined in the previous transmission rate filing (EB-2012-0031). This delay and associated increase in cost is due to inclusion of additional work to replace: existing protection and control systems, three oil circuit breakers, and sections of buswork to deal with increased short circuit requirements. A recoverable amount of $5 million has also been included in the project cost to reflect an anticipated capital contribution by Bruce Power. However this is subject to the OEB's approval of the proposal submitted by Hydro One Transmission on July 13, 2013 regarding cost sharing of dual-use assets at Bruce A TS.

Result:
This project to completely rebuild the 230 kV switchyard at Bruce A TS will result in eliminating operational risks associated with failure of end of life equipment and insufficient short circuit capability, and will preserve the reliability of the bulk electricity system in the Bruce Area. It will also minimize ongoing life cycle costs due to the conversion of ABCBs to SF6 breakers and satisfy regulatory requirements with the upgrade of protection and control systems to meet current NPCC requirements.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	22.1	26.4	79.6
Operations, Maintenance & Administration and Removals (B)	1.5	1.8	5.1
Gross Investment Cost (A+B)	23.6	28.2	84.7
Recoverable (C)	0.0	0.0	(5.0)
Net Investment Cost (A+C)	22.1	26.4	74.6

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Air Blast Circuit Breaker Replacement - Burlington TS
Work Execution Period: July 2012 to December 2015

Need:
This investment is required to replace Air Blast Circuit Breakers ("ABCBs") and their auxiliary systems at Burlington TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence; which are negatively impacting the operability and reliability of the transmission system.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Investment Summary:
Burlington TS is a critical network station just west of Toronto that facilitates bulk power transfers on the 230kV network. The Burlington TS 230 kV switchyard was originally placed in-service in the 1950s and many assets are approaching end of life.

Assessments and site inspections have identified end of life issues with the ABCBs, as well as with the associated free standing current transformers, high pressure air system, disconnect switches, station service systems, and insulators in the switchyard. There are four 230 kV ABCBs at Burlington TS. These breakers manufactured by CGE (type AT) are at their expected service life and are in need of major work to sustain their functionality. The equipment is also technically obsolete with vendor support for parts and service no longer available. ABCBs are the poorest performing breakers in the Hydro One transmission system. As ABCBs and their auxiliary systems age, the condition of components degrade, forced outages increase and maintenance costs increase.

The project will result in the complete rebuild of the Burlington TS 230 kV switchyard, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be addressed within this project includes the replacement of all four 230 kV ABCBs and associated high pressure air systems with new SF6 breakers, as well as the replacement of four oil circuit breakers, twenty disconnect switches, twelve protection and control systems, and other auxiliary components. Additionally, the electrical configuration of the yard will be modified to accommodate an additional circuit breaker to allow for increased operating flexibility.

The project is in progress with a planned in-service date of 2015, which is a delay from the original planned in-service date of 2014 outlined in the previous transmission rate filing (EB-2012-0031). This delay and associated increase in cost is due to inclusion of additional work to consolidate work to leverage efficiencies during design, construction and commissioning and to provide a more reliable switchyard.

Result:
This project to completely rebuild the 230 kV switchyard at Burlington TS will result in eliminating operational risks associated with failure of end of life equipment, and will preserve the reliability of the bulk electricity system in the Burlington Area. It will also minimize life cycle costs due to the conversion of ABCBs to SF6 breakers, and enhance operating flexibility and minimize outage impact with the reconfiguration of the switchyard.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	11.3	0.0	18.5
Operations, Maintenance & Administration and Removals (B)	0.7	0.0	1.2
Gross Investment Cost (A+B)	12.0	0.0	19.7
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	11.3	0.0	18.5

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: End of Life Station Reconfiguration - Gage TS
Work Execution Period: June 2013 to December 2017

Need:
This investment is required to address multiple assets at Gage TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Gage TS is a transmission station that transforms 115 kV into 13.8 kV and facilitates load delivery to Horizon Utilities in the city of Hamilton in the Hamilton/Niagara region. Major industrial customers supplied from Gage TS include US Steel, Max Aicher North America, and ArcelorMittal Dofasco. The station was originally placed in-service in 1940 and additional capacity was installed in the 1960s. Many assets are in degraded condition and are in need of replacement. The customer load at the station has reduced substantially over the years, to the point where reconfiguration into a smaller capacity and simpler configuration is prudent.

The project will result in the complete rebuild and reconfiguration of the Gage TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. The current station configuration consists of three DESNs (six transformers) supplying Horizon Utilities. The station will be reconfigured to consist of two DESNs (four transformers) by combining two of the existing facilities into a single facility with uprated equipment in order to maintain reliability and supply capability. Equipment to be replaced within this project includes: six transformers and associated spill containment systems, fifty-six circuit breakers, 348 disconnect switches, eighty-one protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. Reconfiguration of the station to integrate two of the existing DESNs into a single facility will minimize ongoing lifecycle costs that would have otherwise been required to support the additional equipment.

The project is underway with a planned in-service date of 2017.

Result:
This project to rebuild Gage TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area. Ongoing lifecycle costs to sustain Gage TS will be reduced through the reduction of station equipment resulting from the consolidation of two of the existing DESNs.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	26.9	26.9	72.4
Operations, Maintenance & Administration and Removals (B)	1.7	1.7	3.7
Gross Investment Cost (A+B)	28.6	28.6	76.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	26.9	26.9	72.4

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: End of Life Station Reconfiguration - Timmins TS
Work Execution Period: January 2013 to December 2015

Need:
This investment is required to address multiple assets at Timmins TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Timmins TS is a transmission station that transforms 115 kV into 27.6 kV and facilitates load delivery to Hydro One Distribution customers around the city of Timmins in the Northern region and is connected to Wawaitin GS, an OPG owned hydroelectric station. The station was originally placed in-service in 1939 and many assets are in degraded condition and are in need of replacement. The existing station configuration is non-standard with three transformers rather than two, making maintenance difficult without costly outage impacts to customers.

The project will result in the partial rebuild and reconfiguration of the Timmins TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. The station and transmission line terminals will be reconfigured to facilitate the replacement of two smaller transformers with a single standard size unit, maintaining supply reliability. The reconfiguration will eliminate end of life wood poles structures within the station and also include the relocation of several poles on the right-of-way. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, nine disconnect switches, five protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. Reconfiguration of the station will minimize ongoing lifecycle costs that would have otherwise been required to support the additional equipment.

The project is underway with a planned in-service date of 2015.

Result:
This project to partially rebuild Timmins TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area. Reconfiguration will address the maintainability issues associated with the current station configuration and reduce ongoing lifecycle costs.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	5.2	0.0	10.7
Operations, Maintenance & Administration and Removals (B)	0.3	0.0	0.7
Gross Investment Cost (A+B)	5.5	0.0	11.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	5.2	0.0	10.7

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: End of Life Station Reconfiguration - Hanmer TS
Work Execution Period: January 2013 to December 2015

Need:
This investment is required to address multiple assets at Hanmer TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area; as well as a negative impact on transmission capacity, reliability and security between Northern and Southern Ontario.

Investment Summary:
Hanmer TS is a transmission station that transforms 500 kV into 230 kV and 27.6 kV and facilitates the transfer of power between Northern and Southern Ontario. The station was originally placed in-service in 1965 and the two existing autotransformers and associated equipment are in degraded condition and are in need of replacement.

The project will result in the partial reconfiguration of the Hanmer TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Two non-standard 360 MVA autotransformers, which are connected electrically in parallel and function as a single unit, are approaching the end of their expected service life, are in degraded condition, and will be replaced by a single 750 MVA unit, maintaining supply reliability and capacity. Equipment to be replaced within this project includes: two autotransformers and associated spill containment systems, four disconnect switches, eight protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. Reconfiguration of the station will minimize ongoing lifecycle costs that would have otherwise been required to support the additional equipment.

The project is underway with a planned in-service date of 2015.

Result:
This project to partially reconfigure Hanmer TS will result in eliminating operational risks associated with operating end of life equipment, preserve the reliability to the load customers in the area and maintain transmission capacity and security between Northern and

Southern Ontario. Station reconfiguration from two autotransformers to a single autotransformer will reduce ongoing lifecycle costs while maintaining reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	8.0	0.0	16.0
Operations, Maintenance & Administration and Removals (B)	0.5	0.0	1.0
Gross Investment Cost (A+B)	8.5	0.0	17.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	8.0	0.0	16.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Dunnville TS
Work Execution Period: September 2012 to June 2015

Need:
This investment is required to address multiple assets at Dunnville TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Dunnville TS is a transmission station that transforms 115 kV into 27.6 kV and facilitates load delivery to Halimand County Hydro and Hydro One Distribution customers around the town of Dunnville in the Niagara region. The station was originally placed in-service in 1952 and many assets are in degraded condition and are in need of replacement.

The project will result in the complete rebuild of the Dunnville TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, four circuit breakers, eleven disconnect switches, fourteen protection and control systems, and other associated auxiliary components.

Halimand County Hydro has also requested the addition of a new feeder position at Dunnville TS to meet the loading requirements of its customers. This work will be staged alongside the rebuild work but a separate Development Capital project (under Exhibit D1, Tab 3, Schedule 3 Section 3.3) addresses this customer request and the associated funding requirements which are fully funded through customer capital contributions.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is underway with a planned in-service date of 2015.

Result:
This project to rebuild Dunnville TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.6	0.0	18.3
Operations, Maintenance & Administration and Removals (B)	0.3	0.0	1.1
Gross Investment Cost (A+B)	4.9	0.0	19.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.6	0.0	18.3

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - National Research Council TS
Work Execution Period: June 2013 to October 2015

Need:
This investment is required to address multiple assets at National Research Council ("NRC TS") that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
NRC TS is a station that transforms 115 kV into 13.8 kV and facilitates load delivery to NRC in Ottawa. The station was originally placed in-service in 1953 and many assets are in degraded condition and are in need of replacement.

The project will result in the complete rebuild of the NRC TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, five circuit breakers, nineteen disconnect switches, ten protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

This investment was included in the previous transmission rate filing (EB-2012-0031) Exhibit D2, Tab 2, Schedule 3 as Reference #S18. The project is underway with a planned in-service date of 2015.

Result:
The project to rebuild NRC TS will result in eliminating the operational risks associated with operating end of life equipment, and will improve reliability to the load customer.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	15.5	0.0	22.1
Operations, Maintenance & Administration and Removals (B)	1.0	0.0	1.4
Gross Investment Cost (A+B)	16.5	0.0	23.5
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	15.5	0.0	22.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Espanola TS
Work Execution Period: September 2013 to December 2016

Need:
This investment is required to address multiple assets at Espanola TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Espanola TS is a transmission station that transforms 115 kV into 44 kV and facilitates load delivery to Espanola Regional Hydro Distribution and Hydro One Distribution customers around the town of Espanola in the North Eastern region. The station was originally placed in-service in 1953 and many assets are in degraded condition and are in need of replacement.

The project will result in the complete rebuild of the Espanola TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, three circuit breakers, fourteen disconnect switches, nine protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2016.

Result:
This project to rebuild Espanola TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	0.9	17.9	18.8
Operations, Maintenance & Administration and Removals (B)	0.1	1.1	1.2
Gross Investment Cost (A+B)	1.0	19.0	20.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	0.9	17.9	18.8

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Strathroy TS
Work Execution Period: September 2014 to December 2017

Need:
This investment is required to address multiple assets at Strathroy TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Strathroy TS is a transmission station that transforms 115 kV into 27.6 kV and facilitates load delivery to Entergrus Power Lines and Hydro One Distribution customers around the town of Strathroy in the Western region. The station was originally placed in-service in 1951 and many assets are in degraded condition and are in need of replacement.

The project will result in the complete rebuild of the Strathroy TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: one transformer and associated spill containment system, two circuit breakers, fifteen disconnect switches, two protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2017.

Result:
This project to rebuild Strathroy TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	0.0	4.7	19.5
Operations, Maintenance & Administration and Removals (B)	0.0	0.3	1.5
Gross Investment Cost (A+B)	0.0	5.0	21.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	0.0	4.7	19.5

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Elgin TS
Work Execution Period: November 2013 to December 2017

Need:
This investment is required to address multiple assets at Elgin TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Elgin TS is a transmission station that transforms 115 kV into 13.8 kV and facilitates load delivery to Horizon Utilities in the city of Hamilton in the Niagara region. The station was originally placed in-service in 1968 and many assets are in degraded condition and are in need of replacement.

The project will result in the complete rebuild of the Elgin TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: four transformers and associated spill containment systems, seventeen circuit breakers, four disconnect switches, thirty-nine protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2017.

Result:
This project to rebuild Elgin TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	18.8	11.3	33.0
Operations, Maintenance & Administration and Removals (B)	1.2	0.7	2.1
Gross Investment Cost (A+B)	20.0	12.0	35.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	18.8	11.3	33.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Gerrard TS
Work Execution Period: January 2013 to December 2015

Need:
This investment is required to address multiple assets at Gerrard TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Gerrard TS is a transmission station that transforms 115 kV into 13.8 kV and facilitates load delivery to Toronto Hydro customers within the city of Toronto in the Greater Toronto Area region. The station was originally placed in-service in 1949 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild of the Gerrard TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: four transformers and associated spill containment systems, eight disconnect switches, ten protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is underway with a planned in-service date of 2015.

Result:
This project to partially rebuild Gerrard TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	18.8	0.0	25.6
Operations, Maintenance & Administration and Removals (B)	1.2	0.0	1.6
Gross Investment Cost (A+B)	20.0	0.0	27.2
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	18.8	0.0	25.6

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Chenaux TS
Work Execution Period: January 2014 to December 2016

Need:
This investment is required to address multiple assets at Chenaux TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Chenaux TS is a transmission station that transforms 230 kV into 115 kV and facilitates supply from Chenaux GS, an OPG owned hydroelectric generating station, to the Pembroke and Cobden areas in the Eastern region. The station was originally placed in-service in 1950 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild of the Chenaux TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, two circuit breakers, nine disconnect switches, twelve protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2016.

Result:
This project to partially rebuild Chenaux TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability of supply in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	14.0	5.9	20.1
Operations, Maintenance & Administration and Removals (B)	0.9	0.4	1.3
Gross Investment Cost (A+B)	14.9	6.3	21.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	14.0	5.9	20.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Overbrook TS
Work Execution Period: September 2013 to December 2015

Need:
This investment is required to address multiple assets at Overbrook TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Overbrook TS is a transmission station that transforms 115 kV into 13.8 kV and facilitates load delivery to Ottawa Hydro customers around the city of Ottawa in the Eastern region. The station was originally placed in-service in 1962 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild of the Overbrook TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, thirteen disconnect switches, four protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2015.

Result:
This project to partially rebuild Overbrook TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	11.3	0.0	16.0
Operations, Maintenance & Administration and Removals (B)	0.7	0.0	1.0
Gross Investment Cost (A+B)	12.0	0.0	17.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	11.3	0.0	16.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Ear Falls TS
Work Execution Period: November 2013 to January 2016

Need:
This investment is required to address multiple assets at Ear Falls TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Ear Falls TS is a transmission station that transforms 115 kV into 44 kV and facilitates load delivery to Hydro One Distribution customers around the town of Ear Falls in the Northern region. The station was originally placed in-service in 1956 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild and reconfiguration of the Ear Falls TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers, four circuit breakers, two disconnect switches, three protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2016.

Result:
This project to partially rebuild Ear Falls TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	5.4	0.0	9.2
Operations, Maintenance & Administration and Removals (B)	0.3	0.0	0.6
Gross Investment Cost (A+B)	5.7	0.0	9.8
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	5.4	0.0	9.2

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Wiltshire TS
Work Execution Period: June 2013 to December 2016

Need:
This investment is required to address multiple assets at Wiltshire TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Wiltshire TS is a transmission station that transforms 115 kV into 13.8 kV and facilitates load delivery to Toronto Hydro in the city of Toronto in the Greater Toronto Area region. The station was originally placed in-service in 1951 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild of the Wiltshire TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: four transformers and associated spill containment systems, four circuit breakers, eighteen disconnect switches, eight protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is in progress with a planned in-service date of 2016.

Result:
This project to partially rebuild Wiltshire TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	5.1	5.2	12.6
Operations, Maintenance & Administration and Removals (B)	0.3	0.3	0.8
Gross Investment Cost (A+B)	5.4	5.5	13.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	5.1	5.2	12.6

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Bridgman TS
Work Execution Period: March 2013 to October 2015

Need:
This investment is required to address multiple assets at Bridgman TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Bridgman TS is a transmission station that transforms 115 kV into 13.8 kV and facilitates load delivery to Toronto Hydro in the city of Toronto in the Greater Toronto Area. The station was originally placed in-service in 1952 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild of the Bridgman TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, four disconnect switches, six protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is underway with a planned in-service date of 2015.

Result:
This project to partially rebuild Bridgman TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.5	0.0	9.4
Operations, Maintenance & Administration and Removals (B)	0.3	0.0	0.6
Gross Investment Cost (A+B)	4.8	0.0	10.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.5	0.0	9.4

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Dundas TS
Work Execution Period: June 2012 to November 2015

Need:
This investment is required to address multiple assets at Dundas TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Dundas TS is a transmission station that transforms 115 kV into 27.6 kV and facilitates load delivery to Horizon Utilities in the city of Hamilton in the Hamilton/Niagara region. The station was originally placed in-service in 1961 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild of the Dundas TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: two transformers and associated spill containment systems, six disconnect switches, eight protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is underway with a planned in-service date of 2015.

Result:
This project to partially rebuild Dundas TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	3.4	0.0	15.6
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	1.3
Gross Investment Cost (A+B)	3.4	0.0	16.9
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	3.4	0.0	15.6

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Goderich TS
Work Execution Period: December 2013 to December 2017

Need:
This investment is required to address multiple assets at Goderich TS that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Goderich TS is a transmission station that transforms 115 kV into 27.6 kV and facilitates load delivery to West Coast Huron Energy and Hydro One Distribution customers around the town of Goderich in the Western region. The station was originally placed in-service in 1950 and many assets are in degraded condition and are in need of replacement.

The project will result in the partial rebuild of the Goderich TS station, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: three transformers and associated spill containment systems, eight circuit breakers, twenty-three disconnect switches, eight protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2017.

Result:
This project to partially rebuild Goderich TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	0.9	6.6	14.1
Operations, Maintenance & Administration and Removals (B)	0.1	0.4	0.9
Gross Investment Cost (A+B)	1.0	7.0	15.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	0.9	6.6	14.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated DESN Replacement - Leaside TS
Work Execution Period: January 2014 to August 2017

Need:
This investment is required to address multiple assets at the Leaside TS on the 27.6 kV switchyard that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

Investment Summary:
Leaside TS is a transmission station that provides 230 kV and 115 kV switching as well as transformation of 230 kV into 115 kV. Leaside TS serves as the eastern supply into the Toronto 115 kV system. In addition, it also facilitates load delivery through transforming 115 kV into 27.6 kV for supply to Toronto Hydro in the city of Toronto in the Greater Toronto Area. The 27.6 kV switchyard was originally placed in-service in 1956 and many assets are in degraded condition and are in need of replacement.

The project will result in the complete rebuild of the Leaside TS 27.6 kV switchyard, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes: fourteen circuit breakers, thirty-six disconnect switches, seventeen protection and control systems, and other associated auxiliary components.

Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The project is under development with a planned in-service date of 2017.

Result:
This project to completely rebuild the 27.6 kV switchyard at Leaside TS will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability to the load customers in the area.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	1.9	9.7	17.0
Operations, Maintenance & Administration and Removals (B)	0.1	0.6	1.1
Gross Investment Cost (A+B)	2.0	10.3	18.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	1.9	9.7	17.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station Component Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address multiple assets at a station that are in need of replacement due to degraded condition and asset demographics, which are negatively impacting the operability and reliability of the transmission station, but where the scope of work does not warrant a major rebuild of the station as would be the case in the Integrated DESN Replacement category.

Implications of not completing this work will result in a significant risk of further equipment deterioration and declining reliability to the transmission system and customer supply.

Investment Summary:
Hydro One Transmission currently owns and manages 286 transmission stations, operating equipment of varying condition, vintages, and demographics. Hydro One Transmission has identified stations where multiple assets are operating beyond expected service life and require replacement over the test years.

Many factors are utilized in the determination of asset replacement needs. The criteria includes: the age demographic, physical condition based on diagnostics and inspections, parts obsolescence, reliability and safety considerations.

This program will result in the integrated replacement of existing aged and degraded infrastructure with new equipment built to current standards. Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

This program was a started in 2013 on a pilot basis with nine transmission stations identified spanning over 2013 to 2016. The intention of the pilot was to work through a modified approach to planning and executing component replacement work to leverage efficiencies through better integration. Learning's from this pilot approach will be applied in future rate applications, as Hydro One Transmission continues towards executing a greater portion of planned work in an integrated fashion.

Result:
This investment will result in eliminating operational risks associated with operating end of life equipment, and will preserve the reliability of the transmission system and customer supply.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	15.4	0.9	16.3
Operations, Maintenance & Administration and Removals (B)	0.4	0.0	0.4
Gross Investment Cost (A+B)	15.8	0.9	16.7
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	15.4	0.9	16.3

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Power Transformer Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of end of life power transformers, by proactively replacing those that represent the highest risk to system and/or customer connection reliability.

Implications of not proactively managing the transformer population will result in a trend of equipment unavailability and increase in probability of equipment failure which is a significant risk to customer supply reliability. A transformer failure can also have serious environmental consequences due to oil spills and increased safety hazards to personnel due to explosions or fire.

Investment Summary:
Power transformers are the devices used to connect systems of different voltages for the purpose of power flow and voltage regulation. Transformers are the most critical and expensive components of the transmission system. Hydro One Transmission currently owns and manages 722 power transformers to support the transmission system.

There are several different types of power transformers, the primary two types are step-down transformers and autotransformers, other transformers include: phase shifting transformers, regulating transformers, and shunt reactors. The step-down transformers convert a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Whereas the autotransformers connect two high voltage transmission systems such as 500/230 kV and 230/115 kV.

Specific maintenance tests have been developed to obtain the data required to determine the condition and likelihood of failure of these power transformers. The results from these tests, in combination with data on operating history, individual transformer and transformer family performance, equipment criticality and age demographic are used to assess the transformers and determine if a unit is deemed to be at end of life.

Approximately 24% of the in-service transformers have exceeded their and expected service life, and 8% are of a degraded condition that puts them as high or very high risk of failure. Thus continued replacements are required to mitigate impacts to reliability, environment, and safety.

The power transformers scheduled for replacement in the test years will be replaced with new standardized transformers to maintain a reliable supply of electricity. It is typical to also replace associated auxiliary elements within the transformer outage zone at the same time, such as insulators, surge arresters, and protections; these are assessed on a case-by-case basis. The proposed plan will replace 21 power transformers over the test years 2015 and 2016. This represents an average annual rate of replacement of approximately 1.5% of the power transformer fleet over the test years; which is consistent with the bridge year.

Result:
This plan will replace 21 power transformers to reduce the operational risks associated with operating transformers at or near end of life, eliminate safety and environmental issues, and manage customer connection reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	20.7	60.1	80.8
Operations, Maintenance & Administration and Removals (B)	1.1	4.1	5.2
Gross Investment Cost (A+B)	21.8	64.2	86.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	20.7	60.1	80.8

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Operating Spare Transformer Purchases
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to provide adequate spare coverage for timely replacement of transformers in the event of failure.

Implications of not proceeding with this investment will result in increased risks to customer supply reliability and system security.

Investment Summary:
Hydro One Transmission currently owns and operates a fleet of 722 transformers across the province. In order to ensure timely response in the event of a failure, spare transformers are required. The number of spares Hydro One Transmission maintains is based on a probabilistic cost/risk analysis model, consistent with industry standards. The model determines the optimum number of spares required for each group of transformers by taking into consideration several factors: such as demographics, failure rate, repair/replacement time, internal performance trends and national performance levels supplied by the Canadian Electricity Association. Delivery lead time is also accounted for in the analysis.

The transformers scheduled for procurement in the test years for use as operating spares will replenish transformers drawn down from system reserves to support demand failure replacements. Transformers purchased under this investment will vary in sizes and types of transformers in order to support the sizes and types of the in-service transformer fleet.

Result:
This plan will ensure adequate spare coverage to minimize the restoration time in the event of a transformer failure thereby maintaining customer reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	3.2	8.4	11.6
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	3.2	8.4	11.6
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	3.2	8.4	11.6

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Disconnect Switch Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of high and low voltage disconnect switches at end of life, by proactively replacing those that represent the highest risk to system reliability.

Implications of not proactively managing this population of switches will result in increased risk to system reliability, increased safety hazards to personnel, and an increased inability to complete scheduled work as a result of switch failures during isolation procedures.

Investment Summary:
Disconnect switches perform essential roles in the power system. These switches facilitate the electrical isolation and connection of system components such as high voltage lines, transformers and breakers and low voltage buses and feeder circuits. They are both manual and motor driven and can be single or three phase. Hydro One Transmission currently owns and manages approximately 5,600 high voltage disconnect switches and 8,500 low voltage switches.

Hydro One Transmission's switch replacement program is focused on managing switches that are deemed end of life. Condition information for high and low voltage switches is primarily obtained from visual inspections of the current carrying components, insulators, mechanism and linkages as well as operational tests. This condition information in combination with data on the age demographic, performance statistics, equipment reliability including likelihood and consequence of failure, recorded equipment defects, safety concerns, spare parts availability, and customer needs are utilized in the determination of end of life and asset replacement needs.

Approximately 10% of the disconnect switches are at or beyond their expected service life. These older switches do not meet current system design requirements and are no longer supported by the manufacturer with replacement current carrying parts obsolete due to their design.

The disconnect switches scheduled for replacement in the test years will be replaced with new disconnect switches. The proposed plan will be to replace 64 and 87 disconnect switches in the 2015 and 2016 test years respectively. This represents an annual replacement rate of approximately 0.5% of the switch fleet over the test years, which is in line with the historic years.

Result:
This plan will replace a total of 151 high voltage disconnect switches over the test years in order to maintain reliability and system performance as well as decrease the probability of switches failures that impact the ability to effectively maintain equipment and pose potential safety hazards to personnel.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	5.4	7.8	13.2
Operations, Maintenance & Administration and Removals (B)	0.2	0.2	0.4
Gross Investment Cost (A+B)	5.6	8.0	13.6
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	5.4	7.8	13.2

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Capacitor Bank Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of capacitor banks at end of life, by proactively replacing those that represent the highest risk to system security and reliability.

Implications of not proactively managing this population of capacitor banks will result in reduced system voltage support, increased transmission losses, customer power quality issues and an increase in the potential for an environmental and /or safety impact in the event of a failure.

Investment Summary:
Capacitor banks are static devices that provide reactive power to the transmission system, which results in an improved power factor and allows for more efficient power transmission. Hydro One Transmission currently owns and manages 68 high-voltage capacitor banks and 293 low-voltage capacitor banks throughout the transmission system. The high-voltage capacitor banks operate at voltages of 115 kV and 230 kV with reactive capability ranging from 15 MVAR to 410 MVAR, whereas the low-voltage capacitor banks operate at lower voltages between 4.16 kV to 44 kV with reactive capability ranging from 4 to 33 MVAR.

Hydro One Transmission's capacitor bank replacement program is focused on capacitor banks which are in degraded condition and can no longer be relied upon to provide voltage support and power factor correction. Condition information for capacitor banks is primarily obtained through visual inspection of the individual capacitor units, and the associated capacitor bank structure, insulators, and fuses. This condition information in combination with data on the age demographics, equipment defects, and criticality to the system are utilized in the determination of asset replacement needs. Currently there are approximately 11% of the capacitor banks that are beyond their expected service life and are in degraded condition.

The capacitor banks scheduled for replacement in the test years will be replaced with new capacitor banks build to current standards. The proposed plan will be to replace four high-voltage capacitors and six low-voltage capacitors over the test years. This represents an annual replacement rate of approximately 1% of the total capacitor bank fleet over the test years, which is in line with the bridge year; however is an increase over historic levels. This is attributable to an increased rate of replacement as more units reach end of life.

Result:
This plan will replace a total of 10 capacitor banks over the test years to improve system security and reliability as well as reduce operational constraints, environmental and safety risks associated with capacitor bank failures.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	6.3	6.5	12.8
Operations, Maintenance & Administration and Removals (B)	0.2	0.2	0.4
Gross Investment Cost (A+B)	6.5	6.7	13.2
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	6.3	6.5	12.8

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Instrument Transformer Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of instrument transformers at end of life, by proactively replacing those that represent the highest risk to system reliability.

Implications of not proactively managing this population of instrument transformers will result in increased risk to system reliability, increased safety hazards to personnel, and an increased inability to complete scheduled work as a result of instrument transformer failures.

Investment Summary:
Instrument transformers perform an essential role in the power system. These devices allow low power instruments to accurately measure parameters of the power system. Types of instrument transformers include current and voltage transformers. These instrument transformers usually connect to high voltage buses or lines and send low voltage signals to protection and control systems and provide necessary metering information for system operators to ensure the safe and reliable operation of the system. Hydro One Transmission currently owns and manages over 7,000 free-standing instrument transformers throughout the transmission system.

Instrument transformers are not run until failure devices because some models will fail explosively. The chance of having an explosive failure increases as the equipment ages and its expected service life is exceeded. When instrument transformers fail, not only is it an outage to the instrument transformer, but the failure also results in a force outage of the associated bus or line out of service. Approximately 15% of instrument transformers are beyond their expected service life.

Hydro One Transmission's instrument transformer replacement program is focused on managing instrument transformers that are deemed end of life. Condition information for instrument transformers is obtained through visual inspections of bushings, corrosion or external contamination of the unit, and low oil levels; as well as through diagnostic testing including: resistance tests, power factor and capacitance measurements, dissolved gas analysis and oil moisture tests. This condition information in combination with data on the age demographics, performance statistics, equipment reliability, safety hazards and obsolescence are utilized in the determination of end of life and asset replacement needs. These replacements also assist Hydro One Transmission in achieving the PCB contamination requirements mandated by Environment Canada, by eliminating oil filled equipment in excess of PCB contamination thresholds from the transmission system.

The instrument transformers scheduled for replacement in the test years will be replaced with new units built to current standards. The proposed plan will be to replace 70 and 52 instrument transformers in the 2015 and 2016 test years respectively. This represents an average annual replacement rate of approximately 1% of the fleet over the test years, which is in line with historic and bridge years.

Result:
This plan will replace a total of 122 instrument transformers over the test years in order to maintain reliability and system performance as well as decrease the probability of instrument transformer failures that impact the ability to effectively maintain equipment and pose safety hazards to personnel.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.5	3.9	8.4
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	4.5	3.9	8.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.5	3.9	8.4

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Insulator Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of station insulators at end of life, by proactively replacing those that represent the highest risk to system reliability.

Implications of not proactively managing this population of station insulators will result in increased risk to system reliability, increased safety hazards to personnel, and an increased inability to complete scheduled work as a result of insulator failures.

Investment Summary:
Insulators are used in transmission stations to insulate current carrying parts from one another and from ground, and for termination of conductors at structures or to support buses and other power equipment such as: disconnect switches, circuit breakers, and instrument transformers. There are three basic types of insulators in use at Hydro One transmission stations: pin type (mostly cap & pin), post type and strain type. Station insulators are subject to both electrical and mechanical stresses at the installation point. Adequate electrical insulation is one of the basic requirements of any electrical system and failure of insulators is the source of many forced outages. Hydro One Transmission currently owns and manages over 220,000 insulators throughout the transmissions' stations.

Hydro One Transmission primarily obtains condition information for station insulators through visual inspections. However, with the increasing failure rates of its insulators, Hydro One Transmission has implemented more widespread invasive testing to detect cracked insulators. This condition information in combination with data on age demographics, equipment defects, safety hazards and criticality to system are utilized in the determination of end of life and asset replacement needs.

Hydro One Transmission's insulator replacement program is focused on managing the more failure prone cap and pin and multi-cone rigid insulators together with the older porcelain strain insulators. The proposed plan will be to replace approximately 2,500 over the two test years. This represents an annual replacement rate of 0.5% of the fleet over the test years, which is in line with historic years.

Result:
This plan will replace 2,500 station insulators in order to maintain reliability and system performance as well as decrease the probability of insulator failures that impact the ability to effectively maintain equipment and pose safety hazards to personnel.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.4	4.5	8.9
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	4.4	4.5	8.9
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.4	4.5	8.9

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Service Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of station service systems at end of life, by proactively replacing those that represent the highest risk to system security and reliability.

Implications of not proactively managing this population of station service systems will result in the inability to operate transmission station equipment as a result of loss of AC or DC power.

Investment Summary:
Station service systems comprise all equipment necessary to distribute AC or DC power to transmission station facilities from the battery and battery charger systems. The AC station service system supplies power for transformer cooling, tap changer control, switchgear heating, battery chargers, HVAC, etc., all of which are essential to the supply of reliable power from transmission stations to connected loads. The DC station service system supplies power for protection, control and communication systems, which protect and provide remote control of station equipment. In the event of a power supply failure, the station service system is designed to enable the transfer of loads over to the second station service supply. If the transfer fails, transmission elements at the transmission station could be forced out of service or de-rated.

Hydro One Transmission currently owns and manages approximately 190 AC station service systems (70 at BES stations and another 120 at DESN stations), and approximately 60 DC station service systems. Many factors are utilized in the determination of end of life and asset replacement needs. The criteria used to assess the station service systems is primarily a function of results of visual inspections, age demographics, operating history and spare parts availability. Another factor for the AC station service systems specifically, is the external condition of the unit, as these systems are housed within poorly insulated outdoor cubicles that are deteriorating due to corrosion. Approximately 35% AC station service systems and 40% DC station service systems are beyond their expected service life.

The station service systems schedule for replacement in the test years will be replaced with new systems including the transfer schemes, LV fuses, cables, enclosures, and distribution panels. The proposed plan will be to replace 4 station service systems at BES stations and 8 station service systems at DESN stations. This represents an annual replacement rate of approximately 2.5% of the fleet over the test years, which is in line with historic years.

Result:
This plan will replace a total of 12 station service systems over the test years to maintain system security and reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	12.0	12.3	24.3
Operations, Maintenance & Administration and Removals (B)	0.4	0.4	0.8
Gross Investment Cost (A+B)	12.4	12.7	25.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	12.0	12.3	24.3

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Spill Containment
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the environmental risk of releasing oil off site at various transmission stations, by proactively installing, replacing or refurbishing transformer oil spill containment systems.

Implications of not proactively managing the spill containment systems will lead to negative environmental impacts and potential regulatory action by the Ministry of Environment ("MOE") under the powers of the Environmental Protection Act R.S.O. 1990, c. E. 19.

Investment Summary:
Transformers utilized at transmission stations contain large volumes (up to 240,000 L) of insulating oil. Periodically, transformers leak or fail catastrophically releasing large volumes of oil. Spill containment systems are designed to capture the oil contained within a transformer. They also are designed to take into account significant accumulations of rain in the event of a severe rain storm. Oil water separators are used to prevent spilled oil from leaving the station while allowing rainwater to drain offsite.

Hydro One Transmission currently has approximately 75% of its power and autotransformer fleet equipped with spill containment systems. Of the spill containment systems installed, 156 of these systems are regulated by the MOE issued Environmental Compliance Approval ("ECA"), formerly known as Certificate of Approval, which mandates operational and maintenance requirements.

Hydro One Transmission's spill containment program is primarily focused on addressing the older spill containment systems (i.e. pit liner systems installed in the 1970s) that have either significantly reduced functionality or are nearing end of life and do not meet Hydro One Transmission's current standards. The criteria utilized in the determination of end of life and asset replacement needs for spill containment systems includes: condition information, site environmental and geotechnical data, drainage effluent quality, transformer leak records, and station-specific spill risk analysis.

The combination of leaking spill containment pits and severe transformer oil leaks present a serious environmental concern. Oil spill containment systems with chronic oil leaks have been identified by tracking the amount of oil that has leaked from a transformer using oil volume top-up records. Where problems with traces of oil leaching into the drainage ditch are identified, temporary control measures such as berms are required to prevent oil from migrating off site and potentially into adjacent waterways. These are not long term solutions, and as such spill containment systems must be refurbished or replaced to restore adequate protection.

The spill containment systems schedule to be addressed in the test years will involve the refurbishment of existing containment pits as well as the installation of passive oil water separators. Refurbishing the spill containment system mitigates the risk of releasing oil to the environment and the addition of passive oil water separators reduces labour resources by eliminating the need to manually pump out the water from the containment units. The proposed plan will be to install or refurbish 19 and 20 spill containment systems in the 2015 and 2016 test years respectively. This is an increase compared to historic years and is primarily attributable to increased ECA requirements from the MOE expanding the scope of work to upgrade total spill site containment to ensure the entire station is up to modern ECA standards.

Result:
This plan will install or refurbish a total of 39 spill containment systems over the test years to reduce the environmental risk of off-site pollutant migration as well as minimize the potential for punitive action by the MOE as a result of oil spills and leaks to the environment.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	11.3	10.8	22.1
Operations, Maintenance & Administration and Removals (B)	0.6	0.6	1.2
Gross Investment Cost (A+B)	11.9	11.4	23.3
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	11.3	10.8	22.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Integrated Station P&C Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address entire protection and control systems at end of life, by proactively replacing those that represent the highest risk to supply reliability.

Implications of not proactively managing this population of protection and control systems will result in increasing rates of failures, jeopardizing the operability and reliability of the transmission system.

Investment Summary:
Hydro One Transmission has protection and control systems at each of its transmission stations. These systems are critical to the operation and protection of the transmission system and are utilized to sense and isolate abnormal system conditions, provide real-time operational data and remote equipment control, and capture detailed records for post-event analysis. When these systems reach end of life the probability of failure increases, which can result in improper operation causing widespread outages, equipment damage or injury to workers and the public. Failed protection systems jeopardize the operability and reliability of the transmission system due to potential operating restrictions that may be imposed until full operation is restored. The criteria used to assess the protection and control system includes: demographics, performance, manufacturer support, spares availability and technical obsolescence.

At older stations typically a number of the protection and control system components reach end of life at about the same time. Efficiency gains are achieved by replacing the entire protection and control system at the station rather than individual component replacements.

The protection and control systems scheduled for replacement in the test years will be replaced with an entire new relay building, consisting of protection, control, telecom, metering, and battery and charger systems designed to current standards. This standardized design solution is the optimal approach for the replacement of end of life protection and control systems at a station where multiple components have reached end of life. The packaged design solution has all required protection and control equipment installed in a prefabricated building. The building is fully constructed and wired off-site according to Hydro One Transmission specifications and delivered to the identified station for connection and commissioning.

The proposed plan will be to install 6 new relay buildings in each of the 2015 and 2016 test years, which is in line with historic years.

Result:
This plan will replace the protection and control systems at a total of 12 load supply stations over the test years to mitigate the risk of operating end of life equipment and preserve reliability of supply to load customers in the area and maintain overall system operability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	28.7	31.4	60.1
Operations, Maintenance & Administration and Removals (B)	1.5	1.0	2.5
Gross Investment Cost (A+B)	30.2	32.4	62.6
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	28.7	31.4	60.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Protection Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address individual protection systems operating at or beyond their expected service life, by proactively replacing those that represent the highest risk to transmission system reliability and operability.

Implications of not proactively managing this population of protection systems will result in jeopardizing the reliable operation of the transmission system.

Investment Summary:
Protection systems are essential to the operation of the power system. These systems are utilized to sense and isolate abnormal system conditions by removing faulted or damaged equipment from service. There are three main vintages of protection systems: electromechanical, solid state, and microprocessor based intelligent electronic devices. Hydro One Transmission currently owns and manages 12,135 protection systems.

Hydro One Transmission's protection replacement program is focused on addressing the large population of electromechanical and solid-state relays that are operating beyond their expected service life. When these systems reach end of expected service life, the probability of failure and improper operation increases. The failure of a protection system to operate correctly when required can have serious consequences including one or more of: equipment damage, injury to people, and outages. Equipment such as transformers, busses and lines, for which the protection systems are known to be non-functional or un-reliable, must be removed from service. Consequently, replacement of protection systems before they are likely to fail is required to minimize impacts to the operation of the transmission system.

The criteria used to assess the protection and control system includes: demographics, performance, manufacturer support, spares availability and technical obsolescence. Protection systems at or beyond expected service life will be prioritized based on likelihood of failure and consequences to system reliability.

Currently approximately 17% of the protection systems are operating beyond their expected service life. The performance of electromechanical systems in particular can degrade over time, potentially causing improper operation, while solid state or microprocessor based systems are more likely to exhibit complete failure. By replacing protection systems operating beyond the expected service life before failure, extended outages and operating restrictions affecting supply and system reliability can be avoided.

The electromechanical and solid state protection relays scheduled for replacement in the test years will be replaced with new microprocessor based intelligent electronic devices. The proposed plan will be to replace approximately 150 and 170 protection systems in the 2015 and 2016 test years respectively. This represents an annual replacement rate of approximately 1.5% of the protection systems over the test years, which is an increase in rate over the historic years. This increase is required to reduce the number of protection systems that are currently operating beyond their expected service life; as well as address the shorter life cycles of the newer relay designs compared to the legacy electromechanical systems.

Result:
This plan will replace approximately 320 protection systems in total over the test years in order to maintain the reliability and integrity of the transmission system.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	18.4	21.6	40.0
Operations, Maintenance & Administration and Removals (B)	0.1	0.1	0.2
Gross Investment Cost (A+B)	18.5	21.7	40.2
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	18.4	21.6	40.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: RTU and SER Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of remote terminal units ("RTUs") and sequence of event recorders ("SERs") at end of life, by proactively replacing those that represent the highest risk to the operability and monitoring capability of the transmission system.

Implications of not proactively managing these assets will result in a reduction in the reliability of the assets and operability of the system, as well as a potential breach of the Market Rules.

Investment Summary:
RTUs and SERs are essential components for the operation of the transmission network providing remote monitoring and operational control of all transmission stations to the system operators. RTUs are also used to provide telemetry to the IESO and transmission-connected customers in accordance with the obligations of the Market Rules and the Transmission System Code respectively. Failure of an RTU results in complete loss of monitoring and control of a station. The consequences of this include delayed or no response to equipment alarms, delayed restoration of customer outages, delayed switching for planned work, and constraint of generation. SERs provide detailed, station level equipment operation information required for transmission system event investigations. Hydro One Transmission currently owns and manages approximately 500 RTUs and over 100 SERs of various type and vintage.

Hydro One Transmission's RTU and SER replacement program is focused on addressing only the devices identified to be end of life and on a priority basis. There are currently about 16% of the RTUs that are at end of life. In addition, Hydro One Transmission is experiencing operational and maintenance challenges with legacy RTU installations that utilize manufacturers' proprietary communication protocols. The criteria used to assess these devices includes: the ability to meet the Market Rule requirements, age demographics, condition information, equipment obsolescence, lack of vendor support, and the ability to accommodate planned station expansion or required control functions. SERs are typically scheduled for replacement in conjunction with RTU replacements to leverage efficiencies in design, construction and commissioning.

The proposed plan will be to replace approximately 14 RTUs and associated SERs over the 2015 and 2016 test years. This represents an average annual rate of replacement of approximately 1.5% over the test years; which is in line with historic years.

Result:
This plan will replace approximately 14 RTUs and associated SERs over the test years in order to maintain the required functionality and reliability of monitoring and control of the transmission system and maintain compliance with the obligations set forth under the Market Rules and Transmission System Code.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.3	8.2	12.5
Operations, Maintenance & Administration and Removals (B)	0.8	0.1	0.9
Gross Investment Cost (A+B)	5.1	8.3	13.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.3	8.2	12.5

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: DC Signaling (Remote Trip) Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the remaining direct current (“DC”) signaling systems currently in use within the Hydro One transmission system, including customer owned stations.

Implications of not replacing these assets will result in further jeopardizing load supply reliability at stations where DC signaling provides protection path.

Investment Summary:
DC signaling is a legacy technology that is still used in the protection systems of many of Hydro One transmission circuits which have tapped load supply stations. The reliability of DC signaling is essential to the reliability of load supply at these stations. DC signaling relies on transmission of DC voltages over dedicated, continuous metallic telephone wires between stations, and uses DC based relaying to transmit, receive and monitor the communications channels. If the DC signaling for a transmission circuit is degraded or unavailable, the redundant supply capability of the tapped stations is lost and the load is vulnerable to single contingency events or, in some cases, transformers will be removed from service compromising load supply reliability. Hydro One Transmission currently owns and manages approximately 300 DC signaling channels and associated relaying components.

Over 10 years ago, telecommunications providers advised that new DC signaling would no longer be provided and maintenance of existing leased DC cables will be reduced. The manufacturing of this equipment was discontinued in the mid 1980's, hence spare equipment required to maintain the devices is limited by the ability to reclaim components from old relays. In 2003, Hydro One Transmission embarked on a DC signaling replacement program to replace over 500 DC signaling channels and associated relaying. Approximately 40% of the DC channels have been replaced to date.

Hydro One Transmission’s DC signaling replacement program continues to focus on addressing these DC signaling facilities that are at end of life. Both the Hydro One owned and leased metallic cables used for DC signaling are over 40 years old and have been deemed end of life due to increasing deterioration of cable insulation and frequent failures of the compressor equipment required for the operation of these cables. The DC signaling systems scheduled for replacement in the test years will be replaced with modern tone based teleprotection systems. Individual replacements will be done throughout the province as well as targeted replacements within close localized geographic proximity areas where possible which allows for realization of efficiencies during design, construction and commissioning due to the interconnected nature of telecommunications.

The proposed plan will be to replace approximately 25 DC signaling systems in each of the 2015 and 2016 test years. This represents an average replacement rate of 8% over the test years; which is inline the bridge year however this is a decrease from historic years. This decrease is a result of the shift from completing work in the north-eastern GTA to initiating the planning work for the replacement of DC signaling channels within the Niagara region; which requires significant telecommunications infrastructure upgrades prior to migrating from DC signaling.

Result:
This plan will replace a total of 50 DC signaling channels over the test years in order to reduce outages associated with DC signaling and maintain load supply reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	6.7	4.6	11.3
Operations, Maintenance & Administration and Removals (B)	0.6	0.2	0.8
Gross Investment Cost (A+B)	7.3	4.8	12.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	6.7	4.6	11.3

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Protection Tone Channel Replacements
Work Execution Period: January 2015 to December 2016 (on-going program)

Need:
This investment is required to address end of life protection tone channel systems by proactively replacing the ones that represent the highest risk to the secure and reliable operation of the transmission system.

Implications of not replacing these assets will lead to deterioration of reliability of the transmission system and the potential to violate NPCC and NERC reliability standards.

Investment Summary:
Line protection systems rely on telecommunications to transfer protection signals between the terminals of high voltage transmission lines. One of the early technologies developed for this application functioned by changing the pitch of a tone; which are referred to as tone channels. The equipment used for tone channels deployed from the late 1960s through the 1970s started reaching end of life in 2001. As such, in 2002, Hydro One Transmission embarked on a protection tone channel replacement program to replace these assets, initially focusing on a specific models deemed end of life. At that time, there were 370 models that were deemed end of life, of which 70% have been replaced to date. This program has since expanded to include the replacement of all protection tone channel equipment as it reaches end of life. Hydro One Transmission currently owns and manages over 1,100 tone channel devices.

The Hydro One Transmission protection tone channel replacement program is focused on replacing end of life tone channel equipment from protection systems on high voltage transmission lines; with higher priority assigned to circuits subject to NERC and NPCC reliability standards. Due to the interconnectivity between telecommunications devices and protection systems, it is most cost effective to replace tone equipment at the same time as the associated protection system. Consequently, this program is coordinated with protection replacements to realize efficiencies during design and construction.

The protection tone channel systems scheduled for replacement in the test years will be replaced with modern protection tone equipment designed to current standards. The proposed plan will be to replace approximately 17 tone channel devices in each of the 2015 and 2016 test years. This represents an average annual replacement rate of 1.5% over the test years; which is an increase over the historic years. This increase is required due to the expansion of this program to include all tone channel devices.

Result:
This plan will replace a total of 34 tone channel devices over the test years in order to maintain the reliability and integrity of critical portions of the transmission system.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.2	4.2	8.4
Operations, Maintenance & Administration and Removals (B)	0.2	0.2	0.4
Gross Investment Cost (A+B)	4.4	4.4	8.8
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.2	4.2	8.4

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: PLC Device Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the power line carrier ("PLC") devices at end of life, by proactively replacing the ones that represent the highest risk to the safe, secure, reliable operation of the transmission system.

Implications of not proactively managing these devices will lead to deterioration of reliability of the transmission system and the potential to violate NPCC and NERC reliability standards.

Investment Summary:
PLC is a telecommunications medium that allows audio signals to be transmitted through a high voltage transmission line. High frequency audio signals in the range of 30 kHz to 500 kHz are modulated into the 60 Hz power signal and transmitted over a power line. The receiving end filters out and demodulates the high frequencies signals which are processed by the telecommunications end devices. PLC provides a cost effective medium that can bridge very long, and often remote, distances for high speed fault clearance and equipment isolation when a protection system detects a power system disturbance or for transmitting control and monitoring data. Hydro One Transmission currently owns and manages approximately 1,000 PLC devices throughout the transmission system.

PLC was primarily installed in Eastern and Northern Ontario to provide highly reliable and high-speed long haul communication for protection and control functions required by the transmission network. PLC equipment installed in these regions is approaching end of life and is technically obsolete and therefore must be replaced to maintain the secure and reliable operation of the transmission system.

Hydro One Transmission's PLC device replacement program is focused on replacing end of life PLC system components. Many factors are utilized in the determination of asset replacement needs for PLC devices including: demographics, performance, reliability, safety and technical obsolescence.

The PLC devices scheduled for replacement in the test years will be replaced with modern PLC equipment designed to current standards. The proposed plan will be to replace approximately 40 PLC devices in each of the 2015 and 2016 test years. This represents an average annual replacement rate of 4% over the test years; which is an increase over the historic years. This increase is required to address the increasing number of PLC assets that have begun reaching end of life and must be replaced in order to maintain operational reliability.

Result:
This plan will replace a total of 80 PLC devices over the test years in order to maintain the safe, secure and reliable operation of the transmission system and reduce the risk of interruption of supply to customers.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.6	4.7	9.3
Operations, Maintenance & Administration and Removals (B)	0.2	0.3	0.5
Gross Investment Cost (A+B)	4.8	5.0	9.8
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.6	4.7	9.3

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Cyber Security NERC CIP V5 Readiness
Work Execution Period: March 2014 to April 2016

Need:
This investment is required to address the new revision to the NERC Cyber Security Standards that will come into effect April 1, 2016. This standard expands the scope of cyber assets that are required to be under security management.

Implications of not proceeding with this investment would result in Hydro One Transmission being non-compliant with the requirements of this new standard.

Investment Summary:
Hydro One Transmission cyber security compliance initiatives began in 2007 with the original NERC CIP Version 1 standards. On November 22, 2013 Version 5 (V5) of the NERC CIP standards were approved by the FERC. The new NERC CIP V5 standards now include additional asset classifications; which nearly doubles the scope and footprint of affected Hydro One Transmission facilities. Work is currently in progress to determine the impact of the revised standards on Hydro One Transmission facilities. Under NERC CIP V5 it is anticipated that 90 additional Hydro One transmission stations will require physical security boundaries and cyber asset management systems such as access control management and logging, firmware patch control, firewalls and intrusion detection. Hydro One will need to have these upgrades complete by April 1, 2016 in order to demonstrate compliance.

Result:
This plan will ensure Hydro One Transmission will maintain compliance with evolving NERC Cyber Security Standard requirements.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	9.9	1.5	15.6
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	9.9	1.5	15.6
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	9.9	1.5	15.6

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Cyber Security of Load Stations
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to protect transmission stations supplying major urban or industrial load against cyber attacks through the implementation of physical and cyber security requirements defined in the NERC CIP standards.

Implications of not proceeding with this investment would result in potential risks to the reliable supply to major urban and industrial load centres.

Investment Summary:
Once design standards, security management systems and processes are in place and fully mature for meeting the evolving NERC CIP V5 standards, outlined in Exhibit D2, Tab 2, Schedule 3 Reference # S40, it is prudent to apply these to expand beyond the existing station standards to protect stations supplying major cities and industrial load centres.

The proposed plan is to upgrade eight stations to apply NERC CIP compliant design standards and security management systems over the test years.

Result:
This plan will ensure eight stations supplying major cities and industrial load centres will be upgraded to the latest NERC CIP cyber security standards in order to maintain supply reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	1.5	4.5	6.0
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	1.5	4.5	6.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	1.5	4.5	6.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Building Infrastructure
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address end of life infrastructure, functional deficiencies, and safety concerns in the transmission station building infrastructure that represent the highest risk to safety and reliability of the station buildings.

Implications of not proactively managing these assets will result in diminished functionality of the station building infrastructure and increased risk to employee safety and reliability.

Investment Summary:
Transmission station building infrastructure comprises of station heating, ventilation and air conditioning ("HVAC") systems, water supply systems, and building components. These systems provide infrastructure and support services for buildings designed to house Hydro One Transmission staff and in some cases, electrical assets (i.e. protection, control and telecom equipment).

This program includes HVAC system replacements and general building renovations, including building roof and water supply upgrades. Investments are identified based on end of life determination which includes asset condition assessments, inspections, known deficiencies, system needs, consequences of failure and regulatory requirements, where applicable. These investments ensure these systems are functional, compliant with provincial regulations, and do not negatively impact transmission reliability and/or employee safety.

Capital expenditures over the test years 2015 and 2016 are in line with the bridge year but represent an increase over historic spending. This increase in replacements and refurbishments is required to address asset aging and demographic pressures in order to ensure proper operation of the station building infrastructure.

Result:
This program will replace HVAC systems and refurbish or replace building roofs and water supply facilities to mitigate the reliability and safety risks and ensure the systems are compliant with provincial regulations.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	8.5	8.6	17.1
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	8.5	8.6	17.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	8.5	8.6	17.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Stations

Investment Name: Station Civil Infrastructure
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address deficiencies in the transmission station civil infrastructure that represent the highest risk to safety and reliability of the station.

Implications of not proactively managing these assets will result in diminished functionality of the station infrastructure and increased risk to employee safety.

Investment Summary:
Transmission station civil infrastructure comprises of station drainage systems, yard surface / subsurface and access roads, structural footings and foundations. These systems provide infrastructure and support services to station equipment (i.e. circuit breakers; power transformers; other power equipment; protection, control and metering, systems) and station environmental systems. Transmission stations require sound roads and yard surface to safely access electrical power equipment, on-site buildings and other facilities. Deterioration, settlement and/or upheaval of roadways, as well as poor yard conditions, make it difficult for maintenance vehicles to safely access station equipment and cause local flooding.

This program manages the systems considered at risk due to diminished functionality, deterioration, reduced performance, increasing maintenance costs, safety concerns, and non-compliance with regulatory requirements. Functional deficiencies and safety concerns associated with certain civil infrastructure assets have been identified at various transmission stations, through condition assessments, engineering inspections and visual inspections.

This program will result in the refurbishment and replacement for various aging civil infrastructure systems such as cable trench covers, yard lighting, access roads, yard surface/subsurface, and fire detection systems across multiple stations. These investments are required to ensure these systems are functional, compliant with provincial regulations, and do not negatively impact transmission reliability, employee safety or the environment. Capital expenditures over the test years 2015 and 2016 represents a decrease from bridge year and historic spending to reflect the asset needs as identified in assessments.

Result:
This program will refurbish and replace various civil infrastructure systems to mitigate the reliability, safety and environmental risks and ensure the systems are compliant with provincial regulations.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	7.6	7.9	15.5
Operations, Maintenance & Administration and Removals (B)	0.4	0.4	0.9
Gross Investment Cost (A+B)	8.0	8.3	16.3
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	7.6	7.9	15.5

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Wood Pole Replacements
Work Execution Period: January 2015 to December 2016 (*on-going program*)

Need:
This investment is required to address wood pole structures that have reached end of life, by proactively replacing those that represent the highest risk to reliability and safety.

Implications of not proactively managing this population of wood poles will result in increased risk of structure failures during adverse weather conditions impacting public safety and transmission system reliability. Furthermore, since the majority of wood pole lines are single supply, failure of these lines usually cause supply interruptions to customers.

Investment Summary:
Hydro One Transmission currently owns and manages approximately 42,000 wood pole structures spanning about 7,000 route kilometers. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. Wood structures deteriorate over time; the rate of deterioration depends on location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location.

Wood pole structures are comprised of either a single pole or multiple wood poles that support a wood cross-arm which is bolted to the wood pole and is used to support the insulator strings and conductors. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure. Since the 1990's these wood cross-arms have been replaced with steel cross-arms which are expected to have a longer service life. Furthermore for the Gulfport type structures, the small wood pole cross-arms that support the conductor are known to have internal premature rotting and have caused several structure failures in the past. Many of these structures are contained within the critical east west tie line across the northern part of Ontario to Manitoba. Originally there were approximately 5,800 Gulfport structures on the transmission system. To date, approximately 80% of these structures have been removed from the system; the remaining defective Gulfport structures will be addressed within the next 4 years.

Replacement candidates are based on on-going condition assessments. Wood pole structure condition is collected from visual inspections of the various components that make up the structure including the cross-arms. Visual inspections include both a detailed helicopter inspection to assess the upper area of wood structures and a ground line inspection to assess the lower part of wood structures. In addition to the visual inspections other diagnostic testing, focusing on external rot and wood pecker holes, is used to assess condition. Representative samples of wood poles are drilled once they meet a certain age criteria to determine the presence of internal rot. Poles are deemed end of life when the surface condition degrades and are no longer climbable, there is significant pole top rot, or where wood pecker holes have weaken the strength of the pole. Poles that are drill tested that have 2 inches or less of solid circumferential wood remaining from internal rot will be replaced as they have fallen below their required design strength. All wood poles and components are replaced when their condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions.

The wood pole structures scheduled for replacement in the test years will be replaced with new wood pole or composite structures. The proposed plan will be to replace approximately 850 wood poles in each of the test years 2015 and 2016. This represents an average annual replacement rate of approximately 2% of the poles over the test years which is in line with historic years. This rate of replacement has been able to keep pace with end of life wood poles identified through inspections as well as address other known wood pole deficiencies, such as the Gulfport structures, on the transmission system.

Result:
This plan will replace a total of approximately 1,700 wood pole structures over the test years to maintain reliability, and reduce hazards to employees and the public from failing structures.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	27.7	28.2	55.9
Operations, Maintenance & Administration and Removals (B)	3.8	3.9	7.6
Gross Investment Cost (A+B)	31.5	32.1	63.5
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	27.7	28.2	55.9

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Steel Structure Coating

Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:

This investment is required to restore the galvanized coating that protects the steel structures from corrosion in order to extend the steel structures service life.

Implications of not restoring the coating will result in further deterioration of the steel structures impacting both system and customer reliability; as well as employee and public safety. It will also eventually lead to advancing the replacement of structures at a substantially greater cost.

Investment Summary:

Hydro One Transmission currently owns and manages approximately 50,000 steel structures spanning 21,000 route kilometers of overhead transmission lines that transmit electric power via integrated network and radial circuits. There are several types and configurations of steel structure designs in the Hydro One transmission system; but lattice towers are the most predominant structure type. Transmission lattice towers can be further subdivided into the following components: legs, diagonals, struts, arms, and redundant members. Each component serves a specific purpose in supporting the tower and has a unique set of forces and stresses associated with it.

The steel used in transmission structures is manufactured with a zinc-based galvanized coating to protect steel towers from corrosion. Over time the galvanized zinc coating corrodes, exposing the bare steel underneath to the environment. This results in the bare steel beginning to corrode and typically at a much faster rate. In many cases the bare steel has been found to corrode up to 25 times faster than while protected by the zinc. If the tower is not painted with a galvanized coating and corrosion is allowed to continue, the steel components will begin to lose mechanical strength due to excessive metal loss resulting in the structure no longer meeting Hydro One Transmission design standards.

The condition of steel structures is determined through a combination of visual inspections, sample zinc coating measurements, and detailed corrosion assessments. Detailed corrosion assessments have been developed in accordance with Nation Association of Corrosion Engineers guidelines. These assessments involve climbing towers and measuring the remaining thickness of protective coating, loss of metal if any and assessment of bolts and fittings. Towers galvanized coating degrades at varying rates across the province depending on the quality and level of galvanizing on the steel but more importantly the corrosive nature of the installed environment.

Reinstating the protective coating by painting presents the lowest life cycle cost and technically could be carried out on an ongoing basis to extend the life of these assets in perpetuity. The proposed plan will be to restate the protective coating on 350 and 400 steel structures in the 2015 and 2016 test years respectively. This represents an average recoating rate of approximately 1% of the structures each year over the test years; which is higher than the historic years. Historically the number of towers coated per year has been consistently lower than the optimal rate due to the inability to secure planned outages during the time period when weather conditions are conducive to painting process and for a sufficient duration required for the painting process. To enable the increased rate in the test years, Hydro One Transmission has carried out field trials on an alternative tower steel coating product which requires far less steel preparation prior to coating and is a faster-drying product. This should reduce outage time and therefore permit a higher number of towers to be coated within the limited outage windows. This product also has a higher tolerance for cold weather application than the current product being used, which will permit a longer coating season.

Result:
This plan will involve the application of protective galvanized coating on a total of 750 steel structures over the test years to extend the life of steel structures in order to maintain reliability and optimize the life-cycle costs of these structures.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	8.8	10.3	19.1
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	8.8	10.3	19.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	8.8	10.3	19.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Steel Structure Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to replace steel structures that have reached end of life, by proactively replacing those that represent the highest risk to reliability and safety.

Implications of not proactively managing this population of steel structures will result in increased risk of structure failure during adverse weather conditions, impacting both; system and customer reliability as well as employee and public safety.

Investment Summary:
Hydro One Transmission currently owns and manages approximately 50,000 steel structures spanning 21,000 route kilometers of overhead transmission lines that transmit electric power via integrated network or radial circuits. There are several types and configurations of steel structure designs in the Hydro One transmission system, but lattice towers are the most predominant type. Transmission lattice towers can be further subdivided into the following components: legs, diagonals, struts, arms, and redundant members. Each component of the structure serves a specific purpose in supporting the tower and has a unique set of forces and stresses associated with it.

The steel used in transmission structures is manufactured with a zinc-based galvanized coating to protect steel towers from corrosion. Over time the galvanized zinc coating corrodes, exposing the bare steel underneath to the environment. This results in the bare steel beginning to corrode, and typically at a much faster rate. In many cases, the bare steel has been found to corrode up to 25 times faster than while protected by the zinc. If the tower is not painted with a galvanized coating and corrosion is allowed to continue, the steel components will begin to lose mechanical strength due to excessive metal loss resulting in the structure no longer meeting Hydro One Transmission design standards.

Replacement candidates are based on on-going condition assessments. Steel structure condition is collected from a combination of visual inspections, and sample zinc coating measurements. Once a structure is identified in unacceptable condition, a detailed corrosion assessment is undertaken to determine whether it is possible to replace a portion of the steel members and coat the remaining structure to protect it from corrosion or whether the entire structure requires replacement.

The steel structures scheduled for replacement in the test years will be replaced with completely new structures to ensure the integrity of the structure. The proposed plan will be to replace approximately 4 and 12 structures in each of the 2015 and 2016 test years respectively. These numbers are in line with previous year replacement levels and replacements are expected to continue at this rate in the future to address structures that are deteriorated to a level that are no longer practical to recoat.

Result:
This plan will replace a total of 16 steel structures over the test years in order to maintain reliability and reduce safety hazards to employees and the public from potential structure collapse.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	1.9	5.7	7.6
Operations, Maintenance & Administration and Removals (B)	0.2	0.6	0.8
Gross Investment Cost (A+B)	2.1	6.3	8.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	1.9	5.7	7.6

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Steel Structure Foundation Refurbishments
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address the condition of steel structure foundations at end of life, by proactively refurbishing those that represent the highest risk to system reliability.

Implications of not proactively addressing the steel structure foundations will result in an increase probability of structure collapse impacting public safety and reliability of the transmission system.

Investment Summary:
Hydro Ones Transmission currently owns and manages approximately 50,000 steel structures spanning 21,000 route kilometers of overhead transmission lines operating at 115 kV, 230 kV and 500 kV. There are several types and configurations of steel structures in the Hydro One transmission system; but lattice towers are the most predominant structure design. Most of the lattice steel structures are four legged, self-supporting structures; however there are some that are a “V” type with a single point foundation supported by two to four guys and anchors. All types of lattice steel structures are supported by a foundation, in most cases grillage (buried steel) or concrete.

From the early 1900’s into the 1960’s, most lattice steel structures were constructed with a grillage (buried steel) foundation. Concrete foundations were introduced as the new standard for transmission line lattice steel structures starting in the 1960’s with the transition to the new standard by 1970. There are approximately 31,000 grillage footings and approximately 3,100 guyed structures which rely on the integrity of the steel grillage and anchors to support these structures. The majority of these installations are greater than 50 years old.

Steel tower grillage foundations and anchors are fabricated with a zinc-based galvanized coating which protects the underlying steel against corrosion. The coating life can vary considerably depending on the surrounding environment. Once the galvanizing has been depleted, the underlying bare steel begins to corrode and typically at a rate much faster than the galvanized coating. The accelerated corrosion results in metal loss which reduces the mechanical strength of the component.

Hydro One Transmission’s steel structure foundation refurbishment program is focused on assessing, restoring, and refurbishing the grillage foundations to extend the life of the steel that is at and below the ground line.

The refurbishment candidates are based on on-going condition assessments. If no metal loss is visible at the time of assessment, the footings and/or anchors are re-coated to restore the corrosion protection and extend the life of the component(s). If metal loss is visible at the time of assessment, the affected components are scheduled for refurbishment. Past assessments indicate that grillage foundations and anchors in damp/acidic soil conditions, that are in close proximity to cathodic protection systems (railways, pipelines, etc.), and/or are greater than 60 years old are at a higher risk of corrosion degradation.

The proposed plan will be to assess, coat and refurbish 1,000 grillage foundations each year over the test years. This represents an average refurbishment rate of 2% of the foundations each year; which is in-line with the bridge year. Based on the results of recent assessment data these levels are expected to continue into the future.

Result:
This plan will involve addressing a total of 2,000 grillage foundations over the test years to extend the life of steel structure foundations, reduce the risk of public and worker safety incidents related to structure collapse as well as maintain the reliability of the transmission system.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.7	5.5	10.2
Operations, Maintenance & Administration and Removals (B)	0.3	0.4	0.7
Gross Investment Cost (A+B)	5.0	5.9	10.9
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.7	5.5	10.2

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: Shieldwire Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address shieldwire that is at end of life, by proactively replacing those that represent the highest risk of failure.

Implications of not proactively managing this population of shieldwire will result in jeopardizing system reliability, increasing the number of customer interruptions, and increasing the risk of safety hazards to employees and the public.

Investment Summary:
Hydro One's transmission system consists of about 35,000 kilometers of overhead shieldwire. Almost all overhead transmission lines have shieldwire strung above the conductor to protect against lightning strikes and provide grounding continuity. The majority of shieldwire in Hydro One's transmission system is made of galvanized steel wire, whose protective zinc coating deteriorates over time. When the galvanizing corrosion protection has depleted, the underlying steel begins to corrode resulting in loss of metal, reduction in mechanical strength, and eventual failure of the shieldwire. When failure does occur, the broken shieldwire usually makes contact with the conductors before falling to the ground, resulting in a circuit outage; as well as can pose a safety risk to the public depending on the location of the failure.

Hydro One Transmission's shieldwire replacement program is focused on mitigating the risk of shieldwire failures. The condition of the shieldwire is monitored through an annual shieldwire testing program which selects samples from line sections throughout the transmission system to test ductility and tensile strength. If the test data for a particular shieldwire meets the end of life criteria, then that shieldwire is replaced. End of life criteria is based on the remaining tensile strength determined through pull tests, as well as a torsional ductility determined through a turns or twist test. Currently, the shieldwire test results indicated that approximately 1.5% of galvanized shieldwire is at end of life and in high to very high risk of failure.

The proposed plan will be to replace about 150 km of shieldwire per year in the test years 2015 and 2016. This represents an average replacement rate of about 0.5% over the test years; which is in line with the bridge year but is an increase over the historic year to address the asset needs identified through the sample and testing program.

Result:
This plan will replace a total of 300 km end of life shieldwire over the test years in order to maintain reliability and decrease the probability of shieldwire failures that pose safety hazards to employees and the public.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.4	4.4	8.8
Operations, Maintenance & Administration and Removals (B)	0.6	0.6	1.2
Gross Investment Cost (A+B)	5.0	5.0	10.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.4	4.4	8.8

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: Insulator Replacements
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to address transmission line insulators at end of life, by proactively replacing those that are at the highest risk of failure resulting in outages and safety hazards.

Implications of not proactively managing this population of insulators will result in negatively impacting the system reliability, causing an increased number of customer interruptions, and increasing public and employee safety risks.

Investment Summary:
Hydro One Transmission currently owns and manages about 410,000 insulator strings. Insulators are used to support the current carrying conductors and provide electric isolation to the supporting steel or wood structures. There are three main types of string insulators used on the transmission system: porcelain, glass and polymer. Transmission line insulators normally have a life expectancy similar to that of conductors. However, some insulators require replacement before the conductor reaches end of life due to manufacturing defects, lightning strikes and vandalism.

Hydro One Transmission's insulator replacement program replaces transmission lines insulators that are at end of life or insulators that have known design or manufacturing defects. The condition of insulator strings is assessed by visual inspections of the insulator string's units or skirts. In addition, porcelain insulator units greater than 50 years of age are electrically tested. Typically porcelain and glass insulator strings that contain three or more defective insulator units are deemed end of life and require replacement. This condition information in combination with data on the age demographics, known manufacturing defects, criticality, and safety hazards are utilized in the prioritization of asset replacement needs.

There are known manufacturing defects for string insulators both on porcelain insulators installed between the 1960s and 1980s and on polymer insulators installed between the 1980s and 1990s. The porcelain insulators were manufactured with a defective grout used to cement the metal fittings into the porcelain in order to form a string of insulators. This cement when subjected to the elements (moisture) causes it to expand or grow, resulting in cracking and failure of the porcelain to provide electrical isolation. The polymer insulators design deficiencies stem from the effects from corona and result in these insulators having a much shorter life than glass or porcelain depending on their installed orientation on the line. The most problematic of the polymer insulators are on the 115kV and 230 kV transmission lines where installed as a dead-end orientation or horizontal to the line.

The proposed plan will be to replace 1000 insulator strings per year in the test years 2015 and 2016. These levels are generally in line with historic levels with variations from year to year dependent upon the results of ongoing insulator test program results.

Result:
This plan will replace a total of 2,000 insulator strings over the test years in order to reduce employee and public safety risks associated with insulator failures and minimize the risk of unplanned circuit outage.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	3.6	3.7	7.3
Operations, Maintenance & Administration and Removals (B)	0.5	0.5	1.0
Gross Investment Cost (A+B)	4.1	4.2	8.3
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	3.6	3.7	7.3

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: Transmission Lines Emergency Restoration
Work Execution Period: January 2015 to December 2016 *(on-going program)*

Need:
This investment is required to make emergency repairs to the overhead transmission system as they occur.

Not proceeding with this investment is typically not an option, since transmission line emergency restoration is normally required to address the presence of a public or employee safety hazard or a circuit outage and/or customers interruption.

Investment Summary:
Hydro One's transmission system consists of approximately 30,000 circuit kilometers of overhead transmission line, which includes approximately 50,000 steel structures and 42,000 wood structures and associated hardware ranging in age from new to over 100 years old.

When structures and/or components fail under emergency circumstances it is not usually due to age or condition and, in most cases, the failure could not have been prevented. The reasons for failure include but are not limited to; normal weather conditions (i.e. lightning), severe weather events (i.e. tornado), motor vehicle accidents, design defects, acts of vandalism, etc.

In addition to structures and/or components that have failed, Hydro One Transmission must also respond to structures and/or components that are "at risk of imminent failure" that are identified through condition patrols. An example would be a wooden arm or structure that has been damaged by lightning. It may not have failed but is very close to failing. Such repairs are also considered an emergency.

Hence an emergency is defined as: a structure or component that has "failed" or is at "risk of imminent failure"; where the failure could result in a serious public or employee safety hazard, circuit outage and/or property damage. The proposed funding for the transmission lines emergency restoration during the test years are based on recent historic levels of spending associated with emergency repairs.

Result:
This plan will ensure that failures and imminent failures are responded to in a timely fashion in order to minimize public and employee safety risks and circuit outages and/or customer interruptions.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	10.9	11.1	22.0
Operations, Maintenance & Administration and Removals (B)	1.5	1.5	3.0
Gross Investment Cost (A+B)	12.4	12.6	25.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	10.9	11.1	22.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: C25H Line Refurbishment
Work Execution Period: January 2013 to December 2015

Need:
This investment is required to address the condition of the conductor on the 230 kV circuit C25H from Chats Falls SS to Havelock TS. The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Implications of not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:
Conductors are a critical element of a transmission line. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductor on circuit C25H is of ACSR construction. These conductors are manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension.

The existing conductor, insulators, hardware and the shieldwire on circuit C25H are part of the original line built 86 years ago. Conductor tests reveal that the tensile strength and ductility has deteriorated to the extent that the conductor has reached its end of life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. Furthermore, the insulators, hardware and shieldwire on this circuit are also approaching end of life.

The project will result in a rebuild of circuit C25H between Chats Falls SS and Havelock TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes the replacement of the existing 795 kcmil ACSR conductor with a new similar size conductor; as well as the replacement of shieldwire, insulators and all associated hardware on the 170 kilometer section of line between Chats Falls SS and Havelock TS. In addition, all structures will be refurbished as required.

The project is in progress with a planned in-service date of 2015; which is ahead of the originally planned in-service of 2017 outlined in the previous transmission rate filing (EB-2012-0031). It was necessary to advance this work to accommodate circuit outage availability.

Result:
This project to rebuild the 230 kV circuit C25H will result in reducing the safety hazards to workers and the public from potential component failures and maintain customer delivery reliability and line performance.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	27.1	0.0	52.4
Operations, Maintenance & Administration and Removals (B)	0.9	0.0	1.7
Gross Investment Cost (A+B)	28.0	0.0	54.1
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	27.1	0.0	52.4

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: H24C Line Refurbishment
Work Execution Period: January 2013 to December 2016

Need:
This investment is required to address the condition of the conductor on the 230 kV circuit H24C from Marine Junction to Oshawa North Junction. The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Implications of not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:
Conductors are a critical element of a transmission line. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductor on circuit H24C is of ACSR construction. These conductors are manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension.

The existing conductor, insulators, hardware and the shieldwire on circuit H24C are part of the original line built 85 years ago. Conductor tests reveal that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end of life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end of life.

The project will result in a rebuild of circuit H24C between Marine Junction and Oshawa North Junction, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes the replacement of the existing 795 kcmil ACSR conductor with a new similar size conductor; as well as the replacement of shieldwire, insulators and all associated hardware on the 54 kilometer section of the line between Marine Junction and Oshawa North Junction. In addition, all structures will be refurbished as required.

The project is in progress with a planned in-service date of 2016; which is a delay from the original planned in-service date of 2014 outlined in the previous transmission rate filing (EB-2012-0031). This delay was necessary to accommodate circuit outage availability which resulted from advancement of work on the C25H outlined in Exhibit D2, Tab 2, Schedule 3 Reference #S51.

Result:
This project to rebuild a section of the 230 kV circuit H24C will result in reducing the safety hazards to workers and the public from potential component failures and maintain customer delivery reliability and line performance.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.9	12.0	21.7
Operations, Maintenance & Administration &Removals (B)	0.2	0.6	0.8
Gross Investment Cost (A+B)	5.1	12.6	22.5
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.9	12.0	21.7

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: D10S/D9HS Line Refurbishment
Work Execution Period: January 2015 to December 2015

Need:
This investment is required to address the condition of the conductors on the 115 kV circuits D10S and D9HS from Louth Junction to Glendale TS. The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Implications of not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:
Conductors are a critical element of a transmission line. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductors on circuits D10S and D9HS are of ACSR construction. These conductors are manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension.

The existing conductor, insulators, hardware and the shieldwire on circuits D10S and D9HS are part of the original line built 92 years ago. These circuits are supported by a double circuit lattice steel tower structure. Conductor tests reveal that the tensile strength and ductility has deteriorated to the extent that the conductor has reached its end of life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end of life.

The project will result in a rebuild of circuits D10H and D9HS between Louth Junction and Glendale TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes the replacement of the existing 605 kcmil ACSR conductor with a new similar size conductor; as well as the replacement of shieldwire, insulators and all associated hardware on the 6 kilometer section of both lines between Louth Junction and Glendale TS. In addition, all structures will be refurbished as required.

The project is in progress with a planned in-service date of 2015.

Result:
This project to rebuild a section of the 115 kV circuits D10H and D9HS will result in reducing the safety hazards to workers and the public from potential component failures and maintain customer delivery reliability and line performance.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.8	0.0	4.8
Operations, Maintenance & Administration and Removals (B)	0.2	0.0	0.2
Gross Investment Cost (A+B)	5.0	0.0	5.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.8	0.0	4.8

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Q11S/Q12S Line Refurbishment
Work Execution Period: January 2015 to December 2016

Need:
This investment is required to address the condition of the conductors on the 115 kV circuits Q11S and Q12S from Beck #1 SS to Glendale TS. The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Implications of not completing this work will result in an increase in the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the region. Conductor failures also create a risk to public safety.

Investment Summary:
Conductors are a critical element of a transmission line. Conductors deteriorate over time and the rate of deterioration depends on location, weather, and atmospheric contamination levels. The conductors on circuits Q11S and Q12S are of ACSR construction. These conductors are manufactured with aluminum strands surrounding steel strands (core). The steel core strands, which supply the majority of the conductor's strength, are galvanized. The galvanized coating wears off over decades due to weather, strand movement and corrosion. Once the protective galvanized coating has worn off the exposed steel strands will corrode quickly and lose their strength and ductility. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension.

The existing conductor, insulators, hardware and the shieldwire on circuits Q11S and Q12S are part of the original line built 92 years old ago. Conductor tests reveal that the tensile strength and ductility have deteriorated to the extent that the conductor has reached its end of life. The conductor steel core has lost the majority of its galvanizing and has rusted badly, making the conductor susceptible to failure from loading caused by wind and ice. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end of life.

The project will result in a rebuild of circuit Q11S and Q12S between Beck #1 SS and Glendale TS, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes the replacement of the existing 605 kcmil ASCR conductor with a new similar size conductor; as well as the replacement of shieldwire, insulators and all associated hardware on the 26 kilometer section of both lines between Beck #1 SS and Glendale TS. In addition, all structures will be refurbished as required.

This project is in progress with a planned in-service date of 2016.

Result:
This project to rebuild a section of the 115 kV circuits Q11S and Q12S will result in reducing the safety hazards to workers and the public from potential component failures and maintain customer delivery reliability and line performance

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	0.0	17.1	17.1
Operations, Maintenance & Administration and Removals (B)	0.0	0.5	0.5
Gross Investment Cost (A+B)	0.0	17.6	17.6
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	0.0	17.1	17.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: Secondary Land Use and Recoverable Projects
Work Execution Period: January 2015 to December 2016

Need:
This investment is required to relocate, remove, or reinforce transmission assets in order to facilitate third-party projects such as roadwork, transit systems, and other major infrastructure or development work that may encroach upon or impact Hydro One Transmission assets and right-of-ways.

Implications of not completing this work will result in impeding third-party projects and may lead to legal action against Hydro One, as well as customer dissatisfaction and poor public perception.

Investment Summary:
Hydro One's transmission system consists of approximately 30,000 circuit km of overhead transmission lines. These transmission lines are used to transmit electric power, via network and radial circuits, to either direct transmission customers, or to transformation points for distribution to retail customers.

This program enables the relocation, removal, and reinforcement of transmission lines assets in order to facilitate third-party development projects, for which the costs are fully recoverable. The known third-party proponent-driven projects include:

- Keith TS Hwy 401 Expansion – this project requires the relocation of several transmission line lattice steel towers in order to accommodate the construction of a new bridge to the United States and associated customs plaza in the Windsor area.

- Waterloo LRT – this project requires the replacement of overhead transmission line lattice steel towers with underground transmission cables in order to accommodate a new light rapid transit line in the Region of Waterloo.

- Manvers Aggregate Pit – this project requires the relocation of several transmission line lattice steel towers in order to accommodate the commercial extraction of aggregate material from underneath their current location in the Kawartha Lakes Region.

- Thunder Bay Hwy 11/17 Widening – this project requires the relocation of several transmission line lattice steel towers in order to accommodate the widening of Hwy 11/17 near Pearl Lake, northeast of Thunder Bay.

These projects are required to meet reliability expectations, regulatory and legal requirements, and to minimize safety impacts associated with transmission line sections that may be impacted by third-party proponent-driven projects.

Result:
This investment will allow Hydro One Transmission to make obligatory relocation, removal, or reinforcement of transmission assets, thereby enabling third-party proponents to proceed with their projects without impacting Hydro One transmission assets.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	44.8	25.6	83.6
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	44.8	25.6	83.6
Recoverable (C)	(44.8)	(25.6)	(83.6)
Net Investment Cost (A+C)	0.0	0.0	0.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: H2JK / K6J Cable Replacement
Work Execution Period: January 2011 to June 2015

Need:
This investment is required to address the condition of the 115 kV low pressure oil filled underground transmission cables H2JK and K6J between Strachan TS and Riverside Junction along Toronto's waterfront. The cables have deteriorated to the point where they have reached end of life.

Implications of not completing this work will result in reliability and supply issues to the downtown Toronto area, and unmitigated environmental risks.

Investment Summary:
Hydro One Transmission manages approximately 290 circuit kilometers of underground 115 kV and 230 kV transmission cables that are located primarily in the cities of Toronto, Hamilton and Ottawa with isolated sections in London, Sarnia, Windsor, Picton and Thunder Bay. Some of the cables located in major cities have experienced a significant increase in loading since original installation, which impacts the aging process, level of redundancy and leads to cable failures. The failure of underground cables can take significant time to repair and can place considerable strain on the network as it may restrict outages required for maintenance and repair for other equipment.

Circuits H2JK and K6J are critical in order to maintain adequate supply to downtown Toronto from Manby TS to Strachan TS and John TS. These underground cables were installed in 1957 and are beyond their expected service life. A combination of defects and widespread corrosion of the lead sheath have led to multiple oil leaks that have become progressively worse over time. The terminal accessories are also in poor condition and continue to experience nuisance oil leaks. If the oil leak rates increase to a level that is unmanageable, a decision would have to be made to shut off the oil supply and remove the circuits from service which would reduce redundancy of supply to downtown Toronto. These leaks have already resulted in multiple long-duration forced outages to attempt to locate and repair. However, repairs were not feasible and hence replacement of the cables is required.

The project will result in a replacement of the underground transmission cables H2JK and K6J between Strachan TS and Riverside Junction, replacing existing aged and degraded infrastructure with new equipment built to current standards. Equipment to be replaced within this project includes the replacement of the existing 115 kV low pressure oil filled cables with new XPLE cables on the approximately 6 kilometers section between Strachan TS and Riverside Junction, as well as the replacement of associated terminal equipment.

The project is in progress with a final completion date of 2015, although the majority of the work will be completed and in-serviced in 2014 which is consistent with the planned in-service date as outlined in the previous transmission rate filing (EB-2012-0031).

Result:
This project to replace the 115 kV underground transmission cables H2JK and K6J will result in maintaining supply reliability to customers in Toronto's downtown core. It will also reduce the risks of public safety incidents and address environmental risks by replacing old oil filled cables with new extruded plastic cables.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	12.1	0.0	62.0
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.4
Gross Investment Cost (A+B)	12.1	0.0	62.4
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	12.1	0.0	62.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Sustaining Capital – Lines

Investment Name: H7L / H11L Cable Replacement
Work Execution Period: January 2015 to December 2016

Need:
This investment is require to address the condition of the 115 kV low pressure oil filled underground transmission cables H7L and H11L between Leaside TS and Main TS. The cables have deteriorated to the point where they have exceeded the expected service life and have been assessed as being among the worst condition of the current cable population.

Implications of not completing this work will result in an increase in the probability of failures that will adversely impact the supply reliability to the east end of Toronto.

Investment Summary:
Hydro One Transmission manages approximately 290 circuit kilometers of underground 115 kV and 230 kV transmission cables that are located primarily in the cities of Toronto, Hamilton and Ottawa with isolated sections in London, Sarnia, Windsor, Picton and Thunder Bay. Some of the cables located in major cities have experienced a significant increase in loading since original installation, which impacts the aging process, level of redundancy and leads to cable failures. The failure of underground cables can take significant time to repair and can place considerable strain on the network as it may restrict outages required for maintenance and repair for other equipment.

Circuits H7L and H11L provide a critical network path from Portlands Generating Station to Leaside TS and supply to Main TS and the load that these cables serve is critical. These 115 kV circuits are a hybrid line consisting of two parallel circuits of overhead lines and two sections of underground cables. The underground cables are over 60 years old and are beyond their expected service life. A combination of higher than normal oil pressures and poor sheath bonding configurations have led to multiple oil leaks, a couple major cable failures, and cable sheath jacket failures. The poor backfill soil thermal resistivity has also resulted in de-rating of the cables that may result in future supply constraints. The oil pressurization systems and terminal accessories are also in poor condition and continue to experience nuisance oil leaks.

The project will result in a replacement of the underground transmission cables H7L and H11L between Leaside TS and Main TS, replacing existing aged cables and associated ancillary equipment with new equipment built to current standards. Equipment to be replaced within this project includes the replacement of the existing 115 kV low pressure oil filled cables with new XLPE cables for a route distance of 2.5 kilometers.

The project is under development with a planned in-service date of 2016.

Result:
This project to replace the 115 kV underground transmission cables H7L and H11L will result in reducing operational risks, maintaining supply reliability to the east end of Toronto. It will also reduce the risks of public safety incidents and address environmental risks by replacing old oil filled cables with new extruded plastic cables.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	14.3	14.5	28.8
Operations, Maintenance & Administration and Removals (B)	0.1	0.1	0.2
Gross Investment Cost (A+B)	14.4	14.6	30.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	14.3	14.5	28.8

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Development Capital - Inter-Area Network Transfer Capability

Investment Name: New 500kV Bruce to Milton Double Circuit Transmission Line
Work Execution Period: Please refer to the table below and to Table 2 in Exhibit D1, Tab 3, Schedule 3, Appendix A for this Development project's schedule.

Need:
To construct a new double-circuit 500kV line between Bruce and Milton in accordance with the Ontario Power Authority recommendation; to address the inadequate transmission capacity to transmit renewable and base load generation in the Bruce Area to the load in southern Ontario.

Summary:
The existing transmission in southern Ontario was not capable of accommodating the generation expected to come into service in the Bruce Area; hence additional transmission capability was required. The Ontario Power Authority determined that the preferred solution to increase the transfer capability of the 500kV system was to build a new 500kV double circuit transmission line between the Bruce Complex and Milton SS to securely incorporate the generation from all eight units from Bruce NGS and the committed renewable generation in the Bruce Area.

The new 500kV double circuit line will span a distance of 176km adjacent to the existing 500kV double circuit line utilizing an expanded transmission corridor. One of the 500kV circuits will connect at Bruce A TS, and the other at Bruce B SS. Both circuits will terminate at Milton SS. Addition of new equipment at the existing switchyards is also being undertaken to accommodate the connection of the new circuits.

The Ontario Energy Board granted Hydro One 'Leave to Construct' approval under Section 92 of the OEB Act in its Decision and Order dated September 15, 2008 in Proceeding EB-2007-0050 and an Order-In-Council granting Environmental Assessment approval was received in December 2009. The Niagara Escarpment Commission granted approval under the provision of the Niagara Escarpment Planning and Development Act in its Notice of Decision dated May 10, 2011.

The project construction was completed in May 2012 with project closeout work including removal of temporary access roads and right-of-way environmental mitigation continuing into 2013. As well, expenditures (2014 - $6.9M, 2015 - $3.3M, 2016 - $3.2M, 2017 - $6.5M) will be incurred between 2014 and 2017 for real estate costs associated with the expropriation of lands that were approved by the OEB under Section 99 of the OEB Act in its Decision Order dated March 15, 2011 in Proceeding EB-2010-0023.

Result:
Provide sufficient transmission capacity to reliably transmit the output of the Bruce NGS and 1700 MW of renewable generation in the Bruce Area and surrounding counties.

Costs:
The current cost projection for this project is $709.4M. The table below shows the project costs from Table 2 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D01	204.1	100.1	9.6	6.9	3.3	3.2	709.4	0.5	709.0

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to satisfy the recommendations outlined by the Ontario Power Authority to accommodate new generation.

Hydro One Networks – Investment Summary Document

Development Capital - Inter-Area Network Transfer Capability

Investment Name: D02 - Clarington TS: Build new 500/230kV Station, D03 - Installation of Shunt Capacitor Banks at Cherrywood TS
D03 – Installation of Shunt Capacitor Banks at Cherrywood TS
Work Execution Period: Please refer to the table below and to Table 2 in Exhibit D1, Tab 3, Schedule 3, Appendix A for these Development projects' schedules.

Need:
To build new 500/230kV auto-transformation facilities, provide reactive support and reinforce the 230kV supply capability in the east GTA following the retirement of Pickering Nuclear Generating Station (NGS). Not proceeding with this investment would result in inadequate capacity to supply the east GTA loads.

Investment Summary:
The Pickering Nuclear Generating Station is coming to the end of its useful life and its current nuclear operating license runs out in August 2018. While Ontario Power Generation is exploring the possibility of maintaining the operation of the station to 2020, there may be technical, economic and regulatory issues to be resolved before any extension beyond 2018 can be confirmed.

The shutdown of Pickering NGS will result in overloading on the Cherrywood TS 500/230kV autotransformers and a significant reduction in reactive support. Pickering NGS currently provides 3000 MW of active power and over 1200 MVar of reactive power to supply and support the east GTA loads. The OPA, in letters dated October 3, 2011 and January 11, 2012, asked Hydro One to initiate work to provide additional 500/230kV auto-transformation capacity in the east GTA by Spring 2015 in preparation for the retirement of Pickering NGS. The OPA had also identified that additional reactive support at Cherrywood TS is required and recommended the installation of two 300 MVar capacitor banks coincident with Pickering NGS retirement.

The need for the station was previously described in the OPA document dated May 28, 2012, "Description of Need and Rationale for Oshawa Area TS by 2015" provided in Proceeding EB-2012-0031.

In August 2013 the Canadian Nuclear Safety Commission extended the Pickering NGS operating license to June 2018. The in-service date for the new Clarington TS was rescheduled to ensure the new facilities are available before the Pickering NGS retirement. The project in-service date is now Q3 2017. The OPA provided concurrence of this revised in-service date in the letter dated April 16, 2014 which is attached in Appendix B of this exhibit.

The proposed plan covers building a new station at Hydro One owned lands at the Clarington Junction Site. The new station will be equipped with two 750MVA, 500/230kV autotransformers, appropriate 500kV and 230kV switching facilities and two 300 MVar capacitor banks. Hydro One has obtained all necessary approvals for building the new station and the project is now under construction. Hydro One has also initiated preliminary engineering and project development work for the Cherrywood TS capacitor bank.

Result:
Provide adequate supply to east GTA and maintain system reliability following the retirement of Pickering NGS.

Costs:
The current cost projection for the Clarington TS project is $294.1M and for the Cherrywood Capacitor Bank project is $14M. The table below shows the project costs from Table 2 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

Item #	**Gross Cash Flow ($ Millions)**								
	Historical			**Bridge**	**Test**	**Test**	**Gross Total Cost**	**Capital Contribution**	**Net Total Cost**
	2011	**2012**	**2013**	**2014**	**2015**	**2016**			
D02	0.0	6.8	4.5	36.9	91.7	101.1	294.1	0.0	294.1
D03	0.0	0.0	0.1	0.0	0.1	3.4	14.0	0.0	14.0

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The projects are needed to satisfy the recommendations of the OPA to address the east GTA supply needs following the retirement of Pickering NGS.

Hydro One Networks – Investment Summary Document

Development Capital – Local Area Supply Adequacy

Investment Name: Midtown Transmission Reinforcement Plan

Work Execution Period: Please refer to the table below and to Table 3 in Exhibit D1, Tab 3, Schedule 3 Appendix A for this Development project's schedule.

Need:

To replace aging facilities and provide adequate supply capacity to meet future load growth in the Midtown Toronto area. Not proceeding with this investment would result in increased risk of customer interruptions affecting supply reliability for customers and would not support future area growth.

Summary:

The existing transmission facilities in the Midtown Toronto area consists of three 115 kV transmission lines that run between Leaside TS and Wiltshire TS. These lines provide the supply to Toronto Hydro customers served via Bridgman TS and Dufferin TS as well as provide load transfer capability between the Leaside TS and Manby TS 230/115kV autotransformer stations.

There is a need to refurbish a section of one of the existing 115kV circuits underground cables between Birch Junction and Bayview Junction. This section of cable is at the end of its useful life and has been identified as requiring replacement. There is also a need to provide additional transmission capacity to relieve the overloading under first contingency and address load growth at Bridgman TS and Dufferin TS.

This project provides for the reinforcement of the midtown transmission corridor by installing a new circuit between Leaside TS to Bridgman TS at the same time as the replacement of the Birch Junction to Bayview Junction cable section to minimize costs and avoid unnecessary disruption to the community.

The Ontario Energy Board granted Hydro One "Leave to Construct" approval under Section 92 of the OEB Act in its Decision and Order dated June 17, 2010 under Proceeding EB-2009-0425. This project is subject to the Environmental Assessment Act in accordance with the Class EA for Minor Transmission Facilities. On June 30, 2010 Hydro One filed the final Environmental Study Report with the Ministry of the Environment. The project construction is now underway.

The in-service date has been delayed from Q3-2014 reported in Proceeding EB-2012-0031 to Q4-2015 due to a tunnel shaft shoring failure and difficulty in obtaining outages.

Result:

Improve load meeting capability and transmission reliability for customers in the City of Toronto mid-town area.

Costs:
The project cost projection remains unchanged at $114.5M. The table below shows the project costs from Table 3 in Exhibit D1, Tab 3, Schedule 3, Appendix A. The project cost that is allocated to the development component of the project (i.e. after subtracting cost allocated to replacement of the cable) will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customer. The capital contribution amounts indicated are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D04	13.1	22.3	17.2	36.7	21.6	0.0	114.8	44.9	69.9

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase transmission supply capacity and address end-of-life facilities to reliably serve customers in the City of Toronto.

Hydro One Networks – Investment Summary Document

Development Capital – Local Area Supply Adequacy

Investment Name: D05 - Guelph Area Transmission Reinforcement, D06 - Preston TS Transformation
D06 – Preston TS Transformation

Work Execution Period: Please refer to the table below and to Table 3 in Exhibit D1, Tab 3, Schedule 3 Appendix A for these Development projects' schedules.

Need:
To reinforce the electricity supply to the South-Central Guelph area and to the Kitchener/Cambridge area, and provide adequate capacity to accommodate future 115 kV load growth in the South-Central Guelph area. Not proceeding with this investment would impair the ability to provide a reliable supply and support future area load growth.

Investment Summary:
The south central area of the City of Guelph is supplied at 115kV by 230/115kV transformation located at Burlington and Cambridge via two 115kV double circuit lines. This area has experienced significant growth in electricity demand and the existing facilities are reaching their supply capability limit. The load is forecast to continue to grow over the next 20 years, with continuing development of the Hanlon Industrial Park being one of the key contributors to this growth.

Work on reinforcing the area supply is covered under two projects. The first project adds 230/115kV transformation in the Guelph area by building a new 230/115kV autotransformer station at Cedar TS, complete with 115kV switching in order to provide termination of all the existing 115kV circuits into the new station. The new auto transformer station is connected to the existing 230kV system via a 5 km overhead line tap that will be rebuilt from the existing 115kV to a 230 kV double circuit line. The project will also provide for new switches at the Guelph North Junction to address restoration performance requirements, reliability and operational issues.re. The project is currently underway following OEB approval for "Leave to Construct" under Proceedings EB-2013-0053. The expected project in-service date is Q2 2016.

The second project covers provision of an additional 230/115kV autotransformer and associated switching at the existing Preston TS to reinforce the 230kV circuits that supply Cambridge and the 115kV circuits that supply the Kitchener area to improve reliability of supply for the area customers. It also includes provision for new special protection schemes and reactive facilities to be installed at the area stations to improve voltages under contingency condition.

The planning of the Preston project is currently in the Regional Infrastructure Planning (RIP) Process led by Hydro One. Project development and preliminary engineering studies are currently underway in accordance with the RIP process. The earliest project in-service date is expected to be Q2 2017.

Result:
Improve the reliability of supply to the South-Central Guelph area and to the Kitchener/Cambridge area.

Costs:
The cost of the Guelph Area Transmission Refurbishment project is projected at $94.3 M. This is higher than the $88M cost estimate submitted in EB-2013-0053 and is mainly due to the increased cost based on vendor bids for the station work at Cedar TS and the increased scope of work identified during detailed engineering for protection and control at remote sites and for drainage work at Cedar TS. The cost of the Preston project is $24.9M. The table below shows the projects costs from Table 3 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D05	0.1	0.5	1.1	13.5	48.3	29.9	94.3	0.0	94.3
D06	0.0	0.0	0.0	0.3	10.0	4.6	24.9	0.0	24.9

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase reliable transmission capacity in the Guelph, Kitchener and Cambridge areas to supply new load customers.

Hydro One Networks – Investment Summary Document

Development Capital – Local Area Supply Adequacy

Investment Name: Toronto Area Station Upgrades for Short Circuit Capability: Manby TS
Work Execution Period: Please refer to the table below and to Table 3 in Exhibit D1, Tab 3, Schedule 3 Appendix A for this Development project's schedule.

Need:
To replace aging 115kV breakers and associated 115kV switchyard facilities at Manby TS and to improve short circuit ratings at these stations to comply with the Transmission System Code. Not proceeding with this investment would result in risk of poor reliability to customers and an inability to connect new generation in the Toronto 115kV area.

Summary:
The Manby autotransformer station supplies the western section of the Toronto 115kV supply area. It is one of the three stations – the others being Leaside TS and Hearn SS – which needed to have the 115kV switchyard uprated to allow more generation to be connected in the Toronto 115kV area.

The Manby TS 115kV switchyard is equipped with 115kV oil breakers with an asymmetrical current rating of 45.5A. The station uprating work requires that 16 existing oil breakers in the 115kV switchyard be replaced and sections of the station strain bus uprated. The average age of these oil breakers is 51 years and the breakers are approaching end of life. Three oil breakers associated with decommissioned circuits K7B and K8B are to be removed.

A number of additional components such as 115kV instrument transformers and insulators have also been identified as end of life and due for replacement. The project includes the replacement of all end-of-life components at the Manby TS 115kV switchyard to take advantage of 115kV outages.

Result:
Replace aging equipment and allow incorporation of new generation in the City of Toronto.

Costs:
The project was previously reported in Proceeding EB-2012-0031 with an estimated cost of $17.5M and an in-service date of Q4 2014. However, additional deficiencies were identified during the execution phase – station service, new cable trenches and trays, more protection and control work. Significant delays were also introduced due to the necessity to coordinate outages with a number of other major projects in the area. The current project cost is estimated at $24.3M and the in-service date is Q2-2016. To facilitate renewable and high efficiency generation connections in the Toronto 115kV area, the breaker replacement work is targeted for completion by Q4 2014. The remaining station refurbishment work would be done in 2015 and 2016. The table below shows the project costs from Table 3 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

Item #	**Gross Cash Flow ($ Millions)**								
	Historical			**Bridge**	**Test**	**Test**	**Gross Total Cost**	**Capital Contribution**	**Net Total Cost**
	2011	**2012**	**2013**	**2014**	**2015**	**2016**			
D07	0.2	5.2	5.8	3.4	5.7	3.9	24.3	0.7	23.6

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	The project is required to address end-of-life equipment at Manby TS and to meet compliance and reliability requirements.

Hydro One Networks – Investment Summary Document

Development Capital – Local Area Supply Adequacy

Investment Name: Hawthorne TS: Replace 2 Existing Tranformers

Work Execution Period: Please refer to the table below and to Table 3 in Exhibit D1, Tab 3, Schedule 3 Appendix A for this Development project's schedule.

Need:

To provide increased 230/115kV auto-transformation capacity at Hawthorne TS to meet the load growth requirements for the Ottawa 115kV area. Not proceeding with this investment would result in increased risk of customer interruptions affecting supply reliability to customers and would not support future area growth.

Investment Summary:

The Ottawa Area 115kV system is supplied from six 230/115kV autotransformers, two at Merivale TS and four at Hawthorne TS. While most of the autos are rated at 250MVA and a limited time rating of over 300MVA, two of the Hawthorne TS autos – units T5 and T6 – which are 53 and 54 years old respectively - have a lower rating of 225MVA and a limited time rating of 256MVA.

Preliminary studies carried out as part of the Ottawa Area Regional Planning Study have identified that the load meeting capability for the Ottawa 230/115kV system is limited due to the capability of the lower rated transformers. Additional transformation capacity is required to meet the forecast for future loads.

The simplest and lowest cost approach to meet the 230/115 kV autotransformer capacity need is to replace the older, lower rated 225MVA transformers with standard 250MVA units.

The expected project in-service date is Q2 2017.

Result:

The replacement of older, lower rated autotransformers will increase the 230/115kV load meeting capability in the Ottawa Area and address future area load growth.

Costs:

The total project cost is currently estimated at $12.5 M. The table below shows the project costs from Table 3 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D08	0.0	0.0	0.0	0.0	1.0	7.0	12.5	0.0	12.5

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is needed to provide adequate load meeting capability for the Ottawa Area 115kV load.

Hydro One Networks – Investment Summary Document

Development Capital – Local Area Supply Adequacy

Investment Name: York Region – Increase Transmission Capability for B82V/B83V Circuits
Work Execution Period: Please refer to the table below and to Table 3 in Exhibit D1, Tab 3, Schedule 3, Appendix A for this Development project's schedule.

Need:
To increase transmission capability of the Claireville TS x Brown Hill TS line (B82V/B83V) to meet forecast load growth in Northern Vaughan and Northern York Region and to improve restoration capability following major outages. Not proceeding with this investment would result in increased risk of customer interruptions affecting supply reliability for customers.

Summary:
The double-circuit 230kV Claireville-to-Brown Hill line (B82/83V) supplies loads in Northern York Region through three Hydro One owned 230kV/44kV step-down transformer stations—Holland TS, Armitage TS and Brown Hill TS. The 393MW York Energy Center generating station is connected to the line close to Holland TS.

Following a joint Regional planning study for the area, the OPA in its letter dated June 14, 2013, asked Hydro One to proceed with work to improve the load meeting capability of the transmission line. This work includes:

- Installation of two in-line breakers and associated motorized disconnect switches on the B82V/B83V circuits at or near the Holland TS property.
- Design and implementation of a Load Rejection (L/R) scheme for the stations connected to the B82V/B83V system, or have available operational measures adequate for providing similar relief.

These measures will increase the load meeting capability from 540MW to about 750 MW for the near and medium term and allow the line to supply additional customer loads in Northern Vaughan and Northern York Region. It will also allow restoration of customer loads with York Energy Centre as a local supply source, following a major outage on the main transmission line.

The expected project in-service date is Q2 2017.

Result:
Improve load meeting capability and transmission reliability for customers in Northern Vaughan and Northern York Region.

Costs:
The total project cost is currently estimated at $20 M. The project cost will be recovered from the network rate pool and no capital contribution is required from customers. The table below shows the project costs from Table 3 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D09	0.0	0.0	0.0	1.0	5.0	7.0	20.0	0.0	20.0

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase transmission supply capacity to reliably serve customers in Northern Vaughan and Northern York Region.

Hydro One Networks – Investment Summary Document

Development Capital – Load Customer Connection

Investment Name: Copeland MTS: Build Line Connection for Toronto Hydro

Work Execution Period: Please refer to the table below and to Table 4 in Exhibit D1, Tab 3, Schedule 3 Appendix A for this Development project's schedule.

Need:

To provide connection to Toronto Hydro's proposed Municipal Transformer Station, Copeland MTS (formerly known as Bremner MTS). Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by area customers.

Summary:

Toronto Hydro is building a new municipal transformer station on the west side of the Roundhouse at Bremner Blvd and Rees Street in downtown Toronto. The new station will be connected to the 115kV cable circuits that span between John TS and Esplanade TS.

The connection requires extending and looping the existing 115kV circuits through Copeland MTS and building a high voltage switching facility at the station to connect Toronto Hydro's step down transformers. The 115kV circuit extensions will be installed in a tunnel to be built by Toronto Hydro. High voltage gas insulated switching (GIS) facilities will be installed inside the Toronto Hydro Copeland MTS building for the connection of the 115kV cables and the step down transformers. Both the cable extensions and the high voltage switching facilities will be owned and operated by Hydro One.

The project is now in the construction stage after the OEB gave approval to Toronto Hydro to proceed with building Copeland MTS in Proceeding EB-2012-0064. Toronto Hydro has obtained the necessary Environmental Assessment approvals from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities).

The expected project in-service date is Q3 2015.

Result:

To provide connection to the new Toronto Hydro Copeland MTS in downtown Toronto.

Costs:

The project cost will be fully recoverable through capital contribution from the customer Toronto Hydro, as indicated in the table below which shows the project costs from Table 4 of Exhibit D1, Tab 3, Schedule 3 Appendix A. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D10	0.2	0.3	3.1	27.3	9.5	0.0	40.4	40.4	0.0

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to satisfy Toronto Hydro's supply requirements

Hydro One Networks – Investment Summary Document

Development Capital – Load Customer Connection

Investment Name: Seaton TS: Build New 230-28kV Transformer Station

Work Execution Period: Please refer to the table below and to Table 4 in Exhibit D1, Tab 3, Schedule 3 Appendix A for this Development project's schedule.

Need:

To provide transformation capacity in the Seaton area (in northern Pickering) to meet future load growth and to improve supply reliability. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:

The new community of Seaton in northern Pickering will be served by Veridian Utilities. Veridian requires new 27.6kV supply capacity for Seaton. Veridian has requested a dual circuit connection for the proposed new station. They have also requested estimates for a new station. The future work may include site selection for the new station, environmental approvals, removing an existing section of single circuit line, building the new dual circuit line connection facilities and building the transformer station facilities.

Seaton TS will be connected to the transmission system via two 230kV circuits. The project will include two new 230kV/27.6kV, 75/125MVA transformers and a low voltage switchyard with up to eight feeder positions. The new transformer station will provide reliable supply for the growing community of Seaton.

The expected project in-service date is Q2 2017.

Result:

To provide connection to the new Seaton TS in northern Pickering.

Costs:

The total project cost is currently estimated at $30.6M. The table below shows the project costs from Table 4 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

The project cost will include a capital contribution from the customer, as indicated in the table below. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Item #	**Gross Cash Flow ($ Millions)**								
	Historical			**Bridge**	**Test**	**Test**	**Gross Total Cost**	**Capital Contribution**	**Net Total Cost**
	2011	**2012**	**2013**	**2014**	**2015**	**2016**			
D11	0.0	0.0	0.1	0.5	11.0	11.0	30.6	14.5	16.1

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to satisfy Veridian's supply requirements

Hydro One Networks – Investment Summary Document

Development Capital – Load Customer Connection

Investment Name: Supply to Essex County Transmission Reinforcement

Work Execution Period: Please refer to the table below and to Table 4 in Exhibit D1, Tab 3, Schedule 3 Appendix A for this Development project's schedule.

Need:

To increase transmission capacity to accommodate forecast load requirements and to improve reliability in the Windsor - Essex region in the near-term. The load meeting capability of the Kingsville – Leamington subsystem has been exceeded, and is expected to continue to be exceeded into the long-term. Further, the restoration of loads, supplied from the 115 kV system, following outages cannot be accomplished within applicable timelines. Not proceeding with this investment would result in increasing degradation of load supply reliability in the region.

Investment Summary:

The Windsor – Essex region has a well-established history in manufacturing and farming, in particular greenhouse vegetable production. The region is a major regional load centre in Ontario, and had a combined peak demand of over 1000 MW in the years before 2008 but has been below 1,000 MW since 2008, a reflection of the severe economic downturn in the region. Future demand growth in the region is expected to be largely driven by the load growth in the Kingsville-Leamington subsystem. The growth in demand in this subsystem is largely attributable to expected growth in the greenhouse sector (as indicated by customer connection requests and the current outlook for expansion of existing greenhouse operations) and anticipated growth from new operations. The region's load is supplied by transformers connected to 230 kV circuits C21J, C22J, C23Z and C24Z, and 115 kVcircuits J3E, J4E, Z1E, Z7E, E8F, E9F, K2Z and K6Z. In 2013, the Ontario Power Authority (OPA) recommended the implementation of the Supply to Essex County Transmission Reinforcement (SECTR) project to address near-term transmission inadequacies in the region.

The SECTR project consists of establishing a new 230/27.6kV, 75/100/125 MVA transformer station (Leamington TS) in the Municipality of Leamington; and building a 13 km 230 kV double-circuit line on a new right-of-way between the new station and new taps on the 230 kV circuits C21J and C22J between Chatham TS and Sandwich Junction at a location about 20 km from Sandwich Junction.

An Environmental Study Report was filed with the Ministry of the Environment in February 2010, and a "Leave to Construct" application, EB-2013-0421 was filed with the OEB in January 2013, for the SECTR project. The in-service date in that filing was shown as May, 2016. The expected project in-service date is now Q1 2017.

Result:

Meet supply capacity needs, improve local area reliability and meet restoration performance needs in the Windsor - Essex region in the near term.

Costs:
The total project cost is currently estimated at $77.0M with customer capital contributions of approximately $40.4M. The table below shows the project costs from Table 4 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

The project cost that is not allocated to the network pool will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customers as indicated in the table below. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D12	0.8	0.2	0.3	2.0	25.0	37.5	77.0	40.4	36.6

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase reliable transmission capacity in the Windsor –Essex region to accommodate future load, and to meet ORTAC requirements.

Hydro One Networks – Investment Summary Document

Development Capital – Generation Customer Connection

Investment Name: Napanee Gas Generation Connection

Work Execution Period: Please refer to the table below and to Table 5 in Exhibit D1, Tab 3, Schedule 3 Appendix A for this Development project's schedule.

Need:

To connect a 910 MW natural gas plant to the transmission network. The generation project was awarded a contract from the OPA for connection to Lennox TS. Failure to proceed with this investment will not meet Hydro One's obligation to connect generator customers under the Transmission System Code.

Investment Summary:

TransCanada Inc. was awarded a contract from the OPA to connect 910 MW of gas turbine generation at Lennox TS. The station is located in the County of Lennox and Addington near the Town of Napanee. The point of connection for Napanee GS will be the 500kV bus in the Lennox TS switchyard. A short double circuit overhead line will enter the Lennox TS 500kV switchyard from the Napanee GS switching station.

The project is in the preliminary planning stage. The Hydro One connection work consists of installing two 500kV terminations and associated switching facilities at the Lennox TS 500kV bus.

The expected project in-service date is Q1 2017.

Results:

Provide connection of a 910 MW gas generating station to the transmission network at Lennox TS.

Costs:

The total project cost is currently estimated at $6.5 with full funding by the customer. The table below shows the project costs from Table 5 in Exhibit D1, Tab 3, Schedule 3, Appendix A.

The project cost will be fully recoverable through capital contributions from the customers, as indicated in the table below. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Item #	Gross Cash Flow ($ Millions)								
	Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost
	2011	2012	2013	2014	2015	2016			
D13	0.0	0.0	0.0	0.5	1.0	4.5	6.5	6.5	0.0

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to incorporate new generation that was contracted by the OPA under direction from the Ontario Government.

Hydro One Networks – Investment Summary Document

Development Capital – Protection and Control for Enablement of Distribution Connected Generation

Investment Name: Transmission Station P&C Upgrades for DG

Work Execution Period: Please refer to the table below and to Table 6 in Exhibit D1, Tab 3, Schedule 3, Appendix A for this Development project's schedule.

Need:

This investment is required to preserve the loading and protection capability of the feeders, to maintain proper protection for Transmission assets, to maintain reliability of supply to the distribution systems and to provide a safe interconnection for generators.

Not proceeding with this investment will result in the inability of many generators to connect to the distribution systems connected to Hydro One's transmission system.

Summary:

The connection of generation to the Distribution Systems supplied from the Hydro One Transmission System requires a number of modifications and additions to the Protection and Control systems in the Transmission Stations. These may include:

- Feeder Protection Replacement to preserve the loading capability of the feeders and provide directioning to prevent false tripping
- Bus Protection Modification to prevent false tripping
- Line Back-up Protections to protect transmission assets from energy back fed from generation on the distribution systems
- Basic Transfer Trip Signaling to prevent DG islanding and coordinate with reclosing
- Station Telecom facilities for Transfer Trip
- Station telemetry expansion for feeder telemetry and additional equipment alarms

Result:

Allow the connection of renewable generation to the distribution systems throughout Ontario without deterioration in Transmission supply reliability while maintaining protection of Transmission assets and load carrying capacity of the feeders.

Costs:

The table below shows the project costs from Table 6 in Exhibit D1, Tab 3, Schedule 3, Appendix A. The cost of these investments is recovered from the generators as shown in Table 6.

Item #	**Cash Flow ($ Millions)**					
	Historical			**Bridge**	**Test**	**Test**
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
D14	4.3	8.6	3.3	17.5	17.5	18.0

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to incorporate new generation that was contracted by the OPA under direction from the Ontario Government.

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Network Management System Capital Sustainment
Work Execution Period: 04/2013 to 09/2015

Need:
The Network Management System (NMS) at the Ontario Grid Control Centre and the Backup Control Centre, needs to be upgraded before reaching end of life of the software, hardware components and operating system in order to maintain North American Electric Reliability Corporation (NERC) compliance and to mitigate the associated business risks. In late 2014, the current application software, Alstom (formerly Areva) Energy Management System (EMS) 2.5, will be two releases out of date and will not support future business requirements. The server hardware has been in continuous operation since 2008, and its different components are reaching end of life between 2013 and 2015. The existing operating system becomes end of life in 2015.

The upgrade must be completed by 2015 to allow Hydro One to remain within the supportability window stipulated by the vendors. This ensures Hydro One will receive an appropriate level of hardware support and vendor supplied software patches to maintain NERC Cyber Security compliance and to mitigate the business risks associated with operating the Transmission System using a control system that is at end-of-life.

Investment Summary:
The NMS is the mission critical operating tool used for monitoring and control of the Hydro One Transmission System. The reliable operation of the Ontario Power System is dependent on the continued availability and high performance of the NMS.

This investment upgrades the NMS power system software. Additional upgrades to the server operating system, database software and all end of life monitoring and control compute, network and storage hardware will be completed. In addition, this investment will provide capacity for Transmission System growth, the opportunity to leverage new baseline functionality and ensures the NMS remains a fully supported system.

Result:
This investment will maintain required levels of NMS performance, reliability, availability and regulatory compliance by upgrading all NMS end of life components; (i) power system, operating system, database software and (ii) monitoring and control infrastructure hardware for continued sustainability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	12.6	-	34.5
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)	12.6	-	34.5
Recoverable (C)	-	-	-
Net Investment Cost (A+C)	12.6	-	34.5

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustainment Project
Project Need:	Non-discretionary

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Backup Control Centre – New Facility Development
Work Execution Period: 06/2014 to 09/2018

Need:
This investment is required to establish a new Backup Control Centre (BUCC) facility to ensure Network Operations remains compliant with North American Electric Reliability Council (NERC) requirements and reliability and availability targets can be sustained in the event the Ontario Grid Control Centre (OGCC) or its computer systems are rendered unavailable.

The BUCC facility consists of the physical building which houses the backup control rooms for the Hydro One Transmission and Distribution Systems and the associated computer rooms. The existing computer rooms are one of the most limiting factors that put the BUCC at risk. They have reached their design limits in terms of physical space, power supply and environmental controls. As a result, full redundancy of all systems is not currently available and the reliability of Operating back-up facilities has been reduced. Operating has experienced an increase in critical failures, and emergency preparedness considerations have become a significant concern.

Investment Summary:
This investment will fund the new BUCC building at a new location. This investment does not include any additional systems, tools or associated infrastructure that will be required for Network Operating's monitoring and control functions (i.e. servers and racks).

Benefits resulting from this investment will include:

- Provides a modern facility, employing emergency preparedness considerations and industry best practices
- Provides required capacity with expansion potential for current and future requirements
- Improves the reliability of all associated facilities, systems and tools.

Result:
This investment will ensure the BUCC can meet or exceed NERC regulatory requirements, utility best practices and Network Operating business needs. This also mitigates existing BUCC risk factors and ensures the backup facilities are sustainable.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	0.5	11.0	21.4
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)	0.5	11.0	21.4
Recoverable (C)	-	-	-
Net Investment Cost (A+C)	0.5	11.0	21.4

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Development Project
Project Need:	Non-discretionary

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Wide Area Network (WAN) Outreach Program
Work Execution Period: 2015 to 2018

Need:
Hydro One requires expanded telecommunication capacity into many of its transmission stations to support:

- protection and control for transmission development;
- advanced distribution system;
- video surveillance for security; and
- operating, cyber security and enterprise systems such as conferencing and mobile workforce enablement.

Without this investment, Hydro One’s current network will not be able to accommodate any future expansion, current levels of existing telecom services will not be able to be maintained and there will be no room for any future telecom services. This will greatly affect Hydro One’s ability to meet the needs of customers and be compliant with Regulatory requirements.

Investment Summary:
This project will replace the current infrastructure in use since the mid 90’s which consists of point-to-point (e.g. Hub site to OGCC) telecom channels that require high and fixed capacity.

Result:
Technology developments and improvements in WAN technology maintaining inherently efficient use of capacity (bandwidth) will be the enabling technology for existing and new applications such as non-operational data retrieval, cyber security, video surveillance, and SAP/Cornerstone implementation.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.0	4.0	8.0
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	4.0	4.0	8.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.0	4.0	8.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Station Local Area Network (LAN) Program
Work Execution Period: 2015 to 2019

Need:
Modern digital protection, control and monitoring devices located in Transmission Transformer Stations have the ability to be networked together. The internetworking of these devices provides many benefits in the form of reduced cabling costs, reduced cost for primary measuring devices or transducers, reduced design costs, and the ability to achieve business efficiencies by remote interrogation of the devices for fault locating, event analysis and asset utilization information. As end-of-life replacement programs have been installing these modern devices, past practice has been to install Local Area Network (LAN) cabling and equipment among the specific devices being replaced. As Hydro One installs more digital equipment during end-of-life replacements, the addition of new generation connections or station expansion programs, the LAN system is extended to accommodate. This results in different design standards and different vintages of equipment and can cause delays to the affected projects. It has been determined that a more efficient approach is to identify stations that will be needing installation of digital equipment for planned sustainment, development or connection work, and install a standardized and secure station LAN infrastructure sized to meet all forecast LAN capacity needs for that station. This eliminates any impediments to the projects and reduces design and installation costs.

Investment Summary:
This program installs a standardized LAN infrastructure, appropriate to the class of station, which incorporates Cyber Security, remote monitoring and has the capacity, or expandability, to meet all forecast needs.

Result:
For the 2015 and 2016 program six stations will be equipped with LAN infrastructure to ready them for planned sustainment, development or connection projects.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	4.0	5.0	9.0
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	4.0	5.0	9.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	4.0	5.0	9.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Fault Location (Distance to Fault) Project
Work Execution Period: 2015 to 2017

Need:
A robust Fault Location program will facilitate the quicker location of a fault or faulted element on the Transmission System. In turn this will:

- Alleviate the cost and time required to patrol a transmission circuit in order to detect the fault thereby reducing outage times;
- Free up more time for staff to be on the tools rather than patrolling circuits;
- Reduce the cost and carbon footprint of trucks, boats and helicopters currently being used to determine fault location;
- Expedite communications with customers, neighbouring transmitters, etc. regarding the nature of the fault and expected length of outage; and
- Allow for partial restoration of equipment originally removed from service by the contingency by reconfiguring the transmission system.

Overall the Fault Location Project will reduce the effect of contingencies on the transmission system and Hydro One customers.

Investment Summary:
Since the late nineties, Hydro One funded research programs to develop reliable, accurate and automated analytical methods to calculate the location of a fault on transmission lines from information captured by the protective relays and digital fault recorders at all of the terminal stations of the circuit. As end-of-life replacement of electromechanical relays with digital relays progresses, the ability of these modern devices to be internetworked and remotely interrogated makes it possible for Fault Locating to be operationalized at the Ontario Grid Control Centre (OGCC).

In 2004 Hydro One began a program to install data extraction networking infrastructure in the Transmission Transformer Stations. Progress on this was paused during the implementation of the Cyber Security systems mandated by North American Electric Reliability Corporation (NERC) standards. Those systems were completed by 2010 and revised standards for the data extraction infrastructure have been deployed. The first group of thirteen stations with Fault Locating capability connected to the OGCC became operational in 2010 and 2011 with good success reducing helicopter time, staff travel time and shortening restoration on seven occasions in one year. This program will continue to deploy Fault Locating to an additional seventeen stations in 2015 and 2016.

Result:

Benefit calculations indicate annual savings in the range of $0.5 million, outage time reductions of approximately 580 hours, staff driving reduction of 27,000km and reduction in helicopter time of approximately 230 hours. This will serve to increase system reliability, make more efficient use of skilled staff, reduce costs and increase customer satisfaction.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	3.0	3.0	6.0
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	3.0	3.0	6.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	3.0	3.0	6.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Grid Control Network Sustainment Program
Work Execution Period: 2015 to 2019

Need:
The Hydro One Transmission system is centrally operated and monitored at the Ontario Grid Control Centre (OGCC). The Grid Control Network Sustainment Program is a new program to manage the end of life replacement of Grid Control Network communication and computer elements. The program ensures the on-going reliability and performance of control of the Hydro One Transmission system by containing the number of loss-of-control events to acceptable rates by replacement of network equipment just before end-of-life failure rates begin increasing and vendor support is withdrawn. Additionally, the program avoids cost increases associated with maintenance of aging and obsolete equipment.

Investment Summary:
This investment will fund end of life replacement for elements of the Grid Control Network such as routers, firewalls, switches, LANS and gateways.

Result:
The sustainment and replacement will mitigate regulatory and reliability risk and further improve efficiency.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	3.0	2.0	5.0
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	3.0	3.0	5.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	3.0	2.0	5.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Operating Capital

Investment Name: Hub Site End-of-Life and Capacity Expansion
Work Execution Period: 2015 to 2017

Need:

This investment is required to:

- provide capacity expansion for the monitoring and control of new or expanded transmission stations and new transmission connected generators;
- maintain the performance and reliability of monitoring and control of critical grid stations and facilities; and
- refresh end-of-life gateway systems.

Investment Summary:

A Hub Site is comprised of a number of gateway systems that connect the transmission stations in their geographic vicinity to the Ontario Grid Control Centre (OGCC) and Back-Up Control Centre (BUCC). There are thirty-seven Hub Sites. As new assets or transmission-connected generators are added to the grid, the gateways become fully loaded and more gateways need to be added. As the number of gateways at a hub site increases, the risk of loss of that single site exceeds thresholds for grid control reliability and the hub site needs to be split into two or more locations. Presently, there are six sites that exceed these thresholds. Additional gateways will be installed to provide capacity for the monitoring and control of new grid assets and transmission-connected generators. Some new hub sites will be added and large hub sites split.

Gateway systems are computer systems which are subject to software technology obsolescence after a period of six years. This program also refreshes these systems in order to keep the fleet within range of vendor supported versions.

Result:

Grid development projects and generation connections can proceed without impediment or delay and grid loss-of-control risks associated with loss of a hub site are contained to acceptable levels. The 2015 and 2016 program will focus on upgrading and off-loading of the three most critical hubsites.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	2.0	3.0	5.0
Operations, Maintenance & Administration and Removals (B)	0.0	0.0	0.0
Gross Investment Cost (A+B)	2.0	3.0	5.0
Recoverable (C)	0.0	0.0	0.0
Net Investment Cost (A+C)	2.0	3.0	5.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

IT Capital Expenditure

Investment Name: Hardware /Software Refresh and Maintenance
Work Execution Period: January 2015 to December 2016

Need:
Investment levels are intended to ensure that critical systems are highly available and can survive the failure of any single supporting technology component. Further, that the supporting technology components including telecom and IT hardware and software are maintained within vendor support criteria such that they can be fixed and/or replaced expeditiously in the event of failure. To that end, Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program ensuring vendor support is available and decreasing the likelihood of failure. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

Investment Summary:
Included in 2015 through 2016 planned costs are the implementations of enterprise resource planning apps. and tools, further IT security access control and monitoring capabilities, middleware and databases & productivity tools, server upgrades to keep data center infrastructure vendor supported and improvements to the disaster recovery platforms.

Result:
This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investment for problem resolution. This investment in IT system reliability enables general employee productivity because users have access to the tools they require to work and it enables customer satisfaction through availability of customer call centre and outage management systems.

Costs:

($Million)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	12.0	11.2	23.2
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)	12.0	11.2	23.2
Recoverable (C)	-	-	-
Net Investment Cost (A+C)	12.0	11.2	23.2

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

IT Capital Expenditure

Investment Name: MFA Servers and Storage
Work Execution Period: January 2015 to December 2016

Need:
This investment is required to respond to and manage annual growth in demand for additional IT processing and storage capacity and to address end of life issues with the existing Unix and Wintel servers.

Infrastructure servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. Servers and storage devices reach capacity over time and reach their vendor's end-of-support-life at which time they require upgrading or replacement to increase capacity or to ensure cost efficient maintenance that minimizes or eliminates down time. In determining when systems require replacement, the functionality and operating and maintenance costs are assessed. The funding for the servers and storage refresh program varies year over year depending on hardware lifecycles and business requirements for increased processing capacity.

Investment Summary:
Wintel servers are refreshed on a 3-5 year cycle and UNIX servers are refreshed on a 5-7 year cycle. These cycles fall within industry best practices and maintain warranties within an acceptable level. The replacement cycle for refresh of Wintel and Unix servers is to maintain vendor supported levels and includes hardware upgrades, capacity upgrades for core access control and middleware environments in anticipation of increased data processing with SAP-driven processing. Costs in 2015 increase as capital work programs requiring hardware purchases were deferred due to the scheduled 2013 implementation of the SAP Customer Information System Capital project. Costs are higher in 2016 to accommodate typical lifecycle refresh of end of life storage hardware.

Result:
IT system availability directly impacts the productivity of employees who use the technology, and prevents risks to the availability and security of the power network. This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investment for problem resolution. It also reduces the risk to Hydro One's ability to respond to business requirements and project delivery due to IT system integration and scalability impacts.

Costs:

($Million)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	7.1	9.3	16.4
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)	7.1	9.3	16.4
Recoverable (C)	-	-	-
Net Investment Cost (A+C)	7.1	9.3	16.4

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

IT Capital Expenditure

Investment Name: MFA PC and Printer Hardware
Work Execution Period: January 2015 to December 2016

Need:

This investment funds the lifecycle refresh of PC and Printer hardware. This equipment includes desktops, laptops, tablets, printers, and plotters. This equipment is used by Hydro One staff to perform their daily work such as accessing email, desktop applications (i.e. Microsoft Office), and enterprise applications. Rugged tablet computers are used by field staff. Tablets are used with Geospatial Information Systems (“GIS”) applications for undertaking system design work and for asset condition assessments. Plotters are used by Hydro One engineering and operations staff for design work and to plot system maps.

This investment is required for replacement of existing PC and Printer equipment that has reached the end of useful life to address warranty considerations and to maintain hardware reliability, as well as to upgrade existing equipment to meet business needs. Equipment refresh maintains or reduces maintenance costs. Hardware costs tend to increase with age, especially when the hardware is no longer supported under vendor warranty.

Investment Summary:

Hydro One’s practice is to replace desktop and laptop computers every three to five years, and printers and plotters every four to five years. The renewal timeline is consistent with industry practice as identified by Gartner industry benchmarking studies. In practice, the refresh cycle has been slightly longer but has been consistent with maintaining functionality and minimizing maintenance costs.

This funding is required to replace/upgrade existing equipment to ensure it delivers the required level of reliability and service to the business. Old equipment that is past the end of its useful life becomes unreliable and negatively impacts the ability of the business to perform their day to day work, thereby increasing costs to Hydro One and its ratepayers. In addition, existing equipment may need to be upgraded to meet the changing needs of the business. Costs stabilize in 2015 through 2016 and include the purchase of semi rugged tablets for the Mobile IT development project.

Result:

The PC and Printer hardware assets will reliably support business needs and the performance of day-to-day work unimpeded by end-of-life computer reliability problems.

Costs:

($Million)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	5.6	5.3	10.9
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)	5.6	5.3	10.9
Recoverable (C)	-	-	-
Net Investment Cost (A+C)	5.6	5.3	10.9

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

IT Capital Expenditure

Investment Name: Field Workforce Optimization and Mobile IT
Work Execution Period: May 2014 to December 2016

Need:
The existing processes and applications used to manage work within the Provincial Lines organization involve significant manual effort and paper processing. This creates inefficiencies, time delays and data inaccuracies.

All work and information needs to be scheduled, dispatched and surfaced through a standard set of technologies across all LOB's. The existing applications used by the Provincial Lines organization to schedule, dispatch and report work lacks the integration and accuracy to support effective decision making.

Investment Summary:
The project will streamline Hydro One work management processes and deliver an enhanced, integrated Scheduling and Dispatching Mobile solution. All required work information will be surfaced through SAP's latest platform SMP (SAP Mobile Platform) for the Provincial Lines business unit.
The project will address the following:

- SAP's latest mobile technology for Work Management
- PragmaCad Upgrade with integration to SAP and GIS
- Integrated ORMS PragmaCAD and WEP PragmaCAD
- SMP integration with GIS
- Replace E-time with SAP time reporting solution so that all time is reported in SAP
- Standardized processes and terminology for Scheduling and Dispatch

Where it makes sense, this project will leverage Hydro One's investment in SAP. Scheduling, dispatching and mobility tools and data will be synchronized with SAP as the system of record for equipment, materials and resource availability and with GIS for geospatial information. Additionally, the mobile solution will include work execution and status update as well as time reporting.

Result:
The project will provide the schedulers and field staff with real or near time work status update capability, present staff with a consolidated view of work information, render a geographic scheduling tool on PCs or tablets, and provide ownership of maintaining and creating assets in the field.

This project will also provide a near paperless and automated work environment which will help save paper, fuel and natural resources as well as save corporate operating expenses. By reducing manual steps and providing data validation at time of entry, better data integrity and work efficiency will also be realized.

Costs:

($Million)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	5.0	5.0	10.0
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)	5.0	5.0	10.0
Recoverable (C)	-	-	-
Net Investment Cost (A+C)	5.0	5.0	10.0

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
%	%	%	100%

Hydro One Networks – Investment Summary Document

IT Capital Expenditure

Investment Name: Customer Experience
Work Execution Period: January 2014 to December 2016

Need:
Hydro One needs to be able to communicate through the eCustomer portal to our customers in new and improved ways, and provision self-serve capability. The enhancement to the eCustomer portal would involve a smoother online one stop move in and move out process, SMS, improved outage communications, more secure communication and business integration. It would also allow the customer to use "My Account" functionality such as paperless billing, as well as help them to determine where they can reduce their energy profile. Communication with our customers also needs to be via non device dependent mobile applications.

Hydro One's current CTI solution has reached its end of life. The present solution is highly customized and not configured for ease of change. Any changes require an experienced developer and long test cycles. It also cannot meet Hydro One's current and future customer expectations, with the limitation of being single channeled and not flexible. Another area of concern is that it also has limited scalability. During peak times customers are often not able to communicate with Hydro One's call centers.

This project is the first step of the Hydro One Customer Services organizational 5 year road map.

Investment Summary:
This project is currently in the discovery phase. The CTI replacement is required and will be replaced with a modern technology and off the shelf solutions that meet the present and future needs of Hydro One as we interact with our customers. The eCustomer portal will allow customers and suppliers to get better information when they require and push them to becoming more self-sufficient.

Result:
The results of this project will be a better overall customer experience and proactive communication. We will allow the customer to be able to communicate with us how they choose to. Hydro One will be able to keep up with the changing technology that our customers use and be able to proactively respond to them using the same methods, i.e. texting or tweeting. The improvements to the eCustomer portal will allow users to do more online with their account. This increased online functionality will allow them to be self-sufficient and not have to call into the call centers. They will be able to manage their online usage and understand their bill better and will in general have a smoother overall online experience. When the call center has a multi-channeled application and customers take advantage of the online improvements it will decrease the time an agent needs to spend with individuals and thus speed up the average handle time of call center agents. Also the scalability of the new solution will be able to handle the peak

times better and a customer will not hear a busy signal when they are trying to contact us. These improvements will go a long way in improving the customer experience with Hydro One.

Costs:

($Million)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	5.0	1.0	6.0
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)	5.0	1.0	6.0
Recoverable (C)	-	-	-
Net Investment Cost (A+C)	5.0	1.0	6.0

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

IT Capital Expenditure

Investment Name: Corporate Support Optimization
Work Execution Period: January 2016 to December 2016

Need:
Waste Management

- Electrical assets contain various toxic substances that must be managed carefully. Knowing where and what these substances are is important to the health and safety of our field staff and the people and environments of the communities we serve. Housing this data in systems separate from our work management system increases risk of safety incidents due to lack of all necessary information available to those who require it.
- SAP EAM is where the condition of the assets is recorded and monitored. It is also the system used to prioritize the investments required to reduce risk and maintain and/or improve the condition of the asset. The asset managers need to be able to combine the condition and the toxicity of the asset to drive the correct sequence and priority of the refurbishment or replacement of the assets. The costs related to a cleanup and other financial penalties can be significant and garner poor publicity for Hydro One, impacting our public reputation.

ICM

- There are many factors that could cause a serious incident to the health and safety of employees. We need to consolidate our ICM capabilities into SAP in order to create the link between the incidents and the various factors that led to the incident. This will provide the opportunity to improve our health and safety policies and programs necessary to support our Journey to Zero initiative.

Investment Summary:
Several activities will need to be executed to implement the preferred alternative

- Implement SAP EHSM module and configure appropriately to meet Hydro One's ICM requirements.
- Activate sub-module of the existing EAM module to manage and track our assets with toxic substances.
- Convert legacy data to SAP
- Extract the data from SAP to BI/BW via the preconfigured data sources and build the reports or add to the existing asset analytics capabilities.

Result:
Once implemented, the investment will begin to produce immediate results for HS&E as well as financial savings.

- Consolidation of multiple systems into one to manage data and information
- A complete view of the asset demographics that drive investment decisions

- Ability to better determine the cause of an incident and institute corrective actions
- Reduced environmental impact
- Minimizes risk of incurring a fine
- Compliance with regulatory demands
- Improved corporate reputation
- A safer work environment which leads to increased productivity
- Decommissioned systems generate cost savings

Costs:

($Million)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)		3.0	3.0
Operations, Maintenance & Administration and Removals (B)	-	-	-
Gross Investment Cost (A+B)		3.0	3.0
Recoverable (C)	-	-	-
Net Investment Cost (A+C)		3.0	3.0

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Common Corporate Costs – Facilities & Real Estate

Investment Name: Real Estate Head Office and GTA Facilities Capital for 2015
Work Execution Period: January 2015 to December 2015

Need:
The Facilities Capital Work Program is responsible to ensure program delivery in terms of capital improvements and providing for the company's accommodation needs. The funding requirements in 2015 mainly reflect expanded facilities to meet the anticipated work space accommodation needs.

Capital investment of $13.1 million is required in 2015 to provide for head office accommodation improvement work that initially began in late 2011 and is expected to continue in the bridge year 2014 and test year 2015.

Effective February 1, 2010 Hydro One Networks has secured an eleven year lease for 483 Bay Street, to serve its ongoing head office requirements. Within the completed lease renewal, Hydro One was successful in obtaining the commitment of the Landlord to upgrade base building systems and infrastructure, and provide allowances for tenant improvements.

In 2015 the gross leasehold improvements and the furniture systems funding requirements are estimated to be $9.1 million and $4.0 million respectively. The leasehold improvements are necessary as major head office building infrastructure elements are now at end of life and require replacement. Similarly, furniture systems were acquired from the previous tenant, refurbished and are also now considered to be at end of life. The planned tenant improvements are part of the negotiated lease agreement.

Investment Summary:
Capital investment of $13.1 million is required in year 2015 to provide for head office accommodation improvements.

Result:
Completed necessary improvements to head office space.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	13.1	0.0	13.1
Operations, Maintenance & Administration and Removals (B)			
Gross Investment Cost (A+B)	13.1	0.0	13.1
Recoverable (C)			
Net Investment Cost (A+C)	13.1	0.0	13.1

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization

Hydro One Networks – Investment Summary Document

Common Corporate Costs – Facilities & Real Estate

Investment Name: Real Estate Field Facilities Capital
Work Execution Period: January 2015 to December 2016

Need:
The capital investment is required for field facilities in order to continue to provide adequate workspace accommodation for various types of staff resources (e.g. regular, temporary) and accommodate lines of business operating requirements. The investment need is driven by the following key factors:

- aging facilities asset base that are near the end of life; and
- emerging accommodation needs of core work programs and changing business requirements.

Capital investment in the aging facilities asset base is required to meet the accommodation needs of the business units. Approximately 40% of administrative and service centre facilities infrastructure is estimated to be more than 40 years old.

The Facilities Capital Work Program focuses on undertaking facility replacement work on a priority basis. Replacement work includes the provision of new buildings and facility renovations. The work is conducted on a project-basis.

There is also the need to fund security infrastructure investments at transmission stations to deter copper theft, protect the safety of the public and Hydro One staff and minimize the risk of outages due to intrusions or changes to equipment.

Investment Summary:
Key program work activities include:

- addressing accommodation requirements in terms of new buildings, buildings additions and major facility renovations; and
- replacing major building components including roof structures, windows, heating, ventilating and air conditioning (HVAC) systems and other structural elements and building systems;
- installing security infrastructure at transmission stations to effectively deter, delay, detect and respond to security threats. These threats include copper theft, criminal activity, domestic extremism and terrorism and create safety concerns for employees and first responders where tampering with electrically live equipment has occurred.

A capital investment of $34.8M is required for year 2015 and $40.0 million is required for 2016. These amounts are needed to fund new accommodation solutions, address needs for new buildings, buildings additions, and facilities improvements, all as required by the company's work programs.

The locations targeted for investments starting in 2014 – 2016 are set out in Table 1. Projects can be multi-year projects, and work is contingent on obtaining the requisite municipal planning approvals.

Table 1: Planned Investment Locations

Project Name	**Planned Investment**	**Start Year**
London,320 South Edgeware (New Garage)	Building and site improvements to acquired property to align with current and planned operations.	2014
London, 425 South Edgeware (New Operation Centre)	Building and site improvements to acquired property to replace existing disparate and undersized facilities at Buchanan TS.	2014
Belleville, 21 Enterprise (New Operation Centre)	Building and site improvements to acquired property to facilitate the consolidation of three facilities that are undersized and ill configured to meet business operations, i.e. Zone 3B FBC (Belleville TS), Travelling Line Crew (120 Adam Street, Belleville) and Bellville Garage.	2014
Alliston Operation Centre (Building & Site Improvements)	Tenant improvements (building and site) to existing leased facility to address health and safety issues and address gaps to operational requirements.	2014
Kleinburg Lines Training (Classrooms)	Additional classrooms to fully address training requirements and replace underperforming office trailers currently serving as classrooms.	2014
Orleans Operation Centre (New Phase 2)	Permanent operations centre for recently created Orleans customer area, which is being serviced by an interim and partially constructed facility (Phase 1).	2015
Bolton, Operation Centre (New)	Permanent operations centre for the recently created Bolton customer area, which is being serviced by an interim trailer facility.	2014
Moosonee Service Centre (Acquisition / New)	Acquisition of current leased facility, which is being divested by owner (Government of Canada).	2014
Dryden Operation Centre (New)	New facility to replace existing undersized and end of life facility, i.e. Dryden Service Centre.	2014
Dryden Garage (New)	New facility to replace existing undersized, ill equipped and end of life facility, i.e. Dryden Garage.	2015
Owen Sound Operation Centre	New facility to replace existing disparate, undersized and end of life facilities, i.e. Rockford Service Centre and Owen Sound Service Centre.	2014
Thunder Bay Hanger	Replace leased facility that is inadequate (undersized and shared with third parties) for operations and must be vacated by Q1 2015.	2014
Thunder Bay Garage	Tenant improvements to existing leased Thunder Bay Garage to replace end-of-life elements and gaps to operational requirements.	2014
Guelph Operation Centre (New Phase 1)	Interim facility to facilitate GATR project at Guelph Cedar TS in 2014, which is being serviced by interim and partially constructed facility (Phase 1).	2014
Sudbury Operation Centre (New or Addition/Renovation)	New or renovated and expanded facility to address crowding, safety issues and gaps to operational requirements.	2015

Result:

- Secured necessary accommodation space in the field in line with work program requirements.
- Improved Administrative and Service Centre facilities through replacement of roof structures, windows, HVAC systems and other structural elements.
- Installed security infrastrastructure at transmission stations to manage the risk of severe injury or fatality from intrusions and the risk of outages impacting local and system reliability.

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	34.8	40.0	74.8
Operations, Maintenance & Administration and Removals (B)			
Gross Investment Cost (A+B)	34.8	40.0	74.8
Recoverable (C)			
Net Investment Cost (A+C)	34.8	40.0	74.8

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Common Corporate Costs and Other

Investment Name: Transport & Work Equipment
Work Execution Period: January 2015 to December 2016

Need:
TWE expenditures for 2015 through 2016 are required primarily to replace end of life core TWE, to support the growing levels of transmission and distribution capital and OM&A sustainment, development and operations work programs; and to support the Electro-Forestry Journey Person Forestry Program (EFJP), Mechanical Brushing Program, Provincial Lines Pole Replacement Program and the replacement of aging helicopters.

TWE capital expenditures include incremental requirements to replace single-engine helicopters with a newer, safer and more capable twin-engine helicopter in 2016. This requirement is driven by regulatory changes being developed by Transport Canada. To protect public safety, Transport Canada has restricted low level single-engine flight in urbanized areas and has begun implementing more stringent waiver criteria limiting low level single-engine helicopter use in the future.

Investment Summary:
Hydro One controls and manages approximately 7,300 transport and work equipment units, which support the various lines of business, including Provincial Lines, Stations, Forestry and Construction Services. Fleet vehicles must be maintained at an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations. These include, but are not limited to CSA 225, the *Highway Traffic Act* and the Commercial Vehicle Operator's Registration regulations. This results in minimized environmental impacts and optimized line-of-business productivity by minimizing downtime, travel time, and by optimizing technology and continuous improvement opportunities.

Fleet Capital Replacement requirements are based on industry standards (manufacturer's recommendations) for life cycle expectancy, Net Book Value (NBV) to Original Capital Value (OCV) ratios and operating cost drivers which are then linked to the Business Plan and Work Programs. Currently the fleet is at 39% NBV to OCV where industry standards suggest 45% as an optimum level. Our present replacement criteria are based on manufacturers' recommendations and repair history.

Key contributors to the 2015-2016 capital program include:
- Primarily the replacement of core transport and work equipment;
- Additional vehicle and equipment requirements to support the Electro-Forestry Journey Person Forestry Program;
- Additional vehicle and equipment requirements to support the Mechanical Brushing Program

- Additional vehicle and equipment requirements to support the Provincial Lines Pole Replacement Program;
- Replacement of one single engine helicopter in 2016

Result:
This investment will:
- Ensure compliance with all safety standards, as well as Ministry of Transportation (MTO) and regulatory requirements
- Allow Hydro One to maintain and improve its present core fleet level of 39% vs. the 45% NBV to OCV established through a combination of Canadian Utility Fleet Manager workshops, direction from Fleet Management Companies and Industry experts
- Maximize productivity and utilization
- Maximize equipment availability
- Optimize repair time and fleet size
- Maximize efficiency and life cycle benefits

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	54.5	62.5	117
Operations, Maintenance & Administration and Removals (B)			
Gross Investment Cost (A+B)	54.5	62.5	117
Recoverable (C)			
Net Investment Cost (A+C)	54.5	62.5	117

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Hydro One Networks – Investment Summary Document

Common Corporate Costs and Other

Investment Name: Service Equipment
Work Execution Period: January 2015 to December 2016

Need:
Minor fixed asset expenditures for service equipment for 2015 through 2016 are required to support the growing levels of transmission and distribution capital and OM&A sustainment, development, and operations work programs and to replace end of life and obsolete equipment.

Investment Summary:
Minor fixed asset (MFA) spending for service equipment consists of capital items of $2,000 or more, required by Hydro One staff to carry out construction and maintenance work programs. MFA expenditures for services equipment are required to replace equipment at end of life, replace technologically obsolete service equipment when new standards and safer work practices come into effect, and provide for sufficient levels of new service equipment consistent with work program expansion.

Purchases in this category include:

- Specialized transportation equipment such as all-terrain vehicles, boats, barges, snowmobiles and related accessories to transport crews to off-road work sites
- Measuring and testing equipment to carry out a variety of work activities including trouble shooting, performance testing of equipment, wood pole density testing, battery testing, relay test systems, moisture analyzers, circuit breaker testers, resistance testers, etc.,
- Tools and a wide range of other miscellaneous equipment such as PCB waste bins, portable generators, cabling trailers and equipment, satellite equipment for mobile emergency preparedness, insulator power washing equipment, Automated External Defibrillator devices, conventional line tensioning puller ropes and Maintenance shop equipment to describe a few.
- Mobile equipment includes relatively large tanker units utilized in the service of transformers including SF6 gas carts, degassifiers used to remove impurities from insulating oil, heated oil tankers, oil filters, oil farm upgrades and dry air machines

MFA service equipment requirements will vary year to year depending on a number of factors including the overall asset condition, the number of large cost “one-time” items that occur from year to year, the size of the work program and associated staffing levels projected in the business plan, random equipment failures, unanticipated system impacts, weather severity and trends which affect the intensity and use of certain types of equipment particularly related to storm and trouble call programs

Spending in 2015 through 2016 is focused on the level of equipment required to accomplish the growth in overall transmission and distribution work programs, and end of life replacement.

Decreases in spending are largely due to Stations Services repairing and replacing fewer oil shipping tankers, mobile degreassifiers and railcar movers.

Result:
- Maintained equipment and tool fleets at the required levels to accomplish the growing levels of capital and OM&A sustainment, development and operation work programs in 2015 through 2016
- Reduced operating costs
- Increased efficiency and reliability

Costs:

($M)	**2015**	**2016**	**Total**
Capital* and Minor Fixed Assets (A)	9.1	7.9	17.0
Operations, Maintenance & Administration and Removals (B)			
Gross Investment Cost (A+B)	9.1	7.9	17.0
Recoverable (C)			
Net Investment Cost (A+C)	9.1	7.9	17.0

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

School Energy Coalition (SEC) INTERROGATORY #15

Interrogatory

Reference: [Ex.D1-3-3/p.13]

Please provide a copy of the referenced Appendix A.

Response

The referenced Appendix A is included in Attachment 1.

SEC-15-Attachment1

Table 2
Inter-Area Network Transfer Capability: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2011	2012	2013	2014	2015	2016				
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line[4]	Development, Non-Discretionary	Category 1	Completed	Completed	204.1	100.1	9.6	6.9	3.3	3.2	709.4	0.5	709.0	Q2 2012
D02	Clarington TS: Build new 500/230kV Station	Development, Non-Discretionary	Category 3	Completed	Not Required	0.0	6.8	4.5	36.9	91.7	101.1	294.1	0.0	294.1	Q3 2017
D03	Installation of Shunt Capacitor Banks at Cherrywood TS	Development, Non-Discretionary	Category 3	Not Required	Not Required	0.0	0.0	0.1	0.0	0.1	3.4	14.0	0.0	14.0	Q2 2018
	Other Capital Projects (<$3M) with 2015-16 Cashflows[5]					0.0	0.0	0.0	0.1	1.0	2.0	5.1[7]	0.0	5.1	
	Other Historical Projects (pre-2015)[6]					65.2	11.3	27.6	15.4	0.0	0.0	804.2	4.3	799.9	
	Total					**269.3**	**118.2**	**41.8**	**59.3**	**96.1**	**109.7**				

__Notes__

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2015 and after 2016 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 4: Significant post-in-service cash flows are shown in bridge and test years due to further real estate and closeout work that is required. See D1-3-3 section 3.1.2 and ISD D01 for further details.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2015 or 2016.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2015 or 2016.
Note 7: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2016, which have some minimal cashflow in 2015 and/or 2016 in order to perform preliminary studies and engineering.

Table 3
Local Area Supply Adequacy: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2011	2012	2013	2014	2015	2016				
D04	Midtown Transmission Reinforcement Plan	Development, Non-Discretionary	Category 2	Completed	Completed	13.1	22.3	17.2	36.7	21.6	0.0	114.8	44.9	69.9	Q4 2015
D05	Guelph Area Transmission Reinforcement	Development, Non-Discretionary	Category 2	Completed	Completed	0.1	0.5	1.1	13.5	48.3	29.9	94.3	0.0	94.3	Q2 2016
D06	Preston TS Transformation	Development, Non-Discretionary	Category 3	Not Required	Not Required	0.0	0.0	0.0	0.3	10.0	4.6	24.9	0.0	24.9	Q2 2017
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	Development, Non-Discretionary	Category 1	Not Required	Not Required	0.2	5.2	5.8	3.4	5.7	3.9	24.3	0.7	23.6	Q2 2016
D08	Hawthorne TS: Replace 2 existing Transformers	Development, Non-Discretionary	Category 3	Not Required	Not Required	0.0	0.0	0.0	0.0	1.0	7.0	12.5	0.0	12.5	Q2 2017
D09	York Region – Increase Transmission Capability for B82V/B83V Circuits	Development, Non-Discretionary	Category 3	Required	Not Required	0.0	0.0	0.0	1.0	5.0	7.0	20.0	0.0	20.0	Q2 2017
	Provision for Regional Planning Projects					0.0	0.0	0.0	0.0	0.0	15.0	148.0	0.0	148.0	
	Other Capital Projects (<$3M) with 2015-16 Cashflows[4]					6.8	6.8	3.4	6.7	2.8	0.0	26.9[6]	0.9	26.0	
	Other Historical Projects (pre-2015)[5]					43.8	63.2	35.6	22.1	0.0	0.0	480.6	22.9	457.7	
	Total					**64.0**	**98.0**	**63.1**	**83.7**	**94.4**	**67.4**				

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2015 and after 2016 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 4: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2015 or 2016.
Note 5: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2015 or 2016.
Note 6: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2015, which have some minimal cashflow in 2015 and/or 2016 in order to perform preliminary studies and engineering.

Table 4
Load Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2011	2012	2013	2014	2015	2016				
D10	Copeland MTS: Build line connection for Toronto Hydro	Development, Non-Discretionary	Category 2	Completed	Not Required	0.2	0.3	3.1	27.3	9.5	0.0	40.4	40.4	0.0	Q3 2015
D11	Seaton TS: Build New 230-28kV Transformer Station	Development, Non-Discretionary	Category 3	Required	Required	0.0	0.0	0.1	0.5	11.0	11.0	30.6	14.5	16.1	Q2 2017
D12	Supply to Essex County Transmission Reinforcement	Development, Non-Discretionary	Category 3	Completed	In Progress	0.8	0.2	0.3	2.0	25.0	37.5	77.0	40.4	36.6	Q1 2017
	Provision for Future Load Connection Projects	Development, Non-Discretionary				0.0	0.0	0.0	0.0	0.0	12.0	79.0	26.4	52.6	
	Other Capital Projects (<$3M) with 2015-16 Cashflows[4]					0.2	0.6	8.7	23.6	4.1	2.0	39.2[6]	26.9	12.3	
	Other Historical Projects (pre-2015)[5]					66.9	75.1	30.3	24.5	0.0	0.0	392.5	88.2	304.3	
	Total					**68.1**	**76.2**	**42.5**	**77.9**	**49.6**	**62.5**				

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2015 and after 2016 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 4: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2015 or 2016.
Note 5: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2015 or 2016.
Note 6: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2016, which have some minimal cashflow in 2015 and/or 2016 in order to perform preliminary studies and engineering.

Table 5
Generation Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2011	2012	2013	2014	2015	2016				
D13	Napanee Gas Generation Connection	Development, Non-Discretionary	Category 3	Not Required	Not Required	0.0	0.0	0.0	0.5	1.0	4.5	6.5	6.5	0.0	Q1 2017
	Provision for Unforeseen Projects	Development, Non-Discretionary	Category 2	Required	Not Required	0.0	0.0	0.0	0.0	2.0	5.0	17.0	17.0	0.0	
	Other Capital Projects (<$3M) with 2015-16 Cashflows[4]					0.8	15.6	46.1	50.8	8.2	2.0	124.1	123.7	0.4	
	Other Historical Projects (pre-2015)[5]					10.5	3.2	22.4	33.2	0.0	0.0	171.1	99.4	71.7	
	Total					**11.3**	**18.8**	**68.5**	**84.5**	**11.2**	**11.5**				

__Notes__

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2015 and after 2016 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 4: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2015 or 2016.
Note 5: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2015 or 2016.

Table 6
Protection and Control Modifications for Enablement of Distribution Connected Generation
Summary of Development Capital Projects in Excess of $3 Million

Item #	Investment Description	Classification as per OEB Filing Guideline	Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2011	2012	2013	2014	2015	2016
D14	Transmission Station P&C Upgrades for DG	Development Non-Discretionary	4.3	8.6	3.3	17.5	17.5	18.0
	Other Capital Projects (<$3M) With 2015-16 Cashflows[4]		0.0	0.0	0.0	2.5	3.6	2.1
	Other Historical Projects (pre-2015)[5]		9.9	13.9	19.3	0.0	0.0	0.0
	Total Gross Capital		**14.1**	**22.5**	**22.6**	**20.0**	**21.1**	**20.1**
	Capital Contributions		*11.0*	*22.5*	*22.6*	*20.0*	*21.1*	*20.1*
	Total Net Capital		**3.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

<u>Notes</u>

Note 4: The cash flows shown in **“Other Capital Projects”** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2015 or 2016.
Note 5: The cash flows shown in **“Other Historical Projects”** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2015 or 2016.

Table 7
Protection and Control Modifications for Consequences of Connected Distribution Generation
Summary of Development Capital Projects in Excess of $3 Million

Item #	Investment Description	Classification as per OEB Filing Guideline	Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2011	2012	2013	2014	2015	2016
	Other Capital Projects (<$3M) With 2015-16 Cashflows[4]		0.0	0.0	0.0	3.9	2.6	4.2
	Other Historical Projects (pre-2015)[5]		0.0	2.5	1.2	0.0	0.0	0.0
	Total Gross Capital		**0.0**	**2.5**	**1.2**	**3.9**	**2.6**	**4.2**
	Capital Contributions		*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Total Net Capital		**0.0**	**2.5**	**1.2**	**3.9**	**2.6**	**4.2**

Notes

Note 4: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2015 or 2016.
Note 5: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2015 or 2016.

Table 8
Smart Grid: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2011	2012	2013	2014	2015	2016
	Smart Grid	Development Non-Discretionary	5.8	10.7	8.8	5.6	3.1	0.0
	Total		**5.8**	**10.7**	**8.8**	**5.6**	**3.1**	**0.0**

Table 9
Performance Enhancement: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2011	2012	2013	2014	2015	2016
	Various lines and TSs outliers-inliers	Development Non-Discretionary	1.2	0.7	0.1	2.6	0.9	0.9
	Total		**1.2**	**0.7**	**0.1**	**2.6**	**0.9**	**0.9**

Table 10
Risk Mitigation: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)						In-Service Years
			Historical			Bridge	Test	Test	
			2011	2012	2013	2014	2015	2016	
	Other Capital Projects (<$3M) With 2015-16 Cashflows[4]		2.1	9.1	16.9	16.2	8.1	4.8	
	Other Historical Projects (pre-2015)[5]		15.8	9.0	11.5	7.6	0.0	0.0	
	Total Gross Capital		**17.9**	**18.1**	**28.4**	**23.8**	**8.1**	**4.8**	
	Capital Contributions		*0.0*	*0.4*	*0.9*	*1.6*	*2.7*	*2.8*	
	Total Net Capital		**17.9**	**17.7**	**27.5**	**22.2**	**5.4**	**2.0**	

<u>Notes</u>

Note 4: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2015 or 2016.
Note 5: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2015 or 2016

School Energy Coalition (SEC) INTERROGATORY #16

Interrogatory

[Ex.D1-1-1/p.3] Please provide a copy of the Navigant Consulting lead-lag study.

Response

The Navigant Consulting Lead-Lag Study is included in Attachment 1.

Working Capital Requirements of Hydro One Networks' Transmission Business

Prepared for:

Navigant Consulting, Inc.
333 Bay Street
Suite 1250
Toronto, ON, M5H 2R2

www.navigant.com

March 18, 2014

This report (the "report") was prepared for Hydro One Networking Inc. ("HONI") by Navigant Consulting, Ltd. ("Navigant"). The report was prepared solely for the purposes of HONI's rate filing to before the Ontario Energy Board and may not be used for any other purpose. Use of this report by any third party outside of HONI's rate filing is prohibited. Use of this report should not, and does not, absolve the third party from using due diligence in verifying the report's contents. Any use which a third party makes of this report, or any reliance on it, is the responsibility of the third party. Navigant extends no warranty to any third party.

Table of Contents

List of Tables

Section I: Executive Summary

Summary

In preparation for a 2015-2016 transmission rate filing before the Ontario Energy Board ("OEB"), Hydro One Networks, Incorporated ("HONI") retained Navigant Consulting Limited ("Navigant") to prepare an update to its prior working capital study. This report provides the results of the update and the working capital requirements of HONI's distribution business.

Listed below are key findings and conclusions from this study:

1. In terms of lead-lag days, the results from this study are generally comparable with HONI's previous transmission working capital study (EB-2012-0031). Where there are differences, they have been identified, explained, and their impact on working capital requirements quantified;
2. The approach and methods used in this study are generally consistent with prior HONI studies as well as studies performed by other local distribution companies in Ontario; and,
3. Data from calendar year 2012 was used as a basis for this analysis. Results from the lead-lag study applied to HONI's test years identify the following working capital amounts.

Table 1: Summary of Working Capital Requirements

Year	2015	2016
Percentage of OMA	2.81%	2.27%
Working Capital Requirement $(M)	$12.7	$10.4

Organization of the Report

Section II of this report discusses the lag times associated with HONI's collections of revenues. This includes a description of the sources revenues and how an overall revenue lag is derived.

Section III presents the lead times associated with HONI's expenses. This includes a description of the types of expenses incurred by HONI's distribution operations and how expenses are treated for the purposes of deriving an overall expenses lead.

Section IV presents the working capital requirements of HONI's distribution business including the working capital requirement associated with the Harmonized Sales Tax ("HST").

Section V presents a summary comparison of the results from this study with results from EB-2012-0031 study. Differences between the two have been noted, explained, and their impacts on working capital quantified. The intent of presenting the discussion in Section V is to demonstrate that the approach used in this study is an accurate reflection of the current distribution operations of HONI and that the results are reasonable when compared with the prior distribution studies.

Section II: Working Capital Methodology

Working capital is the amount of funds that are required to finance the day-to-day operations of a regulated utility and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for determination of working capital and was used by Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to HONI (or "lag") together with the time between which HONI receives goods and services from its vendors and pays for them at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are dollar-weighted where appropriate.[2] The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in HONI's rate base for the purpose of deriving revenue requirements.

Key Concepts

Two key concepts need to be defined as they appear throughout this report:

Mid-Point Method

When a service is provided to (or by) HONI over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([Y-X]+1)}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. The formula uses the number of days in a year (A) and the number of periods in a year (B):

$$\text{Mid-Point} = \frac{A/B}{2}$$

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

[2] The notion of dollar-weighting is pursued further in the sub-section titled "Key Concepts".

Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made to (or by) HONI. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation with significant penalties for late payments. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

Expense Lead Components

As used in this study, Expense Leads are defined to consist of two components:

1. Service Lead component (services are assumed to be provided to HONI evenly around the mid-point of the service period), and
2. Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left HONI's possession).

Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 Million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars actually flow.

Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated transmission business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of HONI's operations, interviews with personnel within HONI's Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) HONI, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to distribution operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

Section III: Revenue Lags

A utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by HONI until the date payments are received from customers and funds are available to HONI.
Interviews with HONI personnel indicate that its transmission business receives funds from the following funding streams:

1. The Independent Electric System Operator ("IESO"); and,
2. Other sources including municipalities, electricity retailers, and for miscellaneous services such as jobbing and contracting work performed by HONI.

Data from HONI's billing system indicates that in 2012, payments from the IESO contributed approximately 79% of HONI's transmission revenues. The lag times associated with the funding streams above were weighted and combined to calculate an overall revenue lag time as shown below.

Table 2: Summary of Revenue Lag

Description	Lag Days	Revenues ($M)	Weighting	Weighted Lag
IESO Revenues	35.69	$1,475	79%	28.20
Other Revenues	53.29	$392	21%	11.19
Total		**$1,867**	**100%**	**39.39**

IESO Revenues

HONI receives revenues from the IESO monthly in a manner that is consistent with the settlement and payment procedures outlined in the IESO's tariff. Taking this information into account and using actual amounts and dates received for 2012, a revenue lag of 35.69 days was determined. The derivation is shown in Table 3 below.

Table 3: Summary of IESO Revenues

Period Beginning	Period Ending	Payment Date	Payment Amount	Weighting Factor	Service Lag Time	Payment Lag Time	Total Lag Time	Weighted Lag
1/1/2012	1/31/2012	2/21/2012	$123.96	8%	15.50	21.00	36.50	3.07
2/1/2012	2/29/2012	3/20/2012	$115.31	8%	14.50	20.00	34.50	2.70
3/1/2012	3/31/2012	4/23/2012	$116.25	8%	15.50	23.00	38.50	3.03
4/1/2012	4/30/2012	5/18/2012	$106.72	7%	15.00	18.00	33.00	2.39
5/1/2012	5/31/2012	6/20/2012	$123.21	8%	15.50	20.00	35.50	2.97
6/1/2012	6/30/2012	7/20/2012	$141.32	10%	15.00	20.00	35.00	3.35
7/1/2012	7/31/2012	8/21/2012	$145.47	10%	15.50	21.00	36.50	3.60
8/1/2012	8/31/2012	9/21/2012	$134.33	9%	15.50	21.00	36.50	3.32
9/1/2012	9/30/2012	10/19/2012	$122.89	8%	15.00	19.00	34.00	2.83
10/1/2012	10/31/2012	11/21/2012	$109.97	7%	15.50	21.00	36.50	2.72
11/1/2012	11/30/2012	12/20/2012	$117.10	8%	15.00	20.00	35.00	2.78
12/1/2012	12/31/2012	1/21/2013	$118.40	8%	15.50	21.00	36.50	2.93
Total			**$1,474.92**					**35.69**

Other Revenues

The lag time associated with other revenues is defined as the sum of an average service lag time and a dollar-weighted payment lag time. The expectation is that HONI bills monthly for services such as merchandising, jobbing, and rents and leases of HONI property. Thus, the mid-point of a month (i.e., 15.21 days) was used as indicative of the service lag, i.e., for non-energy related services provided by Hydro One to outside parties. Accounts receivable balances on other revenues for 2012 were reviewed to determine a dollar-weighted payment lag which was determined to be 38.09 days. Taken together, the lag time associated with other revenues was determined as 53.29 days.

Section IV: Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by HONI's transmission business, and the lead times associated with payments for services provided to HONI. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. OM&A Expenses;
2. Removal & Environmental Remediation Costs;
3. Interest on Long Term Debt;
4. Payments in Lieu of Taxes; and,
5. HST.

OM&A Expenses

For the purpose of the transmission lead-lag study, OM&A expenses were considered to consist of payments made by HONI to its vendors in the following categories:

1. Payroll & Benefits;
2. Property Taxes;
3. Corporate Procurement Card;
4. Trinity Lease Payments;
5. Payments to Inergi;
6. Consulting & Contract Staff; and,
7. Miscellaneous OM&A

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 26.26 days for OM&A expenses.

Table 4: Summary of OM&A Expenses

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Payroll & Benefits	$1,091.25	59%	8.20	4.80
Property Taxes	$71.11	4%	-15.47	-0.59
Corporate Procurement Card	$100.09	5%	33.36	1.79
Trinity Lease Payments	$11.95	1%	-14.25	-0.09
Payments to Inergi	$152.09	8%	44.40	3.62
Consulting and Contract Staff	$200.55	11%	80.15	8.62
Miscellaneous OM&A	$237.83	13%	63.60	8.11
Total	**$1,864.87**	**100%**		**26.26**

Payroll & Benefits

The following items were considered to be expenses related to the Payroll & Benefits of HONI:

1. Four types of payroll including basic, trades, management, and board of directors payroll;
2. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings;
3. Contributions made by Hydro One to the Hydro One Pension Plan;
4. Group Health, Dental, and Life Insurance related administrative fees and claims;
5. Payments made by Hydro One on account of the Employer Health Tax ("EHT"); and,
6. Payments made by Hydro One to the Worker Safety Improvement Board ("WSIB").

When all Payroll, Withholdings and Benefits were dollar-weighted using actual payment data, the weighted average expense lead time associated with Payroll & Benefits was determined to be 8.20 days as shown in Table 5 below.

Table 5: Summary of Payroll & Benefits Expenses

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Pensions	$171.12	16%	-45.68	-7.16
WSIB	$6.61	1%	45.28	0.27
EHT	$17.54	2%	30.88	0.50
Group Life Insurance	$16.71	2%	6.56	0.10
Group Health & Dental – ASO	$6.71	1%	30.83	0.19
Group Health & Dental – Claims	$45.11	4%	1.89	0.08
Payroll – Basic	$355.68	33%	18.50	6.03
Payroll – Construction	$134.99	12%	18.50	2.29
Payroll – Management	$59.64	5%	-0.80	-0.04
Payroll – Board of Directors	$0.49	0%	59.64	0.03
Payroll – Sup Pensions	$2.18	0%	-15.13	-0.03
Payroll Withholdings – Basic	$181.20	17%	26.14	4.34
Payroll Withholdings – Construction	$57.44	5%	26.16	1.38
Payroll Withholdings – Management	$35.06	3%	7.22	0.23
Payroll Withholdings – Board of Directors	$0.19	0%	66.38	0.01
Payroll Withholdings – Sup Pensions	$0.59	0%	-8.50	0.00
Total	**$1,091.25**	**100%**	**267.87**	**8.20**

Property Taxes

HONI makes property tax payments to a number of municipalities and taxing authorities in the Province of Ontario. These payments are made in the current year for the current year and are typically made in installments. Using actual payment dates and amounts associated with HONI's transmission business for calendar year 2012, a dollar-weighted expense lag time of 15.47 days was determined.

Corporate Procurement Card

Procurement (or charge) cards are used by the HONI's employees for a variety of company related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on actual invoices from the HONI's charge card provider and payments made by HONI, a dollar-weighted expense lead time of 33.36 days was determined.

Trinity Lease Payments

HONI leases its office space in the Bell Trinity Square Building from Northam Realty. HONI generally makes its lease payments on or around the end of the month prior for the current month. Taking this information into account and using actual invoices and payments for 2012, a dollar-weighted expense lag time of 14.25 days was determined.

Payments to Inergi

Inergi (a division of CapGemini) provides a number of services to HONI including (and not limited to) customer service operations, finance, human resources, accounts payable, information technology, IESO settlement services, and supply management services. HONI generally makes payments to Inergi on or around the last day of the month for the current month. Based on a review of payments made by HONI to Inergi in 2012, a dollar-weighted expense lead time of 44.40 days was determined.

Consulting and Contract Staff

HONI engages consulting and contract staff to provide assistance in the areas of engineering, environmental services, receivables management, accounting, and general consulting.
A dollar-weighted expense lead time of 80.15 days was determined based on a review of invoices rendered and payments made by HONI in 2012.

Miscellaneous OM&A

This category of expense includes items such as product purchases, equipment rentals, and provision of general services to HONI. Based on transactions in HONI's accounts payable system under this category, a dollar-weighted expense lead time of 63.60 days was derived.

Removal and Environmental Remediation Costs

HONI incurs costs when removing or replacing equipment from existing sites or right of ways. Further, costs relating to environmental remediation at these sites are also incurred. While costs are required to be reported as a depreciation and amortization expense for accounting purposes, there is a cash flow impact associated with HONI's expenditures on such removal and environmental remediation costs. Based upon discussions with HONI staff, estimates for the derivation of removal and environmental remediation costs were determined and summarized in Table 6 below.

Table 6: Summary of Removal and Environmental Remediation Expenses

Description	Expense Lead Time	% of Remediation Expenses	Weighted Lead Time
Removal			
HONI Labour	8.20	85.00%	6.97
HONI Materials	63.60	15.00%	9.54
External Labour	80.15	0.00%	0.00
External Materials	63.60	0.00%	0.00
Total		**100.00%**	**16.51**
Environmental Remediation			
HONI Labour	8.20	42.50%	3.49
HONI Materials	63.60	7.50%	4.77
External Labour	80.15	42.50%	34.06
External Materials	63.60	7.50%	4.77
Total		**100.00%**	**47.09**

Interest on Long Term Debt

HONI makes interest payments on its long term debt outstanding out of current year revenues. Such payments are generally made twice a year. Taking into account the various bonds and other long term debt instruments, a dollar-weighted expense lead time of 8.46 days was determined for the 2012 calendar year.

Payments in Lieu of Taxes ("PILs")

HONI makes payments in lieu of taxes in monthly installments to the relevant taxing authorities. Using payment amounts that were made in calendar year 2012, a dollar-weighted expense lag time of 114.74 days was determined for PIL's.

HST

The expense lead times associated with the following items that attract HST were considered in HONI's distribution lead-lag study.

1. IESO Revenues;
2. OM&A[3]; and,
3. Removals, Environmental Remediation and Capital Costs.

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in Table 7. Note that the statutory approach described at the outset was used to determine the expense lead times associated with HONI's remittances and disbursements of HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice.

Table 7: Summary of HST Working Capital Amounts

Description	HST Lead Time	Working Capital Factor	2015 ($M)	2016 ($M)
IESO Revenues	-45.92	-13%	-$26.65	-$27.72
OM&A Expenses	42.92	12%	$2.27	$2.29
Environmental Remediation	44.30	12%	$0.04	$0.03
Removals	44.30	12%	$0.07	$0.06
Capital	44.30	12%	$8.94	$8.79
Total			**-$15.34**	**-$16.55**

[3] Costs within OM&A that attract HST include Corporate Procurement Card, Trinity Lease Payments, Payments to Inergi, Consulting and Contract Staff and Miscellaneous OM&A

Section V: Hydro One Transmission – Working Capital Requirements

Using the results described under the discussion of revenue lags and expense leads, and applying them to HONI's proposed transmission expenses for the 2015-2016 test years, HONI's working capital requirements were determined and shown in the tables below.

Table 8: HONI Transmission Working Capital Requirements (2015)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	39.39	26.26	13.13	4%	$452.46	$16.27
PILS	39.39	114.74	-75.35	-21%	$72.43	-$14.95
Interest Expense	39.39	8.46	30.93	8%	$289.06	$24.50
Environmental Remediation	39.39	47.09	-7.70	-2%	$6.30	-$0.13
Removals	39.39	16.51	22.88	6%	$38.09	$2.39
Total					**$858.34**	**$28.1**
HST						-$15.3
Total - Including HST						**$12.7**
Working Capital as a Percent of OM&A incl. Cost of Power						**2.81%**

Table 9: HONI Transmission Working Capital Requirements (2016)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	39.39	26.26	13.13	4%	$457.89	$16.42
PILS	39.39	114.74	-75.35	-21%	$82.88	-$17.06
Interest Expense	39.39	8.46	30.93	8%	$302.94	$25.60
Environmental Remediation	39.39	47.09	-7.70	-2%	$5.99	-$0.13
Removals	39.39	16.51	22.88	6%	$33.74	$2.11
Total					**$883.44**	**$26.9**
HST						-$16.5
Total - Including HST						**$10.4**
Working Capital as a Percent of OM&A incl. Cost of Power						**2.27%**

Section VI: Findings and Conclusions

The purpose of this section is to compare the results from this study to HONI's prior working capital transmission study as per EB-2012-0031. In addition, this section demonstrates that the results from this study reflect the current operations of HONI.

Comparison with Prior Transmission Study

Table 10: Working Capital Requirements From Prior Study (2013)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	36.15	23.01	13.14	4%	$451.84	$16.27
PILS	36.15	58.93	-22.78	-6%	$42.69	-$2.66
Interest Expense	36.15	15.16	20.99	6%	$261.98	$15.07
Environmental Remediation	36.15	27.99	8.16	2%	$6.14	$0.14
Removals	36.15	24.40	11.76	3%	$35.25	$1.14
Total					**$797.90**	**$29.94**
HST						-$17.29
Total - Including HST						**$12.66**
Working Capital as a Percent of OM&A incl. Cost of Power						**2.80%**

Table 11: Working Capital Requirements (2015 VS 2013)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	3.24	3.25	-0.01	0%	$0.62	$0.01
PILS	3.24	55.81	-52.58	-14%	$29.74	-$12.29
Interest Expense	3.24	(6.70)	9.94	3%	$27.08	$9.43
Environmental Remediation	3.24	19.10	-15.86	-4%	$0.17	-$0.27
Removals	3.24	(7.88)	11.12	3%	$2.84	$1.25
Total					**$60.44**	**-$1.87**
HST						$1.95
Total - Including HST						**$0.08**
Working Capital as a Percent of OM&A incl. Cost of Power						**0.01%**

Revenue Lag

As shown in Table 11 above, the overall revenue lag in the current study has increased versus the prior study. The primary driver of this change is an increase in the Other (External) Revenue that HONI is receiving.

OM&A Expenses

OM&A expense lead days have increased slightly overall by approximately 3 days versus the prior study. Factors driving the increase include longer expense lead times for Payments to Inergi, Consulting and Contract Staff and Miscellaneous OM&A. Factors driving the decrease is primarily due to a decrease in pension payment lead days. After dollar-weighting all OM&A categories however, the impact of these increased and decreased expense lead times is minimal on HONI's overall working capital requirements.

PILs

PILs expense lead days have increased significantly in this study versus the prior study primarily due to a large true-up payment made in 2012 for 2011. Discussions with HONI subject matter experts indicated that these true-up payments are expected to continue with the same magnitude and scheduling parameters in the future.

Removals & Environmental Remediation

Removals & Environmental Remediation expense lead days have decreased by approximately 8 days and increased by approximately 19 days respectively. This change is primarily driven by different allocations of Removals & Environmental Remediation expenses into HONI Labour/Materials, and Outside Labour/Materials. Discussions with HONI subject matter experts confirmed that these updated allocations are indicative of how Removals & Environmental Remediation expenses are currently allocated and how they are supposed to be allocated in the future. After dollar-weighting all OM&A categories however, the impact of these changes is minimal on HONI's overall working capital requirements.

Comparison with Prior Distribution Study Using Constant Revenue Lag Days

Since the revenue lag days was one of the most significant changes over the prior study, an analysis using constant revenue lag days was conducted to show the individual impacts of the differences in expense leads days. Table 12 below shows that when holding revenue lag days constant, working capital requirement in 2015 is approximately 1.7% lower than the amount in 2013.

Table 12: Working Capital Requirements with 2013 Revenue Lag Days Held Constant (2015 VS 2013)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements
OM&A Expenses	0.00	3.25	-3.25	-1%	$0.62	-$4.01
PILS	0.00	55.81	-55.81	-15%	$29.74	-$12.93
Interest Expense	0.00	(6.70)	6.70	2%	$27.08	$6.87
Environmental Remediation	0.00	19.10	-19.10	-5%	$0.17	-$0.33
Removals	0.00	(7.88)	7.88	2%	$2.84	$0.91
Total					$60.44	-$9.48
HST						1.95
Total - Including HST						**-$7.54**
Working Capital as a Percent of OM&A incl. Cost of Power						**-1.67%**

Conclusions

The results of this study indicate a similar working capital requirement compared to HONI's EB-2012-0031 transmission lead-lag study. Table 13 below summarizes the working capital requirements calculated in this study along with historical working capital amounts.

Table 13: Summary of Historical Working Capital Requirements

	2010 Study		2012 Study		2014 Study	
Test Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
WCR as a % of OM&A	**1.57%**	**1.12%**	**2.80%**	**2.58%**	**2.81%**	**2.27%**

School Energy Coalition (SEC) INTERROGATORY #17

Interrogatory

[Ex.F1-1-p.2] Please provide the referenced Exhibits F2, Tab 1, Schedules 1-3.

Response

The referenced Exhibits F2, Tab1, Schedules 1-3 are included in Attachment 1.

1 # SEC-17-ATTACHMENT1A

HYDRO ONE NETWORKS INC.
TRANSMISSION
Regulatory Accounts for Approval
As at December 31, 2014
($ Millions)

Line No.	Particulars	Balance as at Dec 31, 2013	Forecast Balance as at Dec 31, 2014
		(a)	(b)
1	Excess Export Service Deferred Revenue	(41.9)	(23.5)
2	External Secondary Land Use Revenue	(32.8)	(18.5)
3	External Stations, EC&S Revenue and Other Revenue	(6.4)	(1.3)
4	Tax Rate Changes Account	(3.6)	0.8
5	Rights Payments	(3.6)	(1.9)
6	Pension Cost Differential	20.8	8.2
7	Long-Term Transmission Future Corridor Acquisition and Development	0.1	0.1
8	**Total Regulatory Accounts**	**(67.4)**	**(36.1)**

(a) 2013 interest is based on the OEB prescribed rates.

(b) 2014 includes disposition amounts as approved by the Board in EB 2012-0031 and forecast interest improvement for 2014

2

SEC-17-ATTACHMENT1B

HYDRO ONE NETWORKS TRANSMISSION
Planned Disposition of Regulatory Accounts
Schedule of Annual Recoveries*
Year Ending December 31
($ Millions)

Line No.	Particulars	2015	2016	Total
		(a)	(b)	(c)
1	Adjustment to Revenue Requirement	(18.0)	(18.1)	(36.1)

* Note: Above figures do not include interest improvement during the recovery period

Continuity Schedules
Regulatory Accounts

		2010								
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments 6	Board-Approved Disposition during 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other 3	Closing Interest Amounts as of Dec-31-10
Excess Export Service Revenue	2405	(4,816,978)	(4,286,661)	-	(9,103,639)	(20,718)	(51,769)			(72,487)
External Revenue - Secondary Land Use	2405	(3,189,127)	(6,122,487)		(9,311,614)	(2,354)	(46,592)			(48,946)
External Stations Maintenance, E&CS & Other External Revenue	2405	(4,385,050)	(6,437,136)	-	(10,822,186)	(3,236)	(53,650)			(56,886)
Tax Rate Changes	1592	(8,716,521)	(4,324,565)	(9,266,664)	(3,774,422)	(366,559)	(39,968)			(406,527)
Tax Rate Changes	1592	(8,716,521)	(1,824,565)	(9,266,664)	(1,274,422)	(366,559)	(36,187)			(402,746)
HST - PST Savings	1592	-	(2,500,000)		(2,500,000)	-	(3,781)			(3,781)
Rights Payments	2405	-	-	-	-	-	-			-
Pension Costs Differential	2405	3,174,463	7,977,416	(133,331)	11,285,210	(61,585)	57,478			(4,107)
Long-Term Transmission Future Corridor Acquisition and Developmen	1508	-			-	-				-
Total Transmission Regulatory Accounts for Disposition		**(17,933,213)**	**(13,193,433)**	**(9,399,995)**	**(21,726,651)**	**(454,452)**	**(134,501)**	**-**	**-**	**(588,953)**
Excess Export Service Revenue	2405	(11,746,107)	-	(12,391,489)	645,383	(3,565,813)	(35,589)			(3,601,402)
Long Term Projects Development Costs	1508	1,931,962	4,552,221	-	6,484,183	1,980	39,136			41,116
Total Transmission Accounts NOT requesting Disposition		**(9,814,145)**	**4,552,221**	**(12,391,489)**	**7,129,566**	**(3,563,833)**	**3,547**	**-**	**-**	**(3,560,286)**
Total Transmission Regulatory Accounts		**(27,747,357)**	**(8,641,212)**	**(21,791,484)**	**(14,597,085)**	**(4,018,285)**	**(130,954)**	**-**	**-**	**(4,149,239)**

Continuity Schedules
Regulatory Accounts

		2011							
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments 6	Board-Approved Disposition during 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Closing Interest Amounts as of Dec-31-11
Excess Export Service Revenue	2405	(9,103,639)	(14,175,454)	(4,816,978)	(18,462,115)	(72,487)	(202,871)	(83,022)	(192,336)
External Revenue - Secondary Land Use	2405	(9,311,614)	(8,036,104)	(3,189,127)	(14,158,591)	(48,946)	(219,112)	(10,872)	(257,185)
External Stations Maintenance, E&CS & Other External Revenue	2405	(10,822,186)	1,386,255	(4,385,050)	(5,050,881)	(56,886)	(78,165)	(14,950)	(120,102)
Tax Rate Changes	1592	(3,774,422)	-	-	(3,774,422)	(406,527)	(55,484)	-	(462,011)
Tax Rate Changes	1592	(1,274,422)	-	-	(1,274,422)	(402,746)	(18,734)		(421,480)
HST - PST Savings	1592	(2,500,000)	-	-	(2,500,000)	(3,781)	(36,750)	-	(40,531)
Rights Payments	2405	-	(1,725,664)	-	(1,725,664)	-	(2,447)		(2,447)
Pension Costs Differential	2405	11,285,210	4,307,499	3,174,462	12,418,247	(4,107)	170,196	(74,463)	240,552
Long-Term Transmission Future Corridor Acquisition and Development	1508	-			-	-			-
Total Transmission Regulatory Accounts for Disposition		**(21,726,651)**	**(18,243,468)**	**(9,216,693)**	**(30,753,426)**	**(588,953)**	**(387,883)**	**(183,307)**	**(793,529)**
Excess Export Service Revenue	2405	645,383	(645,383)		-	(3,601,402)	665,862		(2,935,540)
Long Term Projects Development Costs	1508	6,484,183	-	1,931,962	4,552,221	41,116	82,239	68,037	55,318
Total Transmission Accounts NOT requesting Disposition		**7,129,566**	**(645,383)**	**1,931,962**	**4,552,221**	**(3,560,286)**	**748,101**	**68,037**	**(2,880,222)**
Total Transmission Regulatory Accounts		**(14,597,085)**	**(18,888,851)**	**(7,284,731)**	**(26,201,205)**	**(4,149,239)**	**360,218**	**(115,270)**	**(3,673,751)**

Continuity Schedules
Regulatory Accounts

		2012							
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-12	Transactions Debit / (Credit) during 2012 excluding interest and adjustments 6	Board-Approved Disposition during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Closing Interest Amounts as of Dec-31-12
Excess Export Service Revenue	2405	(18,462,115)	(12,813,450)		(31,275,565)	(192,336)	(339,248)		(531,584)
External Revenue - Secondary Land Use	2405	(14,158,591)	(9,703,383)		(23,861,974)	(257,185)	(293,753)		(550,938)
External Stations Maintenance, E&CS & Other External Revenue	2405	(5,050,881)	193,940		(4,856,941)	(120,102)	(59,791)		(179,893)
Tax Rate Changes	1592	(3,774,422)	785,229		(2,989,193)	(462,011)	(51,858)		(513,869)
Tax Rate Changes	1592	(1,274,422)	785,229		(489,193)	(421,480)	(15,108)		(436,588)
HST - PST Savings	1592	(2,500,000)			(2,500,000)	(40,531)	(36,750)		(77,281)
Rights Payments	2405	(1,725,664)	(967,779)		(2,693,443)	(2,447)	(42,064)		(44,511)
Pension Costs Differential	2405	12,418,247	1,858,090		14,276,337	240,552	204,668		445,220
Long-Term Transmission Future Corridor Acquisition and Development	1508	-			-	-			-
Total Transmission Regulatory Accounts for Disposition		**(30,753,426)**	**(20,647,353)**	**-**	**(51,400,778)**	**(793,529)**	**(582,046)**	**-**	**(1,375,575)**
Excess Export Service Revenue	2405	-			-	(2,935,540)			(2,935,540)
Long Term Projects Development Costs	1508	4,552,221			4,552,221	55,318	66,917		122,235
Total Transmission Accounts NOT requesting Disposition		**4,552,221**	**-**	**-**	**4,552,221**	**(2,880,222)**	**66,917**	**-**	**(2,813,305)**
Total Transmission Regulatory Accounts		**(26,201,205)**	**(20,647,353)**	**-**	**(46,848,557)**	**(3,673,751)**	**(515,130)**	**-**	**(4,188,881)**
		c/bal 2011	(19,209,472)						
		2012 trans total	**#REF!**						

Continuity Schedules
Regulatory Accounts

Account Descriptions	Account Number	2013 Opening Principal Amounts as of Jan-1-13	Transactions Debit / (Credit) during 2013 excluding interest and adjustments 6	Board-Approved Disposition during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	Board-Approved Disposition during 2013	Closing Interest Amounts as of Dec-31-13
Excess Export Service Revenue	2405	(31,275,565)	(9,601,270)		(40,876,835)	(531,584)	(511,206)		(1,042,790)
External Revenue - Secondary Land Use	2405	(23,861,974)	(7,986,055)	-	(31,848,029)	(550,938)	(395,471)		(946,409)
External Stations Maintenance, E&CS & Other External Revenue	2405	(4,856,941)	(1,312,043)		(6,168,984)	(179,893)	(76,603)		(256,496)
Tax Rate Changes	1592	(2,989,193)			(2,989,193)	(513,869)	(43,821)		(557,690)
Tax Rate Changes	1592	(489,193)	-	-	(489,193)	(436,588)	(7,171)		(443,760)
HST - PST Savings	1592	(2,500,000)			(2,500,000)	(77,281)	(36,649)		(113,930)
Rights Payments	2405	(2,693,443)	(786,951)		(3,480,394)	(44,511)	(55,963)		(100,474)
Pension Costs Differential	2405	14,276,337	5,855,169		20,131,507	445,220	239,345		684,565
Long-Term Transmission Future Corridor Acquisition and Development	1508	-	68,391		68,391	-	619		619
Total Transmission Regulatory Accounts for Disposition		**(51,400,778)**	**(13,762,758)**	**-**	**(65,163,536)**	**(1,375,575)**	**(843,101)**	**-**	**(2,218,676)**
Excess Export Service Revenue	2405	-			-	(2,935,540)			(2,935,540)
Long Term Projects Development Costs	1508	4,552,221			4,552,221	122,235	66,919		189,153
Total Transmission Accounts NOT requesting Disposition		**4,552,221**	**-**	**-**	**4,552,221**	**(2,813,305)**	**66,919**	**-**	**(2,746,387)**
Total Transmission Regulatory Accounts		**(46,848,557)**	**(13,762,758)**	**-**	**(60,611,315)**	**(4,188,881)**	**(776,182)**	**-**	**(4,965,062)**

Continuity Schedules
Regulatory Accounts

2014 - Projected Principal and Interest Balances on Dec-31-2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Forecast Transactions Debit / (Credit) during 2014 excluding interest and adjustments 6	Board-Approved Disposition during 2014	Closing Principal Balances as of Dec 31-14 Adjusted for Dispositions and Forecast Additions during 2014	Opening Interest Amounts as of Jan-1-14	Interest Disposition during 2014 - instructed by Board	Projected Interest Jan-1 to Dec-31-14	Projected Interest Balance as at Dec 31 - 14 balance adjusted for disposition during 2014 9	Total Projected Balances as at Dec 31 2014 Requested for disposition
Excess Export Service Revenue	2405	(40,876,835)		18,462,115	(22,414,720)	(1,042,790)	463,729	(465,193)	(1,044,254)	(23,458,974)
External Revenue - Secondary Land Use	2405	(31,848,029)		14,158,591	(17,689,438)	(946,409)	486,216	(364,100)	(824,293)	(18,513,731)
External Stations Maintenance, E&CS & Other External Revenue	2405	(6,168,984)		5,050,880	(1,118,104)	(256,496)	173,451	(53,560)	(136,605)	(1,254,709)
Tax Rate Changes	1592	(2,989,193)		3,774,422	785,229	(557,690)	517,495	38,825	(1,369)	783,860
Tax Rate Changes	1592	(489,193)		1,274,422	785,229	(443,760)	440,214	2,176	(1,369)	783,860
HST - PST Savings	1592	(2,500,000)		2,500,000	-	(113,930)	77,281	36,649	-	-
Rights Payments	2405	(3,480,394)		1,725,664	(1,754,730)	(100,474)	27,814	(38,478)	(111,139)	(1,865,868)
Pension Costs Differential	2405	20,131,507		(12,418,247)	7,713,259	684,565	(423,100)	204,659	466,124	8,179,383
Long-Term Transmission Future Corridor Acquisition and Development	1508	68,391			68,391	619		1,005	1,624	70,015
Total Transmission Regulatory Accounts for Disposition		**(65,163,536)**	**-**	**30,753,424**	**(34,410,112)**	**(2,218,676)**	**1,245,604**	**(676,842)**	**(1,649,913)**	**(36,060,025)**
Excess Export Service Revenue	2405	-			-	(2,935,540)	2,935,540	-	-	-
Long Term Projects Development Costs	1508	4,552,221		(4,552,221)	0	189,153	(122,236)	(66,918)	-	0
Total Transmission Accounts NOT requesting Disposition		**4,552,221**	**-**	**(4,552,221)**	**0**	**(2,746,387)**	**2,813,304**	**(66,918)**	**-**	**0**
Total Transmission Regulatory Accounts		**(60,611,315)**	**-**	**26,201,204**	**(34,410,111)**	**(4,965,062)**	**4,058,909**	**(743,759)**	**(1,649,913)**	**(36,060,024)**
					-	-		-	-	-

School Energy Coalition (SEC) INTERROGATORY #18

Interrogatory

[H1-5] Please provide a forecast of ETS revenue for 2015 and 2016 for a $1.7/MWh tariff.

Response

Please see response to Energy Probe IR 31 at Exhibit I, Tab 4, Schedule 31.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #1

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Please provide the definition of the term “shared asset (for export)”.

Response

“Net Shared Assets” are the assets that are left after deducting the assets exclusively dedicated to domestic customers and exclusively dedicated to interconnections.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #2

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Please provide a complete list and brief description of the assets considered to be "dedicated assets" (for the purposes of export) in the Elenchus Study.

Response

The Elenchus Study is based on fixed assets as of the end of 2013.
There are no station assets in the Network pool dedicated to interconnections. The following line sections in the Network pool are dedicated to interconnections:

Operating Designation	Line Section Number	From Station	To Station	Length (kM)	Operating Voltage (kV)	Number of Circuits
A41T	1	Hawthorne TS	IPB Masson JCT	21.15	230	2
A42T	1	Hawthorne TS	IPB Masson JCT	21.15	230	2
B31L	2	IPB Baudet JCT	B5D-B31L SS JCT	0.13	230	1
B3N	2	Mid R. JCT Bunce Crk	Sun Oil Co JCT	2.38	230	1
B3N	3	Sun Oil Co JCT	Vidal JCT	0.71	230	89% 3-cct, 11% 1-cct
B3N	4	Vidal JCT	Sarnia Scott JCT	2.35	230	2
B3N	5	Sarnia Scott JCT	Sarnia Scott TS	0.29	230	2
BP76	1	Beck #2 TS	Mid R. JCT Niagara	1.03	230	2
D4Z	1	Dymond TS	Nine Mile JCT	14.45	115	1
D4Z	2	Nine Mile JCT	IPB Casey JCT	15.5	115	1
D5A	6	Cumberland JCT	IPB Masson JCT	2.56	230	81% 2-cct, 19% 1-cct
F3M	1	Fort Frances TS	H2O Pwr FtFrnces CTS	0.86	115	2
F3M	2	H2O Pwr FtFrnces CTS	Int'l Bdy Minn JCT	0.35	115	73% 2-cct, 27% 1-cct
H4Z	1	Otto Holden TS	IPB La Cave JCT	1.05	115	1
H9A	13	Gamble H9A JCT	IPB Masson JCT	0.71	115	68% 2-cct, 32% 1-cct

Operating Designation	Line Section Number	From Station	To Station	Length (kM)	Operating Voltage (kV)	Number of Circuits
J5D	1	Keith TS	Mid R. JCT Waterman	1.83	230	1
K21W	1	Kenora TS	IPB Manitoba 230 JCT	62.56	230	7% 2-cct, 83% 1-cct
K22W	1	Kenora TS	IPB Manitoba 230 JCT	62.56	230	7% 2-cct, 83% 1-cct
L33P	1	St.Lawrence TS	Massena JCT	4.3	230	94% 2-cct, 6% 1-cct
L34P	1	St.Lawrence TS	Massena JCT	4.28	230	94% 2-cct, 6% 1-cct
L4D	1	Lambton TS #2	Mid R JCT St Cl L4D	3.99	345	1
L51D	1	Lambton TS #2	Mid R JCT St Cl L51D	1.13	230	1
L51D	3	Lambton TS #2	Lambton TS #2	0.28	230	1
L51D	4	Lambton TS #2	Lambton TS #2	0.28	230	1
P33C	2	IPB Ottawa River JCT	Chats Falls SS	8.87	230	27% 2-cct, 73% 1-cct
PA27	1	Beck #2 TS	Mid R. JCT Niagara	1.03	230	2
PA301	1	Beck #2 TS	Beck #2 TS	0.27	230	2
PA301	2	Beck #2 TS	Mid R JCT Niagra 345	0.42	345	2
PA302	1	Beck #2 TS	Beck #2 TS	0.27	230	2
PA302	2	Beck #2 TS	Mid R JCT Niagra 345	0.42	345	2
Q4C	2	IPB Ottawa River JCT	Chats Falls SS	5.78	230	1
SK1	2	Forgie JCT	IPB Manitoba 115 JCT	19.23	115	1
X2Y	2	Chenaux JCT	IPB Bryson JCT	3.4	115	1

Association of Power Producers of Ontario (APPrO) INTERROGATORY #3

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Please provide the actual financial data used in the Elenchus Study associated with:

a. The “dedicated assets” cost
b. The “dedicated assets” expenses
c. The “shared assets” OM&A expenses (attributable to export customers)

Response

Please see response to VECC IR 14 at Exhibit I, Tab 6, Schedule 14.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #4

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

For an ETS that is based solely on the methodology in the Elenchus Study, how would any future capital expenses associated with the dedicated assets be treated?

Response

Future capital expenses associated with the dedicated assets would be reflected in any future update to establish future ETS rates applying the proposed methodology.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #5

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

For each dedicated asset (for the purpose of exports), please prepare a table showing HONI's forecasted capital expenditures by year for the period 2014 to 2024.

Response

The scope of this application and the ETS Study is for test years 2015 & 2016. Future expenditures on these assets will be determined by a number of factors including but not limited to condition of asset, rate of deterioration, priority work based on customer requirements and reliability, public policy, operational effectiveness, etc. Therefore the following table lists sustainment capital work that is planned on interconnection assets in 2014, 2015 & 2016:

Operating Designation	Line Section Number	**2014 ($M)**	**2015 ($M)**	**2016 ($M)**	**Planned Capital - Description**
B3N	2	2.380	-	-	Line refurbishment
B3N	3	0.700	-	-	Line refurbishment
B3N	4	2.400	-	-	Line refurbishment
B3N	5	0.300	-	-	Line refurbishment
D4Z	1	0.200	0.100	-	Telecom upgrades, facilitating removal of A/Gs associated with transfromers T3&T4 on 115 @ dymond
D4Z	2	*See D4Z Note*	*See D4Z Note*	-	See D4Z: Line Segment 1
H4Z	1	-	-	0.200	Upgrade 115kV Protections @ Otto Holden
K22W	1	-	0.200	-	Wood pole replacement
L4D	1	-	0.200	2.500	Protection and telecommunications upgrades for L4D/L51D between ITC (Michigan) and HONI
L51D	1	-	*See Note L4D*	*See Note L4D*	Work captured under L4D
L51D	3	-	*See Note L4D*	*See Note L4D*	Work captured under L4D

Operating Designation	Line Section Number	**2014 ($M)**	**2015 ($M)**	**2016 ($M)**	**Planned Capital - Description**
L51D	4	-	*See Note L4D*	*See Note L4D*	Work captured under L4D
PA302	1	1.024	0.022	-	Upgrading line, transformer, bus and breaker protections associated with the line
PA302	2	*See Note PA302*	*See Note PA302*	-	Note: work on Line Segment 1, will also affect this segment (i.e. line protection)
X2Y	2	-	0.500	0.500	Rebuild 115 yard including removal of A/G and telecom upgrades

There are currently no development capital plans to upgrade or modify the interconnection assets in 2015 & 2016.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #6

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

In section 5.1.2 of the Elenchus Study, the ETS rate is increased by 3.4% to account for the revenue requirements of the other (i.e., non-Hydro One) Ontario transmitters.

a. Please confirm that the "revenue requirement for all Ontario transmitters" in sections 5.1.2 and 5.2.2 only includes the "Network function" portion of HONI's as well as other transmitters' overall revenue requirement.
b. If applicable, please provide a description of the "shared Network assets" and "dedicated assets" owned by other (i.e., non-Hydro One) Ontario transmitters.
c. Please provide the amount attributable to "shared Network assets" and "dedicated assets" for other transmitters included in the "revenue requirement for all Ontario transmitters" referenced in 6.a.

Response

a. Confirmed.

b. and c. The information requested is not available to Elenchus or Hydro One. In developing the Uniform Transmission Rates, the functions for other transmitters is being derived by applying to the other transmitters total revenue requirement, the Hydro One proportions of Network, Line Connections and Transformation Connections revenue requirements. Other transmitters do not provide their revenue requirement broken down into the three functions as Hydro One does.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #7

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Please confirm that the "dedicated assets" referred to in the Elenchus Study are also used to import power into Ontario.

Response

All the dedicated assets referred to in the Elenchus study are used to import power into Ontario with the exception of two interties with Quebec:

- H4Z - 1.05 km 115 kV circuit
- Q4C – 5.78 km 230 kV circuit

These two circuits are used only for the export of power to Quebec.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #8

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Please confirm that, when constructed, the purpose of Hydro One's assets (i.e., those interconnected with neighbouring jurisdictions) was to enhance the reliability of the Ontario transmission grid.

Response

Yes, the purpose of the intertie facilities was to provide for enhanced reliability of the Ontario transmission grid in addition to facilitating the economic transfers and sales opportunities.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #9

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Please confirm that the benefits from imports and the increased reliability provided by interconnections with neighbouring utilities are for the sole benefit of domestic Ontario electricity customers.

Response

The interconnection facilities with neighbouring utilities provide increased reliability benefits for Ontario customers as well as the interconnected jurisdictions. Being part of a larger interconnected system has benefits for all the interconnected members including higher transfer capabilities, better frequency support, opportunities for reserve sharing, greater operational flexibility and it is more robust to system disturbances. Imports into Ontario will benefit Ontario consumers by providing lower cost generation and/or additional generation to meet system reliability needs when there are supply shortages or constraints in Ontario.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #10

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

In Table 8 and 9 in the Elenchus Study, is 1 CP or 12 CP used to derive the ETS rate (please see Scenario 5 in each of the tables)?

Response

Scenario 5 is based on 12 CP.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #11

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Please confirm that using 12 CP solely with 2013 load data (section 5.2.1 of Elenchus Study) and 2011-2013 load data (section 5.2.3, Scenario 1 of Elenchus Study) both produce identical ETS rates of $1.62/MWh and $1.63/MWh for 2015 and 2016 respectively.

Response

Using 12 CP for 2013, or the average of 12 CP for the period 2011 to 2013, result in the same percentage allocation for domestic and export customers, as shown in Table 4 (rounded to two decimal places). Therefore, the ETS rate using 12 CP for 2013 and using the average of 2011 to 2013 12 CP result in the same ETS rate of $1.63/MWh for 2015 and $1.62/MWh for 2016.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #12

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

What are the reasons for not using strictly 2013 load data as the most representative of future load conditions?

Response

2013 actual sales data, domestic and export, is used in order to determine the demand allocators used in the proposed 2015 and 2016 ETS rate. 2013 is the last year for which actual sales data is available. Elenchus proposes that the last year of actual hourly data for domestic and export should be used in the future when updating the proposed cost allocation methodology to determine the ETS rate. Elenchus has no basis to determine that 2013 load data is the most representative of future load conditions.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #13

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Is $1.68/MWh the most appropriate ETS rate if the analysis uses 2013 load data and the HONI proposed 2015/2016 financial data?

Response

As stated in Elenchus report on page 20, lines 22 to 25, applying the proposed methodology and taking into account other transmitters revenue requirement, the ETS rate is $1.68/MWh for 2015 and $1.67/MWh for 2016. The results are based on using 2013 actual load data and the financial data for Hydro One Transmission for 2015 and 2016.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #14

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

Are any external revenues referenced in section 4.1 associated with dedicated assets or shared assets? If so, what are the amounts?

Response

As stated in Elenchus report on page 11, lines 6 to 10, Elenchus reviewed the sources of External Revenues and it is Elenchus' view that external revenue is generated from assets which have been designed to serve domestic customers only. Therefore any benefit or external revenue resulting from the use of these assets should only benefit domestic customers.

Association of Power Producers of Ontario (APPrO) INTERROGATORY #15

Interrogatory

Reference: Issue 7 - What is the appropriate level for Export Transmission Rates in Ontario?

At the very end of the Elenchus Study (page 23), Elenchus recommends that the proposed ETS rate be maintained "for at least 2 years to provide stability in determining the rate".

a. Did Elenchus prepare any analysis of the stability of the proposed ETS rate methodology over time? If so, what were the results?
b. Would Elenchus support maintaining the proposed ETS rate for four years?
c. Would Hydro One support maintaining the proposed rate for ETS rate for four years? Please provide reasons as to why or why not.

Response

a. No.

b. Elenchus will defer to the OEB to decide how often should the ETS rate be updated. Elenchus suggests that the proposed ETS rate be maintained for at least 2 years, (page 23, lines 3 to 5), consistent with the frequency of Hydro One Transmission revenue requirement application to the OEB.

c. Hydro One will accept the Board's decision regarding how often should the ETS rate be updated.

Consumers Council of Canada (CCC) INTERROGATORY #1

Interrogatory

HON is applying for approval of distribution rates for five years under the Board's RRFE. To what extent has the Board's RRFE Framework impacted the transmission side of the business? What is HON doing to respond to the RRFE with respect to transmission? Has the RRFE impacted the revenue requirements for 2015 and 2016? If so, how?

Response

Hydro One has been an active participant in the Board's RRFE Framework consultation process. Several consultation initiatives are relevant to transmitters (e.g. Approaches to Mitigation for Electricity Transmitters & Distributors, Defining and Measuring Performance of Electricity Transmitters & Distributors, and Regional Planning for Electricity Infrastructure).

In light of these OEB consultation initiatives, Hydro One had reviewed and revised (if necessary) its policies and planning processes to make sure the company will meet the OEB's expectations from these RRFE initiatives.

The RRFE has not materially impacted the transmission revenue requirements for 2015 and 2016.

Consumers Council of Canada (CCC) INTERROGATORY #2

Interrogatory

HON currently has an application before the Board with respect to its distribution rates for 2015-2019. Distribution and Transmission have a component of the respective revenue requirements that are shared. How does HON propose to deal with these common costs in the context of this negotiation, given the determination of these costs is currently before the Board?

Response

Please refer to Exhibit I, Tab 2, Schedule 13, part b (Canadian Manufacturers & Exporters Interrogatory question #13).

Consumers Council of Canada (CCC) INTERROGATORY #3

Interrogatory

If the Board makes changes to the way in which the cost of capital is derived, as set out in the Cost of Capital Report, would HON be seeking to change the approved revenue requirements for 2015 and 2016 to reflect those changes, or would those changes be deferred until rebasing?

Response

Please see Hydro One's response to LPMA interrogatory 3 at Exhibit I, Tab 3, Schedule 3.

Consumers Council of Canada (CCC) INTERROGATORY #4

Interrogatory

With respect to the information package provided when did HON undertake the Bridge Year forecast in all areas (2014)? When were the 2015 and 2016 budgets developed?

Response

The bridge year was developed throughout 2013 as part of the the business planning process, then updated in May of 2014 to reflect 2013 actuals. The 2015 and 2016 budgets were developed under a similar timeline to ensure consistency across the plan.

Consumers Council of Canada (CCC) INTERROGATORY #5

Interrogatory

Reference: (Ex. D1/T3/S2/p. 12)

The major driver for increases in the Station Re-investment budget is Air Blast Circuit Breaker Replacements. Has HON considered spreading these replacements over a longer period of time? If not, why not? What would be the implications of doing so?

Response

Air blast circuit breakers (ABCBs) are perennially the poorest performing circuit breakers in the Hydro One transmission system, have the highest operating costs, and are installed at critical stations throughout the province. Their unreliable performance impacts major generators out of Bruce A TS, Bruce B SS, Pickering A SS, Cherrywood TS, Beck 1 SS, Beck 2 SS, Lennox TS, as well as other key transmission network stations like Richview TS and Burlington TS.

Replacement plans for the remaining ABCBs are already spread out over a long period of time, with the first planned replacements happening approximately 10 years ago and replacements will continue to be an area of focus for Sustaining Capital for approximately another 10 years.

Expenditures over the 2011 to 2016 period have been focused on addressing the breakers that have been identified as highest risk due to condition, performance, technical obsolescence and customer / system impact.

Completion of the projects will mitigate existing performance risk, which otherwise would continue to have impacts on generators (most commonly nuclear and hydroelectric) and the transmission system as a whole. Replacement of the ABCBs with modern SF6 circuit breakers also has the benefit of reduced maintenance costs.

Consumers Council of Canada (CCC) INTERROGATORY #6

Interrogatory

Reference: Ex. A/T15/S2

The OPA and the LDCs are currently developing a new CDM framework for the period 2015-2020. How does HON intend to incorporate those new targets into its load forecast for 2015 and 2016?

Response

The peak savings associated with the new targets have already been incorporated in the load forecast as presented Exhibit A, Tab 15, Schedule 2, page 20, Table 3. Please see the response to Exhibit I-04 EP-09 for more details.

Consumers Council of Canada (CCC) INTERROGATORY #7

Interrogatory

Reference: Ex. A/T18/S1/pp. 2-4

Please explain, in detail, how the total annual savings related to transmission for the years 2011-2016 were derived.

Response

The full list of initiatives related to transmission can be found in Exhibit I, Tab 10, Schedule 4.

Consumers Council of Canada (CCC) INTERROGATORY #8

Interrogatory

Reference: Ex. C1/T2/S2/p. 3

With respect to Sustaining OM&A Please provide the Board approved amounts for 2011, 2012 and 2013.

Response

Please see table below for the Sustaining OM&A Board Approved amounts for 2011 through 2013.

Description	**Board Approved ($M)**		
	2011	**2012**	**2013**
Stations	166.0	171.2	168.0
Lines	50.8	54.6	55.1
Engineering and Environmental Support	10.9	11.7	12.6
Total	**227.7**	**237.5**	**235.7**

Consumers Council of Canada (CCC) INTERROGATORY #9

Interrogatory

Reference: Ex. C1/T2/S2/p. 15

With respect to Other Maintenance and Inspection programs why is there a significant increase from 2013 to 2014-2016?

Response

There are two primary factors contributing to the trend in the Other Maintenance and Inspection programs. Firstly, the expenditures in 2013 are lower than other years in the 2011 to 2016 period primarily due to lower planned accomplishment of maintenance on operating spares at Central Maintenance Services. Secondly, there is an increased focus over the 2014 to 2016 period on managing customer reliability through the nuisance wildlife control program.

Consumers Council of Canada (CCC) INTERROGATORY #10

Interrogatory

Reference: Ex. C1/T3/S3/p. 20

Please provide a detailed breakdown of the Regulatory Affairs Function (Table 8). Please include Board-approved costs. Also, please break out the cost specifically related to previous transmission proceedings and indicate what has been assumed for those proceedings in 2015 and 2016.

Response

The table below provides the breakdown of total Networks' Regulatory costs on a historic and future basis.

Description	**Approved**	**Actual**	**Actual**	**Actual**	**Forecast**	**Test**	
	2011	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Compliance		1.4	1.2	1.2	1.7	1.4	1.4
Major Applications		0.7	0.9	0.6	1.5	1.8	2.5
Major Projects		1.8	1.4	1.5	0.7	0.7	0.7
VP / Pricing & Support		5.2	3.9	4.2	4.4	4.0	3.2
Subtotal		9.1	7.4	7.5	8.3	7.9	7.8
OEB/NEB Costs		11.0	13.2	13.1	15.8	13.5	14.5
Total	**20.7**	**20.1**	**20.6**	**20.6**	**24.1**	**21.5**	**22.4**

The last rate case for Transmission was filed in 2012 for 2013-2014 rates. The costs of the 2012 Transmission proceeding are included below along with the forecasted 2014 costs. Note that the 2012 proceeding was settled on virtually all issues which lowered the cost of the proceeding significantly. Moreover, the one issue that was not settled in 2012, the ETS rate, accounted for approximately 30%-40% of the eventual cost.

Estimated Transmission Rate Proceeding Costs		
Categories	**2012**	**2014**
Stakeholder consultation	0.02	0.06
Publication of Notices	0.06	0.05
Miscellaneous/Courier/Printing	0.001	0.04
OEB Variable Costs	0.05	0.08
Intervenors	0.65	0.50
Consultants	0.09	0.31
TOTAL	**0.87**	**1.04**

Consumers Council of Canada (CCC) INTERROGATORY #11

Interrogatory

Reference: Ex. A/T15/S1/pp. 2-3

Please provide the most recent Global Insight Forecasts and Ontario CPI forecasts that are used to determine cost escalation levels. Please explain how they are applied to produce the OM&A forecasts.

Response

The Global Insight and Ontario CPI forecasts can be found in the response to interrogatory Exhibit I, Tab 3, Schedule 1.

The Transmission Cost Escalations for Operations & Maintenance are used in conjunction with Hydro One planning tools to predict expenditure level changes for transmission materials and services.

The CPI is also used in conjunction with Hydro One planning tools to forecast expenditure level changes for items such as fleet and sundry costs.

Consumers Council of Canada (CCC) INTERROGATORY #12

Interrogatory

Reference: Ex. D1/T1/S1/p. 4

Please provide a schedule in the same format as Table 3 – Board Approved vs actual rate base for the years 2009, 2010, 2011 and 2012.

Response

For 2009 and 2010 rate base information, please see the tables below. For 2011 and 2012 information, please see the response to LPMA's interrogatory 16 at Exhibit I, Tab 3, Schedule 16.

2009 Board Approved versus 2009 Rate Base
($M)

Rate Base Component	2009 Actual	2009 Board Approved
Gross Plant	10,781.3	10,940.0
Accumulated Depreciation	(3,966.6)	(3,954.4)
Net Utility Plant	**6,814.7**	**6,985.6**
Cash Working Capital[1]	9.4	9.4
Materials & Supplies Inventory	11.7	36.7
Total Rate Base	**6,835.8**	**7,031.7**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2009 approved amount was used for illustrative purposes.

2010 Board Approved versus 2010 Rate Base
($M)

Rate Base Component	2010 Actual	2010 Board Approved
Gross Plant	11,504.7	11,768.2
Accumulated Depreciation	(4,191.3)	(4,179.6)
Net Utility Plant	**7,313.4**	**7,588.6**
Cash Working Capital[1]	8.6	8.6
Materials & Supplies Inventory	12.5	38.7
Total Rate Base	**7,334.5**	**7,635.9**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2010 approved amount was used for illustrative purposes.

Consumers Council of Canada (CCC) INTERROGATORY #13

Interrogatory

Reference: Ex. D1/T1/S2/p. 1

Please recast Table 1 (In-Service Capital Additions 2013-2016) to include 2012 and 2013.

Response

Please refer to Exhibit I, Tab 2, Schedule 7 (CME Interrogatory #7).

Consumers Council of Canada (CCC) INTERROGATORY #14

Interrogatory

Reference: Ex. D1/T1/S2/p. 2

With respect to the delay in the in-service additions actual vs Board approved for 2014 – what is the current status of those projects referred to in the evidence? Have those amounts ($160 million) been incorporated into the forecasts for 2015 and 2016?

Response

Please see Hydro One's response to SEC's interrogatory 11 for the requested information. Yes, these amounts have been incorporated into the forecasts for 2015 and 2016.

Consumers Council of Canada (CCC) INTERROGATORY #15

Interrogatory

Reference: Ex. A/T16/S8/p. 3-4

Please re-cast Table 1 – Transmission Capital Expenditures - to include Board approved numbers where they are available.

Response

Please see the response to CME's interrogatory 6 part a, at Exhibit I, Tab 2, Schedule 6, for the requested information.

Consumers Council of Canada (CCC) INTERROGATORY #16

Interrogatory

Reference: Ex. D1/T3/S1/p. 2

Please re-cast Table 1 to include Board approved amounts.

Response

Please see the response to CME's interrogatory 6 part a, at Exhibit I, Tab 2, Schedule 6, for the requested information.

Consumers Council of Canada (CCC) INTERROGATORY #17

Interrogatory

Reference: Ex. E/T2/S1/p. 2

Please provide Board approved amounts for External Revenues for the years 2011-2014.

Response

Board Approved Amounts
External Revenues ($ Millions)

$M	2011	2012	2013	2014
Secondary Land Use	12.6	12.5	13.2	13.2
Station Maintenance	7.0	7.0	8.1	8.1
Engineering & Project Delivery	11.0	6.0	3.0	3.0
Other External Revenues	3.2	3.2	7.3	12.3
Totals	**33.8**	**28.7**	**31.6**	**36.6**

Consumers Council of Canada (CCC) INTERROGATORY #18

Interrogatory

Reference: Ex. H/T5/S1/p. 4

What is HON's position as to what is the appropriate level for the ETS tariff?

Response

Hydro One has submitted the ETS cost allocation study prepared by Elenchus Research Associates in response to the Board's direction in EB-2012-0031. Hydro One will accept the resultant Board direction of the settlement for Hydro One's 2015-2016 Transmission rates regarding the ETS tariff.

SECTION III

SUBSECTION iv

TECHNICAL CONFERENCE UNDERTAKING RESPONSES

July 23rd Information Session: Question #1 - Consumers Council of Canada (CCC)

Reference: Slide #2 of the July 23, 2014 presentation

Question

In 2012, the OEB approved in-service capital addition was $1,592 million and the actual in-service capital addition was $1,199 million (i.e. a variance of $-393 million).

How much of this 2012 variance has been delayed to 2013?

Response

Of the $392.5 million in-service capital variance in 2012, $215.4 million was delayed into 2013. The following table includes further breakdown, including variance due to advancement, delays into 2014 and beyond, and variance due to causes other than advancement or deferral.

	Advanced	**Delayed**	**Other**	**Total**
	(118.1)	(326.4)	52.5	(392.5)
Delayed to 2013		(215.4)		
Delayed to 2014		(87.7)		
Delayed to 2015+		(33.4)		

July 23rd Information Session: Question #2 - School Energy Coalition (SEC)

Reference: Slide #5 of the July 23, 2014 presentation

Question

A large portion of the sustaining and development in-service capital additions (ISA) planned for 2015-16 are projects that are already in later stages of development. As of mid-2014, 97% of the projects that are associated with the planned 2015 ISA are already underway; 74% of the projects that are associated with the planned 2016 ISA are already underway.

Can you provide the same percentage you had in mid-2012 for planned 2013 ISA and also the same percentage you had in mid-2013 for planned 2014 ISA?

Response

As of June 30, 2012, 76% of the approved ISA for Sustaining and Development for 2013 was associated with work already underway.

As of June 30, 2013, 71% of the approved ISA for Sustaining and Development for 2014 was associated with work already underway.

July 23rd Information Session: Question #3 - School Energy Coalition (SEC)

Reference: Exhibit I-10-12 (SEC interrogatory #12)

Question

Can you update the in-service months in your response to Exhibit I, Tab 10, Schedule 12 based on up-to-date information?

Response

Please see table below for updates to in-service month column of the tables from Exhibit I, Tab 10, Schedule 12.

SUSTAINING

ISD#	Investment Summary Description	I/S Additions ($M)	I/S (Year)	I/S (Month)
S05	Air Blast Circuit Breaker Replacement - Beck #2 TS	32.7	2016	December
S07	Air Blast Circuit Breaker Replacement - Burlington TS	18.5	2015	December
S09	End of Life Station Reconfiguration – Timmins TS	10.7	2015	December
S10	End of Life Station Reconfiguration - Hanmer TS	16.0	2015	December
S11	Integrated DESN Replacement - Dunnville TS	18.3	2015	~~June~~ July
S12	Integrated DESN Replacement – National Research Council	22.1	2015	October
S13	Integrated DESN Replacement - Espanola TS	18.8	2016	December
S16	Integrated DESN Replacement - Gerrard TS	25.6	2015	~~December~~ May
S17	Integrated DESN Replacement – Chenaux TS	20.1	2016	December
S18	Integrated DESN Replacement - Overbrook TS	16.0	2015	December
S19	Integrated DESN Replacement – Ear Falls TS	9.2	2016	January
S20	Integrated DESN Replacement - Wiltshire TS	12.6	2016	~~December~~ January
S21	Integrated DESN Replacement - Bridgman TS	9.4	2015	October
S22	Integrated DESN Replacement – Dundas TS	15.6	2015	November
S40	Cyber Security NERC CIP V5 Readiness	15.6	2016	April
S51	C25H Line Refurbishment	52.4	2015	December
S52	H24C Line Refurbishment	21.7	2016	December
S53	D10S/D9HS Line Refurbishment	4.8	2015	December
S54	Q11S/Q12S Line Refurbishment	17.1	2016	December
S56	H2JK/K6J Cable Replacement	62.0	2015	June
S57	H7L/H11L Cable Replacement	28.8	2016	December

DEVELOPMENT

ISD#	Investment Summary Description	I/S Additions ($M)	I/S (Year)	I/S (Month)
D04	Midtown Transmission Reinforcement Plan	69.9	2015	December
D05	Guelph Area Transmission Reinforcement	94.3	2016	June
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate *	23.6	2016	June
D10	Copeland MTS: Build line connection for Toronto Hydro**	0.0	2015	~~September~~ December
D14	Transmission Station P&C Upgrades for DG **	0.0	2016	December

**As per Exhibit I, Tab 4, Schedule 20, Table 2 the in-service additions per year are shown. This exhibit also shows the in-service additions in 2015 and 2016 for project D1- New 500kV Bruce to Milton Double Circuit Transmission Line.*
***Represents a project that is fully funded by the customer, and hence Net Cost = 0 and does not impact rate base*

OPERATING

ISD#	Investment Summary Description	I/S Additions ($M)	I/S (Year)	I/S (Month)
O1	NMS Capital Sustainment	35.2	2015	September

July 23rd Information Session: Question #4 - Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit I-9-9 (AMPCO interrogatory #9)

Question

Can you provide the Elenchus ETS Model?

Response

The Elenchus Export Tariff cost allocation model was provided to participants via email July 25, 2014.

July 23rd Information Session: Question #5 - Energy Probe Research Foundation (EP)

Reference: The response to I-4-1 (EP interrogatory #1) was provided in "PDF" format.

Question

Can you provide the response to I-4-1 in excel format?

Response

Please see attached excel spreadsheet titled "I-4-1 Attachment 1".

July 29th Information Session: Question #1 - Vulnerable Energy Consumers Coalition (VECC)

Question

When the Elenchus ETS model allocates OM&A, is it on network shared assets (not total assets)?

Response

The Elenchus ETS model allocates OM&A on total assets.

Changing the allocation of shared OM&A costs from total assets to network assets and following the same approach for shared OM&A of Network Dual function lines, Generation line connection and Generation transformation connection results in an ETS rate of $2.09/MWh for 2015 and $2.08/MWh for 2016, which compares to the base case ETS rate of $1.63 in 2015 and $1.62 in 2016.

The Elenchus model is a simple cost based model to determine the ETS rate. The change from allocating shared OM&A based on total assets is a refinement to the Elenchus model. There are other refinements to the model that could be done that result in a slightly lower ETS rate, for example, moving assets used primarily for imports from the dedicated to interconnect assets and into the shared network assets, (please see response to TCJ2.04).

July 29th Information Session: Question #2 - Vulnerable Energy Consumers Coalition (VECC)

Reference: Elenchus ETS study, Exhibit H1-05-01, Attachment p.14 and p.16

Question

Is it a coincidence that the "1-CP line" in table 4 (92.74% and 7.26%) is the same as the "network shared asset line" (92.74% and 7.26%) in table 6? Or is it an error?

Response

Yes, it is coincidence that the two values are the same in the two tables. Using more than 2 decimals result in different numbers.

July 29th Information Session: Question #3 - Vulnerable Energy Consumers Coalition (VECC)

Question

What is captured in “other amortization” in the model?

Response

The “other amortization” costs referred to in the ETS model are captured in the Transmission Amortization Expense Table (Exhibit C1, Tab 7, Schedule 1, Table 2 and section 3.1). The “other amortization” is allocated to the dedicated interconnection, dedicated domestic and shared network asset pools as shown under Tab I3 TB Data of the model based on the gross book value of the assets.

July 29th Information Session: Question #4 - Association of Power Producers of Ontario APPrO)

Reference: APPro IR #2

Question

Circuits D4Z and P33C in IR APPro #2 – please confirm whether these 2 circuits are used exclusively for import?

Please confirm, per APPrO IR#2, that circuits D4Z and P33C are used exclusively for import, **and if so, please explain why it is appropriate to allocate these costs to exports (i.e. included in the "dedicated assets")?**

Response

Circuits D4Z, P33C and X2Y are used primarily for imports. The impact of allocating these circuits to the shared network pool instead of to the dedicated to interconnect network pool is a reduction of $0.03/MWh and $0.04/MWh in the base case ETS rate in 2015 and 2016 respectively.

Elenchus model is a simple cost based model to determine the ETS rate. Removing these assets from dedicated to interconnect network pool and into shared network pool has minimal impact on the ETS results and Elenchus considers this change to be a possible refinement on the simple cost based model being proposed.

July 29th Information Session: Question #5 - Association of Power Producers of Ontario (APPrO)

Reference: VECC #11, part B

Question

Please confirm that the primary purpose of the Phase Shifter is to eliminate the Lake Erie circulation and to relieve congestion in Ontario. And also using this to import and export power is a secondary benefit.

Response

While the Ontario-Michigan Phase Shifters relieve conjestion in Ontario, they also provide the benefit of import capability and controlling the Laker Erie circulation effect. The import capability would not be achieved without controlling the Lake Erie circulation effect. Therefore the current treatment of Phase Shifters in the shared asset pool, is appropriate.

July 29th Information Session: Question #6 - Vulnerable Energy Consumers Coalition (VECC)

Reference: VECC #11, part B

Question

What costs are included in the revenue requirement (and where) for the Niagara reinforcement project?

Response

The construction of the Niagara Reinforcement Project is currently on hold due to the Caledonia dispute. The total Construction Work in Progress for this project is approximately $100 million. In EB-2006-0501 the Board decided to allow Hydro One to expense – rather than capitalize – the AFUDC, or carrying costs, associated with the project based on the actual expenditures made to date. This translates into $5 million in revenue requirement in this rate application as shown in Exhibit E1, Tab 1, Schedule 1, Table 1. The uplift in debt costs was added across all asset categories. Approximately $30,000 is assigned to the dedicated interconnection asset pool. The remainder is assigned to the shared asset and dedicated domestic pools.

July 29th Information Session: Question #7 - Energy Probe Research Foundation (EP)

Question

Please ask the IESO if there is an update to the rates in neighboring jurisdictions and the reciprocity information.

Response

The IESO has confirmed the most recent information they have in regards to rates in neighbouring jurisdictions and reciprocity is what was presented in Hydro One's last transmission rates proceeding, EB-2012-0031, Exhibit H1, Tab 5, Schedule 2, Appendix B.

July 30th Information Session: Question #1 - London Property Management Association (LPMA)

Question

Submit Continuity Schedules for property, plant and equipment for 2013 to 2016.

Response

Please see the attached schedules.

D2-03-01 - CONTINUITY OF PROPERTY, PLANT & EQUIPMENT

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment
Historical (2011, 2012, 2013), Bridge (2014) & Test (2015, 2016) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1 *	2011	11,928.1	791.8	(27.6)	(3.6)	(1.9)	12,686.9	12,307.5
2	2012	12,686.9	1,190.3	(40.7)	(3.2)	(0.1)	13,833.2	13,260.0
3	2013	13,833.2	703.8	(67.0)	0.0	(5.6)	14,464.4	14,148.8
Bridge								
4	2014	14,464.4	863.3	(49.4)		0.0	15,278.3	14,871.36
Test								
5	2015	15,278.3	821.3	(46.8)		0.0	16,052.8	15,665.55
6	2016	16,052.8	673.3	(72.9)		0.0	16,653.2	16,353.00

* Per EB-2012-0031

D2-03-02 - CONTINUITY OF ACCUMULATED DEPRECIATION

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2011, 2012, 2013), Bridge (2014) & Test (2015, 2016) Years
Year Ending December 31
($ Millions)

Line No.	Year	Opening Balance	Provision	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1 [#]	2011	4,310.6	282.3	(27.6)	(3.2)	0.3	4,562.4	4,436.5
2	2012	4,562.4	301.4	(40.7)	(2.9)	19.0	4,839.2	4,700.8
3	2013	4,839.2	304.3	(67.0)	(5.0)	17.8	5,089.3	4,964.3
Bridge								
4	2014	5,089.3	321.2	(49.4)		0.0	5,361.1	5,225.2
Test								
5	2015	5,361.1	356.0	(46.8)		0.0	5,670.3	5,515.7
6	2016	5,670.3	370.9	(72.9)		0.0	5,968.3	5,819.3

Per EB-2012-0031

July 30th Information Session: Question #2 - London Property Management Association (LPMA)

Question

Update Exhibit I, Tab 4, Schedule 1 (in excel and pdf format) for corrections in 2014.

Response

		Financial Summary 2013-2016					
		Approved	Actual	Approved	Forecast	Proposed	Proposed
		2013	2013	2014	2014	2015	2016
Total OM&A Expense		440.3	388.4	449.7	448.6	452.0	457.4
Depreciation & Amortization		345.0	326.3	371.5	366.5	394.2	404.0
Capital Expenditures		982.4	718.5	1,121.5	899.2	899.4	866.3
Rate Base		9,353.4	9,209.3	9,933.8	9670.7	10,176.5	10,558.0
Return on Capital		609.3	610.3	659.7	664.6	699.3	744.9
Income Taxes		43.1	78.5	54.5	51.3	71.8	82.8
Total Gross Revenue Requirement		**1,437.7**	**1,403.5**	**1,535.3**	**1,531.0**	**1,617.3**	**1,689.1**
External Revenues		-31.6	-46.6	-36.6	-36.6	-28.4	-28.8
Export Revenue Credit		-27.0	-27.0	-34.1	-34.1	-33.4	-34.3
Regulatory Assets Recovery		0.0	0.0	-30.3	-30.3	-17.6	-17.6
LV Switch Gear		11.6	11.6	12.1	12.1	13.2	13.9
RATES REVENUE REQUIREMENT		**1,390.8**	**1,341.5**	**1,446.4**	**1442.1**	**1550.9**	**1622.1**
	Variation		**-49.3**		**-4.3**		
Total Debt		5,612.1	5,525.6	5,960.3	5,802.4	6,105.9	6,334.8
Common Equity		3,741.4	3,683.7	3,973.5	3,868.3	4,070.6	4,223.2
Total Rate Base		9,353.4	9,209.3	9,933.8	9,670.7	10,176.5	10,558.0
	Variation		**-144.1**		**-263.1**		
		CAPEX and In Service Asset Additions					
Capital Expenditures							
Total Sustaining Capital		584.3	480.0	652.1	579.3	581.9	548.6
Total Development Capital		277.8	171.7	354.4	195.6	209.7	211.8
Total Operations Capital		38.5	17.7	42.7	38.5	38.4	37.4
Total Capital Common Corporate Costs& Other		80.6	49.1	71.0	85.8	69.4	68.5
Total Transmission Capital		**981.2**	**718.5**	**1120.4**	**899.2**	**899.4**	**866.3**
	Variation		**-262.7**		**-221.2**		
In-Service Asset Additions							
Sustaining		443.3	403.8	701.1	588.4	572.2	480.9
Development		261.8	231.7	205.8	177.3	134.7	119.4
Operations		15.1	5.9	48.0	19.0	50.4	10
Common & Other		64.0	62.4	68.0	78.7	64.1	63.1
TOTAL ISAs		**784.2**	**703.8**	**1022.9**	**863.4**	**821.4**	**673.4**
	Variation		**-80.4**		**-159.5**		
		OM&A					
Description		**Bd Approv**	**Actual**	**Bd Approv**	**Forecast**	**Test**	**Test**
		2013	**2013**	**2014**	**2014**	**2015**	**2016**
Sustaining		235.7	221.0	246.5	236.2	238.7	241.1
Development		13.7	8.6	14.7	12.9	12.9	13.4
Operations		57.7	56.7	58	57.4	58.5	59.1
Customer Care		4.9	5.3	4.7	5.8	5.5	5.5
Common Corporate and Other OM&A		61.9	75.8	59	70.6	70.2	71.3
Property Taxes & Rights Payments		66	21.2	66.8	65.6	66.3	67
TOTAL		**439.9**	**388.6**	**449.7**	**448.5**	**452.1**	**457.4**
	Variation		**-51.3**		**-1.2**		

July 30th Information Session: Question #3 - London Property Management Association (LPMA)

Question

Explain increase in staffing levels for 2013 to 2014 in Exhibit I, Tab 4, Schedule 3 (EP #3).

Response

Due to delays in hiring regular employees, the 2013 year-end figure was below the historic levels of about 5,400 in 2011 and 2012.

The 2013 figure for casual employees is year-end actual. Since a large percentage of casual employees are laid off/stood down at year end, the actual year end number does not reflect the usage of this category during the peak months. The forecasted casual employees in years 2014-19 is FTE's.

July 30th Information Session: Question #4 - Energy Probe Research Foundation (EP)

Question

Provide similar tables for 2011 and 2012 and add footnote for Other** in attachment 1 for Exhibit I, Tab 4, Schedule 3.

Response

Please see the table below. The footnote for Other** is at the end of the table.

HYDRO ONE COMPENSATION CHART

2011

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,456	353,770,142	275,254,552	63,197,265		15,318,324	79,645
SOCIETY Reg	1,330	134,279,772	126,051,768	4,947,039	2,250.00	3,278,715	94,776
MCP Reg	644	88,234,049	73,880,625	69,859	9,414,079	4,869,486	114,721
Total Reg	**5,430**	**576,283,963**	**475,186,946**	**68,214,163**	**9,416,329**	**23,466,525**	**87,511**
PWU Temp	211	5,508,958	5,331,454	85,668		91,836	25,268
Society Temp	79	5,234,552	4,983,808	26,116		224,627	63,086
MCP Temp	22	1,660,391	1,612,601	1,331		46,460	73,300
Total Temp	**312**	**12,403,901**	**11,927,862**	**113,115**		**362,923**	**38,230**
CASUAL	1488	106,663,199	80,054,576	14,588,897		12,019,727	53,800.12
TOTAL	**7,230**	**695,351,063**	**567,169,384**	**82,916,175**	**9,416,329**	**35,849,175**	**78,447**

2012

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,475	357,280,035	284,842,527	56,320,273	3,000.00	16,114,235	81,969
SOCIETY Reg	1,336	139,483,054	131,185,379	4,758,285	54,686.00	3,484,704	98,193
MCP Reg	643	88,165,625	73,683,706	126,637	9,884,915	4,470,367	114,594
Total Reg	**5,454**	**584,928,714**	**489,711,612**	**61,205,195**	**9,942,601**	**24,069,306**	**89,789**
PWU Temp	214	5,476,528	5,366,490	78,090	0.00	31,949	25,077
Society Temp	61	3,758,898	3,549,772	28,883	0.00	180,243	58,193
MCP Temp	18	1,061,210	1,018,662	0	0	42,548	56,592
Total Temp	**293**	**10,296,636**	**9,934,925**	**106,973**		**254,739**	**33,908**
CASUAL	1493	104,268,709	81,843,677	10,569,037		11,855,994	54,818.27
TOTAL	**7,240**	**699,494,059**	**581,490,214**	**71,881,205**	**9,942,601**	**36,180,039**	**80,316**

2013

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,321	361,121,121	282,009,791	63,909,056	5,000.00	15,197,274	84,917
SOCIETY Reg	1,260	137,307,219	127,603,743	6,218,672	18,650.00	3,466,154	101,273
MCP Reg	600	82,932,593	70,297,687	176,885	8,236,068	4,221,953	117,163
Total Reg	**5,181**	**581,360,932**	**479,911,220**	**70,304,613**	**8,259,718**	**22,885,381**	**92,629**
PWU Temp	205	6,747,274	6,521,171	189,533	0.00	41,214	31,811
Society Temp	46	3,144,181	2,911,798	115,174	0.00	117,601	63,300
MCP Temp	25	1,221,374	1,175,065	1,172	0	45,138	47,003
Total Temp	**276**	**11,112,830**	**10,608,034**	**305,878**	**0.00**	**203,953**	**38,435**
CASUAL	1781	127,908,507	98,518,887	14,668,063	11,000.00	14,710,557	55,317
TOTAL	**7,238**	**720,387,304**	**589,038,140**	**85,278,555**	**8,270,718**	**37,799,890**	**81,381**

2014

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,467	381,570,832	300,295,846	65,187,237		16,087,749	86,615
SOCIETY Reg	1,311	145,456,033	135,424,029	6,343,045		3,688,958	103,298
MCP Reg	622	90,121,621	74,332,774	180,423	11,149,916	4,458,508	119,506
Total Reg	**5,400**	**617,148,485**	**510,052,648**	**71,710,705**	**11,149,916**	**24,235,215**	**94,454**
PWU Temp	381	12,624,883	12,362,231	193,323	0.00	69,328	32,447
Society Temp	103	7,035,467	6,650,294	117,477	0.00	267,695	64,566
MCP Temp	56	2,789,114	2,684,789	1,195	0	103,131	47,943
Total Temp	**540**	**22,449,464**	**21,697,314**	**311,996**	**0.00**	**440,154**	**40,180**
CASUAL	2283	167,171,831	128,813,583	19,178,514		19,179,734	56,422.94
TOTAL	**8,223**	**806,769,780**	**660,563,545**	**91,201,215**	**11,149,916**	**43,855,104**	**80,331**

2015

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,435	386,223,662	303,474,633	66,490,982		16,258,047	88,348
SOCIETY Reg	1,281	145,118,122	134,971,583	6,469,906		3,676,634	105,364
MCP Reg	592	87,499,293	72,162,544	184,032	10,824,382	4,328,336	121,896
Total Reg	**5,308**	**618,841,077**	**510,608,760**	**73,144,919**	**10,824,382**	**24,263,017**	**96,196**
PWU Temp	410	13,842,539	13,569,252	197,190	0.00	76,097	33,096
Society Temp	132	9,162,915	8,693,161	119,827	0.00	349,927	65,857
MCP Temp	85	4,317,515	4,156,628	1,219	0	159,669	48,902
Total Temp	**627**	**27,322,970**	**26,419,041**	**318,236**	**0.00**	**585,693**	**42,136**
CASUAL	2283	170,515,267	131,389,854	19,562,084		19,563,329	57,551.40
TOTAL	**8,218**	**816,679,314**	**668,417,655**	**93,025,239**	**10,824,382**	**44,412,039**	**81,336**

2016

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,414	391,954,343	307,651,717	67,820,801		16,481,826	90,115
SOCIETY Reg	1,252	144,818,913	134,554,340	6,599,304		3,665,268	107,472
MCP Reg	574	86,541,326	71,367,780	187,712	10,705,167	4,280,666	124,334
Total Reg	**5,240**	**623,314,582**	**513,573,837**	**74,607,818**	**10,705,167**	**24,427,760**	**98,010**
PWU Temp	437	15,035,958	14,752,093	201,134	0.00	82,731	33,758
Society Temp	148	10,464,228	9,941,815	122,224	0.00	400,189	67,174
MCP Temp	94	4,870,026	4,688,676	1,243	0	180,106	49,880
Total Temp	**679**	**30,370,212**	**29,382,585**	**324,600**	**0.00**	**663,026**	**43,273**
CASUAL	2283	173,925,572	134,017,651	19,953,325		19,954,596	58,702.43
TOTAL	**8,202**	**827,610,366**	**676,974,074**	**94,885,744**	**10,705,167**	**45,045,382**	**82,538**

Other** includes payouts such as: travel time, standby allowance, shift allowance and vacation payouts, depending on the nature of the position.

July 30th Information Session: Question #5 - Energy Probe Research Foundation (EP)

Question

Is the treatment of depreciation for financial statements calculated using half year rule or monthly?

Response

Depreciation for financial statements is calculated using half year rule.

July 30th Information Session: Question #6 - School Energy Coalition (SEC)

Question

Provide in-service dates for the projects identified in the list of capital projects that were directed by the OPA, IESO or Government found in the information package after the presentation. Cross reference the in-service dates with those found in Exhibit I, Tab 10, Schedule 12.

Response

The following table provides the planned in-service dates for the referenced list of projects, as well as in-service addition (ISA) amounts for the 2015 and 2016 test years. This information is consistent with information provided in in Exhibit I, Tab 4, Schedule 20, and Exhibit I, Tab 10, Schedule 12.

ISD #	Investment Summary Description	I/S Year	I/S Date	ISA ($ millions)	
				ISA 2015	ISA 2016
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	2012	Q2	3.3	3.2
D02	Clarington TS: Build new 500/230kV Station	2017	Q3	0.0	0.0
D03	Installation of Shunt Capacitor Banks at Cherrywood TS	2018	Q2	0.0	0.0
D05	Guelph Area Transmission Reinforcement	2016	Q2 (June)	0.0	94.3
D06	Preston TS Transformation	2017	Q2	0.0	0.0
D07	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	2016	Q2 (June)	0.0	16.2
D08	Hawthorne TS: Replace two existing Transformers	2017	Q2	0.0	0.0
D09	York Region - Increase Transmission Capability for B82V/B83V Circuits	2017	Q2	0.0	0.0
D12	Supply to Essex County Transmission Reinforcement	2017	Q1	0.0	0.0
D13	Napanee Gas Generation Connection	2017	Q1	0.0	0.0
D14	Transmission Station P&C Upgrades for DG	-	-	0.0	0.0

July 30th Information Session: Question #7 - Vulnerable Energy Coalition of Canada (VECC)

Question

Provide the percentage that relates to the budgeted short term incentive (STI) compared to the maximum STI. (Reference: Exhibit I, Tab 3, Schedule 10 or LPMA#10)

Response

Year	Short Term Incentive Policy Limit*	Actual Payout for Short Term Incentive	
	Amount in Dollars	Amount in Dollars	% of Budget
2011	10,778,255	10,750, 950	99.7
2012	11,094,546	9,522,858	85.8
2013	10,876,838	8,391,901	77.2

* Short Term Incentive Policy Limit – This amount is 75% of the mechanical maximum. Hydro One Policy states that STI cannot exceed 75% of the mechanical maximum.

July 30th Information Session: Question #8 - School Energy Coaliton (SEC)

Question

In the Hydro One Scorecard, the targeted amount for the in-service additions metric is 85% of budget. Provide dollar amounts and compare to Board approved amount and numbers consistent with this application.

Response

Part of the 2014 corporate scorecard target for Transmission is to achieve a minimum of 85% of the 2014 budgeted in-service capital addition (ISA) amount. For purposes of the corporate scorecard, the budgeted Transmission ISA amount is $920 million, and a minimum $782 million is required to meet the target (85% x $920 million = $782 million).

The 2014 OEB Approved ISA amount of $1,023 million was determined as part of EB-2012-0031 proceeding based on a plan developed throughout 2011. The budgeted 2014 ISA of $920 million was determined during the development of the 2014 business plan throughout 2013 and is more recent when compared to the 2014 OEB Approved amount.

This application includes an updated 2014 bridge-year ISA forecast of $863 million (Exhibit D1, Tab 1, Schedule 2, Table 1), which was developed in April 2014.

July 30th Information Session: Question #9 - Vulnerable Energy Coalition of Canada (VECC)

Question

Provide budgets for productivity savings consistent with the distribution productivity request.

Response

VECC requested Hydro One to provide the budgets for the productivity savings in the VECC Distribution interrogatory 43 (Exhibit I, Tab 2.03, Schedule 6 VECC 43) and in VECC Transmission interrogatory 15 (Exhibit I, Tab 6, Schedule 15). The message in response to both of these interrogatories was virtually the same:

"The productivity categories provide information on the types of savings that are occurring at Hydro One. Individual initiatives often have an impact on many different programs or divisions and as a result it is not possible to apply the productivity category approach to the business plan budgets or align these budgets to the categories without creating overlap and duplication."

In the Distribution undertaking TCJ1.02, VECC requested Hydro One *"To provide the sum of the back-office costs that you are actually saving $26.7-million from"*. Hydro One's response was:

"In reference to the distribution back office savings of $26.7 million found in Exhibit A, Tab 19, Schedule 1, the sum of the distribution back office costs is $109 million."

The back office savings are discussed in the Distribution pre-filed evidence (Exhibit A, Tab 19, Schedule 1, page 5 of 20, line 11 to page 6 of 20, line 10) and the Transmission exhibit (Exhibit A, Tab 18, Schedule 1, page 5 of 17, line 11 to page 6 of 17, line 10) in the Cost Efficiencies / Productivity exhibits. Page 6, line 1 of both exhibits states:

"Hydro One negotiated a multi-year outsourcing contract for back office work programs…."

This productivity savings category only consists of one initiative unlike the other savings categories. Therefore Hydro One could provide the response to Distribution undertaking TCJ1.02. Hydro One cannot provide the budgets for the other productivity savings as stated in the response to the VECC interrogatories.

July 30th Information Session: Question #10 - Consumers Council of Canada (CCC)

Question

What is the reason for the increase for 2015 and 2016 for the major applications in the Regulatory budget? (Reference Exhibit 1, Tab 12, Schedule 10)

Response

The table below provides the breakdown of total Networks' Regulatory costs on a historic and future basis.

Description	Approved 2011	Actual 2011	Actual 2012	Actual 2013	Forecast 2014	Test 2015	Test 2016
Compliance		1.4	1.2	1.2	1.7	1.4	1.4
Major Application		1.8	1.4	1.5	1.5	1.5	1.5
Major Projects		0.7	0.9	0.6	0.7	0.7	0.7
VP & Support		5.2	3.9	4.2	1.7	1.6	1.5
Pricing					2.7	2.7	2.7
SubTotal		9.1	7.4	7.5	8.3	7.9	7.8
OEB/NEB Costs		11	13.2	13.1	15.8	13.5	14.5
Total	20.7	20.1	20.6	20.6	24.1	21.5	22.4

Two corrections should be noted in explanation of the budget distribution for Regulatory Affairs. Firstly, the historical Actuals for Major Projects and Major Applications had been switched in the original IR, which has been corrected. Secondly, costs between the categories were incorrectly allocated. However, the OEB/NEB costs and the Total cost remain unaffected.

July 30th Information Session: Question #11 - Consumers Council of Canada (CCC)

Question

What would the rate increases be without the deferral and variance accounts for 2015 and 2016?

Response

The proposed 3.2% increase on average transmission rates in 2015 quoted in the Hydro One June 25, 2014 presentation slide #7 will change to 4.4%. There would be no change to the forecast 2016 average transmission rates increase of 3.3%.

July 30th Information Session: Question #12 - School Energy Coalition (SEC)

Question

Provide Uniform Transmission Rate exhibit for revenue requirement, rates and charge determinants and reconcile to Exhibit I, Tab 4, Schedule 29.

Response

Please see Attachment 1 - Proposed Uniform Transmission Rates (UTR).

2015 Draft Uniform Transmission Rates effective January 1, 2015

Transmitter	**Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI (Note 3)	$3,809,294	$841,788	$1,676,006	$6,327,089
CNPI (Note 4)	$2,776,973	$613,663	$1,221,807	$4,612,443
GLPT (Note 5)	$22,867,783	$5,053,386	$10,061,326	$37,982,496
H1N (Note 1)	$933,586,799	$206,306,610	$410,757,846	$1,550,651,254
All Transmitters	$963,040,849	$212,815,448	$423,716,986	$1,599,573,282

Transmitter	**Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI (Note 3)	187.120	213.460	76.190	
CNPI (Note 4)	583.420	668.600	668.600	
GLPT (Note 5)	3,445.341	2,461.434	455.652	
H1N (Note 2)	245,485.314	237,023.292	203,699.845	
All Transmitters	249,701.195	240,366.786	204,900.287	

Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.86**	**0.89**	**2.07**	
FNEI Allocation Factor	**0.00396**	**0.00396**	**0.00396**	
CNPI Allocation Factor	**0.00288**	**0.00288**	**0.00288**	
GLPT Allocation Factor	**0.02375**	**0.02375**	**0.02375**	
H1N Alocation Factor	**0.96941**	**0.96941**	**0.96941**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2015 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2015 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement per Board Decision and Order on EB-2012-0300 dated on December 19, 2013, and GLPT Charge Determinants per Board Decision and Order on EB-2012-0300 dated on November 1, 2012.
Note 6: Calculated data in shaded cells.

1 **2016 Draft Uniform Transmission Rates effective January 1, 2016**

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI (Note 3)	$3,791,178	$850,337	$1,685,574	$6,327,089
CNPI (Note 4)	$2,763,766	$619,895	$1,228,782	$4,612,443
GLPT (Note 5)	$22,759,028	$5,104,706	$10,118,762	$37,982,496
H1N (Note 1)	$971,972,691	$218,007,350	$432,143,252	$1,622,123,293
All Transmitters	$1,001,286,662	$224,582,289	$445,176,370	$1,671,045,321

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	3,445.3	2,461.4	455.7	
H1N (Note 2)	248,110.0	240,598.2	206,772.4	
All Transmitters	252,325.9	243,941.6	207,972.8	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.97**	**0.92**	**2.14**	
FNEI Allocation Factor	**0.00379**	**0.00379**	**0.00379**	
CNPI Allocation Factor	**0.00276**	**0.00276**	**0.00276**	
GLPT Allocation Factor	**0.02273**	**0.02273**	**0.02273**	
H1N Alocation Factor	**0.97072**	**0.97072**	**0.97072**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2016 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2016 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement per Board Decision and Order on EB-2012-0300 dated on December 19, 2013, and GLPT Charge Determinants per Board Decision and Order on EB-2012-0300 dated on November 1, 2012.
2 *Note 6: Calculated data in shaded cells.*

SECTION IV

INFORMATION TO SATISFY FILING REQUIREMENTS

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2013

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprise the balance sheet as at December 31, 2013, the statement of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting in Note 2 of these financial statements.

Management's Responsibility for the Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these financial statements in accordance with the basis of accounting in Note 2 to these financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the 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 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 financial statements.

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Transmission Business (a business of Hydro One Networks Inc.) as at December 31, 2013 and its statement of operations and comprehensive income, and cash flows for the year then ended, in accordance with the basis of accounting as set out in Note 2 to these financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to these financial statements, which describes the basis of accounting and composition of Transmission Business (a business of Hydro One Networks Inc.). In particular, in preparing these financial statements, long-term debt, shared functions and service costs, and payments in lieu of corporate income taxes have been allocated to the Transmission Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to these financial statements. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position, results of operations and cash flows that would have resulted had the Transmission Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. These financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, these financial statements may not be suitable for another purpose. Our report is intended solely for Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 26, 2014

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Revenues		
Transmission tariff *(Note 18)*	1,493	1,453
Other	36	29
	1,529	1,482
Costs		
Operation, maintenance and administration *(Note 18)*	388	414
Depreciation and amortization *(Note 4)*	326	320
	714	734
Income before financing charges and provision for payments in lieu of corporate income taxes	815	748
Financing charges *(Notes 5, 18)*	215	211
Income before provision for payments in lieu of corporate income taxes	600	537
Provision for payments in lieu of corporate income taxes *(Notes 6, 18)*	79	80
Net income	521	457
Other comprehensive income	–	–
Comprehensive income	521	457

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	**2012**
Assets		
Current assets:		
Inter-company demand facility *(Notes 12, 13, 18)*	325	–
Accounts receivable (net of allowance for doubtful accounts – $2; 2012 – $2) (Notes 7, 18)	192	156
Materials and supplies	13	13
Regulatory assets *(Note 10)*	28	12
Deferred income tax assets *(Note 6)*	10	11
Derivative instruments *(Note 12)*	2	–
Other	8	7
	578	199
Property, plant and equipment *(Note 8)*		
Property, plant and equipment in service	14,140	13,522
Less: accumulated depreciation	4,951	4,698
	9,189	8,824
Construction in progress	737	712
Future use land, components and spares	91	91
	10,017	9,627
Other long-term assets:		
Regulatory assets *(Note 10)*	1,066	958
Intangible assets (net of accumulated amortization – $104; 2012 – $124) *(Note 9)*	116	107
Deferred debt costs	22	21
Derivative instruments *(Note 12)*	3	8
	1,207	1,094
Total assets	11,802	10,920

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS (continued)
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	**2012**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Notes 12, 13, 18)*	–	12
Accounts payable	60	66
Accrued liabilities *(Notes 6, 14, 15, 18)*	219	182
Accrued interest *(Note 18)*	61	58
Regulatory liabilities *(Note 10)*	55	2
Long-term debt payable within one year *(Notes 11, 12, 13, 18)*	327	370
	722	690
Long-term debt *(Notes 11, 12, 13, 18)*	4,954	4,632
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	636	604
Deferred income tax liabilities *(Note 6)*	806	698
Environmental liabilities *(Note 15)*	89	85
Regulatory liabilities *(Note 10)*	43	70
Net unamortized debt premiums	9	11
Asset retirement obligations *(Note 16)*	10	12
Long-term accounts payable and other liabilities	8	6
	1,601	1,486
Total liabilities	7,277	6,808
Contingencies and commitments (Notes 20, 21)		
Excess of assets over liabilities *(Notes 13, 17)*	4,525	4,112
Total liabilities and excess of assets over liabilities	11,802	10,920

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Sandy Struthers
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Operating activities		
Net income	521	457
Environmental expenditures	(6)	(6)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	301	298
Regulatory assets and liabilities	14	23
Deferred income taxes	(5)	(11)
Other	7	4
Changes in non-cash balances related to operations *(Note 19)*	48	12
Net cash from operating activities	880	777
Financing activities		
Long-term debt issued	652	611
Long-term debt retired	(370)	(276)
Payments to Hydro One Inc. to finance dividends	(108)	(163)
Other	(3)	(1)
Net cash from financing activities	171	171
Investing activities		
Capital expenditures *(Note 19)*		
Property, plant and equipment	(720)	(769)
Intangible assets	(4)	(17)
Other	10	7
Net cash used in investing activities	(714)	(779)
Net change in inter-company demand facility	337	169
Inter-company demand facility, beginning of year	(12)	(181)
Inter-company demand facility, end of year	325	(12)

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The Transmission Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements have been prepared for the specific use of the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2013 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Transmission Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Transmission Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Transmission Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Transmission Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Transmission Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes (PILs) have been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Transmission Business was a separate taxpaying entity. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB. Certain comparative figures have been reclassified to conform to the presentation of these Financial Statements (see Note 19 – Statements of Cash Flows).

Hydro One Networks performed an evaluation of subsequent events through to March 26, 2014, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these financial statements. See Note 22 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations (AROs), asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by the Company's Transmission Business beginning with the year 2012.

In May 2010, Hydro One Networks filed a cost-of-service application with the OEB for 2012 transmission rates. The OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 uniform transmission rates, with an effective date of January 1, 2012. In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 transmission rates, seeking approval for a 2013 revenue requirement of $1,465 million. In December 2012, the OEB approved a revenue requirement of $1,438 million for 2013. The reduced approved revenue requirement included reductions to proposed operation, maintenance and administration costs, and capital expenditures.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Transmission Business' regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission Business continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Transmission Business judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers. Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Transmission Business' best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Transmission Business estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 110 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One Networks is required to remit PILs to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from, or payable to, the OEFC.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net asset balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Transmission Business has recognized regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Transmission Business uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Transmission Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacements of asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overhead includes a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Transmission Business' intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

Hydro One periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate (%) Range	Rate (%) Average
Transmission	57 years	1% – 2%	2%
Communication	21 years	1% – 5%	5%
Administration and service	14 years	6% – 10%	6%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software assets range from 9% to 11%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation and amortization, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset’s carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Transmission Business’ long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2013, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges, and the change in fair value on the Company's proportionate share of existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its share of unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt. OCI and net income are presented in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. Hydro One Networks determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with its risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various derivative instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedge relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized in its Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Statements of Operations and Comprehensive Income. Additionally, Hydro One enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2013.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment funds are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets of Hydro One for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets. For the year ended December 31, 2013, the measurement date for the Plans was December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the pension plan allocated to, or funded separately by, entities within the consolidated group. Consequently, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2013.

Post-retirement and post-employment benefits

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

The Company records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2013.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Transmission Business' Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Transmission Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Transmission Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Transmission Business records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The present value is determined with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As it is anticipated that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. The estimates of future environmental expenditures are reviewed annually or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in-service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some transmission assets, particularly those located on unowned easements and rights-of-way, may have AROs, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Transmission Business expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such case, an ARO would be recorded at that time.

The Transmission Business' AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU was required to be applied retrospectively and was effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. The adoption of this ASU did not have a significant impact on the Transmission Business' Financial Statements.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required under US GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under US GAAP that provide additional detail about those amounts. This ASU was required to be applied prospectively and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. The adoption of this ASU did not have a significant impact on the Transmission Business' Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The adoption of this ASU is not anticipated to have a significant impact on the Transmission Business' Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Depreciation of property, plant and equipment	274	269
Amortization of intangible assets	21	23
Asset removal costs	25	22
Amortization of regulatory assets	6	6
	326	320

5. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Interest on long-term debt	247	248
Other	6	8
Interest on inter-company demand facility	–	1
Less: Interest capitalized on construction and development in progress	(33)	(40)
Gain on interest-rate swap agreements	(4)	(6)
Interest earned on inter-company demand facility	(1)	–
	215	211

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME 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. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Income before provision for PILs	600	537
Canadian Federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	159	142
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(44)	(34)
Pension contributions in excess of pension expense	(13)	(11)
Interest capitalized for accounting but deducted for tax purposes	(9)	(10)
Overheads capitalized for accounting but deducted for tax purposes	(8)	(8)
Prior year's adjustments	(3)	–
Environmental expenditures	(2)	(2)
Post-retirement and post-employment benefit expense in excess of cash payments	1	–
Other	(3)	2
Net temporary differences	(81)	(63)
Net permanent differences	1	1
Total provision for PILs	79	80
Current provision for PILs	84	91
Deferred provision for PILs	(5)	(11)
Total provision for PILs	79	80
Effective income tax rate	13.17%	14.90%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2013, $8 million receivable from the OEFC was included in accounts receivable on the Balance Sheet (December 31, 2012 – payable of $4 million included in accrued liabilities).

The total provision for PILs includes deferred recovery of PILs of $5 million (2012 – $11 million) that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,003)	(878)
Regulatory amounts not recognized for tax	(54)	(62)
Post-retirement and post-employment benefits expense in excess of cash payments	236	224
Environmental expenditures	24	26
Other	1	3
Total deferred income tax liabilities	(796)	(687)
Less: current portion	10	11
	(806)	(698)

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates generated a $47 million increase).

7. ACCOUNTS RECEIVABLE

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable – billed	19	15
Accounts receivable – unbilled	175	143
Accounts receivable, gross	194	158
Allowance for doubtful accounts	(2)	(2)
Accounts receivable, net	192	156

The write-offs and additions to the allowance for doubtful accounts for the years ended December 31, 2013 and 2012 were not material.

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,395	4,211	671	8,855
Communication	806	453	44	397
Administration and Service	421	213	22	230
Easements	609	74	–	535
	14,231	4,951	737	10,017

December 31, 2012 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	11,823	3,987	641	8,477
Communication	790	425	43	408
Administration and Service	394	198	28	224
Easements	606	88	–	518
	13,613	4,698	712	9,627

Financing charges capitalized on property, plant and equipment under construction were $33 million (2012 – $40 million).

9. INTANGIBLE ASSETS

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	214	101	2	115
Other	4	3	–	1
	218	104	2	116

December 31, 2012 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	218	122	9	105
Other	4	2	-	2
	222	124	9	107

Financing charges capitalized on intangible assets under development were immaterial in 2013 and 2012. The estimated annual amortization expense for intangible assets is as follows: 2014 – $20 million; 2015 – $20 million; 2016 – $20 million; 2017 – $20 million; and 2018 – $15 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Transmission Business has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Regulatory assets:		
Deferred income tax regulatory assets	835	715
Post-retirement and post-employment benefits	133	139
Environmental	100	97
Pension cost variance	21	14
Long-term project development costs	5	5
Total regulatory assets	1,094	970
Less: current portion	28	12
	1,066	958
Regulatory liabilities:		
External revenue variance	81	61
Deferred income tax regulatory liability	7	2
PST savings deferral	3	3
Other	7	6
Total regulatory liabilities	98	72
Less: current portion	55	2
	43	70

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Transmission Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Transmission Business' provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be reflected in future rates. As a result, the 2013 provision for PILs would have been higher by approximately $84 million (2012 – $93 million).

Post-Retirement and Post-Employment Benefits

The Transmission Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2013 OCI would have been higher by $6 million (2012 – lower by $85 million).

Environmental

The Transmission Business records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, an equivalent amount was recorded as a regulatory asset. In 2013, the change in the environmental regulatory asset was insignificant (2012 – $2 million decrease) to reflect related changes in the PCB liability, and increased by $5 million (2012 – $1 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Transmission Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by $5 million (2012 – lower by $1 million). In addition, 2013 amortization expense would have been lower by $6 million (2012 – $6 million), and 2013 financing charges would have been higher by $4 million (2012 – $4 million).

Pension Cost Variance

A pension cost variance account was established for the Transmission Business to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $7 million (2012 – $1 million).

Long-term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2012, the OEB approved the recovery of the December 31, 2012 balance, including accrued interest, to be recovered over a one-year period from January 1, 2014 to December 31, 2014.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenue. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Transmission Business, PST was included in rates between July 1, 2010 and December 31, 2010 and recorded in a deferral account per direction from the OEB.

11. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Transmission Business as at December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Long-term debt	5,276	4,994
Add: Unrealized marked-to-market loss[1]	5	8
Less: Long-term debt payable within one year	(327)	(370)
Long-term debt	4,954	4,632

[1] The unrealized marked-to-market loss relates to $150 million of Transmission Business' $325 million note due 2014, and $150 million of Transmission Business' $300 million note due 2015. The unrealized marked-to-market loss is offset by a $5 million (2012 – $8 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occurs with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non−Derivative Financial Assets and Liabilities

At December 31, 2013 and 2012, the carrying amounts of accounts receivable, inter-company demand facility, and accounts payable are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Transmission Business's long-term debt at December 31, 2013 and 2012 are as follows:

December 31 (millions of Canadian dollars)	2013 Carrying Value	2013 Fair Value	2012 Carrying Value	2012 Fair Value
Long-term debt				
$150 million of $325 million notes due 2014[1]	152	152	154	154
$150 million of $300 million notes due 2015[2]	153	153	154	154
Other notes and debentures[3]	4,976	5,397	4,694	5,574
	5,281	5,702	5,002	5,882

[1] The fair value of $150 million of Transmission Business' $325 million notes due 2014, subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of $150 million of Transmission Business' $300 million notes due 2015, subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[3] The fair value of other notes and debentures, and the portions of Transmission Business' $325 million and $300 million notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2013, the Transmission Business' share of the Company's derivative instruments include $300 million of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt (2012 – $300 million). These interest-rate swaps are classified as fair value hedges. The Transmission Business' fair value hedge exposure was equal to about 6% (2012 – 6%) of its long-term debt. At December 31, 2013, the Transmission Business' interest-rate swaps designated as fair value hedges were as follows:

(a) a $150 million fixed-to-floating interest-rate swap agreement to convert $150 million of the $325 million notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $75 million fixed-to-floating interest-rate swap agreements to convert $150 million of the $300 million notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2013, the Transmission Business' share of interest-rate swaps classified as undesignated contracts consisted of the following:

(c) three $150 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2013 to December 11, 2014, from February 19, 2013 to February 19, 2014, and from February 19, 2014 to November 19, 2014, respectively;

(d) two $30 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on the $30 million floating-rate notes maturing July 24, 2015, from January 24, 2013 to January 24, 2014, and from January 24, 2014 to January 24, 2015, respectively, and;

(e) a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating-rate on the $30 million floating-rate notes maturing December 3, 2016, from December 3, 2013 to December 3, 2014.

At December 31, 2013 and 2012, the carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2013 and 2012 was as follows:

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	325	325	325	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	5	5	–	5	–
	330	330	325	5	–
Liabilities:					
Long-term debt	5,281	5,702	–	5,702	–
	5,281	5,702	–	5,702	–

December 31, 2012 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Derivative instruments					
Fair value hedges – interest-rate swaps	8	8	–	8	–
	8	8	–	8	–
Liabilities:					
Inter-company demand facility	12	12	12	–	–
Long-term debt	5,002	5,882	–	5,882	–
	5,014	5,894	12	5,882	–

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the un-hedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2013 and 2012.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although Hydro One could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. This could be mirrored in the Company. The Company is exposed to fluctuations in interest rates as the regulated rate of return for its Transmission Business is derived using a formulaic approach that is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Transmission Business' rate of return would reduce the Transmission Business' results of operations by approximately $19 million (2012 – $18 million).

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, Hydro One may utilize interest-rate derivative instruments to lock in interest rate levels in anticipation of future financing. Hydro One may also enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed-rate borrowing requirements. Such arrangements are typically designated as cash flow hedges. The Company's derivative instrument policy is consistent with Hydro One. No cash flow hedge agreements were outstanding as at December 31, 2013 or 2012.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Transmission Business' results of operations for the years ended December 31, 2013 or 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instruments as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Transmission Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2013 and 2012 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Unrealized loss (gain) on hedged debt	(3)	(5)
Unrealized loss (gain) on fair value interest-rate swaps	3	5
Net unrealized loss (gain)	–	–

At December 31, 2013, the amount of the Transmission Business' fair value hedges outstanding related to interest-rate swaps was $300 million (2012 – $300 million), with assets at fair value of $5 million (2012 – $8 million). During the years ended December 31, 2013 and 2012, there was no significant impact on the Transmission Business' results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2013 and 2012, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business did not earn a significant amount of revenue from any individual customer. At December 31, 2013 and 2012, there was no significant accounts receivable balance due from any single customer.

At December 31, 2013, the Transmission Business' allowance for doubtful accounts was $2 million (2012 – $2 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013 and 2012, the Transmission Business' net accounts receivable aged more than 60 days were not significant.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Hydro One's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. In addition to payment netting language in master agreements, Hydro One establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. Hydro One would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Hydro One as specified in each agreement. Hydro One monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Transmission Business' credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2013, accounts payable and accrued liabilities in the amount of $279 million (2012 – $248 million) were expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2013, the principal amount of the Transmission Business' long-term debt was $5,276 million (2012 – $4,994 million). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Principal Outstanding on Long-term Debt** *(millions of Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	325	249	3.2
2 years	330	239	2.9
3 years	300	223	4.4
4 years	405	217	5.2
5 years	412	195	2.8
	1,772	1,123	3.7
6 – 10 years	499	876	3.7
Over 10 years	3,005	2,594	5.5
	5,276	4,593	4.7

13. CAPITAL MANAGEMENT

The Transmission Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Transmission Business considers its capital structure to consist of excess of assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Long-term debt payable within one year	327	370
Inter-company demand facility	(325)	12
	2	382
Long-term debt	4,954	4,632
Excess of assets over liabilities	4,525	4,112
Total capital	9,481	9,126

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Excess of assets over liabilities, January 1	4,112	3,818
Net income	521	457
Payments to Hydro One to finance dividends	(108)	(163)
Excess of assets over liabilities, December 31	4,525	4,112

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included in post-retirement and post-employment benefit liability on the Balance Sheets.

Pension Benefits

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One's annual Pension Plan contributions for 2013 of $160 million (2012 – $163 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2013 pensionable earnings. Hydro One's estimated annual Pension Plan contributions for 2014 are approximately $160 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

At December 31, 2013, based on the December 31, 2011 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $6,576 million (2012 – $6,507 million). The fair value of Pension Plan assets available for these benefits was $5,731 million (2012 – $4,992 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2013, the Transmission Business charged $20 million (2012 – $19 million) of post-retirement and post-employment benefit costs to operations, and capitalized $36 million (2012 – $24 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2013 were $19 million (2012 – $19 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $6 million (2012 – increased by $85 million).

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets within the following line items:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Accrued liabilities	20	21
Post-retirement and post-employment benefit liability	636	604
	656	625

15. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2013 and 2012:

Year ended December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	81	16	97
Interest accretion	3	1	4
Expenditures	–	(6)	(6)
Revaluation adjustment	–	5	5
Environmental liabilities, December 31	84	16	100
Less: current portion	8	3	11
	76	13	89

Year ended December 31, 2012 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	83	17	100
Interest accretion	4	–	4
Expenditures	(4)	(2)	(6)
Revaluation adjustment	(2)	1	(1)
Environmental liabilities, December 31	81	16	97
Less: current portion	10	2	12
	71	14	85

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	101	17	118
Less: discounting accumulated liabilities to present value	17	1	18
Discounted environmental liabilities	84	16	100

December 31, 2012 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	99	17	116
Less: discounting accumulated liabilities to present value	(18)	(1)	(19)
Discounted environmental liabilities	81	16	97

At December 31, 2013, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2014	11
2015	11
2016	10
2017	2
2018	1
Thereafter	83
	118

At December 31, 2013, of the total estimated future environmental expenditures, $101 million relates to PCBs (2012 – $99 million) and $17 million relates to LAR (2012 – $17 million).

The Transmission Business records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.8% to 5.1%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. The Transmission Business records a regulatory asset reflecting the expectation that future environmental costs will be recoverable in rates.

PCBs

In September 2008, Environment Canada published regulations governing the management, storage and disposal of PCBs, enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under these regulations and the Company's approved end-of-use extension, PCBs in concentrations of 500 parts per million (ppm) or more have to be disposed of by the end of 2014, with the exception of specifically exempted equipment, and PCBs in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts, must be disposed of by the end of 2024. Management judges that the Transmission Business currently has very few PCB-contaminated assets in excess of 500 ppm. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $101 million. These expenditures are expected to be incurred over the period from 2014 to 2024. The Company's annual review of environmental liabilities resulted in no PCB environmental liability revaluation adjustment for the Transmission Business in 2013 (2012 – revaluation adjustment to reduce PCB liability by $2 million).

LAR

The Transmission Business' best estimate of the total estimated future expenditures to complete its LAR program is $17 million. These expenditures are expected to be incurred over the period from 2014 to 2022. As a result of the Company's annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2013 to increase the LAR environmental liability by $5 million (2012 – $1 million).

16. ASSET RETIREMENT OBLIGATIONS

The Company records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' AROs represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2013, the Company had recorded AROs of $10 million (2012 – $12 million), related to its Transmission Business, consisting of $4 million (2012 – $4 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $6 million (2012 – $8 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal and there have been no significant expenditures associated with these obligations in 2013.

17. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks has 14,875,720 issued and outstanding cumulative preferred shares and 148,821,741 issued and outstanding common shares. The Company is authorized to issue an unlimited number of preferred shares and common shares.

Hydro One Networks makes common share and preferred share dividend payments to Hydro One. The Transmission Business makes payments to finance its share of the Company's common share and preferred share dividends. During 2013, the Transmission Business' payments to finance these dividends totaled $108 million (2012 – $163 million).

18. RELATED PARTY TRANSACTIONS

The Transmission Business is a separately regulated business of a subsidiary of Hydro One, and Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to the Transmission Business because they are controlled or significantly influenced by the Province. Transactions between these parties and the Transmission Business are described below.

The Transmission Business receives amounts for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Amounts received for the year ended December 31, 2013 were $1,509 million (2012 – $1,474 million). Consistent with the Company's revenue recognition policy, the Transmission Business recognized $1,493 million (2012 – $1,453 million) related to these services.

Under the *Ontario Energy Board Act, 1998,* the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. In 2013, the Transmission Business incurred $5 million (2012 – $5 million) in OEB fees.

The Company has service level agreements with OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. In 2013, revenues of the Transmission Business related to the provision of construction and equipment maintenance services with respect to these service level agreements were $8 million (2012 – $8 million). Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were less than $1 million in both 2013 and 2012.

Hydro One pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999. The Transmission Business' allocation of this fee is $4 million.

PILs and payments in lieu of property taxes were paid or payable to the OEFC.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable	140	121
Accrued liabilities	6	(45)

Hydro One and Subsidiaries

The Transmission Business provides services to, and receives services from, Hydro One and its subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of shared corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2013 revenues of the Transmission Business include $3 million (2012 – $2 million) related to the provision of services to Hydro One and its subsidiaries. Operation, maintenance and administration costs of the Transmission Business include $17 million (2012 – $16 million) related to the services received from Hydro One and its subsidiaries.

The Transmission Business' long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or due from Hydro One. Financing charges include interest expense on the long-term debt in the amount of $247 million (2012 – $248 million), and interest income on the inter-company demand facility in the amount of $1 million (2012 – interest expense of $1 million). At December 31, 2013, the Transmission Business had accrued interest payable to Hydro One totaling $61 million (2012 – $58 million).

19. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Accounts receivable	(36)	4
Materials and supplies	–	3
Other assets	(1)	1
Accounts payable	4	(7)
Accrued liabilities	38	(18)
Accrued interest	3	6
Long-term accounts payable and other liabilities	2	–
Post-retirement and post-employment benefit liability	38	23
	48	12

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Capital investments in property, plant and equipment	(706)	(759)
Net change in accruals included in capital investments in property, plant and equipment	(14)	(10)
Capital expenditures – property, plant and equipment	(720)	(769)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Capital investments in intangible assets	(8)	(17)
Net change in accruals included in capital investments in intangible assets	4	–
Capital expenditures – intangible assets	(4)	(17)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Net interest paid	241	242
PILs	88	115

20. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Transmission Business are available for the satisfaction of the debts, contingent liabilities and commitments of both the Company and Hydro One.

21. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Transmission Business. However, the net assets of the Transmission Business are available to satisfy the commitments of both the Company and Hydro One.

22. SUBSEQUENT EVENTS

On January 29, 2014, Hydro One issued $50 million notes under its MTN Program, with a maturity date of January 29, 2064 and a coupon rate of 4.29%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt, of which $30 million was allocated to the Company's Transmission Business.

On March 21, 2014, Hydro One issued $125 million floating-rate notes under its MTN Program, with a maturity date of March 21, 2019. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt, of which $75 million was allocated to the Company's Transmission Business.

RECONCILIATION OF REGULATORY FINANCIAL RESULTS WITH AUDITED FINANCIAL STATEMENTS (2013)

Hydro One Networks Inc.

Transmission

Reconciliation of Regulatory Financial Results with Audited Financial Statements
For year ended December 31, 2013

	Total per Exhibit A-10-1	Adjustments	Utility Income
	(a)	(b)	(c)
Revenue			
Transmission Tariff	1,493.00		1,493.00
Other	36.00		36.00
	1,529.00	-	1,529.00
Costs			
Operations, maintenance and administration (Note 1) (Note 2)	388.00	(1.90)	386.10
Depreciation and amortization	326.00		326.00
Capital Taxes (Note 1)	-	-	-
	714.00	(1.90)	712.10
Income before financing charges and provision for payments in lieu of corporate income taxes	815.00	1.90	816.90
Financing Charges	215.00		215.00
Income before provision for payments in lieu of corporate income taxes	600.00	1.90	601.90
Provision for Payments in lieu of corporate income taxes	79.00		79.00
Net Income	521.00	1.90	522.90

Note 1: Balance in "Capital Tax and Other Costs" (TB acct#683010) is $0. Therefore, no adjustment.

Note 2: Excluding $1.9M of cost relating to *Licence Amendment to Upgrade TSs to Facilities Renewable Generation*

Canada Revenue Agency | Agence du revenu du Canada

T2 Corporation Income Tax Return

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 87086 5821 RC0001

Corporation's name
002 Hydro One Networks Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 483 Bay Street, 8th Floor
012 South Tower

City	Province, territory, or state
015 Toronto	**016** ON
Country (other than Canada)	Postal code/Zip code
017	**018** M5G 2P5

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o Giovanna Baragetti
022 483 Bay Street, 7th floor
023 South Tower

City	Province, territory, or state
025 Toronto	**026** ON
Country (other than Canada)	Postal code/Zip code
027	**028** M5G 2P5

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 483 Bay Street, 7th floor
032 South Tower

City	Province,territory, or state
035 Toronto	**036** ON
Country (other than Canada)	Postal code/Zip code
037	**038** M5G 2P5

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** ________ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2013-01-01 (YYYY MM DD)
Tax year-end **061** 2013-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end in according to subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . **079** ________

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

095 | **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170	X	29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134
Did the corporation have any controlled foreign affiliates?	258		T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? ..... 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible ..... 294 ________ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? ..... 295 1 Yes [ ] 2 No [ ]

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	428,405,133	A
Deduct: Charitable donations from Schedule 2	311	662,500			
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction*	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal		662,500	►	662,500	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				427,742,633	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	427,742,633	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				427,742,633	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	428,405,133	A
Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 4 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	427,742,633	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 **** 14,481,000 D / 11,250 = 643,600,000 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = 430 ______ G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)			427,742,633	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income	432	D		
Amount used to calculate the credit union deduction (amount F from Schedule 17)		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6*		G		
Total of amounts B to G		►		H
Amount A **minus** amount H (if negative, enter "0")			427,742,633	I

Amount I	427,742,633	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	J
Amount I	427,742,633	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x	13 %	= 55,606,542	K

General tax reduction for Canadian-controlled private corporations – Amount J **plus** amount K . . . 55,606,542 L
Enter amount L on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				M
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		N		
Amount QQ from Part 13 of Schedule 27		O		
Personal service business income	434	P		
Amount used to calculate the credit union deduction (amount F from Schedule 17)		Q		
Total of amounts N to Q		►		R
Amount M **minus** amount R (if negative, enter "0")				S

Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x	13 %	=	U

General tax reduction – Amount T **plus** amount U . . . V
Enter amount V on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	**440**	x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632 on page 7				B
Deduct:				
Foreign investment income from Schedule 7	**445**	x 9 1 / 3 % =		C
		(if negative, enter "0")		D
Amount A **minus** amount D (if negative, enter "0")				E
Taxable income from line 360 on page 3			427,742,633	F
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				G
Foreign non-business income tax credit from line 632 on page 7		x 100 / 35 =		H
Foreign business income tax credit from line 636 on page 7		x 1(0.38 – X*) / 4 =		I
		Subtotal		J
			427,742,633	K
		x 26 2 / 3 % =	114,064,702	L
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			60,818,854	M
Refundable portion of Part I tax – Amount E, L, or M, whichever is the least	**450**			N

* General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**	11,910		
Deduct: Dividend refund for the previous tax year	**465**	11,910		
				O
Add the total of:				
Refundable portion of Part I tax from line 450 above				P
Total Part IV tax payable from Schedule 3				Q
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	**480**			
				R
Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R	**485**			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	220,455,653	x 1 / 3 =	73,485,218	S
Refundable dividend tax on hand at the end of the tax year from line 485 above				T
Dividend refund – Amount S or T, whichever is less (enter this amount on line 784 on page 8)				

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	162,542,201	A
Recapture of investment tax credit from Schedule 31			602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	427,742,633		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	427,742,633 ▶	427,742,633	ii

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** amounts A to C)		162,542,201	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	42,774,263			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount L on page 5	638	55,606,542			
General tax reduction from amount V on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	3,342,542			
Subtotal		101,723,347	▶	101,723,347	E

Part I tax payable – Amount D **minus** amount E	60,818,854	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	60,818,854
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		60,818,854

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	41,170,220	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		

(The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.)

Total provincial or territorial tax		41,170,220 ▶	41,170,220
Total tax payable	770		101,989,074 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	115,100,000
Total credits	890	115,100,000 ▶ 115,100,000 B

Refund code 894 2 Overpayment 13,110,926

Balance (amount A **minus** amount B) -13,110,926

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

Certification

I, 950 BARAGETTI (Last name (print)) 951 GIOVANNA (First name (print)) 954 Vice President, Corporate Tax (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2014-08-15 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 Selma Yam Name (print) 959 (416) 345-6827 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, personal information bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	1,517,000,000	1,017,000,000
	Total tangible capital assets	2008	+	24,211,000,000	23,058,000,000
	Total accumulated amortization of tangible capital assets	2009	–	8,234,000,000	7,779,000,000
	Total intangible capital assets	2178	+	393,000,000	339,000,000
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,811,000,000	1,616,000,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	19,698,000,000	18,251,000,000
	Liabilities				
	Total current liabilities	3139	+	1,613,000,000	1,637,000,000
	Total long-term liabilities	3450	+	11,090,000,000	10,177,000,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	12,703,000,000	11,814,000,000
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	6,995,000,000	6,437,000,000
	Total liabilities and shareholder equity	3640	=	19,698,000,000	18,251,000,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	3,637,000,000	3,079,000,000

* Generic item

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

Income statement information

Description	GIFI	
Operating name	0001	Hydro One Networks Inc.
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	5,502,000,000	5,197,000,000
	Cost of sales	8518	–	2,620,000,000	2,413,000,000
	Gross profit/loss	8519	=	2,882,000,000	2,784,000,000
	Cost of sales	8518	+	2,620,000,000	2,413,000,000
	Total operating expenses	9367	+	2,002,000,000	1,946,000,000
	Total expenses (mandatory field)	9368	=	4,622,000,000	4,359,000,000
	Total revenue (mandatory field)	8299	+	5,502,000,000	5,197,000,000
	Total expenses (mandatory field)	9368	–	4,622,000,000	4,359,000,000
	Net non-farming income	9369	=	880,000,000	838,000,000
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	880,000,000	838,000,000
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	104,000,000	133,000,000
	Future (deferred) income tax provision	9995	–	-2,000,000	-10,000,000
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	778,000,000	715,000,000

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes checklist

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [X] 2 No [ ]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [ ]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [ ]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . 200 1 Yes [X] 2 No [ ]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	274,945
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . 255 1 Yes [X] 2 No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . 260 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

Assets – lines 1000 to 2599

1060	1,080,000,000	1061	-34,000,000	1120	19,000,000
1401	369,000,000	1480	65,000,000	1483	18,000,000
1599	1,517,000,000	1900	23,151,000,000	1901	-8,234,000,000
1920	1,060,000,000	2008	24,211,000,000	2009	-8,234,000,000
2010	320,000,000	2012	73,000,000	2178	393,000,000
2420	1,811,000,000	2589	1,811,000,000	2599	19,698,000,000

Liabilities – lines 2600 to 3499

2620	930,000,000	2629	99,000,000	2700	503,000,000
2960	81,000,000	3139	1,613,000,000	3140	8,094,000,000
3240	1,112,000,000	3320	1,884,000,000	3450	11,090,000,000
3499	12,703,000,000				

Shareholder equity – lines 3500 to 3640

3500	2,991,000,000	3520	372,000,000	3541	4,000,000
3580	-9,000,000	3600	3,637,000,000	3620	6,995,000,000
3640	19,698,000,000				

Retained earnings – lines 3660 to 3849

3660	3,079,000,000	3680	778,000,000	3700	-220,000,000
3849	3,637,000,000				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

Description

Operating name . . . . **0001** Hydro One Networks Inc.

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	5,502,000,000	8089	5,502,000,000	8299	5,502,000,000

Cost of sales – lines 8300 to 8519

8320	2,620,000,000	8518	2,620,000,000	8519	2,882,000,000

Operating expenses – lines 8520 to 9369

8570	47,000,000	8670	601,000,000	8710	352,000,000
9284	1,002,000,000	9367	2,002,000,000	9368	4,622,000,000
9369	880,000,000				

Extraordinary items and taxes – lines 9970 to 9999

9970	880,000,000	9990	104,000,000	9995	-2,000,000
9999	778,000,000				

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				777,655,248 A
Add:				
Provision for income taxes – current		101	103,720,402	
Provision for income taxes – deferred		102	-1,936,044	
Interest and penalties on taxes		103	63,665	
Amortization of tangible assets		104	600,784,391	
Amortization of intangible assets		106	47,307,965	
Charitable donations and gifts from Schedule 2		112	662,500	
Scientific research expenditures deducted per financial statements		118	6,841,552	
Non-deductible meals and entertainment expenses		121	5,868,528	
Reserves from financial statements – balance at the end of the year		126	1,892,534,680	
Subtotal of additions			2,655,847,639 ►	2,655,847,639
Other additions:				
Capital items expensed		206	8,058,886	
Debt issue expense		208	3,298,220	
Miscellaneous other additions:				
600 Other Adds - See attached schedule		290	11,496,708	
601 US GAAP Adjustments for OPEB deduct in sch 13		291	13,038,248	
603 Federal apprenticeship credit prior year	346,346			
Total	346,346	293	346,346	
604 Capital Contributions received 12(1)(x)	108,266,110			
Legal Fees	1,575,680			
Restricted Transmission Asset Depreciation	1,907,334			
2013 Ontario co-op underaccrual	401,873			
2013 Ontario apprentice underaccrual	73,402			
2012 Prov to return for ONT ITC in OMA	179,896			
ARO expense reversed through depn	216,748			
Total	112,621,043	294	112,621,043	
Subtotal of other additions		199	148,859,451 ►	148,859,451
Total additions		500	2,804,707,090 ►	2,804,707,090 B
Amount A **plus** amount B				3,582,362,338

Deduct:

Capital cost allowance from Schedule 8		403	915,933,645	
Cumulative eligible capital deduction from Schedule 10		405	11,230,577	
Deferred and prepaid expenses		409	5,710,940	
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	9,171,882	
Reserves from financial statements – balance at the beginning of the year		414	1,803,248,792	
Contributions to deferred income plans from Schedule 15		417	87,396,653	
Subtotal of deductions			2,832,692,489 ▶	2,832,692,489

Other deductions:

Miscellaneous other deductions:

700 Interest cap for acct, exp for tax (761401/761402)		390	49,574,624	
701 Capital Contributions - 13(7.4) election		391	108,266,110	
703 Deduct OPEB costs capitalized in Sch013 addback	69,721,797			
Total	69,721,797	393	69,721,797	
704 Other deductions (see attached)	93,235,334			
Income included in OCI	274,945			
2013 accrued OBRI credit	191,906			
Total	93,702,185	394	93,702,185	
Subtotal of other deductions		499	321,264,716 ▶	321,264,716
Total deductions		510	3,153,957,205 ▶	3,153,957,205
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				428,405,133

T2 SCH 1 E (12)

Canada

Attached Schedule with Total

Line 409 – Deferred and prepaid expenses

Title D-Sch 001 - Deferred or prepaid expenses deducted for tax(line 409)

Description	Amount	
20(1)(e) deduction re: underwriting fees	4,389,000	00
20(1)(e) deduction re: prospectus fees	148,943	00
20(1)(e) deduction re: upfront loan fees	532,600	00
20(1)(e) deduction re: legal fees for deferred financing	200,397	00
Bond Discount	440,000	00
Total	5,710,940	00

Attached Schedule with Total

Line 208 – Debt issue expense

Title B-Sch 001- Debt issue expenses added back for tax (line 208)

Description	Amount	
Amortization of underwriting fee (GL #761780)	2,423,829	00
Amortization of Prospectus fees (GL #761790)	195,765	00
Amortization of Upfront Loan Fee (included in GL #761730)	403,681	00
Amortization of Hedge Loss (GL# 761770)	274,945	00
Total	3,298,220	00

Attached Schedule with Total

Line 704 – Amount

Title 704.1 - Amount for line 704.1

Description	Amount	
Removal Costs	6,406,702	00
Reverse environmental interest reflected on S-13	9,987,443	00
Reverse environmental valuation reflected on S-13	20,520,374	00
Capitalized Overhead general and administration	51,531,420	00
Bond Premium/Discount Amortization (761120, 761130)	2,401,005	00
Landscaping adjustments	2,146,271	00
Amortization of Capital contribution (741701)	169,273	00
Mark to Market	72,846	00
Total	93,235,334	00

Attached Schedule with Total

Line 206 – Capital items expensed

Title Line 206 – Capital items expensed

Description	Amount	
Computer system software (AC 620040)	130,363	00
Computer Application Software (AC 620046)	7,495,921	00
Equipment under 2k (GL 620510)	432,602	00
Total	8,058,886	00

Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

Description	Amount	
Project Cancellation costs	9,565,077	00
ARO Interest Accretion	204,474	00
Non deductible fees re: tax-exempt income	965,766	00
Non-deductible fees: re: due diligence fees	114,311	00
Non-deductible fees: re: exclusivity payments	350,000	00
Non-deductible fees: re: acquisition fees	297,080	00
Total	11,496,708	00

Attached Schedule with Total

Line 391 – Amount for line 701

Title Line 391 – Amount for line 701

Explanatory note

Included in this return is an election under subsection 13(7.4) with respect to amounts that would normally be included in income under paragraph 12(1)(x). The amount in respect of which the election was made, and so was not included in income but was the amount by which the cost of depreciable property was reduced, is $108,266,110

Description	Amount	
Subsection 13(7.4) Election	108,266,110	00
Total	108,266,110	00

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column F3 – Enter if dividends have been received or not after December 20, 2012. This information is required for corporations that must complete Schedules 71 and 72. For more details with regards to this column, consult the Help.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected			
Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note) 220	E Non-taxable dividend under section 83 230

Total (enter on line 402 of Schedule 1)

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.
For more details, consult the Help.

				Complete if payer corporation is connected		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	F3	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270
						J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation	Business Number	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note)	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
	400	410	420	430	
1	Hydro One Inc.	86999 4731 RC0001	2013-12-31	220,455,653	

Note
If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

Total 220,455,653

Total taxable dividends paid in the tax year to other than connected corporations	450	
Eligible dividends (included in line 450)	450a	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)	460	220,455,653

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			220,455,653
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	220,455,653
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			220,455,653

Canada Revenue Agency / Agence du revenu du Canada

Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia Offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
427,742,633		427,742,633	49,155,403

Ontario basic income tax (from Schedule 500)	270	49,190,403		
Deduct: Ontario small business deduction (from Schedule 500)	402	35,000		
Subtotal		49,155,403	49,155,403	A6
Add:				
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal				B6
Subtotal (amount A6 **plus** amount B6)			49,155,403	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414	10,673		
Ontario political contributions tax credit (from Schedule 525)	415			
Other Ontario non-refundable credits				
Subtotal		10,673	10,673	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			49,144,730	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416		590,423	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			48,554,307	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			48,554,307	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal				H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			48,554,307	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	1,516,774		
Ontario apprenticeship training tax credit (from Schedule 552)	454	5,692,313		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470	175,000		
Subtotal		7,384,087	7,384,087	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		41,170,220	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 41,170,220

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

Canada Revenue Agency Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Adjustments and transfers**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate % ****	9 Recapture of capital cost allowance***** (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ******	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		201	203	205	207	211		212	213	215	217	220
1.	1		3,979,728,192	9,869,611	-45,043,961	0	4,934,806	3,939,619,036	4	0	0	157,584,761	3,786,969,081
2.	2		935,877,099			0		935,877,099	6	0	0	56,152,626	879,724,473
3.	3		254,234,289	7,366,716		0	3,683,358	257,917,647	5	0	0	12,895,882	248,705,123
4.	6		77,862,055	10,888,563		0	5,444,282	83,306,336	10	0	0	8,330,634	80,419,984
5.	7		34,932			0		34,932	15	0	0	5,240	29,692
6.	8		152,371,899	42,317,200	10,741	0	21,158,600	173,541,240	20	0	0	34,708,248	159,991,592
7.	9		2,864,745			0		2,864,745	25	0	0	716,186	2,148,559
8.	10		144,167,917	56,118,785	-89,990	1,361,850	27,378,468	171,456,394	30	0	0	51,436,918	147,397,944
9.	12		19,316,567	194,852,177		0	97,426,089	116,742,655	100	0	0	116,742,655	97,426,089
10.	13	Leases	831,580		-143,146	0		688,434	NA	0	0	201,043	487,391
11.	17		53,935,209	9,084,662		0	4,542,331	58,477,540	8	0	0	4,678,203	58,341,668
12.	35		294,598		-172,803	0		121,795	7	0	0	8,526	113,269
13.	42		88,012,082	4,504,686		0	2,252,343	90,264,425	12	0	0	10,831,731	81,685,037
14.	45	Computers - old cl.10 post Mar 2	1,028,272			0		1,028,272	45	0	0	462,722	565,550
15.	46	cl.8 post Mar 22/04	5,235,679	9,761,112	-51,988	0	4,880,556	10,064,247	30	0	0	3,019,274	11,925,529
16.	47	Electricity Assets > 22-02-2005	4,325,791,747	818,027,787	25,500,489	181,446	408,923,171	4,760,215,406	8	0	0	380,817,232	4,788,321,345
17.	50	Computers	103,826,359	70,846,241		0	35,423,121	139,249,479	55	0	0	76,587,213	98,085,387
18.	13	Barrie Office (WBS 700004578)	736,400			0		736,400	NA	0	0	210,400	526,000
19.	13	Atrium on Bay (WBS 300040666	128,161			0		128,161	NA	0	0	28,480	99,681
20.	13	Newmarket Garage (WBS 30004	186,269			0		186,269	NA	0	0	33,867	152,402
21.	13	255 Matheson Mississauga (WBS	1,694,982			0		1,694,982	NA	0	0	260,766	1,434,216
22.	13	95 Mural Street (WBS 70001035	30,784		-19,642	0		11,142	NA	0	0	4,867	6,275
23.	13	Nipigon (WBS 700011829)	188,512			0		188,512	NA	0	0	25,135	163,377
24.	13	Kemptville (WBS 700009832)	10,874			0		10,874	NA	0	0	2,416	8,458

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Adjustments and transfers** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
25.	13	Sudbury (WBS 700010356)	315,202			0		315,202	NA	0	0	23,348	291,854
26.	13	Lionhead (WBS 700015140)	45,090			0		45,090	NA	0	0	5,305	39,785
27.	13	483 Bay St (WBS 300042991C)		4,159,133		0	2,079,567	2,079,566	NA	0	0	159,967	3,999,166
		Totals	10,148,749,495	1,237,796,673	-20,010,300	1,543,296	618,126,692	10,746,865,880				915,933,645	10,449,058,927

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost:
– Amounts transferred under section 85, or transferred on amalgamation and winding-up of a subsidiary.
Items that **reduce** the undepreciated capital cost:
– Government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	Hydro One Inc.		86999 4731 RC0001	1					
2.	Hydro One Remote Communities In		87083 6269 RC0001	3					
3.	Hydro One Telecom Inc.		86800 1066 RC0001	3					
4.	Hydro One Telecom Link Limited		88786 7513 RC0001	3					
5.	Hydro One Brampton Networks Inc.		86486 7635 RC0001	3					
6.	Hydro One Lake Erie Link Managem		87892 1519 RC0001	3					
7.	Hydro One Lake Erie Link Company		87560 6519 RC0001	3					
8.	Hydro One B2M LP Inc.		81838 2046 RC0001	2	1	100.000			1
9.	B2M GP INC.		81838 1840 RC0001	2	999	100.000			999
10.	Hydro One B2M Holdings Inc.		82217 7531 RC0001	3					
11.	1908872 Ontario Inc		82581 6838 RC0001	3					
12.	1908873 Ontario Inc.		83392 0978 RC0001	3					
13.	1893080 Ontario Inc.		82217 7333 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11) Canada

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")	200	157,649,556	A
Add: Cost of eligible capital property acquired during the taxation year	222	3,716,350	
Other adjustments	226		
Subtotal (line 222 plus line 226) 3,716,350 x 3 / 4 =		2,787,263	B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =	C
amount B minus amount C (if negative, enter "0") 2,787,263 ▶		2,787,263	D
Amount transferred on amalgamation or wind-up of subsidiary	224		E
Subtotal (add amounts A, D, and E)	230	160,436,819	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H
Other adjustments	246		I
(add amounts G,H, and I) x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)		160,436,819	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)			
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business	249		
amount K 160,436,819			
less amount from line 249			
Current year deduction 160,436,819 x 7.00 % =	250	11,230,577 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 11,230,577 ▶		11,230,577	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")	300	149,206,242	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			**400**	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			**401**	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402**	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408**	4			
Line 3 minus line 4 (if negative, enter "0")		▶		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	**409**	▶		9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
		Line 5	x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
		Amount R	x 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				**410**	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability Short Term	42,382,000				42,382,000
2	OPEB Liability Long Term	1,389,674,668		69,961,926		1,459,636,594
3	Environmental Short Term	20,562,246		3,733,964		24,296,210
4	Environmental Long Term	216,145,456		12,196,694		228,342,150
5	Contingent Liabilities	11,232,152		1,293,273		12,525,425
6	Regulatory Accounts	113,926,847	106,387	2,004,848		116,038,082
7	Tenant Inducement	106,305			2,026,924	-1,920,619
8	Asset Retirement Obligations	9,112,731			2,633,748	6,478,983
9	General Bad Debt Reserve			3,908,361		3,908,361
10	Unpaid Bonus Accrual			847,494		847,494
11						
	Reserves from Part 2 of Schedule 13					
	Totals	1,803,142,405	106,387	93,946,560	4,660,672	1,892,534,680

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	155,510,059	1059104			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . 155,510,059 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 68,113,406 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") . . . . 87,396,653 C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

T2 SCH 15 (13)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2013

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	Hydro One Networks Inc.	87086 5821 RC0001	1	500,000	100.0000	500,000
2	Hydro One Inc.	86999 4731 RC0001	1	500,000		
3	Hydro One Remote Communities Inc.	87083 6269 RC0001	1	500,000		
4	Hydro One Telecom Inc.	86800 1066 RC0001	1	500,000		
5	Hydro One Telecom Link Limited	88786 7513 RC0001	1	500,000		
6	Hydro One Brampton Networks Inc.	86486 7635 RC0001	1	500,000		
7	Hydro One Lake Erie Link Management Inc	87892 1519 RC0001	1	500,000		
8	Hydro One Lake Erie Link Company Inc.	87560 6519 RC0001	1	500,000		
9	Hydro One B2M LP Inc.	81838 2046 RC0001	1	500,000		
10	B2M GP INC.	81838 1840 RC0001	1	500,000		
11	Hydro One B2M Holdings Inc.	82217 7531 RC0001	1	500,000		
12	1908872 Ontario Inc	82581 6838 RC0001	1	500,000		
13	1908873 Ontario Inc.	83392 0978 RC0001	1	500,000		

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400	
14	1893080 Ontario Inc.	82217 7333 RC0001	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

Canada Revenue Agency Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release*.*
- For more information on SR&ED, see Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada*, and T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more information.

Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013***	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****:	
– after March 28, 2012, and before 2014****	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015****	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . 101 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . 102 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* 103

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
			Total of investments for qualified property and qualified resource property	A

* CCA: capital cost allowance

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . . B

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal (line 210 **plus** line 215) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) . . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) . . . . . . x 5 % = 242

Credit allocated from a partnership 250

Subtotal (total of lines 230 to 250) ▶ D

Total credit available (line 220 **plus** amount D) . . . . E

Deduct:

Credit deducted from Part I tax (enter at amount D in Part 30) 260

Credit carried back to the previous year(s) (amount H from Part 6) . . . . . . a

Credit transferred to offset Part VII tax liability 280

Subtotal (total of line 260, amount a, and line 280) ▶ F

Credit balance before refund (amount E **minus** amount F) . . . . G

Deduct:

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) 310

ITC closing balance of investments from qualified property and qualified resource property (amount G **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter at amount a in Part 5) H

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5) I

Credit balance before refund (amount G from Part 5) . . . . J

Refund (40 % of amount I or J, whichever is less) . . . . K

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)	13,108,931			
Add:				
Contributions to agricultural organizations for SR&ED*				
Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)*	13,108,931	▶	350	13,108,931
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**			360	
Repayments made in the year (from line 560 on Form T661)			370	
Qualified SR&ED expenditures (total of lines 350 to 370)			380	13,108,931

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [X] 2 No [ ]

Complete lines 390 and 398 if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied)	390	
Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million	398	

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone corporation:			$ 8,000,000	
Deduct:				
Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more		x 10 =		A
Excess ($8,000,000 **minus** amount A; if negative, enter "0")				B
$ 40,000,000 **minus** line 398 from Part 9		a		
Amount a **divided** by $ 40,000,000				C
Expenditure limit for the stand-alone corporation (amount B **multiplied** by amount C)				D*
For an associated corporation:				
If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49		400		E*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D or E ______ x Number of days in the tax year 365 / 365 = ______ F

Your **SR&ED expenditure limit for the year** (enter the amount from line D, E, or F, whichever applies) 410 ______

* Amount D or E cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less*	420		x	35 % =		G
Line 350 **minus** line 410 (if negative, enter "0")**	430	13,108,931	x	20 % =	2,621,786	H
Line 410 **minus** line 350 (if negative, enter "0")			b			
Capital expenditures (line 360 from Part 8) or amount b above, whichever is less*	440		x	35 % =		I
Line 360 **minus** amount b above (if negative, enter "0")**	450		x	20 % =		J
Repayments (amount from line 370 in Part 8)						

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**

460		x	35 % =		c
480		x	20 % =		d
			Subtotal (amount c **plus** amount d)		▶ K

Current-year SR&ED ITC (total of amounts G to K; enter on line 540 in Part 12)	2,621,786	L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				M
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)				N
ITC at the beginning of the tax year (amount M **minus** amount N)			520	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit (from amount L in Part 11)	540	2,621,786		
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)		2,621,786	2,621,786	O
Total credit available (line 520 **plus** amount O)			2,621,786	P
Deduct:				
Credit deducted from Part I tax (enter at amount E in Part 30)	560	2,621,786		
Credit carried back to the previous year(s) (amount S from Part 13)				e
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount e, and line 580)		2,621,786	2,621,786	Q
Credit balance before refund (amount P **minus** amount Q)				R
Deduct:				
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED (amount R **minus** line 610)			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	

Total (enter at amount e in Part 12) . . . S

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . 650 1 Yes ☐ 2 No ☒

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) . . . f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* . . . T

Deduct:

Amount T or amount G from Part 11, whichever is less . . . U

Net amount (amount T **minus** amount U; if negative, enter "0") . . . V

Amount V **multiplied** by 40 % . . . W

Add:

Amount U . . . X

Refund of ITC (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) . . . Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) . . . Z

Deduct:

Amount Z or amount G from Part 11, whichever is less . . . AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") . . . BB

Amount BB or amount I from Part 11, whichever is less . . . CC

Amount CC **multiplied** by 40 % . . . DD

Add :

Amount AA . . . EE

Refund of ITC (amount DD **plus** amount EE) . . . FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal (enter this amount at amount C in Part 17) ______ A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	**B** Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	**C** Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

D Amount determined by the formula (A x B) – C	**E** ITC earned by the transferee for the qualified expenditures that were transferred **750**	**F** Amount from column D or E, whichever is less

Subtotal (enter this amount at amount D in Part 17) ______ B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ______

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from amount A in Part 16		C
Recaptured ITC for calculation 2 from amount B in Part 16		D
Recaptured ITC for calculation 3 from line 760 in Part 16		E
Total recapture of SR&ED investment tax credit – total of amounts C to E		F

Enter amount F at amount A in Part 29.

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting . . . . . 810 ______

Geological, geophysical, or geochemical surveys . . . . . 811 ______

Drilling by rotary, diamond, percussion, or other methods . . . . . 812 ______

Trenching, digging test pits, and preliminary sampling . . . . . 813 ______

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping . . . . . 820 ______

Sinking a mine shaft, constructing an adit, or other underground entry . . . . . 821 ______

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts in column 826 ______ ► ______ A

Total pre-production mining expenditures (total of lines 810 to 821 and amount A) . . . . . 830 ______

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above . . . . . 832 ______

Excess (line 830 **minus** line 832) (if negative, enter "0") . . . . . ______ B

Add:

Repayments of government and non-government assistance . . . . . 835 ______

Pre-production mining expenditures (amount B **plus** line 835) . . . . . ______ C

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . . D

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ▶ E

ITC at the beginning of the tax year (amount D **minus** amount E) 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18) . . 870 x 10 % = a

Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18) . . 872 x 5 % = b

Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18) . . 874 x 7 % = c

Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18) . . 876 x 4 % = d

Current year credit (total of amounts a to d) 880 ▶ F

Total credit available (total of lines 850, 860, and amount F) . . . . G

Deduct:

Credit deducted from Part I tax (enter at amount F in Part 30) 885

Credit carried back to the previous year(s) (amount I from Part 20) . . . . e

Subtotal (line 885 **plus** amount e) ▶ H

ITC closing balance from pre-production mining expenditures (amount G **minus** amount H) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	921	
2nd previous tax year				Credit to be applied	922	
3rd previous tax year				Credit to be applied	923	

Total (enter at amount e in Part 19) I

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	Apprentice 1	309A	210	21	21
2.	Apprentice 2	403A	1,910	191	191

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
3.	Apprentice 3	309A	2,896	290	290
4.	Apprentice 4	309A	3,650	365	365
5.	Apprentice 5	434A	4,227	423	423
6.	Apprentice 6	309A	5,950	595	595
7.	Apprentice 7	309A	7,018	702	702
8.	Apprentice 8	309A	7,231	723	723
9.	Apprentice 9	309A	7,296	730	730
10.	Apprentice 10	310T	7,620	762	762
11.	Apprentice 11	434A	7,897	790	790
12.	Apprentice 12	309A	8,178	818	818
13.	Apprentice 13	309A	8,178	818	818
14.	Apprentice 14	309A	8,490	849	849
15.	Apprentice 15	309A	9,350	935	935
16.	Apprentice 16	309A	9,390	939	939
17.	Apprentice 17	309A	9,542	954	954
18.	Apprentice 18	309A	10,568	1,057	1,057
19.	Apprentice 19	309A	10,764	1,076	1,076
20.	Apprentice 20	309A	11,586	1,159	1,159
21.	Apprentice 21	309A	11,762	1,176	1,176
22.	Apprentice 22	444B	12,345	1,235	1,235
23.	Apprentice 23	444B	12,846	1,285	1,285
24.	Apprentice 24	403A	13,404	1,340	1,340
25.	Apprentice 25	444B	14,561	1,456	1,456
26.	Apprentice 26	309A	14,758	1,476	1,476
27.	Apprentice 27	434A	14,791	1,479	1,479
28.	Apprentice 28	309A	16,490	1,649	1,649
29.	Apprentice 29	309A	16,951	1,695	1,695
30.	Apprentice 30	434A	17,139	1,714	1,714
31.	Apprentice 31	309A	17,316	1,732	1,732
32.	Apprentice 32	309A	17,399	1,740	1,740
33.	Apprentice 33	444B	17,436	1,744	1,744
34.	Apprentice 34	434A	17,868	1,787	1,787
35.	Apprentice 35	434A	17,898	1,790	1,790
36.	Apprentice 36	434A	18,044	1,804	1,804
37.	Apprentice 37	434A	18,091	1,809	1,809
38.	Apprentice 38	434A	18,527	1,853	1,853
39.	Apprentice 39	434A	19,091	1,909	1,909
40.	Apprentice 40	309ABA	19,538	1,954	1,954
41.	Apprentice 41	309A	19,748	1,975	1,975
42.	Apprentice 42	434A	19,779	1,978	1,978
43.	Apprentice 43	434A	19,902	1,990	1,990
44.	Apprentice 44	434A	19,944	1,994	1,994
45.	Apprentice 45	309A	19,949	1,995	1,995
46.	Apprentice 46	434A	71,818	7,182	2,000
47.	Apprentice 47	309A	71,880	7,188	2,000
48.	Apprentice 48	403A	50,672	5,067	2,000
49.	Apprentice 49	444B	66,627	6,663	2,000
50.	Apprentice 50	444B	58,013	5,801	2,000
51.	Apprentice 51	444B	55,740	5,574	2,000
52.	Apprentice 52	444B	61,611	6,161	2,000
53.	Apprentice 53	444B	63,304	6,330	2,000
54.	Apprentice 54	444B	66,523	6,652	2,000
55.	Apprentice 55	444B	72,455	7,246	2,000
56.	Apprentice 56	444B	57,303	5,730	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
57.	Apprentice 57	444B	65,387	6,539	2,000
58.	Apprentice 58	444B	72,276	7,228	2,000
59.	Apprentice 59	444B	64,938	6,494	2,000
60.	Apprentice 60	444B	67,495	6,750	2,000
61.	Apprentice 61	444B	74,315	7,432	2,000
62.	Apprentice 62	444B	57,478	5,748	2,000
63.	Apprentice 63	444B	63,863	6,386	2,000
64.	Apprentice 64	434A	42,964	4,296	2,000
65.	Apprentice 65	434A	58,309	5,831	2,000
66.	Apprentice 66	434A	84,154	8,415	2,000
67.	Apprentice 67	434A	63,350	6,335	2,000
68.	Apprentice 68	434A	62,333	6,233	2,000
69.	Apprentice 69	434A	62,750	6,275	2,000
70.	Apprentice 70	434A	59,755	5,976	2,000
71.	Apprentice 71	434A	62,729	6,273	2,000
72.	Apprentice 72	434A	66,307	6,631	2,000
73.	Apprentice 73	434A	58,930	5,893	2,000
74.	Apprentice 74	434A	65,974	6,597	2,000
75.	Apprentice 75	434A	66,093	6,609	2,000
76.	Apprentice 76	434A	66,230	6,623	2,000
77.	Apprentice 77	434A	66,575	6,658	2,000
78.	Apprentice 78	434A	63,288	6,329	2,000
79.	Apprentice 79	434A	80,380	8,038	2,000
80.	Apprentice 80	434A	65,131	6,513	2,000
81.	Apprentice 81	434A	59,454	5,945	2,000
82.	Apprentice 82	309A	51,309	5,131	2,000
83.	Apprentice 83	309A	52,505	5,251	2,000
84.	Apprentice 84	309A	56,157	5,616	2,000
85.	Apprentice 85	309A	52,143	5,214	2,000
86.	Apprentice 86	434A	64,950	6,495	2,000
87.	Apprentice 87	434A	64,004	6,400	2,000
88.	Apprentice 88	434A	58,593	5,859	2,000
89.	Apprentice 89	434A	65,460	6,546	2,000
90.	Apprentice 90	434A	62,244	6,224	2,000
91.	Apprentice 91	434A	62,217	6,222	2,000
92.	Apprentice 92	434A	66,960	6,696	2,000
93.	Apprentice 93	434A	43,525	4,353	2,000
94.	Apprentice 94	434A	56,005	5,601	2,000
95.	Apprentice 95	434A	44,439	4,444	2,000
96.	Apprentice 96	434A	71,750	7,175	2,000
97.	Apprentice 97	434A	58,867	5,887	2,000
98.	Apprentice 98	434A	64,715	6,472	2,000
99.	Apprentice 99	434A	62,310	6,231	2,000
100	Apprentice 100	434A	55,840	5,584	2,000
101	Apprentice 101	434A	59,587	5,959	2,000
102	Apprentice 102	434A	53,773	5,377	2,000
103	Apprentice 103	309A	45,465	4,547	2,000
104	Apprentice 104	309A	34,371	3,437	2,000
105	Apprentice 105	309A	35,639	3,564	2,000
106	Apprentice 106	309A	55,025	5,503	2,000
107	Apprentice 107	309A	39,521	3,952	2,000
108	Apprentice 108	309A	56,942	5,694	2,000
109	Apprentice 109	309A	55,263	5,526	2,000
110	Apprentice 110	309A	45,721	4,572	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
111	Apprentice 111	309A	31,194	3,119	2,000
112	Apprentice 112	309A	42,644	4,264	2,000
113	Apprentice 113	309A	50,820	5,082	2,000
114	Apprentice 114	309A	36,170	3,617	2,000
115	Apprentice 115	434A	75,794	7,579	2,000
116	Apprentice 116	434A	57,710	5,771	2,000
117	Apprentice 117	434A	81,237	8,124	2,000
118	Apprentice 118	434A	47,590	4,759	2,000
119	Apprentice 119	434A	42,321	4,232	2,000
120	Apprentice 120	434A	54,431	5,443	2,000
121	Apprentice 121	434A	73,127	7,313	2,000
122	Apprentice 122	434A	55,572	5,557	2,000
123	Apprentice 123	434A	53,895	5,390	2,000
124	Apprentice 124	434A	73,897	7,390	2,000
125	Apprentice 125	309A	46,739	4,674	2,000
126	Apprentice 126	309A	67,090	6,709	2,000
127	Apprentice 127	444B	46,237	4,624	2,000
128	Apprentice 128	444B	55,150	5,515	2,000
129	Apprentice 129	444BN	43,322	4,332	2,000
130	Apprentice 130	444B	46,371	4,637	2,000
131	Apprentice 131	444B	44,539	4,454	2,000
132	Apprentice 132	444B	41,688	4,169	2,000
133	Apprentice 133	444B	45,274	4,527	2,000
134	Apprentice 134	444B	55,059	5,506	2,000
135	Apprentice 135	444B	53,898	5,390	2,000
136	Apprentice 136	444B	55,615	5,562	2,000
137	Apprentice 137	444B	36,809	3,681	2,000
138	Apprentice 138	444B	48,062	4,806	2,000
139	Apprentice 139	444B	51,811	5,181	2,000
140	Apprentice 140	444B	58,405	5,841	2,000
141	Apprentice 141	444B	61,537	6,154	2,000
142	Apprentice 142	444B	48,390	4,839	2,000
143	Apprentice 143	444B	50,028	5,003	2,000
144	Apprentice 144	444B	56,873	5,687	2,000
145	Apprentice 145	444B	46,933	4,693	2,000
146	Apprentice 146	444B	52,051	5,205	2,000
147	Apprentice 147	444B	45,371	4,537	2,000
148	Apprentice 148	309A	66,873	6,687	2,000
149	Apprentice 149	434A	63,950	6,395	2,000
150	Apprentice 150	434A	75,161	7,516	2,000
151	Apprentice 151	434A	63,419	6,342	2,000
152	Apprentice 152	434A	70,006	7,001	2,000
153	Apprentice 153	434A	59,423	5,942	2,000
154	Apprentice 154	434A	94,338	9,434	2,000
155	Apprentice 155	434A	67,835	6,784	2,000
156	Apprentice 156	434A	55,647	5,565	2,000
157	Apprentice 157	434A	75,086	7,509	2,000
158	Apprentice 158	434A	60,204	6,020	2,000
159	Apprentice 159	434A	66,029	6,603	2,000
160	Apprentice 160	434A	64,529	6,453	2,000
161	Apprentice 161	434A	69,789	6,979	2,000
162	Apprentice 162	310T	29,504	2,950	2,000
163	Apprentice 163	310T	38,889	3,889	2,000
164	Apprentice 164	434A	52,501	5,250	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
165	Apprentice 165	434A	66,196	6,620	2,000
166	Apprentice 166	434A	62,589	6,259	2,000
167	Apprentice 167	434A	50,382	5,038	2,000
168	Apprentice 168	434A	54,675	5,468	2,000
169	Apprentice 169	434A	60,503	6,050	2,000
170	Apprentice 170	434A	92,083	9,208	2,000
171	Apprentice 171	434A	49,944	4,994	2,000
172	Apprentice 172	434A	86,584	8,658	2,000
173	Apprentice 173	434A	59,012	5,901	2,000
174	Apprentice 174	434A	64,273	6,427	2,000
175	Apprentice 175	434A	65,908	6,591	2,000
176	Apprentice 176	434A	54,992	5,499	2,000
177	Apprentice 177	434A	51,612	5,161	2,000
178	Apprentice 178	309A	40,063	4,006	2,000
179	Apprentice 179	309A	59,256	5,926	2,000
180	Apprentice 180	309A	80,562	8,056	2,000
181	Apprentice 181	309A	44,485	4,449	2,000
182	Apprentice 182	403A	74,010	7,401	2,000
183	Apprentice 183	444B	58,794	5,879	2,000
184	Apprentice 184	444B	49,474	4,947	2,000
185	Apprentice 185	444B	47,505	4,751	2,000
186	Apprentice 186	444B	48,687	4,869	2,000
187	Apprentice 187	444B	48,024	4,802	2,000
188	Apprentice 188	444B	52,042	5,204	2,000
189	Apprentice 189	444B	55,013	5,501	2,000
190	Apprentice 190	444B	47,396	4,740	2,000
191	Apprentice 191	444B	49,447	4,945	2,000
192	Apprentice 192	444B	44,407	4,441	2,000
193	Apprentice 193	444B	47,514	4,751	2,000
194	Apprentice 194	444B	60,614	6,061	2,000
195	Apprentice 195	444B	53,081	5,308	2,000
196	Apprentice 196	444B	63,526	6,353	2,000
197	Apprentice 197	309A	45,262	4,526	2,000
198	Apprentice 198	309A	52,278	5,228	2,000
199	Apprentice 199	309A	39,210	3,921	2,000
200	Apprentice 200	309A	43,755	4,376	2,000
201	Apprentice 201	309A	49,963	4,996	2,000
202	Apprentice 202	309A	56,724	5,672	2,000
203	Apprentice 203	403A	60,223	6,022	2,000
204	Apprentice 204	309A	53,093	5,309	2,000
205	Apprentice 205	309A	36,362	3,636	2,000
206	Apprentice 206	309A	61,131	6,113	2,000
207	Apprentice 207	309A	46,185	4,619	2,000
208	Apprentice 208	309A	34,485	3,449	2,000
209	Apprentice 209	309A	34,146	3,415	2,000
210	Apprentice 210	309A	51,620	5,162	2,000
211	Apprentice 211	309A	51,200	5,120	2,000
212	Apprentice 212	309A	33,240	3,324	2,000
213	Apprentice 213	434A	50,996	5,100	2,000
214	Apprentice 214	434A	53,329	5,333	2,000
215	Apprentice 215	434A	50,488	5,049	2,000
216	Apprentice 216	434A	50,968	5,097	2,000
217	Apprentice 217	434A	46,097	4,610	2,000
218	Apprentice 218	434A	53,001	5,300	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
219	Apprentice 219	434A	46,906	4,691	2,000
220	Apprentice 220	434A	47,317	4,732	2,000
221	Apprentice 221	434A	49,669	4,967	2,000
222	Apprentice 222	434A	47,001	4,700	2,000
223	Apprentice 223	434A	51,200	5,120	2,000
224	Apprentice 224	434A	52,153	5,215	2,000
225	Apprentice 225	434A	44,763	4,476	2,000
226	Apprentice 226	434A	59,883	5,988	2,000
227	Apprentice 227	434A	50,073	5,007	2,000
228	Apprentice 228	434A	55,112	5,511	2,000
229	Apprentice 229	434A	48,770	4,877	2,000
230	Apprentice 230	434A	55,240	5,524	2,000
231	Apprentice 231	434A	54,199	5,420	2,000
232	Apprentice 232	434A	50,855	5,086	2,000
233	Apprentice 233	434A	50,141	5,014	2,000
234	Apprentice 234	434A	48,439	4,844	2,000
235	Apprentice 235	434A	46,177	4,618	2,000
236	Apprentice 236	434A	58,464	5,846	2,000
237	Apprentice 237	434A	47,626	4,763	2,000
238	Apprentice 238	310T	46,981	4,698	2,000
239	Apprentice 239	310T	50,184	5,018	2,000
240	Apprentice 240	310T	47,182	4,718	2,000
241	Apprentice 241	310T	41,822	4,182	2,000
242	Apprentice 242	310T	56,856	5,686	2,000
243	Apprentice 243	310T	41,993	4,199	2,000
244	Apprentice 244	434A	82,699	8,270	2,000
245	Apprentice 245	434A	42,336	4,234	2,000
246	Apprentice 246	434A	54,664	5,466	2,000
247	Apprentice 247	434A	49,646	4,965	2,000
248	Apprentice 248	434A	53,205	5,321	2,000
249	Apprentice 249	434A	54,908	5,491	2,000
250	Apprentice 250	434A	44,728	4,473	2,000
251	Apprentice 251	434A	46,294	4,629	2,000
252	Apprentice 252	434A	49,157	4,916	2,000
253	Apprentice 253	434A	45,272	4,527	2,000
254	Apprentice 254	434A	49,237	4,924	2,000
255	Apprentice 255	434A	55,491	5,549	2,000
256	Apprentice 256	434A	51,551	5,155	2,000
257	Apprentice 257	434A	39,212	3,921	2,000
258	Apprentice 258	434A	44,065	4,407	2,000
259	Apprentice 259	434A	54,714	5,471	2,000
260	Apprentice 260	434A	49,747	4,975	2,000
261	Apprentice 261	434A	50,723	5,072	2,000
262	Apprentice 262	434A	45,514	4,551	2,000
263	Apprentice 263	434A	45,437	4,544	2,000
264	Apprentice 264	434A	38,931	3,893	2,000
265	Apprentice 265	434A	54,967	5,497	2,000
266	Apprentice 266	434A	51,632	5,163	2,000
267	Apprentice 267	434A	47,784	4,778	2,000
268	Apprentice 268	444B	31,924	3,192	2,000
269	Apprentice 269	444B	32,951	3,295	2,000
270	Apprentice 270	444B	37,956	3,796	2,000
271	Apprentice 271	444B	33,032	3,303	2,000
272	Apprentice 272	444B	30,900	3,090	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
273	Apprentice 273	444B	31,007	3,101	2,000
274	Apprentice 274	444B	28,599	2,860	2,000
275	Apprentice 275	444B	28,835	2,884	2,000
276	Apprentice 276	444B	28,151	2,815	2,000
277	Apprentice 277	444B	32,200	3,220	2,000
278	Apprentice 278	434A	41,166	4,117	2,000
279	Apprentice 279	434A	46,540	4,654	2,000
280	Apprentice 280	434A	46,238	4,624	2,000
281	Apprentice 281	434A	43,609	4,361	2,000
282	Apprentice 282	434A	67,242	6,724	2,000
283	Apprentice 283	434A	43,079	4,308	2,000
284	Apprentice 284	434A	43,871	4,387	2,000
285	Apprentice 285	434A	44,633	4,463	2,000
286	Apprentice 286	434A	41,580	4,158	2,000
287	Apprentice 287	434A	42,129	4,213	2,000
288	Apprentice 288	434A	37,994	3,799	2,000
289	Apprentice 289	434A	39,518	3,952	2,000
290	Apprentice 290	434A	51,044	5,104	2,000
291	Apprentice 291	434A	32,347	3,235	2,000
292	Apprentice 292	434A	44,050	4,405	2,000
293	Apprentice 293	434A	35,215	3,522	2,000
294	Apprentice 294	434A	44,199	4,420	2,000
295	Apprentice 295	434A	38,595	3,860	2,000
296	Apprentice 296	434A	33,933	3,393	2,000
297	Apprentice 297	434A	33,510	3,351	2,000
298	Apprentice 298	434A	33,892	3,389	2,000
299	Apprentice 299	434A	37,119	3,712	2,000
300	Apprentice 300	434A	36,271	3,627	2,000
301	Apprentice 301	434A	34,227	3,423	2,000
302	Apprentice 302	434A	32,680	3,268	2,000
303	Apprentice 303	434A	39,271	3,927	2,000
304	Apprentice 304	434A	53,176	5,318	2,000
305	Apprentice 305	434A	35,134	3,513	2,000
306	Apprentice 306	434A	35,522	3,552	2,000
307	Apprentice 307	434A	32,646	3,265	2,000
308	Apprentice 308	434A	37,339	3,734	2,000
309	Apprentice 309	434A	45,452	4,545	2,000
310	Apprentice 310	309A	26,367	2,637	2,000
311	Apprentice 311	309A	20,722	2,072	2,000
312	Apprentice 312	309A	26,103	2,610	2,000
313	Apprentice 313	309A	25,913	2,591	2,000
314	Apprentice 314	309A	26,504	2,650	2,000
315	Apprentice 315	309A	30,077	3,008	2,000
316	Apprentice 316	309A	28,192	2,819	2,000
317	Apprentice 317	309A	30,762	3,076	2,000
318	Apprentice 318	309A	25,924	2,592	2,000
319	Apprentice 319	309A	28,610	2,861	2,000
320	Apprentice 320	434A	25,042	2,504	2,000
321	Apprentice 321	343A	41,446	4,145	2,000
322	Apprentice 322	434A	28,627	2,863	2,000
323	Apprentice 323	434A	26,711	2,671	2,000
324	Apprentice 324	434A	32,433	3,243	2,000
325	Apprentice 325	309A	24,641	2,464	2,000
326	Apprentice 326	309A	31,483	3,148	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
327	Apprentice 327	309A	34,415	3,442	2,000
328	Apprentice 328	309A	25,838	2,584	2,000
329	Apprentice 329	309A	24,843	2,484	2,000
330	Apprentice 330	309A	37,142	3,714	2,000
331	Apprentice 331	309A	25,571	2,557	2,000
332	Apprentice 332	309A	21,313	2,131	2,000
333	Apprentice 333	309A	26,591	2,659	2,000
334	Apprentice 334	309A	23,414	2,341	2,000
335	Apprentice 335	309A	25,345	2,535	2,000
336	Apprentice 336	309A	22,418	2,242	2,000
337	Apprentice 337	309A	26,790	2,679	2,000
338	Apprentice 338	309A	36,050	3,605	2,000
339	Apprentice 339	309A	35,825	3,583	2,000
340	Apprentice 340	309A	59,244	5,924	2,000
341	Apprentice 341	309A	24,422	2,442	2,000
342	Apprentice 342	433A	35,618	3,562	2,000
343	Apprentice 343	433A	35,409	3,541	2,000
344	Apprentice 344	433A	62,646	6,265	2,000
345	Apprentice 345	433A	47,234	4,723	2,000
346	Apprentice 346	434A	36,552	3,655	2,000
347	Apprentice 347	434A	35,524	3,552	2,000
348	Apprentice 348	444B	42,694	4,269	2,000
349	Apprentice 349	444B	37,999	3,800	2,000
350	Apprentice 350	444B	24,200	2,420	2,000
351	Apprentice 351	444B	41,740	4,174	2,000
352	Apprentice 352	444B	24,457	2,446	2,000
353	Apprentice 353	444B	22,919	2,292	2,000
354	Apprentice 354	444B	22,654	2,265	2,000
355	Apprentice 355	444B	30,269	3,027	2,000
356	Apprentice 356	444B	22,708	2,271	2,000
357	Apprentice 357	309A	33,827	3,383	2,000
358	Apprentice 358	434A	30,795	3,080	2,000
359	Apprentice 359	434A	28,942	2,894	2,000
360	Apprentice 360	434A	27,496	2,750	2,000
361	Apprentice 361	434A	27,627	2,763	2,000
362	Apprentice 362	434A	26,788	2,679	2,000
363	Apprentice 363	434A	22,895	2,290	2,000
364	Apprentice 364	434A	20,937	2,094	2,000
365	Apprentice 365	309A	21,447	2,145	2,000
366	Apprentice 366	403A	21,107	2,111	2,000
367	Apprentice 367	444B	36,120	3,612	2,000
368	Apprentice 368	444B	37,791	3,779	2,000
369	Apprentice 369	444B	38,887	3,889	2,000
370	Apprentice 370	444B	30,058	3,006	2,000
371	Apprentice 371	444B	34,756	3,476	2,000
372	Apprentice 372	444B	50,325	5,033	2,000
373	Apprentice 373	444B	29,672	2,967	2,000
374	Apprentice 374	444B	52,543	5,254	2,000
375	Apprentice 375	444B	36,016	3,602	2,000
376	Apprentice 376	444B	38,356	3,836	2,000
377	Apprentice 377	434A	39,867	3,987	2,000

Total current-year credit (enter at line 640 in Part 22) 720,756 A

* Net of any other government or non-government assistance received or to be received.

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				B
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal (line 612 **plus** line 615)				C
ITC at the beginning of the tax year (amount B **minus** amount C)	625			
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (amount A from Part 21)	640	720,756		
Credit allocated from a partnership	655			
Subtotal (total of lines 630 to 655)		720,756	720,756	D
Total credit available (line 625 **plus** amount D)			720,756	E
Deduct:				
Credit deducted from Part I tax (enter at amount G in Part 30)	660	720,756		
Credit carried back to the previous year(s) (amount G from Part 23)			a	
Subtotal (line 660 **plus** amount a)		720,756	720,756	F
ITC closing balance from apprenticeship job creation expenditures (amount E **minus** amount F)	690			

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter at amount a in Part 22)		G

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year 715 ____

Add:

Specified child care start-up expenditures from the current tax year . . . . . 705 ____

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ____ A

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A . . . . . 725 ____

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . ____ B

Add:

Repayments by the corporation of government and non-government assistance . . . . . 735 ____

Total eligible expenditures for child care spaces (amount B **plus** line 735) . . . . . 745 ____

* CCA: capital cost allowance

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . . ____ x 25 % = ____ C

Number of child care spaces . . . . . 755 ____ x $ 10,000 = ____ D

ITC from child care spaces expenditures (amount C or D, whichever is less) . . . . . ____ E

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year . . . . F

Deduct:

Credit deemed as a remittance of co-op corporations 765

Credit expired after 20 tax years 770

Subtotal (line 765 **plus** line 770) ► G

ITC at the beginning of the tax year (amount F **minus** amount G) 775

Add:

Credit transferred on amalgamation or wind-up of subsidiary 777

Total current-year credit (amount E from Part 25) 780

Credit allocated from a partnership 782

Subtotal (total of lines 777 to 782) ► H

Total credit available (line 775 **plus** amount H) I

Deduct:

Credit deducted from Part I tax (enter at amount H in Part 30) 785

Credit carried back to the previous year(s) (amount K from Part 27) . . . . a

Subtotal (line 785 **plus** amount a) ► J

ITC closing balance from child care spaces expenditures (amount I **minus** amount J) 790

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2012-12-31	. . . . Credit to be applied	941	
2nd previous tax year	2011-12-31	. . . . Credit to be applied	942	
3rd previous tax year	2010-12-31	. . . . Credit to be applied	943	

Total (enter at amount a in Part 26) K

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ A

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ______

Total recapture of child care spaces investment tax credit (total of line 792, amount A, and line 799) . . . . ______ B

Enter amount B at amount B in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F in Part 17)		A
Recaptured child care spaces ITC (from amount B in Part 28)		B
Total recapture of investment tax credit (amount A **plus** amount B)		C

Enter amount C on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		D
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	2,621,786	E
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		F
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	720,756	G
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		H
Total ITC deducted from Part I tax (total of amounts D to H)	3,342,542	I

Enter amount I at line 652 of the T2 return.

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
		Provide only one number per shareholder				
	100	200	300	350	400	500
1	Hydro One Inc.	86999 4731 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2011 / Number of days in the tax year	/ 365	x	12.00 %	=	%	A1
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	365 / 365	x	11.50 %	=	11.50000 %	A2

Ontario basic rate of tax for the year (rate A1 **plus** A2) 11.50000 ► 11.50000 % A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 427,742,633 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1) . . . . 49,190,403 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	428,405,133	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	427,742,633	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	3
Enter the least of amounts 1, 2, and 3	500,000	D

Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** = 427,742,633.00 / 427,742,633 = 1.00000 E

Amount D x factor E 500,000 a

Ontario taxable income (amount B from Part 2) 427,742,633 b

Ontario small business income (lesser of amount a and amount b) 500,000 F

Number of days in the tax year before July 1, 2011 / Number of days in the tax year: ____ / 365 x 7.50 % = % G1

Number of days in the tax year after June 30, 2011 / Number of days in the tax year: 365 / 365 x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3) 35,000 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3) 500,000 I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17 . . . . J

Deduct:
Ontario adjusted small business income (amount I from Part 4) . . . . K

Subtotal (amount J **minus** amount K) (if negative, enter "0") L

OSBD rate for the year (rate G3 from Part 3) . . . . 7.00000 %

Amount L **multiplied** by the OSBD rate for the year . . . . M

Ontario domestic factor (factor E from Part 3) . . . . 1.00000 N

Ontario credit union tax reduction (amount M **multiplied** by factor N) . . . . O

Enter amount O on line 410 of Schedule 5.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, all legislative references are to the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	160	
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A **minus** line 170)	180	

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included In the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6)	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

- have been earned and are available without restriction to the corporation;
- are attributable to qualifying Ontario SR&ED expenditures;
- have not been deducted under subsection 127(5) or (6) of the federal Act at the end of the corporation's tax year ending immediately before its transition time; and
- do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1, or amount from line 330 in Part 3 of Schedule 506 for the previous tax year)	300	8,347,715,889		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the tax year		8,347,715,889 ►	330	8,347,715,889

Total Ontario balance:

Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year)	340	8,348,179,915		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the tax year		8,348,179,915 ►	370	8,348,179,915
Transitional balance at the end of the tax year (line 330 **minus** line 370)			390	-464,026

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation*.

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:

– the tax year includes January 1, 2009; or
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? **400** 1 Yes [ ] 2 No [X]

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)				B
Deduct:				
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)		1		
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)		2		
Subtotal (amount 1 **plus** amount 2)		►		C
Subtotal (amount B **minus** amount C) (if negative, enter "0")				D
Federal balance before election (amount A from Part 1)				
Deduct:				
Total Ontario balance (amount from line 280 in Part 2)				
Subtotal (if negative, enter "0")				E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

– five calendar years after the time immediately before the start of the corporation's reference period; or

– December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:

– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or

– the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

– the end of the corporation's reference period; or

– the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:

– the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or

– the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:

– enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . **435** ______

– enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) . . . . **440** ______

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

Ontario taxable income* / Taxable income** ______ = ______

Ontario allocation factor (OAF) . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3				G
Amount G x Ontario basic rate of tax*	11.5 % =			H
Amount H x OAF (from line F in Part 6)	1.00000			I

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5 = 365 / 1,825 = 0.20000 J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J)			K
Post-2008 SR&ED balance at the end of the year (amount HH from Part 12)	460		
Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14)	470		
Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470)			L
Total transitional tax debits (amount K **plus** amount L)			M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5		49,155,403	N
Deduct:			
Ontario resource tax credit (from line 404 of Schedule 5)			
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)			
Ontario foreign tax credit (from line 408 of Schedule 5)			
Ontario credit union tax reduction (from line 410 of Schedule 5)			
Subtotal	▶		O
Subtotal (amount N **minus** amount 0)		49,155,403	P

Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012) = 365 / 365 = 1.00000 Q

Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q)	510	49,155,403	
Amount from line 390 in Part 3 (enter as a positive amount)		464,026	R
Amount R x Ontario basic rate of tax* 11.5 % =		53,363	S
Amount S x OAF (from line F in Part 6)		53,363	T

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5 = 365 / 1,825 = 0.20000 U

Current-year transitional tax credit (amount T **multiplied** by amount U)	520	10,673	
Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0")	530	49,144,730	
Transitional tax credit:			
Lesser of amounts on line 510 and 520		10,673	V
Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530			W
Transitional tax credits (amount V **plus** amount W)		10,673	X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)*			1	
Add:				
Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup*	560		2	
Unused transitional tax credit available (amount 1 **plus** amount 2)			▶	Y
Add:				
Current-year transitional tax credit (amount from line 520 in Part 8)			10,673	Z
Subtotal (amount Y **plus** amount Z)			10,673	3
Deduct:				
Transitional tax credit applied (amount X from Part 8)			10,673	AA
Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA)		580		

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a)	610			
Capital SR&ED expenditures in the year under paragraph 37(1)(b)	614			
Repayment of assistance under paragraph 37(1)(c)	618			
Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year	624			
Subtotal (total of lines 610 to 624)			▶	BB
Deduct:				
Assistance under paragraph 37(1)(d)	638			
Investment tax credits deducted under paragraph 37(1)(e)	644			
Subtotal (line 638 **plus** line 644)			▶	CC
Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC)			650	

If the amount on line 650 is positive, enter it on line II In Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

– the corporation's OAF for the tax year that includes its transition time (from line F in Part 6) .... %

– the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) .... %

– the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008 .... %

Relevant OAF .... 660 ________ %

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

– the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;

2) a corporation that wound up into the particular corporation under subsection 88(1); or

3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . ______ DD

SR&ED expenditure amount deducted in the year under subsection 37(1) . . . . 670 ______

Deduct:
Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) . . . . . 675 ______
Subtotal (line 670 **minus** line 675) (if negative, enter "0") ______ ► ______ EE

Subtotal (amount DD **plus** amount EE) ______ FF

Amount FF x 14 % ______ GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . ______ HH
Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) . . . . ______ II
Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 . . . . 700 ______
Subtotal (line II **plus** line 700) ______ JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 . . . . 705 ______

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . 710 ______
Deduct:
Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year . . . . 715 ______
Subtotal (line 710 **minus** line 715) 720 ______

Line 720 / Relevant OAF (from line 660 in Part 11) x 14 % ______ = ... ______ KK

Subtotal (line 705 **minus** amount KK) ______ ► 730 ______

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") . . . . ______ LL
Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . 735 ______ MM
Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . ______ NN
Amount NN x 14 % . . . . ______ ► ______ OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up . . . . 740 ______
Subtotal (amount OO **plus** line 740) ______ PP

Deduct:
Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . 750 ______

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . ______ QQ
Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	13,295,506 A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	175,000 B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		13,120,506 C		
Add: Eligible expenditures transferred to the corporation by another corporation	110	D		
Subtotal (amount C **plus** amount D)		13,120,506	►	13,120,506 E
Deduct: Eligible expenditures the corporation transferred to another corporation			115	F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")			120	13,120,506 G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)		13,120,506	x	4.50 % =	200	590,423 H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205	I

* If there is a disposal or change of use of eligible property, see Part 6

Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210		x	4.50 % =	215	J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =	x	4.50 % =	225	K
Current part of the ORDTC (total of amounts H to K)					230	590,423 L

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year				M	
Deduct: ORDTC expired after 20 tax years	300			N	
ORDTC at the beginning of the tax year (amount M **minus** amount N)	305			O	
Add:					
ORDTC transferred on amalgamation or windup	310			P	
Current part of ORDTC (amount L in Part 2)		590,423 Q			

Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320	R				
Subtotal (amount Q **minus** amount R)		590,423	▶	590,423	S	
ORDTC available for deduction (total of amounts O, P and S)				590,423 ▶	590,423	T
Deduct:						
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)				590,423	U	
ORDTC carried back to a previous tax year (from Part 4)					V	
Subtotal (amount U **plus** amount V)				590,423 ▶	590,423	W
ORDTC balance at the end of the tax year (amount T **minus** amount W)				325		X

* This amount cannot be more than the lesser of the following amounts:
– ORDTC available for deduction (amount T); or
– Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2012-12-31	Credit to be applied	901	
2nd previous tax year	2011-12-31	Credit to be applied	902	
3rd previous tax year	2010-12-31	Credit to be applied	903	

Total (enter amount on line V in Part 3)

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available
1994-03-31	
1995-03-31	
1996-03-31	
1997-03-31	
1998-03-31	
1999-03-31	
1999-12-31	
2000-12-31	
2001-12-31	
2002-12-31	

	Tax year of origin (earliest tax year first) Year Month Day	Credit available
	2003-12-31	
	2004-12-31	
	2005-12-31	
	2006-12-31	
	2007-12-31	
	2008-12-31	
	2009-12-31	
	2010-12-31	
	2011-12-31	
	2012-12-31	
Current tax year	2013-12-31	

Total (equals line 325 in Part 3) __________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) __________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ______ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . 760 ______ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ______ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ______ LL

Amount KK **plus** amount LL . . . . ______ x 23.56 % = ______ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ______ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ______ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures			Capital Expenditures	
Total expenditures for SR&ED		15,465,631				
Add						
• payment of prior years' unpaid expenses (other than salary or wages)	+	830,811				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+					
• expenditures on shared-use equipment				+		
• other additions	+			+		
Subtotal	=	16,296,442		=		
Less						
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–	437,378				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–					
• 20% of contract expenditures for SR&ED performed on your behalf	–	1,984,710				
• prescribed expenditures not allowed by regulations	–			–		
• other deductions	–	578,848		–		
• non-arm's length transactions						
– expenditures for non-arm's length SR&ED contracts	–					
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–			–		
Subtotal	=	13,295,506	I	=		II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)				=	13,295,506	III

Enter amount III on line 100 of Schedule 508.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	19,698,000,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	13,806,920,103
Total assets (total of lines 112 to 116)		33,504,920,103
Total revenue of the corporation for the tax year **	142	5,502,000,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	1,250,037,000
Total revenue (total of lines 142 to 146)		6,752,037,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

	Line	Amount		Line	Total	
Net income/loss per financial statements *				210	777,655,248	
Add (to the extent reflected in income/loss):						
Provision for current income taxes/cost of current income taxes	220	103,720,402				
Provision for deferred income taxes (debits)/cost of future income taxes	222					
Equity losses from corporations	224					
Financial statement loss from partnerships and joint ventures	226					
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230					
Other additions (see note below):						
Share of adjusted net income of partnerships and joint ventures **	228					
Total patronage dividends received, not already included in net income/loss	232					
281	282					
283	284					
Subtotal		103,720,402	▶		103,720,402	A
Deduct (to the extent reflected in income/loss):						
Provision for recovery of current income taxes/benefit of current income taxes	320					
Provision for deferred income taxes (credits)/benefit of future income taxes	322	1,936,044				
Equity income from corporations	324					
Financial statement income from partnerships and joint ventures	326					
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330					
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332					
Gain on donation of listed security or ecological gift	340					
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342					
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344					
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346					
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348					
Other deductions (see note below):						
Share of adjusted net loss of partnerships and joint ventures **	328					
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334					
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336					
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338					
381	382					
383	384					
385	386					
387	388					
389	390					
Subtotal		1,936,044	▶		1,936,044	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)				490	879,439,606	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	879,439,606		
Deduct:					
CMT loss available (amount R from Part 7)					
Minus: Adjustment for an acquisition of control *	518				
Adjusted CMT loss available		▶			C
Net income subject to CMT calculation (if negative, enter "0")		520	879,439,606		

Amount from line 520 879,439,606 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year 365) x 4 % = ______ 1

Amount from line 520 879,439,606 x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = 23,744,869 2

Subtotal (amount 1 **plus** amount 2) 23,744,869 3

Gross CMT: amount on line 3 above x OAF **	540	23,744,869	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		23,744,869	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		48,554,307	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			▶	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		48,554,307	1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)	23,744,869	2			
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)		3			
Gross SAT (line 460 from Part 6 of Schedule 512)		4			
The **greater** of amounts 3 and 4		5			
Deduct: line 2 or line 5, whichever applies:		23,744,869	6		
Subtotal (if negative, enter "0")		24,809,438	▶	24,809,438	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		48,554,307			
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		7,384,087			
Subtotal (if negative, enter "0")		41,170,220	▶	41,170,220	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . _______ Q

Deduct:

CMT loss expired * . . . . 700 _______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . _______ ▶ 720 _______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . 750 _______

CMT loss available (line 720 **plus** line 750) . . . . _______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . _______

Subtotal (if negative, enter "0") _______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . 760 _______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 _______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Hydro One Inc.	86999 4731 RC0001	13,247,000,000	650,000,000
2	Hydro One Remote Communities Inc.	87083 6269 RC0001	73,695,000	50,035,000
3	Hydro One Telecom Inc.	86800 1066 RC0001	76,876,000	80,880,000
4	Hydro One Telecom Link Limited	88786 7513 RC0001	1,111,000	442,000
5	Hydro One Brampton Networks Inc.	86486 7635 RC0001	403,229,000	468,680,000
6	Hydro One Lake Erie Link Management Inc	87892 1519 RC0001	4,990,000	0
7	Hydro One Lake Erie Link Company Inc.	87560 6519 RC0001	18,000	0
8	Hydro One B2M LP Inc.	81838 2046 RC0001	1	0
9	B2M GP INC.	81838 1840 RC0001	999	0
10	Hydro One B2M Holdings Inc.	82217 7531 RC0001	100	0
11	1908872 Ontario Inc	82581 6838 RC0001	0	0
12	1908873 Ontario Inc.	83392 0978 RC0001	1	0
13	1893080 Ontario Inc.	82217 7333 RC0001	2	0
		Total	450 13,806,920,103	550 1,250,037,000

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: Selma Yam

120 Telephone number including area code: (416) 345-6827

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 788,867,244

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$400{,}000}{\$200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$400{,}000}{\$200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	Waterloo	Economics
2.	Waterloo	Economics
3.	Toronto	Engineering
4.	Niagara	Human Resources Management
5.	Niagara	Human Resources Management
6.	Mohawk	Electrical Engineering Technician / Technology
7.	UOIT	Electrical Engineering
8.	UOIT	Electrical Engineering
9.	Toronto	Mechanical Engineering
10.	Toronto	Mechanical Engineering
11.	McMaster	Electrical Engineering
12.	McMaster	Electrical Engineering
13.	McMaster	Electrical Engineering
14.	Toronto	Electrical Engineering
15.	Toronto	Electrical Engineering
16.	Toronto	Engineering
17.	Toronto	Engineering
18.	Mohawk	Electrical Engineering Technician / Technology
19.	Mohawk	Electrical Engineering Technician / Technology
20.	Toronto	Civil Engineering
21.	Toronto	Civil Engineering
22.	Georgian	Business Administration
23.	Georgian	Business Administration

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	Georgian	Business Administration
25.	McMaster	Finance / Accounting
26.	McMaster	Finance / Accounting
27.	Brock	Business Administration
28.	Brock	Business Administration
29.	Mohawk	Electrical Engineering Technician / Technology
30.	UOIT	Electrical Engineering
31.	Mohawk	Electrical Engineering Technician / Technology
32.	McMaster	Electrical Engineering
33.	McMaster	Electrical Engineering
34.	Ryerson	Electrical Engineering
35.	Ryerson	Electrical Engineering
36.	Georgian	Computer Science
37.	Georgian	Electrical Engineering Technician / Technology
38.	Georgian	Electrical Engineering Technician / Technology
39.	Georgian	Electrical Engineering Technician / Technology
40.	Toronto	Mechanical Engineering
41.	Toronto	Mechanical Engineering
42.	Guelph	Real Estate & Housing
43.	Guelph	Real Estate & Housing
44.	McMaster	Electrical Engineering
45.	McMaster	Electrical Engineering
46.	Ryerson	Electrical Engineering
47.	Ryerson	Electrical Engineering
48.	Toronto	Engineering
49.	Waterloo	Electrical Engineering
50.	Brock	Master of Business Economics
51.	Waterloo	Electrical Engineering
52.	Waterloo	Electrical Engineering
53.	Georgian	Electrical Engineering Technician / Technology
54.	Georgian	Electrical Engineering Technician / Technology
55.	Georgian	Electrical Engineering Technician / Technology
56.	Georgian	Electrical Engineering Technician / Technology
57.	Georgian	Electrical Engineering Technician / Technology
58.	Toronto	Civil Engineering
59.	Toronto	Civil Engineering
60.	Ryerson	Electrical Engineering
61.	Ryerson	Electrical Engineering
62.	Mohawk	Electrical Engineering Technician / Technology
63.	Mohawk	Electrical Engineering Technician / Technology
64.	Mohawk	Electrical Engineering Technician / Technology
65.	Mohawk	Electrical Engineering Technician / Technology
66.	Toronto	Civil Engineering
67.	Toronto	Civil Engineering
68.	Georgian	Business Administration
69.	Mohawk	Electrical Engineering Technician / Technology
70.	Georgian	Computer Science
71.	McMaster	Computer Science
72.	Laurier	Business Administration
73.	Brock	Master of Business Administration
74.	Brock	Master of Business Administration
75.	Toronto	Electrical Engineering
76.	Toronto	Electrical Engineering
77.	Fanshawe	GIS and Urban Planning
78.	Toronto	Civil Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
79.	Toronto	Civil Engineering
80.	Guelph	Management Economics and Finance
81.	Guelph	Management Economics and Finance
82.	Toronto	Business Administration
83.	Toronto	Business Administration
84.	Toronto	Business Administration
85.	Lakehead	Master of Computer Science
86.	Toronto	Engineering
87.	York	Finance / Accounting
88.	York	Finance / Accounting
89.	Toronto	Electrical Engineering
90.	Toronto	Electrical Engineering
91.	Toronto	Electrical Engineering
92.	Toronto	Electrical Engineering
93.	Mohawk	Electrical Engineering Technician / Technology
94.	Windsor	Civil Engineering
95.	Georgian	Finance / Accounting
96.	Georgian	Electrical Engineering Technician / Technology
97.	Guelph	Mechanical Engineering
98.	Guelph	Mechanical Engineering
99.	Georgian	Electrical Engineering Technician / Technology
100.	Georgian	Business Accounting Program
101.	Brock	Master of Business Economics
102.	Brock	Master of Business Economics
103.	Georgian	Electrical Engineering Technician / Technology
104.	Toronto	Electrical Engineering
105.	Toronto	Electrical Engineering
106.	Georgian	Electrical Engineering Technician / Technology
107.	Mohawk	Electrical Engineering Technician / Technology
108.	Waterloo	Electrical Engineering
109.	McMaster	Electrical Engineering Technician / Technology
110.	McMaster	Electrical Engineering Technician / Technology
111.	Georgian	Electrical Engineering Technician / Technology
112.	Mohawk	Electrical Engineering Technician / Technology
113.	Mohawk	Electrical Engineering Technician / Technology
114.	Mohawk	Electrical Engineering Technician / Technology
115.	Windsor	Electrical Engineering
116.	Windsor	Electrical Engineering
117.	Toronto	Civil Engineering
118.	Toronto	Civil Engineering
119.	Georgian	Electrical Engineering Technician / Technology
120.	Toronto	Mechanical Engineering
121.	Toronto	Mechanical Engineering
122.	McMaster	Finance/Accounting
123.	McMaster	Finance/Accounting
124.	Toronto	Engineering Science
125.	Toronto	Engineering Science
126.	Georgian	Electrical Engineering Technician / Technology
127.	Georgian	Electrical Engineering Technician / Technology
128.	Georgian	Electrical Engineering Technician / Technology
129.	McMaster	Electrical Engineering
130.	McMaster	Electrical Engineering
131.	McMaster	Electrical Engineering
132.	Windsor	Electrical Engineering
133.	Georgian	Computer Science

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
134.	Guelph	Real Estate & Housing
135.	Guelph	Real Estate & Housing
136.	Brock	Master of Business Administration
137.	Brock	Master of Business Administration
138.	Brock	Master of Business Administration
139.	Brock	Master of Business Administration
140.	Brock	Master of Business Administration
141.	Brock	Master of Business Administration
142.	Seneca	Corporate Communications
143.	Windsor	Electrical Engineering
144.	Windsor	Electrical Engineering
145.	UOIT	Electrical Engineering
146.	Mohawk	Electrical Engineering Technician / Technology
147.	Mohawk	Electrical Engineering Technician / Technology
148.	Mohawk	Electrical Engineering Technician / Technology
149.	Ryerson	Electrical Engineering
150.	Toronto	Civil Engineer
151.	Toronto	Civil Engineer
152.	Guelph	Environmental Science
153.	Georgian	Business Administration
154.	Georgian	Computer Science
155.	Mohawk	Electrical Engineering Technician / Technology
156.	Guelph	Real Estate & Housing
157.	Ryerson	Occupational Health and Safety
158.	Ryerson	Occupational Health and Safety
159.	Western	Electrical Engineering
160.	Western	Electrical Engineering
161.	Brock	Business Administration
162.	Brock	Business Administration
163.	Ryerson	Electrical Engineering
164.	Toronto	Mechanical Engineering
165.	Toronto	Mechanical Engineering
166.	Toronto	Mechanical Engineering
167.	Sheridan	Human Resources Management
168.	Toronto	Civil Engineering
169.	Toronto	Civil Engineering
170.	Laurier	Business Technology Management
171.	Brock	Business Administration
172.	Sheridan	Human Resources Management
173.	McMaster	Finance / Accounting
174.	McMaster	Finance / Accounting
175.	Mohawk	Electrical Engineering Technician / Technology
176.	Mohawk	Electrical Engineering Technician / Technology
177.	Mohawk	Electrical Engineering Technician / Technology
178.	Mohawk	Electrical Engineering Technician / Technology
179.	Georgian	Electrical Engineering Technician / Technology
180.	Queens	Electrical Engineering
181.	Queens	Electrical Engineering
182.	Queens	Electrical Engineering
183.	Georgian	Electrical Engineering Technician / Technology
184.	Georgian	Computer Science
185.	Georgian	Electrical Engineering Technician / Technology
186.	Windsor	Civil Engineering
187.	Windsor	Civil Engineering
188.	Toronto	Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
189.	Toronto	Electrical Engineering
190.	McMaster	Computer Engineering
191.	McMaster	Computer Engineering
192.	Windsor	Electrical Engineering
193.	Windsor	Electrical Engineering
194.	Windsor	Electrical Engineering
195.	Ryerson	Electrical Engineering
196.	Ryerson	Electrical Engineering
197.	Ryerson	Electrical Engineering
198.	Windsor	Electrical Engineering
199.	McMaster	Business Administration
200.	McMaster	Business Administration
201.	Queens	Electrical Engineering
202.	Windsor	Electrical Engineering
203.	Mohawk	Electrical Engineering Technician / Technology
204.	Windsor	Electrical Engineering
205.	Georgian	Electrical Engineering Technician / Technology
206.	Toronto	Finance / Accounting
207.	Toronto	Finance / Accounting
208.	Toronto	Finance / Accounting
209.	McMaster	Electrical Engineering
210.	McMaster	Electrical Engineering
211.	Toronto	Business Administration
212.	Guelph	Real Estate & Housing
213.	Mohawk	Electrical Engineering Technician / Technology
214.	Ryerson	Electrical Engineering
215.	McMaster	Finance/Accounting
216.	McMaster	Finance/Accounting
217.	Georgian	Electrical Engineering Technician / Technology
218.	Laurier	Business Administration
219.	UOIT	Business Administration
220.	Ryerson	Electrical Engineering
221.	Ryerson	Electrical Engineering
222.	Toronto	Electrical Engineering
223.	Toronto	Electrical Engineering
224.	Toronto	Computer Engineering
225.	Toronto	Computer Engineering
226.	Windsor	Electrical Engineering
227.	Western	Computer Science
228.	Western	Computer Science
229.	Toronto	Civil Engineering
230.	Toronto	Civil Engineering
231.	Toronto	Business Administration
232.	Toronto	Business Administration
233.	Toronto	Business Administration
234.	McMaster	Electrical Engineering
235.	McMaster	Electrical Engineering
236.	Mohawk	Electrical Engineering Technician / Technology
237.	McMaster	Electrical Engineering
238.	Waterloo	Finance/Accounting
239.	Brock	Master of Business Administration
240.	Brock	Master of Business Administration
241.	Toronto	Mechanical Engineering
242.	Toronto	Mechanical Engineering
243.	Toronto	Engineering Science

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
244.	McMaster	Electrical Engineering
245.	Georgian	Electrical Engineering Technician / Technology
246.	Georgian	Electrical Engineering Technician / Technology
247.	Guelph	Real Estate & Housing
248.	Guelph	Real Estate & Housing
249.	Georgian	Business Administration
250.	Georgian	Business Administration
251.	McMaster	Finance / Accounting
252.	McMaster	Finance / Accounting
253.	Waterloo	Actuarial Science
254.	Brock	International Master of Accountancy
255.	Toronto	Electrical Engineering
256.	Toronto	Electrical Engineering
257.	Georgian	Electrical Engineering Technician / Technology
258.	Toronto	Engineering
259.	Toronto	Electrical Engineering
260.	Guelph	Mechanical Engineering
261.	Guelph	Mechanical Engineering
262.	Toronto	Engineering
263.	Toronto	Engineering
264.	Toronto	Business Administration/ Commerce
265.	Niagara	Business Administration/ Commerce
266.	Georgian	Computer Science
267.	Georgian	Electrical Engineering Technician / Technology
268.	UOIT	Electrical Engineering
269.	UOIT	Electrical Engineering
270.	Mohawk	Electrical Engineering Technician / Technology
271.	Mohawk	Electrical Engineering Technician / Technology
272.	Mohawk	Electrical Engineering Technician / Technology
273.	UOIT	Electrical Engineering
274.	UOIT	Electrical Engineering
275.	UOIT	Electrical Engineering
276.	Ryerson	Electrical Engineering
277.	Ryerson	Electrical Engineering
278.	York	Finance / Accounting
279.	York	Finance / Accounting
280.	York	Finance / Accounting
281.	Windsor	Electrical Engineering
282.	Windsor	Electrical Engineering
283.	Windsor	Electrical Engineering
284.	Georgian	Electrical Engineering Technician / Technology
285.	Ryerson	Geography
286.	Georgian	Electrical Engineering Technician / Technology
287.	Georgian	Electrical Engineering Technician / Technology
288.	Georgian	Electrical Engineering Technician / Technology
289.	Brock	Accounting
290.	Georgian	Electrical Engineering Technician / Technology
291.	Toronto	Electrical Engineering
292.	Toronto	Electrical Engineering
293.	Toronto	Electrical Engineering
294.	UOIT	Electrical Engineering
295.	UOIT	Electrical Engineering
296.	UOIT	Electrical Engineering
297.	UOIT	Electrical Engineering
298.	Georgian	Electrical Engineering Technician / Technology

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
299.	Georgian	Electrical Engineering Technician / Technology
300.	Brock	Math
301.	Georgian	Electrical Engineering Technician / Technology
302.	Georgian	Electrical Engineering Technician / Technology
303.	Mohawk	Electrical Engineering Technician / Technology
304.	Mohawk	Electrical Engineering Technician / Technology
305.	Mohawk	Electrical Engineering Technician / Technology
306.	Georgian	Business Administration
307.	Georgian	Electrical Engineering Technician / Technology
308.	Mohawk	Electrical Engineering Technician / Technology
309.	Mohawk	Electrical Engineering Technician / Technology
310.	Mohawk	Electrical Engineering Technician / Technology
311.	Brock	Master of Accountancy
312.	Brock	Master of Accountancy
313.	Ryerson	Finance / Accounting
314.	Ryerson	Finance / Accounting
315.	Waterloo	Electrical Engineering
316.	Waterloo	Environment & Resource Studies
317.	Ryerson	Electrical Engineering
318.	Ryerson	Electrical Engineering
319.	Georgian	Electrical Engineering Technician / Technology
320.	Mohawk	Electrical Engineering Technician / Technology
321.	Georgian	Electrical Engineering Technician / Technology
322.	Georgian	Electrical Engineering Technician / Technology
323.	Toronto	Electrical Engineering
324.	Toronto	Electrical Engineering
325.	Western	Computer Science
326.	Western	Computer Science
327.	Georgian	Electrical Engineering Technician / Technology
328.	Georgian	Electrical Engineering Technician / Technology
329.	Georgian	Electrical Engineering Technician / Technology
330.	Toronto	Engineering Science
331.	Toronto	Engineering Science
332.	UOIT	Electrical Engineering
333.	Ryerson	Electrical Engineering
334.	Ryerson	Electrical Engineering
335.	Mohawk	Electrical Engineering Technician / Technology
336.	Brock	Master of Business Administration
337.	Brock	Master of Business Administration
338.	Brock	Master of Business Administration
339.	Waterloo	Geography/Urban Planning
340.	Toronto	Finance / Accounting
341.	Toronto	Finance / Accounting
342.	Fanshawe	GIS and Urban Planning
343.	UOIT	Electrical Engineering
344.	UOIT	Electrical Engineering
345.	Brock	Business Economics
346.	Brock	Business Economics
347.	Brock	Business Economics
348.	Georgian	Business Administration
349.	Georgian	Business Administration
350.	Toronto	Electrical Engineering
351.	Toronto	Electrical Engineering
352.	Toronto	Electrical Engineering
353.	UOIT	Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
354.	Toronto	Electrical Engineering
355.	Georgian	Electrical Engineering Technician / Technology
356.	Georgian	Electrical Engineering Technician / Technology
357.	Georgian	Electrical Engineering Technician / Technology
358.	McMaster	Electrical Engineering
359.	Georgian	Electrical Engineering Technician / Technology
360.	Guelph	Real Estate & Housing
361.	Guelph	Real Estate & Housing
362.	McMaster	Electrical Engineering
363.	McMaster	Electrical Engineering
364.	Windsor	Computer Science
365.	Georgian	Electrical Engineering Technician / Technology
366.	Brock	Master of Business Administration
367.	Brock	Master of Business Administration
368.	Mohawk	Electrical Engineering Technician / Technology
369.	Mohawk	Electrical Engineering Technician / Technology
370.	Lakehead	Master of Computer Science
371.	Ryerson	Industrial Engineering
372.	Ryerson	Industrial Engineering
373.	Windsor	Business Administration
374.	Windsor	Business Administration
375.	Georgian	Computer Science
376.	Western	Management & Organizational Studies
377.	Western	Management & Organizational Studies
378.	Georgian	Electrical Engineering Technician / Technology
379.	UOIT	Electrical Engineering
380.	UOIT	Electrical Engineering
381.	Toronto	Civil Engineering
382.	Toronto	Civil Engineering
383.	Sheridan	Information Systems Security
384.	Georgian	Business Administration
385.	Waterloo	Environmental Science
386.	Toronto	Finance / Accounting
387.	Toronto	Finance / Accounting
388.	Toronto	Computer Engineering
389.	Toronto	Mechanical Engineering
390.	Toronto	Mechanical Engineering
391.	McMaster	Electrical Engineering
392.	Brock	Business Administration
393.	Brock	Business Administration
394.	Toronto	Mechanical Engineering
395.	Toronto	Mechanical Engineering
396.	Toronto	Mechanical Engineering
397.	Ryerson	Electrical Engineering
398.	Georgian	Electrical Engineering Technician / Technology
399.	McMaster	Electrical Engineering
400.	McMaster	Electrical Engineering
401.	Georgian	Electrical Engineering Technician / Technology
402.	Georgian	Electrical Engineering Technician / Technology
403.	Brock	Business Administration
404.	Brock	Business Administration
405.	Georgian	Computer Science/ IT
406.	UOIT	Computer Science
407.	UOIT	Computer Science
408.	Waterloo	Geography

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
409.	Mohawk	Electrical Engineering Technician / Technology
410.	Mohawk	Electrical Engineering Technician / Technology
411.	Mohawk	Electrical Engineering Technician / Technology
412.	Toronto	Engineering Science
413.	Toronto	Engineering Science
414.	UOIT	Electrical Engineering
415.	Brock	Master of Business Administration
416.	Brock	Master of Business Administration
417.	Brock	Master of Business Administration
418.	Toronto	Engineering
419.	Toronto	Electrical Engineering
420.	Toronto	Electrical Engineering
421.	UOIT	Electrical Engineering
422.	UOIT	Electrical Engineering
423.	UOIT	Electrical Engineering
424.	Toronto	Electrical Engineering
425.	Toronto	Electrical Engineering
426.	Toronto	Electrical Engineering
427.	Toronto	Business Administration/ Commerce
428.	Mohawk	Electrical Engineering Technician / Technology
429.	Mohawk	Electrical Engineering Technician / Technology
430.	Mohawk	Electrical Engineering Technician / Technology
431.	Toronto	Industrial Engineering
432.	Toronto	Industrial Engineering
433.	Georgian	Electrical Engineering
434.	Ryerson	Electrical Engineering
435.	Windsor	Electrical Engineering
436.	Georgian	Electrical Engineering Technician / Technology
437.	Mohawk	Electrical Engineering Technician / Technology
438.	Mohawk	Electrical Engineering Technician / Technology
439.	Mohawk	Electrical Engineering Technician / Technology
440.	Toronto	Mechanical Engineering
441.	Toronto	Mechanical Engineering
442.	Toronto	Mechanical Engineering
443.	Georgian	Electrical Engineering Technician / Technology
444.	Ryerson	Electrical Engineering
445.	Ryerson	Electrical Engineering
446.	Toronto	Civil Engineering
447.	Toronto	Civil Engineering
448.	York	Administrative Business
449.	Ryerson	Electrical Engineering
450.	Laurier	Business Administration
451.	Brock	Business Administration
452.	Brock	Business Administration
453.	Georgian	Computer Science
454.	Waterloo	Electrical Engineering
455.	Toronto	Engineering Science
456.	Toronto	Engineering Science
457.	Waterloo	Electrical Engineering
458.	Brock	Master of Business Administration
459.	Brock	Master of Business Administration
460.	Brock	Master of Business Administration
461.	Toronto	Electrical Engineering
462.	Toronto	Electrical Engineering
463.	Mohawk	Electrical Engineering Technician / Technology

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
464.	Mohawk	Electrical Engineering Technician / Technology
465.	Mohawk	Electrical Engineering Technician / Technology
466.	McMaster	Electrical Engineering
467.	McMaster	Electrical Engineering
468.	Toronto	Electrical Engineering
469.	Brock	Master of Business Economics
470.	Brock	Master of Business Economics
471.	Mohawk	Electrical Engineering Technician / Technology
472.	Mohawk	Electrical Engineering Technician / Technology
473.	Mohawk	Electrical Engineering Technician / Technology
474.	McMaster	Business Administration
475.	McMaster	Business Administration
476.	Mohawk	Electrical Engineering Technician / Technology
477.	Mohawk	Electrical Engineering Technician / Technology
478.	Toronto	Finance / Accounting
479.	Toronto	Finance / Accounting
480.	McMaster	Electrical Engineering
481.	McMaster	Electrical Engineering
482.	Toronto	Electrical Engineering
483.	Toronto	Business Administration/ Commerce
484.	McMaster	Electrical Engineering
485.	Toronto	Electrical Engineering
486.	Toronto	Electrical Engineering
487.	Toronto	Finance / Accounting
488.	UOIT	Electrical Engineering
489.	Toronto	Business Administration/ Commerce
490.	Mohawk	Electrical Engineering Technician / Technology
491.	Mohawk	Electrical Engineering Technician / Technology
492.	Brock	Master of Business Administration
493.	Brock	Master of Business Administration
494.	Toronto	Engineering Science
495.	Toronto	Engineering Science
496.	Toronto	Mechanical Engineering
497.	Toronto	Mechanical Engineering
498.	Toronto	Electrical Engineering
499.	Toronto	Electrical Engineering
500.	Toronto	Computer Engineering
501.	Mohawk	Electrical Engineering Technician / Technology
502.	Toronto	Electrical Engineering
503.	Waterloo	Electrical Engineering
504.	Waterloo	Economics
505.	Toronto	Finance / Accounting
506.	Georgian College	Electrical Engineering
507.		

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	Co-op Student 1	2013-01-07	2013-04-30
2.	Co-op Student 1	2013-05-01	2013-08-31
3.	Co-op Student 2	2013-09-02	2013-12-31
4.	Co-op Student 3	2013-05-01	2013-08-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
5.	Co-op Student 3	2013-09-01	2013-12-21
6.	Co-op Student 4	2013-04-22	2013-08-21
7.	Co-op Student 5	2013-01-01	2013-04-30
8.	Co-op Student 5	2013-05-01	2013-08-30
9.	Co-op Student 6	2013-01-01	2013-04-30
10.	Co-op Student 6	2013-05-01	2013-08-28
11.	Co-op Student 7	2013-01-01	2013-04-30
12.	Co-op Student 7	2013-05-01	2013-08-31
13.	Co-op Student 7	2013-09-01	2013-12-20
14.	Co-op Student 8	2013-01-01	2013-04-30
15.	Co-op Student 8	2013-05-01	2013-08-29
16.	Co-op Student 9	2013-08-12	2013-12-31
17.	Co-op Student 10	2013-08-01	2013-12-31
18.	Co-op Student 11	2013-04-29	2013-08-31
19.	Co-op Student 11	2013-09-01	2013-12-31
20.	Co-op Student 12	2013-01-01	2013-04-30
21.	Co-op Student 12	2013-05-01	2013-08-31
22.	Co-op Student 13	2013-01-07	2013-04-26
23.	Co-op Student 14	2013-01-01	2013-05-03
24.	Co-op Student 14	2013-08-26	2013-12-31
25.	Co-op Student 15	2013-01-01	2013-04-30
26.	Co-op Student 15	2013-05-01	2013-08-30
27.	Co-op Student 16	2013-01-01	2013-04-30
28.	Co-op Student 16	2013-05-01	2013-08-29
29.	Co-op Student 17	2013-05-06	2013-08-30
30.	Co-op Student 18	2013-01-01	2013-05-10
31.	Co-op Student 19	2013-04-29	2013-08-30
32.	Co-op Student 20	2013-05-01	2013-08-31
33.	Co-op Student 20	2013-09-01	2013-12-31
34.	Co-op Student 21	2013-05-06	2013-08-31
35.	Co-op Student 21	2013-09-01	2013-12-31
36.	Co-op Student 22	2013-01-07	2013-05-28
37.	Co-op Student 23	2013-09-03	2013-12-21
38.	Co-op Student 23	2013-01-07	2013-04-30
39.	Co-op Student 24	2013-01-07	2013-04-26
40.	Co-op Student 25	2013-01-01	2013-04-30
41.	Co-op Student 25	2013-05-01	2013-09-05
42.	Co-op Student 26	2013-01-07	2013-04-30
43.	Co-op Student 26	2013-05-01	2013-08-30
44.	Co-op Student 27	2013-05-08	2013-08-31
45.	Co-op Student 27	2013-09-01	2013-12-31
46.	Co-op Student 28	2013-01-01	2013-04-30
47.	Co-op Student 28	2013-05-01	2013-08-28
48.	Co-op Student 29	2013-09-05	2013-12-31
49.	Co-op Student 30	2013-05-21	2013-09-07
50.	Co-op Student 31	2013-01-01	2013-05-01
51.	Co-op Student 32	2013-01-10	2013-04-30
52.	Co-op Student 32	2013-08-26	2013-12-26
53.	Co-op Student 33	2013-01-02	2013-04-26
54.	Co-op Student 34	2013-08-19	2013-12-31
55.	Co-op Student 35	2013-09-03	2013-12-21
56.	Co-op Student 36	2013-09-03	2013-12-21
57.	Co-op Student 36	2013-01-07	2013-04-30
58.	Co-op Student 37	2013-01-01	2013-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
59.	Co-op Student 37	2013-05-01	2013-08-29
60.	Co-op Student 38	2013-01-01	2013-04-30
61.	Co-op Student 38	2013-05-01	2013-08-31
62.	Co-op Student 39	2013-01-07	2013-04-26
63.	Co-op Student 40	2013-01-01	2013-04-30
64.	Co-op Student 40	2013-05-01	2013-08-31
65.	Co-op Student 40	2013-09-01	2013-12-17
66.	Co-op Student 41	2013-01-07	2013-04-30
67.	Co-op Student 41	2013-05-01	2013-08-31
68.	Co-op Student 42	2013-01-01	2013-05-03
69.	Co-op Student 43	2013-04-29	2013-08-30
70.	Co-op Student 44	2013-01-14	2013-05-01
71.	Co-op Student 45	2013-09-05	2013-12-31
72.	Co-op Student 46	2013-08-19	2013-12-31
73.	Co-op Student 47	2013-01-01	2013-04-30
74.	Co-op Student 47	2013-05-01	2013-08-28
75.	Co-op Student 48	2013-05-02	2013-08-31
76.	Co-op Student 48	2013-09-01	2013-12-31
77.	Co-op Student 49	2013-05-13	2013-08-30
78.	Co-op Student 50	2013-01-01	2013-04-30
79.	Co-op Student 50	2013-05-01	2013-08-30
80.	Co-op Student 51	2013-01-02	2013-04-30
81.	Co-op Student 51	2013-05-01	2013-08-30
82.	Co-op Student 52	2013-01-01	2013-04-30
83.	Co-op Student 52	2013-05-01	2013-08-31
84.	Co-op Student 52	2013-09-01	2013-12-31
85.	Co-op Student 53	2013-05-09	2013-08-30
86.	Co-op Student 54	2013-09-03	2013-12-31
87.	Co-op Student 55	2013-01-01	2013-04-30
88.	Co-op Student 55	2013-05-01	2013-08-31
89.	Co-op Student 56	2013-01-01	2013-04-30
90.	Co-op Student 56	2013-05-01	2013-08-30
91.	Co-op Student 57	2013-05-08	2013-08-31
92.	Co-op Student 57	2013-09-01	2013-12-31
93.	Co-op Student 58	2013-01-07	2013-04-30
94.	Co-op Student 59	2013-08-29	2013-12-30
95.	Co-op Student 60	2013-05-02	2013-08-29
96.	Co-op Student 60	2013-08-19	2013-12-31
97.	Co-op Student 61	2013-05-02	2013-08-31
98.	Co-op Student 62	2013-09-01	2013-12-31
99.	Co-op Student 63	2013-09-03	2013-12-20
100.	Co-op Student 64	2013-08-22	2013-12-31
101.	Co-op Student 65	2013-04-25	2013-08-31
102.	Co-op Student 65	2013-09-01	2013-12-31
103.	Co-op Student 66	2013-09-03	2013-12-21
104.	Co-op Student 67	2013-01-01	2013-04-30
105.	Co-op Student 67	2013-05-01	2013-08-30
106.	Co-op Student 68	2013-01-02	2013-05-02
107.	Co-op Student 69	2013-01-02	2013-04-26
108.	Co-op Student 70	2013-05-02	2013-08-30
109.	Co-op Student 71	2013-05-13	2013-08-31
110.	Co-op Student 71	2013-09-01	2013-12-31
111.	Co-op Student 72	2013-04-22	2013-08-30
112.	Co-op Student 73	2013-01-01	2013-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
113.	Co-op Student 73	2013-05-01	2013-08-31
114.	Co-op Student 73	2013-09-01	2013-12-17
115.	Co-op Student 74	2013-05-02	2013-08-31
116.	Co-op Student 74	2013-09-01	2013-12-19
117.	Co-op Student 75	2013-01-01	2013-04-30
118.	Co-op Student 75	2013-05-01	2013-08-17
119.	Co-op Student 76	2013-08-19	2013-12-31
120.	Co-op Student 77	2013-05-06	2013-08-31
121.	Co-op Student 77	2013-09-01	2013-12-31
122.	Co-op Student 78	2013-05-02	2013-08-31
123.	Co-op Student 78	2013-09-01	2013-12-31
124.	Co-op Student 79	2013-05-06	2013-08-31
125.	Co-op Student 79	2013-09-01	2013-12-31
126.	Co-op Student 80	2013-09-03	2013-12-19
127.	Co-op Student 81	2013-01-01	2013-05-03
128.	Co-op Student 82	2013-09-03	2013-12-31
129.	Co-op Student 83	2013-01-07	2013-04-30
130.	Co-op Student 83	2013-05-01	2013-08-31
131.	Co-op Student 83	2013-09-01	2013-12-20
132.	Co-op Student 84	2013-09-03	2013-12-30
133.	Co-op Student 85	2013-01-07	2013-05-28
134.	Co-op Student 86	2013-01-07	2013-04-30
135.	Co-op Student 86	2013-05-01	2013-08-30
136.	Co-op Student 87	2013-01-10	2013-04-30
137.	Co-op Student 87	2013-05-01	2013-08-31
138.	Co-op Student 87	2013-09-01	2013-12-31
139.	Co-op Student 88	2013-01-03	2013-04-30
140.	Co-op Student 88	2013-05-01	2013-08-31
141.	Co-op Student 88	2013-09-01	2013-12-24
142.	Co-op Student 89	2013-05-06	2013-08-30
143.	Co-op Student 90	2013-01-02	2013-04-30
144.	Co-op Student 90	2013-05-01	2013-09-09
145.	Co-op Student 91	2013-09-09	2013-12-31
146.	Co-op Student 92	2013-01-02	2013-04-30
147.	Co-op Student 92	2013-05-01	2013-08-31
148.	Co-op Student 92	2013-09-01	2013-12-28
149.	Co-op Student 93	2013-08-15	2013-12-31
150.	Co-op Student 94	2013-05-06	2013-08-31
151.	Co-op Student 94	2013-09-01	2013-12-31
152.	Co-op Student 95	2013-01-03	2013-04-26
153.	Co-op Student 96	2013-04-29	2013-09-06
154.	Co-op Student 97	2013-01-09	2013-05-03
155.	Co-op Student 98	2013-04-29	2013-08-30
156.	Co-op Student 99	2013-08-21	2013-12-31
157.	Co-op Student 100	2013-01-07	2013-04-30
158.	Co-op Student 100	2013-05-01	2013-08-31
159.	Co-op Student 101	2013-05-06	2013-08-31
160.	Co-op Student 101	2013-09-01	2013-12-31
161.	Co-op Student 102	2013-01-01	2013-04-30
162.	Co-op Student 102	2013-05-01	2013-08-24
163.	Co-op Student 103	2013-01-01	2013-04-30
164.	Co-op Student 104	2013-01-01	2013-05-03
165.	Co-op Student 105	2013-01-01	2013-04-30
166.	Co-op Student 105	2013-05-01	2013-07-12

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
167.	Co-op Student 106	2013-08-26	2013-12-20
168.	Co-op Student 107	2013-05-06	2013-08-31
169.	Co-op Student 107	2013-09-01	2013-12-31
170.	Co-op Student 108	2013-08-18	2013-12-31
171.	Co-op Student 109	2013-01-01	2013-05-02
172.	Co-op Student 110	2013-08-09	2013-12-31
173.	Co-op Student 111	2013-01-01	2013-04-30
174.	Co-op Student 111	2013-05-01	2013-09-04
175.	Co-op Student 112	2013-01-07	2013-04-30
176.	Co-op Student 112	2013-05-01	2013-08-31
177.	Co-op Student 112	2013-09-01	2013-12-20
178.	Co-op Student 113	2013-01-01	2013-05-03
179.	Co-op Student 114	2013-05-06	2013-08-24
180.	Co-op Student 115	2013-01-09	2013-04-30
181.	Co-op Student 115	2013-05-01	2013-08-31
182.	Co-op Student 115	2013-09-01	2013-12-20
183.	Co-op Student 116	2013-01-07	2013-04-26
184.	Co-op Student 117	2013-08-26	2013-12-31
185.	Co-op Student 118	2013-01-07	2013-04-26
186.	Co-op Student 119	2013-01-07	2013-04-30
187.	Co-op Student 119	2013-05-01	2013-08-30
188.	Co-op Student 120	2013-01-01	2013-04-30
189.	Co-op Student 120	2013-05-01	2013-08-28
190.	Co-op Student 121	2013-01-01	2013-04-30
191.	Co-op Student 121	2013-05-01	2013-08-28
192.	Co-op Student 122	2013-01-02	2013-04-30
193.	Co-op Student 122	2013-05-01	2013-08-31
194.	Co-op Student 122	2013-09-01	2013-12-31
195.	Co-op Student 123	2013-01-09	2013-04-30
196.	Co-op Student 123	2013-05-01	2013-08-31
197.	Co-op Student 123	2013-09-01	2013-12-20
198.	Co-op Student 124	2013-01-01	2013-04-26
199.	Co-op Student 125	2013-05-06	2013-08-31
200.	Co-op Student 125	2013-09-01	2013-12-31
201.	Co-op Student 126	2013-01-01	2013-05-01
202.	Co-op Student 127	2013-09-05	2013-12-31
203.	Co-op Student 128	2013-05-06	2013-08-30
204.	Co-op Student 129	2013-09-03	2013-12-31
205.	Co-op Student 130	2013-01-07	2013-04-26
206.	Co-op Student 131	2013-01-01	2013-04-30
207.	Co-op Student 131	2013-05-01	2013-08-31
208.	Co-op Student 131	2013-09-01	2013-12-31
209.	Co-op Student 132	2013-05-08	2013-08-31
210.	Co-op Student 132	2013-09-01	2013-12-31
211.	Co-op Student 133	2013-08-27	2013-12-31
212.	Co-op Student 134	2013-09-09	2013-12-19
213.	Co-op Student 135	2013-05-06	2013-08-30
214.	Co-op Student 136	2013-01-01	2013-05-03
215.	Co-op Student 137	2013-05-02	2013-08-31
216.	Co-op Student 137	2013-09-01	2013-12-31
217.	Co-op Student 138	2013-09-03	2013-12-21
218.	Co-op Student 139	2013-01-01	2013-04-26
219.	Co-op Student 140	2013-01-01	2013-05-02
220.	Co-op Student 141	2013-05-06	2013-08-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
221.	Co-op Student 141	2013-09-01	2013-12-31
222.	Co-op Student 142	2013-05-06	2013-08-31
223.	Co-op Student 142	2013-09-01	2013-12-31
224.	Co-op Student 143	2013-01-01	2013-04-30
225.	Co-op Student 143	2013-05-01	2013-08-30
226.	Co-op Student 144	2013-09-06	2013-12-31
227.	Co-op Student 145	2013-05-02	2013-08-31
228.	Co-op Student 145	2013-09-01	2013-12-31
229.	Co-op Student 146	2013-01-01	2013-04-30
230.	Co-op Student 146	2013-05-01	2013-08-29
231.	Co-op Student 147	2013-01-10	2013-04-30
232.	Co-op Student 147	2013-05-01	2013-08-31
233.	Co-op Student 147	2013-09-01	2013-12-31
234.	Co-op Student 148	2013-05-01	2013-08-31
235.	Co-op Student 148	2013-09-01	2013-12-31
236.	Co-op Student 149	2013-05-06	2013-08-30
237.	Co-op Student 150	2013-01-01	2013-04-30
238.	Co-op Student 151	2013-09-03	2013-12-13
239.	Co-op Student 152	2013-05-02	2013-08-31
240.	Co-op Student 152	2013-09-01	2013-12-31
241.	Co-op Student 153	2013-01-01	2013-04-30
242.	Co-op Student 153	2013-05-01	2013-08-30
243.	Co-op Student 154	2013-01-01	2013-05-01
244.	Co-op Student 155	2013-04-30	2013-09-09
245.	Co-op Student 156	2013-01-07	2013-04-26
246.	Co-op Student 156	2013-08-26	2013-12-31
247.	Co-op Student 157	2013-05-06	2013-08-31
248.	Co-op Student 157	2013-09-01	2013-12-24
249.	Co-op Student 158	2013-01-01	2013-05-03
250.	Co-op Student 158	2013-08-26	2013-12-31
251.	Co-op Student 159	2013-01-01	2013-04-30
252.	Co-op Student 159	2013-05-01	2013-08-21
253.	Co-op Student 160	2013-01-01	2013-05-04
254.	Co-op Student 161	2013-08-21	2013-12-31
255.	Co-op Student 162	2013-05-08	2013-08-31
256.	Co-op Student 162	2013-09-01	2013-12-31
257.	Co-op Student 163	2013-05-06	2013-08-30
258.	Co-op Student 164	2013-09-03	2013-12-31
259.	Co-op Student 165	2013-09-03	2013-12-31
260.	Co-op Student 166	2013-01-10	2013-04-30
261.	Co-op Student 166	2013-05-01	2013-08-14
262.	Co-op Student 167	2013-01-01	2013-04-30
263.	Co-op Student 167	2013-05-01	2013-08-21
264.	Co-op Student 168	2013-09-16	2013-12-20
265.	Co-op Student 169	2013-09-03	2013-12-21
266.	Co-op Student 170	2013-05-02	2013-08-30
267.	Co-op Student 171	2013-04-22	2013-08-30
268.	Co-op Student 172	2013-01-01	2013-04-30
269.	Co-op Student 172	2013-05-01	2013-08-31
270.	Co-op Student 173	2013-01-01	2013-04-30
271.	Co-op Student 173	2013-05-01	2013-08-31
272.	Co-op Student 173	2013-09-01	2013-12-17
273.	Co-op Student 174	2013-01-02	2013-04-30
274.	Co-op Student 174	2013-05-01	2013-08-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
275.	Co-op Student 174	2013-09-01	2013-12-20
276.	Co-op Student 175	2013-01-01	2013-04-30
277.	Co-op Student 175	2013-05-01	2013-08-21
278.	Co-op Student 176	2013-01-01	2013-04-30
279.	Co-op Student 176	2013-05-01	2013-08-31
280.	Co-op Student 176	2013-09-01	2013-12-31
281.	Co-op Student 177	2013-01-01	2013-04-30
282.	Co-op Student 177	2013-05-01	2013-08-31
283.	Co-op Student 177	2013-09-01	2013-12-20
284.	Co-op Student 178	2013-09-03	2013-12-21
285.	Co-op Student 179	2013-05-13	2013-08-30
286.	Co-op Student 180	2013-05-01	2013-08-30
287.	Co-op Student 181	2013-09-03	2013-12-20
288.	Co-op Student 182	2013-09-03	2013-12-20
289.	Co-op Student 183	2013-09-09	2013-12-31
290.	Co-op Student 184	2013-01-07	2013-04-25
291.	Co-op Student 185	2013-01-01	2013-04-30
292.	Co-op Student 185	2013-05-01	2013-08-31
293.	Co-op Student 185	2013-09-01	2013-12-20
294.	Co-op Student 186	2013-05-02	2013-08-31
295.	Co-op Student 186	2013-09-01	2013-12-31
296.	Co-op Student 187	2013-01-01	2013-04-30
297.	Co-op Student 187	2013-05-01	2013-08-30
298.	Co-op Student 188	2013-01-07	2013-04-01
299.	Co-op Student 188	2013-09-03	2013-12-20
300.	Co-op Student 189	2013-01-01	2013-05-01
301.	Co-op Student 190	2013-09-03	2013-12-21
302.	Co-op Student 190	2013-01-02	2013-05-01
303.	Co-op Student 191	2013-01-07	2013-04-30
304.	Co-op Student 191	2013-05-01	2013-08-31
305.	Co-op Student 191	2013-09-01	2013-12-20
306.	Co-op Student 192	2013-04-30	2013-08-30
307.	Co-op Student 193	2013-04-22	2013-08-30
308.	Co-op Student 194	2013-01-02	2013-04-30
309.	Co-op Student 194	2013-05-01	2013-08-31
310.	Co-op Student 194	2013-09-01	2013-12-20
311.	Co-op Student 195	2013-05-01	2013-08-31
312.	Co-op Student 195	2013-09-01	2013-12-31
313.	Co-op Student 196	2013-05-06	2013-08-31
314.	Co-op Student 196	2013-09-01	2013-12-28
315.	Co-op Student 197	2013-09-03	2013-12-20
316.	Co-op Student 198	2013-04-29	2013-08-30
317.	Co-op Student 199	2013-05-06	2013-08-31
318.	Co-op Student 199	2013-09-01	2013-12-31
319.	Co-op Student 200	2013-04-29	2013-08-30
320.	Co-op Student 201	2013-05-06	2013-08-30
321.	Co-op Student 202	2013-01-07	2013-04-26
322.	Co-op Student 202	2013-09-01	2013-12-21
323.	Co-op Student 203	2013-01-01	2013-04-30
324.	Co-op Student 203	2013-05-01	2013-09-12
325.	Co-op Student 204	2013-05-02	2013-08-31
326.	Co-op Student 204	2013-09-01	2013-12-31
327.	Co-op Student 205	2013-09-03	2013-12-20
328.	Co-op Student 206	2013-09-03	2013-12-20

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
329.	Co-op Student 207	2013-09-03	2013-12-20
330.	Co-op Student 208	2013-01-01	2013-04-30
331.	Co-op Student 208	2013-05-01	2013-08-24
332.	Co-op Student 209	2013-01-01	2013-05-01
333.	Co-op Student 210	2013-01-01	2013-04-30
334.	Co-op Student 210	2013-05-01	2013-08-30
335.	Co-op Student 211	2013-09-04	2013-12-25
336.	Co-op Student 212	2013-01-01	2013-04-30
337.	Co-op Student 212	2013-05-01	2013-08-31
338.	Co-op Student 212	2013-09-01	2013-12-31
339.	Co-op Student 213	2013-09-03	2013-12-31
340.	Co-op Student 214	2013-01-16	2013-04-30
341.	Co-op Student 214	2013-05-01	2013-08-31
342.	Co-op Student 215	2013-05-13	2013-08-31
343.	Co-op Student 216	2013-01-01	2013-04-30
344.	Co-op Student 216	2013-05-01	2013-08-30
345.	Co-op Student 217	2013-01-10	2013-04-30
346.	Co-op Student 217	2013-05-01	2013-08-31
347.	Co-op Student 217	2013-09-01	2013-12-31
348.	Co-op Student 218	2013-04-22	2013-08-31
349.	Co-op Student 218	2013-09-01	2013-12-31
350.	Co-op Student 219	2013-05-06	2013-08-31
351.	Co-op Student 219	2013-09-01	2013-12-31
352.	Co-op Student 220	2013-09-03	2013-12-31
353.	Co-op Student 221	2013-01-01	2013-05-04
354.	Co-op Student 222	2013-01-01	2013-04-26
355.	Co-op Student 223	2013-01-03	2013-04-30
356.	Co-op Student 223	2013-08-30	2013-12-21
357.	Co-op Student 224	2013-01-07	2013-04-26
358.	Co-op Student 225	2013-09-03	2013-12-31
359.	Co-op Student 226	2013-01-07	2013-05-04
360.	Co-op Student 227	2013-01-02	2013-04-30
361.	Co-op Student 227	2013-05-01	2013-08-31
362.	Co-op Student 228	2013-05-06	2013-08-31
363.	Co-op Student 228	2013-09-01	2013-12-31
364.	Co-op Student 229	2013-04-29	2013-08-31
365.	Co-op Student 230	2013-01-07	2013-04-26
366.	Co-op Student 231	2013-01-10	2013-04-30
367.	Co-op Student 231	2013-05-01	2013-09-05
368.	Co-op Student 232	2013-01-28	2013-04-30
369.	Co-op Student 232	2013-05-01	2013-08-30
370.	Co-op Student 233	2013-01-01	2013-04-26
371.	Co-op Student 234	2013-01-01	2013-04-30
372.	Co-op Student 234	2013-05-01	2013-08-28
373.	Co-op Student 235	2013-01-01	2013-04-30
374.	Co-op Student 235	2013-05-01	2013-08-31
375.	Co-op Student 236	2013-05-02	2013-08-30
376.	Co-op Student 237	2013-01-01	2013-04-30
377.	Co-op Student 237	2013-05-01	2013-08-29
378.	Co-op Student 238	2013-09-03	2013-12-21
379.	Co-op Student 239	2013-05-06	2013-08-31
380.	Co-op Student 239	2013-09-01	2013-12-31
381.	Co-op Student 240	2013-05-06	2013-08-31
382.	Co-op Student 240	2013-09-01	2013-12-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
383.	Co-op Student 241	2013-09-03	2013-12-20
384.	Co-op Student 242	2013-09-05	2013-12-18
385.	Co-op Student 243	2013-01-03	2013-04-26
386.	Co-op Student 244	2013-01-08	2013-04-30
387.	Co-op Student 244	2013-05-01	2013-08-31
388.	Co-op Student 245	2013-01-01	2013-05-04
389.	Co-op Student 246	2013-01-01	2013-04-30
390.	Co-op Student 246	2013-05-01	2013-08-30
391.	Co-op Student 247	2013-01-01	2013-05-03
392.	Co-op Student 248	2013-01-01	2013-04-30
393.	Co-op Student 248	2013-05-01	2013-08-28
394.	Co-op Student 249	2013-01-07	2013-04-30
395.	Co-op Student 249	2013-05-01	2013-08-31
396.	Co-op Student 249	2013-09-01	2013-12-20
397.	Co-op Student 250	2013-08-22	2013-12-31
398.	Co-op Student 251	2013-09-03	2013-12-21
399.	Co-op Student 252	2013-05-06	2013-08-31
400.	Co-op Student 252	2013-09-01	2013-12-31
401.	Co-op Student 253	2013-01-07	2013-04-30
402.	Co-op Student 253	2013-09-03	2013-12-21
403.	Co-op Student 254	2013-05-06	2013-08-31
404.	Co-op Student 254	2013-09-01	2013-12-31
405.	Co-op Student 255	2013-09-05	2013-12-18
406.	Co-op Student 256	2013-01-07	2013-04-30
407.	Co-op Student 256	2013-05-01	2013-08-31
408.	Co-op Student 257	2013-04-29	2013-08-30
409.	Co-op Student 258	2013-01-01	2013-04-30
410.	Co-op Student 258	2013-05-01	2013-08-31
411.	Co-op Student 258	2013-09-01	2013-12-17
412.	Co-op Student 259	2013-01-01	2013-04-30
413.	Co-op Student 259	2013-05-01	2013-08-29
414.	Co-op Student 260	2013-05-23	2013-09-12
415.	Co-op Student 261	2013-01-01	2013-04-30
416.	Co-op Student 261	2013-05-01	2013-08-31
417.	Co-op Student 261	2013-09-01	2013-12-27
418.	Co-op Student 262	2013-08-29	2013-12-31
419.	Co-op Student 263	2013-01-01	2013-04-30
420.	Co-op Student 263	2013-05-01	2013-08-30
421.	Co-op Student 264	2013-01-01	2013-04-30
422.	Co-op Student 264	2013-05-01	2013-08-31
423.	Co-op Student 264	2013-09-01	2013-12-31
424.	Co-op Student 265	2013-09-03	2013-12-31
425.	Co-op Student 266	2013-01-01	2013-04-30
426.	Co-op Student 266	2013-05-01	2013-08-30
427.	Co-op Student 267	2013-08-29	2013-12-31
428.	Co-op Student 268	2013-01-07	2013-04-30
429.	Co-op Student 268	2013-05-01	2013-08-31
430.	Co-op Student 268	2013-09-01	2013-12-20
431.	Co-op Student 269	2013-05-13	2013-08-31
432.	Co-op Student 269	2013-09-01	2013-12-31
433.	Co-op Student 270	2013-09-03	2013-12-20
434.	Co-op Student 271	2013-08-22	2013-12-31
435.	Co-op Student 272	2013-09-03	2013-12-31
436.	Co-op Student 273	2013-01-07	2013-04-26

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
437.	Co-op Student 274	2013-01-01	2013-04-30
438.	Co-op Student 274	2013-05-01	2013-08-31
439.	Co-op Student 274	2013-09-01	2013-12-17
440.	Co-op Student 275	2013-01-10	2013-04-30
441.	Co-op Student 275	2013-05-01	2013-08-31
442.	Co-op Student 275	2013-09-01	2013-12-31
443.	Co-op Student 276	2013-09-03	2013-12-21
444.	Co-op Student 277	2013-05-06	2013-08-31
445.	Co-op Student 277	2013-09-01	2013-12-31
446.	Co-op Student 278	2013-01-01	2013-04-30
447.	Co-op Student 278	2013-05-01	2013-08-30
448.	Co-op Student 279	2013-08-24	2013-12-31
449.	Co-op Student 280	2013-08-01	2013-12-31
450.	Co-op Student 281	2013-04-29	2013-08-30
451.	Co-op Student 282	2013-01-01	2013-04-30
452.	Co-op Student 282	2013-05-01	2013-08-28
453.	Co-op Student 283	2013-05-02	2013-08-30
454.	Co-op Student 284	2013-01-07	2013-04-26
455.	Co-op Student 285	2013-01-01	2013-04-30
456.	Co-op Student 285	2013-05-01	2013-08-10
457.	Co-op Student 286	2013-08-29	2013-12-24
458.	Co-op Student 287	2013-01-10	2013-04-30
459.	Co-op Student 287	2013-05-01	2013-08-31
460.	Co-op Student 287	2013-09-01	2013-12-24
461.	Co-op Student 288	2013-05-06	2013-08-31
462.	Co-op Student 288	2013-09-01	2013-12-31
463.	Co-op Student 289	2013-01-01	2013-04-30
464.	Co-op Student 289	2013-05-01	2013-08-31
465.	Co-op Student 289	2013-09-01	2013-12-17
466.	Co-op Student 290	2013-01-01	2013-04-30
467.	Co-op Student 290	2013-05-01	2013-08-30
468.	Co-op Student 291	2013-09-03	2013-12-31
469.	Co-op Student 292	2013-01-01	2013-04-30
470.	Co-op Student 292	2013-05-01	2013-08-28
471.	Co-op Student 293	2013-01-10	2013-04-30
472.	Co-op Student 293	2013-05-01	2013-08-09
473.	Co-op Student 294	2013-05-06	2013-08-30
474.	Co-op Student 295	2013-01-01	2013-04-30
475.	Co-op Student 295	2013-05-01	2013-08-10
476.	Co-op Student 296	2013-09-03	2013-12-20
477.	Co-op Student 297	2013-01-07	2013-04-26
478.	Co-op Student 298	2013-01-01	2013-04-30
479.	Co-op Student 298	2012-08-23	2013-08-30
480.	Co-op Student 299	2013-05-08	2013-08-31
481.	Co-op Student 299	2013-09-01	2013-12-31
482.	Co-op Student 300	2013-08-29	2013-12-31
483.	Co-op Student 301	2013-08-19	2013-12-31
484.	Co-op Student 302	2013-08-12	2013-12-31
485.	Co-op Student 303	2013-01-01	2013-04-30
486.	Co-op Student 303	2013-05-01	2013-08-28
487.	Co-op Student 304	2013-01-01	2013-04-30
488.	Co-op Student 305	2013-08-01	2013-12-31
489.	Co-op Student 306	2013-08-19	2013-12-31
490.	Co-op Student 307	2013-05-06	2013-08-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
491.	Co-op Student 307	2013-09-01	2013-12-22
492.	Co-op Student 308	2013-04-22	2013-08-31
493.	Co-op Student 308	2013-09-01	2013-12-24
494.	Co-op Student 309	2013-05-06	2013-08-31
495.	Co-op Student 309	2013-09-01	2013-12-31
496.	Co-op Student 310	2013-01-01	2013-04-30
497.	Co-op Student 310	2013-05-01	2013-08-03
498.	Co-op Student 311	2013-05-08	2013-08-31
499.	Co-op Student 311	2013-09-01	2013-12-31
500.	Co-op Student 311	2013-04-30	2013-09-09
501.	Co-op Student 312	2013-05-01	2013-08-30
502.	Co-op Student 313	2013-09-03	2013-12-31
503.	Co-op Student 314	2013-09-03	2013-12-20
504.	Co-op Student 315	2013-09-16	2013-12-20
505.	Co-op Student 316	2013-01-01	2013-05-01
506.	Co-op Student 317	2013-01-01	2013-05-04
507.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	14,725	25.000 %		16
2.		10.000 %	14,725	25.000 %		17
3.		10.000 %	16,201	25.000 %		17
4.		10.000 %	15,772	25.000 %		17
5.		10.000 %	15,772	25.000 %		16
6.		10.000 %	15,810	25.000 %		17
7.		10.000 %	22,289	25.000 %		16
8.		10.000 %	22,289	25.000 %		17
9.		10.000 %	22,373	25.000 %		16
10.		10.000 %	22,373	25.000 %		16
11.		10.000 %	20,014	25.000 %		16
12.		10.000 %	20,014	25.000 %		17
13.		10.000 %	20,014	25.000 %		16
14.		10.000 %	21,114	25.000 %		16
15.		10.000 %	21,114	25.000 %		16
16.		10.000 %	20,604	25.000 %		20
17.		10.000 %	21,218	25.000 %		21
18.		10.000 %	14,842	25.000 %		18
19.		10.000 %	14,842	25.000 %		17
20.		10.000 %	22,745	25.000 %		16
21.		10.000 %	22,745	25.000 %		17
22.		10.000 %	12,976	25.000 %		16
23.		10.000 %	15,185	25.000 %		17
24.		10.000 %	15,185	25.000 %		18
25.		10.000 %	21,100	25.000 %		16
26.		10.000 %	21,100	25.000 %		17
27.		10.000 %	19,310	25.000 %		16
28.		10.000 %	19,310	25.000 %		16
29.		10.000 %	14,433	25.000 %		17
30.		10.000 %	25,239	25.000 %		18
31.		10.000 %	16,403	25.000 %		18
32.		10.000 %	18,181	25.000 %		17
33.		10.000 %	18,181	25.000 %		17
34.		10.000 %	17,638	25.000 %		17
35.		10.000 %	17,638	25.000 %		17
36.		10.000 %	17,772	25.000 %		20
37.		10.000 %	14,697	25.000 %		15
38.		10.000 %	14,697	25.000 %		16
39.		10.000 %	12,445	25.000 %		16
40.		10.000 %	22,215	25.000 %		16
41.		10.000 %	22,215	25.000 %		17
42.		10.000 %	21,329	25.000 %		16
43.		10.000 %	21,329	25.000 %		17
44.		10.000 %	17,458	25.000 %		16
45.		10.000 %	17,458	25.000 %		17
46.		10.000 %	23,497	25.000 %		16
47.		10.000 %	23,497	25.000 %		16
48.		10.000 %	16,021	25.000 %		16
49.		10.000 %	13,229	25.000 %		15
50.		10.000 %	25,653	25.000 %		16
51.		10.000 %	18,397	25.000 %		15

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
52.		10.000 %	18,397	25.000 %		17
53.		10.000 %	33,506	25.000 %		16
54.		10.000 %	29,945	25.000 %		19
55.		10.000 %	12,207	25.000 %		15
56.		10.000 %	13,043	25.000 %		15
57.		10.000 %	13,043	25.000 %		16
58.		10.000 %	22,650	25.000 %		16
59.		10.000 %	22,650	25.000 %		16
60.		10.000 %	21,704	25.000 %		16
61.		10.000 %	21,704	25.000 %		17
62.		10.000 %	15,568	25.000 %		16
63.		10.000 %	13,805	25.000 %		16
64.		10.000 %	13,805	25.000 %		17
65.		10.000 %	13,805	25.000 %		15
66.		10.000 %	18,131	25.000 %		16
67.		10.000 %	18,131	25.000 %		17
68.		10.000 %	15,991	25.000 %		17
69.		10.000 %	15,355	25.000 %		18
70.		10.000 %	12,407	25.000 %		15
71.		10.000 %	14,834	25.000 %		16
72.		10.000 %	18,527	25.000 %		19
73.		10.000 %	22,594	25.000 %		16
74.		10.000 %	22,594	25.000 %		16
75.		10.000 %	17,945	25.000 %		17
76.		10.000 %	17,945	25.000 %		17
77.		10.000 %	19,290	25.000 %		16
78.		10.000 %	19,846	25.000 %		16
79.		10.000 %	19,846	25.000 %		17
80.		10.000 %	19,773	25.000 %		16
81.		10.000 %	19,773	25.000 %		17
82.		10.000 %	18,971	25.000 %		16
83.		10.000 %	18,971	25.000 %		17
84.		10.000 %	18,971	25.000 %		17
85.		10.000 %	19,809	25.000 %		16
86.		10.000 %	15,513	25.000 %		16
87.		10.000 %	21,647	25.000 %		16
88.		10.000 %	21,647	25.000 %		17
89.		10.000 %	21,158	25.000 %		16
90.		10.000 %	21,158	25.000 %		17
91.		10.000 %	17,458	25.000 %		16
92.		10.000 %	17,458	25.000 %		17
93.		10.000 %	18,579	25.000 %		16
94.		10.000 %	16,648	25.000 %		17
95.		10.000 %	12,467	25.000 %		16
96.		10.000 %	16,019	25.000 %		19
97.		10.000 %	19,183	25.000 %		17
98.		10.000 %	19,183	25.000 %		17
99.		10.000 %	11,137	25.000 %		15
100.		10.000 %	13,791	25.000 %		18
101.		10.000 %	19,713	25.000 %		18
102.		10.000 %	19,713	25.000 %		17
103.		10.000 %	13,155	25.000 %		15
104.		10.000 %	21,885	25.000 %		16

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
105.		10.000 %	21,885	25.000 %		17
106.		10.000 %	13,688	25.000 %		16
107.		10.000 %	15,301	25.000 %		16
108.		10.000 %	20,102	25.000 %		17
109.		10.000 %	17,140	25.000 %		16
110.		10.000 %	17,140	25.000 %		17
111.		10.000 %	14,518	25.000 %		19
112.		10.000 %	16,139	25.000 %		16
113.		10.000 %	16,139	25.000 %		17
114.		10.000 %	16,139	25.000 %		15
115.		10.000 %	19,183	25.000 %		17
116.		10.000 %	19,183	25.000 %		15
117.		10.000 %	20,432	25.000 %		16
118.		10.000 %	20,432	25.000 %		15
119.		10.000 %	29,945	25.000 %		19
120.		10.000 %	17,758	25.000 %		17
121.		10.000 %	17,758	25.000 %		17
122.		10.000 %	17,875	25.000 %		17
123.		10.000 %	17,875	25.000 %		17
124.		10.000 %	17,638	25.000 %		17
125.		10.000 %	17,638	25.000 %		17
126.		10.000 %	12,537	25.000 %		14
127.		10.000 %	15,371	25.000 %		17
128.		10.000 %	15,371	25.000 %		16
129.		10.000 %	19,454	25.000 %		16
130.		10.000 %	19,454	25.000 %		17
131.		10.000 %	19,454	25.000 %		16
132.		10.000 %	16,201	25.000 %		16
133.		10.000 %	16,786	25.000 %		20
134.		10.000 %	18,094	25.000 %		16
135.		10.000 %	18,094	25.000 %		17
136.		10.000 %	17,867	25.000 %		15
137.		10.000 %	17,867	25.000 %		17
138.		10.000 %	17,867	25.000 %		17
139.		10.000 %	19,211	25.000 %		16
140.		10.000 %	19,211	25.000 %		17
141.		10.000 %	19,211	25.000 %		16
142.		10.000 %	41,553	25.000 %		17
143.		10.000 %	21,213	25.000 %		16
144.		10.000 %	21,213	25.000 %		18
145.		10.000 %	15,308	25.000 %		16
146.		10.000 %	14,961	25.000 %		16
147.		10.000 %	14,961	25.000 %		17
148.		10.000 %	14,961	25.000 %		17
149.		10.000 %	19,474	25.000 %		19
150.		10.000 %	17,814	25.000 %		17
151.		10.000 %	17,814	25.000 %		17
152.		10.000 %	13,956	25.000 %		16
153.		10.000 %	14,478	25.000 %		19
154.		10.000 %	20,008	25.000 %		16
155.		10.000 %	16,403	25.000 %		18
156.		10.000 %	16,260	25.000 %		18
157.		10.000 %	19,406	25.000 %		16

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
158.		10.000 %	19,406	25.000 %		17
159.		10.000 %	17,638	25.000 %		17
160.		10.000 %	17,638	25.000 %		17
161.		10.000 %	20,241	25.000 %		16
162.		10.000 %	20,241	25.000 %		16
163.		10.000 %	24,336	25.000 %		16
164.		10.000 %	24,934	25.000 %		17
165.		10.000 %	18,429	25.000 %		16
166.		10.000 %	18,429	25.000 %		10
167.		10.000 %	16,978	25.000 %		17
168.		10.000 %	17,638	25.000 %		17
169.		10.000 %	17,638	25.000 %		17
170.		10.000 %	17,258	25.000 %		19
171.		10.000 %	20,858	25.000 %		16
172.		10.000 %	16,186	25.000 %		20
173.		10.000 %	22,562	25.000 %		16
174.		10.000 %	22,562	25.000 %		17
175.		10.000 %	12,833	25.000 %		16
176.		10.000 %	12,833	25.000 %		17
177.		10.000 %	12,833	25.000 %		16
178.		10.000 %	16,626	25.000 %		17
179.		10.000 %	12,650	25.000 %		16
180.		10.000 %	17,072	25.000 %		15
181.		10.000 %	17,072	25.000 %		17
182.		10.000 %	17,072	25.000 %		16
183.		10.000 %	13,991	25.000 %		16
184.		10.000 %	12,083	25.000 %		18
185.		10.000 %	13,085	25.000 %		16
186.		10.000 %	19,298	25.000 %		16
187.		10.000 %	19,298	25.000 %		17
188.		10.000 %	21,835	25.000 %		16
189.		10.000 %	21,835	25.000 %		16
190.		10.000 %	24,548	25.000 %		16
191.		10.000 %	24,548	25.000 %		16
192.		10.000 %	17,077	25.000 %		16
193.		10.000 %	17,077	25.000 %		17
194.		10.000 %	17,077	25.000 %		17
195.		10.000 %	19,339	25.000 %		15
196.		10.000 %	19,339	25.000 %		17
197.		10.000 %	19,339	25.000 %		16
198.		10.000 %	21,371	25.000 %		16
199.		10.000 %	17,638	25.000 %		17
200.		10.000 %	17,638	25.000 %		17
201.		10.000 %	24,112	25.000 %		16
202.		10.000 %	15,642	25.000 %		16
203.		10.000 %	13,218	25.000 %		17
204.		10.000 %	16,201	25.000 %		16
205.		10.000 %	12,929	25.000 %		16
206.		10.000 %	21,205	25.000 %		16
207.		10.000 %	21,205	25.000 %		17
208.		10.000 %	21,205	25.000 %		17
209.		10.000 %	18,030	25.000 %		16
210.		10.000 %	18,030	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
211.		10.000 %	15,214	25.000 %		17
212.		10.000 %	13,402	25.000 %		14
213.		10.000 %	14,818	25.000 %		17
214.		10.000 %	24,808	25.000 %		17
215.		10.000 %	18,059	25.000 %		17
216.		10.000 %	18,059	25.000 %		17
217.		10.000 %	13,155	25.000 %		15
218.		10.000 %	13,954	25.000 %		16
219.		10.000 %	50,074	25.000 %		16
220.		10.000 %	17,590	25.000 %		17
221.		10.000 %	17,590	25.000 %		17
222.		10.000 %	17,591	25.000 %		17
223.		10.000 %	17,591	25.000 %		17
224.		10.000 %	21,521	25.000 %		16
225.		10.000 %	21,521	25.000 %		17
226.		10.000 %	15,755	25.000 %		16
227.		10.000 %	18,059	25.000 %		17
228.		10.000 %	18,059	25.000 %		17
229.		10.000 %	21,169	25.000 %		16
230.		10.000 %	21,169	25.000 %		16
231.		10.000 %	19,276	25.000 %		15
232.		10.000 %	19,276	25.000 %		17
233.		10.000 %	19,276	25.000 %		17
234.		10.000 %	18,181	25.000 %		17
235.		10.000 %	18,181	25.000 %		17
236.		10.000 %	14,804	25.000 %		17
237.		10.000 %	23,665	25.000 %		16
238.		10.000 %	16,201	25.000 %		14
239.		10.000 %	19,183	25.000 %		17
240.		10.000 %	19,183	25.000 %		17
241.		10.000 %	22,135	25.000 %		16
242.		10.000 %	22,135	25.000 %		17
243.		10.000 %	24,112	25.000 %		16
244.		10.000 %	21,752	25.000 %		18
245.		10.000 %	13,370	25.000 %		16
246.		10.000 %	13,370	25.000 %		18
247.		10.000 %	16,540	25.000 %		17
248.		10.000 %	16,540	25.000 %		16
249.		10.000 %	14,400	25.000 %		17
250.		10.000 %	14,400	25.000 %		18
251.		10.000 %	21,243	25.000 %		16
252.		10.000 %	21,243	25.000 %		15
253.		10.000 %	19,947	25.000 %		17
254.		10.000 %	19,181	25.000 %		18
255.		10.000 %	17,458	25.000 %		16
256.		10.000 %	17,458	25.000 %		17
257.		10.000 %	13,204	25.000 %		17
258.		10.000 %	16,201	25.000 %		16
259.		10.000 %	16,111	25.000 %		16
260.		10.000 %	16,685	25.000 %		15
261.		10.000 %	16,685	25.000 %		14
262.		10.000 %	21,132	25.000 %		16
263.		10.000 %	21,132	25.000 %		15

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
264.		10.000 %	12,404	25.000 %		14
265.		10.000 %	12,537	25.000 %		15
266.		10.000 %	13,477	25.000 %		17
267.		10.000 %	14,518	25.000 %		19
268.		10.000 %	20,893	25.000 %		16
269.		10.000 %	20,893	25.000 %		17
270.		10.000 %	16,053	25.000 %		16
271.		10.000 %	16,053	25.000 %		17
272.		10.000 %	16,053	25.000 %		15
273.		10.000 %	19,744	25.000 %		16
274.		10.000 %	19,744	25.000 %		17
275.		10.000 %	19,744	25.000 %		16
276.		10.000 %	21,209	25.000 %		16
277.		10.000 %	21,209	25.000 %		15
278.		10.000 %	21,507	25.000 %		16
279.		10.000 %	21,507	25.000 %		17
280.		10.000 %	21,507	25.000 %		17
281.		10.000 %	19,938	25.000 %		16
282.		10.000 %	19,938	25.000 %		17
283.		10.000 %	19,938	25.000 %		16
284.		10.000 %	11,363	25.000 %		15
285.		10.000 %	17,029	25.000 %		16
286.		10.000 %	13,392	25.000 %		17
287.		10.000 %	10,794	25.000 %		15
288.		10.000 %	13,045	25.000 %		15
289.		10.000 %	12,988	25.000 %		16
290.		10.000 %	13,326	25.000 %		15
291.		10.000 %	19,970	25.000 %		16
292.		10.000 %	19,970	25.000 %		17
293.		10.000 %	19,970	25.000 %		16
294.		10.000 %	19,229	25.000 %		17
295.		10.000 %	19,229	25.000 %		17
296.		10.000 %	21,183	25.000 %		16
297.		10.000 %	21,183	25.000 %		17
298.		10.000 %	12,803	25.000 %		12
299.		10.000 %	12,803	25.000 %		15
300.		10.000 %	22,730	25.000 %		16
301.		10.000 %	12,355	25.000 %		15
302.		10.000 %	13,752	25.000 %		16
303.		10.000 %	14,904	25.000 %		16
304.		10.000 %	14,904	25.000 %		17
305.		10.000 %	14,904	25.000 %		16
306.		10.000 %	16,714	25.000 %		17
307.		10.000 %	14,518	25.000 %		19
308.		10.000 %	15,092	25.000 %		16
309.		10.000 %	15,092	25.000 %		17
310.		10.000 %	15,092	25.000 %		16
311.		10.000 %	13,629	25.000 %		17
312.		10.000 %	13,629	25.000 %		17
313.		10.000 %	18,805	25.000 %		17
314.		10.000 %	18,805	25.000 %		17
315.		10.000 %	17,210	25.000 %		15
316.		10.000 %	22,132	25.000 %		18

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
317.		10.000 %	17,814	25.000 %		17
318.		10.000 %	17,814	25.000 %		17
319.		10.000 %	13,714	25.000 %		18
320.		10.000 %	15,562	25.000 %		17
321.		10.000 %	13,619	25.000 %		16
322.		10.000 %	13,619	25.000 %		16
323.		10.000 %	24,226	25.000 %		16
324.		10.000 %	24,226	25.000 %		18
325.		10.000 %	19,183	25.000 %		17
326.		10.000 %	19,183	25.000 %		17
327.		10.000 %	12,537	25.000 %		15
328.		10.000 %	12,537	25.000 %		15
329.		10.000 %	12,537	25.000 %		15
330.		10.000 %	21,270	25.000 %		16
331.		10.000 %	21,270	25.000 %		16
332.		10.000 %	24,344	25.000 %		16
333.		10.000 %	22,298	25.000 %		16
334.		10.000 %	22,298	25.000 %		17
335.		10.000 %	13,136	25.000 %		15
336.		10.000 %	20,066	25.000 %		16
337.		10.000 %	20,066	25.000 %		17
338.		10.000 %	20,066	25.000 %		17
339.		10.000 %	15,976	25.000 %		16
340.		10.000 %	19,772	25.000 %		14
341.		10.000 %	19,772	25.000 %		17
342.		10.000 %	19,290	25.000 %		16
343.		10.000 %	21,959	25.000 %		16
344.		10.000 %	21,959	25.000 %		17
345.		10.000 %	17,887	25.000 %		15
346.		10.000 %	17,887	25.000 %		17
347.		10.000 %	17,887	25.000 %		17
348.		10.000 %	14,730	25.000 %		19
349.		10.000 %	14,730	25.000 %		17
350.		10.000 %	17,814	25.000 %		17
351.		10.000 %	17,814	25.000 %		17
352.		10.000 %	16,089	25.000 %		16
353.		10.000 %	25,032	25.000 %		17
354.		10.000 %	22,421	25.000 %		16
355.		10.000 %	14,267	25.000 %		16
356.		10.000 %	14,267	25.000 %		16
357.		10.000 %	14,110	25.000 %		16
358.		10.000 %	17,210	25.000 %		16
359.		10.000 %	15,026	25.000 %		17
360.		10.000 %	20,970	25.000 %		16
361.		10.000 %	20,970	25.000 %		17
362.		10.000 %	17,638	25.000 %		17
363.		10.000 %	17,638	25.000 %		17
364.		10.000 %	22,132	25.000 %		18
365.		10.000 %	15,360	25.000 %		16
366.		10.000 %	20,930	25.000 %		15
367.		10.000 %	20,930	25.000 %		17
368.		10.000 %	14,326	25.000 %		13
369.		10.000 %	14,326	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
370.		10.000 %	26,314	25.000 %		16
371.		10.000 %	23,396	25.000 %		16
372.		10.000 %	23,396	25.000 %		16
373.		10.000 %	33,389	25.000 %		16
374.		10.000 %	33,389	25.000 %		17
375.		10.000 %	13,231	25.000 %		17
376.		10.000 %	20,673	25.000 %		16
377.		10.000 %	20,673	25.000 %		16
378.		10.000 %	13,181	25.000 %		15
379.		10.000 %	19,554	25.000 %		17
380.		10.000 %	19,554	25.000 %		17
381.		10.000 %	17,638	25.000 %		17
382.		10.000 %	17,638	25.000 %		17
383.		10.000 %	12,473	25.000 %		15
384.		10.000 %	10,900	25.000 %		14
385.		10.000 %	18,616	25.000 %		16
386.		10.000 %	14,806	25.000 %		15
387.		10.000 %	14,806	25.000 %		17
388.		10.000 %	25,814	25.000 %		17
389.		10.000 %	21,782	25.000 %		16
390.		10.000 %	21,782	25.000 %		17
391.		10.000 %	26,590	25.000 %		17
392.		10.000 %	23,006	25.000 %		16
393.		10.000 %	23,006	25.000 %		16
394.		10.000 %	19,501	25.000 %		16
395.		10.000 %	19,501	25.000 %		17
396.		10.000 %	19,501	25.000 %		16
397.		10.000 %	17,823	25.000 %		18
398.		10.000 %	13,155	25.000 %		15
399.		10.000 %	17,687	25.000 %		17
400.		10.000 %	17,687	25.000 %		17
401.		10.000 %	12,950	25.000 %		16
402.		10.000 %	12,950	25.000 %		15
403.		10.000 %	16,495	25.000 %		17
404.		10.000 %	16,495	25.000 %		17
405.		10.000 %	10,900	25.000 %		14
406.		10.000 %	19,865	25.000 %		16
407.		10.000 %	19,865	25.000 %		17
408.		10.000 %	19,439	25.000 %		18
409.		10.000 %	16,538	25.000 %		16
410.		10.000 %	16,538	25.000 %		17
411.		10.000 %	16,538	25.000 %		15
412.		10.000 %	21,915	25.000 %		16
413.		10.000 %	21,915	25.000 %		16
414.		10.000 %	19,498	25.000 %		15
415.		10.000 %	20,066	25.000 %		16
416.		10.000 %	20,066	25.000 %		17
417.		10.000 %	20,066	25.000 %		17
418.		10.000 %	16,648	25.000 %		17
419.		10.000 %	18,332	25.000 %		16
420.		10.000 %	18,332	25.000 %		17
421.		10.000 %	19,342	25.000 %		16
422.		10.000 %	19,342	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
423.		10.000 %	19,342	25.000 %		17
424.		10.000 %	16,201	25.000 %		16
425.		10.000 %	25,913	25.000 %		16
426.		10.000 %	25,913	25.000 %		17
427.		10.000 %	15,611	25.000 %		17
428.		10.000 %	14,903	25.000 %		16
429.		10.000 %	14,903	25.000 %		17
430.		10.000 %	14,903	25.000 %		16
431.		10.000 %	17,092	25.000 %		16
432.		10.000 %	17,092	25.000 %		17
433.		10.000 %	12,537	25.000 %		15
434.		10.000 %	17,823	25.000 %		18
435.		10.000 %	16,201	25.000 %		16
436.		10.000 %	13,611	25.000 %		16
437.		10.000 %	16,261	25.000 %		16
438.		10.000 %	16,261	25.000 %		17
439.		10.000 %	16,261	25.000 %		15
440.		10.000 %	17,000	25.000 %		15
441.		10.000 %	17,000	25.000 %		17
442.		10.000 %	17,000	25.000 %		17
443.		10.000 %	14,967	25.000 %		15
444.		10.000 %	19,345	25.000 %		17
445.		10.000 %	19,345	25.000 %		17
446.		10.000 %	19,261	25.000 %		16
447.		10.000 %	19,261	25.000 %		17
448.		10.000 %	17,353	25.000 %		18
449.		10.000 %	21,121	25.000 %		21
450.		10.000 %	17,224	25.000 %		18
451.		10.000 %	22,568	25.000 %		16
452.		10.000 %	22,568	25.000 %		16
453.		10.000 %	13,477	25.000 %		17
454.		10.000 %	15,782	25.000 %		16
455.		10.000 %	20,689	25.000 %		16
456.		10.000 %	20,689	25.000 %		14
457.		10.000 %	17,684	25.000 %		16
458.		10.000 %	19,475	25.000 %		15
459.		10.000 %	19,475	25.000 %		17
460.		10.000 %	19,475	25.000 %		16
461.		10.000 %	17,014	25.000 %		17
462.		10.000 %	17,014	25.000 %		17
463.		10.000 %	16,104	25.000 %		16
464.		10.000 %	16,104	25.000 %		17
465.		10.000 %	16,104	25.000 %		15
466.		10.000 %	21,920	25.000 %		16
467.		10.000 %	21,920	25.000 %		17
468.		10.000 %	16,201	25.000 %		16
469.		10.000 %	25,323	25.000 %		16
470.		10.000 %	25,323	25.000 %		16
471.		10.000 %	15,245	25.000 %		15
472.		10.000 %	15,245	25.000 %		14
473.		10.000 %	21,383	25.000 %		17
474.		10.000 %	26,543	25.000 %		16
475.		10.000 %	26,543	25.000 %		14

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
476.		10.000 %	13,155	25.000 %		15
477.		10.000 %	15,084	25.000 %		16
478.		10.000 %	21,931	25.000 %		16
479.		10.000 %	21,931	25.000 %		53
480.		10.000 %	17,458	25.000 %		16
481.		10.000 %	17,458	25.000 %		17
482.		10.000 %	16,287	25.000 %		17
483.		10.000 %	16,220	25.000 %		19
484.		10.000 %	20,153	25.000 %		20
485.		10.000 %	20,935	25.000 %		16
486.		10.000 %	20,935	25.000 %		16
487.		10.000 %	51,609	25.000 %		16
488.		10.000 %	22,675	25.000 %		21
489.		10.000 %	16,220	25.000 %		19
490.		10.000 %	14,516	25.000 %		17
491.		10.000 %	14,516	25.000 %		16
492.		10.000 %	20,221	25.000 %		19
493.		10.000 %	20,221	25.000 %		16
494.		10.000 %	17,814	25.000 %		17
495.		10.000 %	17,814	25.000 %		17
496.		10.000 %	19,760	25.000 %		16
497.		10.000 %	19,760	25.000 %		13
498.		10.000 %	16,900	25.000 %		16
499.		10.000 %	16,900	25.000 %		17
500.		10.000 %	19,962	25.000 %		18
501.		10.000 %	16,520	25.000 %		17
502.		10.000 %	16,201	25.000 %		16
503.		10.000 %	17,210	25.000 %		15
504.		10.000 %	13,286	25.000 %		14
505.		10.000 %	25,488	25.000 %		16
506.		10.000 %	16,019	25.000 %		17
507.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,681	3,000	3,000		3,000
2.	3,681	3,000	3,000		3,000
3.	4,050	3,000	3,000		3,000
4.	3,943	3,000	3,000		3,000
5.	3,943	3,000	3,000		3,000
6.	3,953	3,000	3,000		3,000
7.	5,572	3,000	3,000		3,000
8.	5,572	3,000	3,000		3,000
9.	5,593	3,000	3,000		3,000
10.	5,593	3,000	3,000		3,000
11.	5,004	3,000	3,000		3,000
12.	5,004	3,000	3,000		3,000
13.	5,004	3,000	3,000		3,000
14.	5,279	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
15.	5,279	3,000	3,000		3,000
16.	5,151	3,000	3,000		3,000
17.	5,305	3,000	3,000		3,000
18.	3,711	3,000	3,000		3,000
19.	3,711	3,000	3,000		3,000
20.	5,686	3,000	3,000		3,000
21.	5,686	3,000	3,000		3,000
22.	3,244	3,000	3,000		3,000
23.	3,796	3,000	3,000		3,000
24.	3,796	3,000	3,000		3,000
25.	5,275	3,000	3,000		3,000
26.	5,275	3,000	3,000		3,000
27.	4,828	3,000	3,000		3,000
28.	4,828	3,000	3,000		3,000
29.	3,608	3,000	3,000		3,000
30.	6,310	3,000	3,000		3,000
31.	4,101	3,000	3,000		3,000
32.	4,545	3,000	3,000		3,000
33.	4,545	3,000	3,000		3,000
34.	4,410	3,000	3,000		3,000
35.	4,410	3,000	3,000		3,000
36.	4,443	3,000	3,000		3,000
37.	3,674	3,000	3,000		3,000
38.	3,674	3,000	3,000		3,000
39.	3,111	3,000	3,000		3,000
40.	5,554	3,000	3,000		3,000
41.	5,554	3,000	3,000		3,000
42.	5,332	3,000	3,000		3,000
43.	5,332	3,000	3,000		3,000
44.	4,365	3,000	3,000		3,000
45.	4,365	3,000	3,000		3,000
46.	5,874	3,000	3,000		3,000
47.	5,874	3,000	3,000		3,000
48.	4,005	3,000	3,000		3,000
49.	3,307	3,000	3,000		3,000
50.	6,413	3,000	3,000		3,000
51.	4,599	3,000	3,000		3,000
52.	4,599	3,000	3,000		3,000
53.	8,377	3,000	3,000		3,000
54.	7,486	3,000	3,000		3,000
55.	3,052	3,000	3,000		3,000
56.	3,261	3,000	3,000		3,000
57.	3,261	3,000	3,000		3,000
58.	5,663	3,000	3,000		3,000
59.	5,663	3,000	3,000		3,000
60.	5,426	3,000	3,000		3,000
61.	5,426	3,000	3,000		3,000
62.	3,892	3,000	3,000		3,000
63.	3,451	3,000	3,000		3,000
64.	3,451	3,000	3,000		3,000
65.	3,451	3,000	3,000		3,000
66.	4,533	3,000	3,000		3,000
67.	4,533	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
68.	3,998	3,000	3,000		3,000
69.	3,839	3,000	3,000		3,000
70.	3,102	3,000	3,000		3,000
71.	3,709	3,000	3,000		3,000
72.	4,632	3,000	3,000		3,000
73.	5,649	3,000	3,000		3,000
74.	5,649	3,000	3,000		3,000
75.	4,486	3,000	3,000		3,000
76.	4,486	3,000	3,000		3,000
77.	4,823	3,000	3,000		3,000
78.	4,962	3,000	3,000		3,000
79.	4,962	3,000	3,000		3,000
80.	4,943	3,000	3,000		3,000
81.	4,943	3,000	3,000		3,000
82.	4,743	3,000	3,000		3,000
83.	4,743	3,000	3,000		3,000
84.	4,743	3,000	3,000		3,000
85.	4,952	3,000	3,000		3,000
86.	3,878	3,000	3,000		3,000
87.	5,412	3,000	3,000		3,000
88.	5,412	3,000	3,000		3,000
89.	5,290	3,000	3,000		3,000
90.	5,290	3,000	3,000		3,000
91.	4,365	3,000	3,000		3,000
92.	4,365	3,000	3,000		3,000
93.	4,645	3,000	3,000		3,000
94.	4,162	3,000	3,000		3,000
95.	3,117	3,000	3,000		3,000
96.	4,005	3,000	3,000		3,000
97.	4,796	3,000	3,000		3,000
98.	4,796	3,000	3,000		3,000
99.	2,784	3,000	2,784		2,784
100.	3,448	3,000	3,000		3,000
101.	4,928	3,000	3,000		3,000
102.	4,928	3,000	3,000		3,000
103.	3,289	3,000	3,000		3,000
104.	5,471	3,000	3,000		3,000
105.	5,471	3,000	3,000		3,000
106.	3,422	3,000	3,000		3,000
107.	3,825	3,000	3,000		3,000
108.	5,026	3,000	3,000		3,000
109.	4,285	3,000	3,000		3,000
110.	4,285	3,000	3,000		3,000
111.	3,630	3,000	3,000		3,000
112.	4,035	3,000	3,000		3,000
113.	4,035	3,000	3,000		3,000
114.	4,035	3,000	3,000		3,000
115.	4,796	3,000	3,000		3,000
116.	4,796	3,000	3,000		3,000
117.	5,108	3,000	3,000		3,000
118.	5,108	3,000	3,000		3,000
119.	7,486	3,000	3,000		3,000
120.	4,440	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
121.	4,440	3,000	3,000		3,000
122.	4,469	3,000	3,000		3,000
123.	4,469	3,000	3,000		3,000
124.	4,410	3,000	3,000		3,000
125.	4,410	3,000	3,000		3,000
126.	3,134	3,000	3,000		3,000
127.	3,843	3,000	3,000		3,000
128.	3,843	3,000	3,000		3,000
129.	4,864	3,000	3,000		3,000
130.	4,864	3,000	3,000		3,000
131.	4,864	3,000	3,000		3,000
132.	4,050	3,000	3,000		3,000
133.	4,197	3,000	3,000		3,000
134.	4,524	3,000	3,000		3,000
135.	4,524	3,000	3,000		3,000
136.	4,467	3,000	3,000		3,000
137.	4,467	3,000	3,000		3,000
138.	4,467	3,000	3,000		3,000
139.	4,803	3,000	3,000		3,000
140.	4,803	3,000	3,000		3,000
141.	4,803	3,000	3,000		3,000
142.	10,388	3,000	3,000		3,000
143.	5,303	3,000	3,000		3,000
144.	5,303	3,000	3,000		3,000
145.	3,827	3,000	3,000		3,000
146.	3,740	3,000	3,000		3,000
147.	3,740	3,000	3,000		3,000
148.	3,740	3,000	3,000		3,000
149.	4,869	3,000	3,000		3,000
150.	4,454	3,000	3,000		3,000
151.	4,454	3,000	3,000		3,000
152.	3,489	3,000	3,000		3,000
153.	3,620	3,000	3,000		3,000
154.	5,002	3,000	3,000		3,000
155.	4,101	3,000	3,000		3,000
156.	4,065	3,000	3,000		3,000
157.	4,852	3,000	3,000		3,000
158.	4,852	3,000	3,000		3,000
159.	4,410	3,000	3,000		3,000
160.	4,410	3,000	3,000		3,000
161.	5,060	3,000	3,000		3,000
162.	5,060	3,000	3,000		3,000
163.	6,084	3,000	3,000		3,000
164.	6,234	3,000	3,000		3,000
165.	4,607	3,000	3,000		3,000
166.	4,607	3,000	3,000		3,000
167.	4,245	3,000	3,000		3,000
168.	4,410	3,000	3,000		3,000
169.	4,410	3,000	3,000		3,000
170.	4,315	3,000	3,000		3,000
171.	5,215	3,000	3,000		3,000
172.	4,047	3,000	3,000		3,000
173.	5,641	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
174.	5,641	3,000	3,000		3,000
175.	3,208	3,000	3,000		3,000
176.	3,208	3,000	3,000		3,000
177.	3,208	3,000	3,000		3,000
178.	4,157	3,000	3,000		3,000
179.	3,163	3,000	3,000		3,000
180.	4,268	3,000	3,000		3,000
181.	4,268	3,000	3,000		3,000
182.	4,268	3,000	3,000		3,000
183.	3,498	3,000	3,000		3,000
184.	3,021	3,000	3,000		3,000
185.	3,271	3,000	3,000		3,000
186.	4,825	3,000	3,000		3,000
187.	4,825	3,000	3,000		3,000
188.	5,459	3,000	3,000		3,000
189.	5,459	3,000	3,000		3,000
190.	6,137	3,000	3,000		3,000
191.	6,137	3,000	3,000		3,000
192.	4,269	3,000	3,000		3,000
193.	4,269	3,000	3,000		3,000
194.	4,269	3,000	3,000		3,000
195.	4,835	3,000	3,000		3,000
196.	4,835	3,000	3,000		3,000
197.	4,835	3,000	3,000		3,000
198.	5,343	3,000	3,000		3,000
199.	4,410	3,000	3,000		3,000
200.	4,410	3,000	3,000		3,000
201.	6,028	3,000	3,000		3,000
202.	3,911	3,000	3,000		3,000
203.	3,305	3,000	3,000		3,000
204.	4,050	3,000	3,000		3,000
205.	3,232	3,000	3,000		3,000
206.	5,301	3,000	3,000		3,000
207.	5,301	3,000	3,000		3,000
208.	5,301	3,000	3,000		3,000
209.	4,508	3,000	3,000		3,000
210.	4,508	3,000	3,000		3,000
211.	3,804	3,000	3,000		3,000
212.	3,351	3,000	3,000		3,000
213.	3,705	3,000	3,000		3,000
214.	6,202	3,000	3,000		3,000
215.	4,515	3,000	3,000		3,000
216.	4,515	3,000	3,000		3,000
217.	3,289	3,000	3,000		3,000
218.	3,489	3,000	3,000		3,000
219.	12,519	3,000	3,000		3,000
220.	4,398	3,000	3,000		3,000
221.	4,398	3,000	3,000		3,000
222.	4,398	3,000	3,000		3,000
223.	4,398	3,000	3,000		3,000
224.	5,380	3,000	3,000		3,000
225.	5,380	3,000	3,000		3,000
226.	3,939	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
227.	4,515	3,000	3,000		3,000
228.	4,515	3,000	3,000		3,000
229.	5,292	3,000	3,000		3,000
230.	5,292	3,000	3,000		3,000
231.	4,819	3,000	3,000		3,000
232.	4,819	3,000	3,000		3,000
233.	4,819	3,000	3,000		3,000
234.	4,545	3,000	3,000		3,000
235.	4,545	3,000	3,000		3,000
236.	3,701	3,000	3,000		3,000
237.	5,916	3,000	3,000		3,000
238.	4,050	3,000	3,000		3,000
239.	4,796	3,000	3,000		3,000
240.	4,796	3,000	3,000		3,000
241.	5,534	3,000	3,000		3,000
242.	5,534	3,000	3,000		3,000
243.	6,028	3,000	3,000		3,000
244.	5,438	3,000	3,000		3,000
245.	3,343	3,000	3,000		3,000
246.	3,343	3,000	3,000		3,000
247.	4,135	3,000	3,000		3,000
248.	4,135	3,000	3,000		3,000
249.	3,600	3,000	3,000		3,000
250.	3,600	3,000	3,000		3,000
251.	5,311	3,000	3,000		3,000
252.	5,311	3,000	3,000		3,000
253.	4,987	3,000	3,000		3,000
254.	4,795	3,000	3,000		3,000
255.	4,365	3,000	3,000		3,000
256.	4,365	3,000	3,000		3,000
257.	3,301	3,000	3,000		3,000
258.	4,050	3,000	3,000		3,000
259.	4,028	3,000	3,000		3,000
260.	4,171	3,000	3,000		3,000
261.	4,171	3,000	3,000		3,000
262.	5,283	3,000	3,000		3,000
263.	5,283	3,000	3,000		3,000
264.	3,101	3,000	3,000		3,000
265.	3,134	3,000	3,000		3,000
266.	3,369	3,000	3,000		3,000
267.	3,630	3,000	3,000		3,000
268.	5,223	3,000	3,000		3,000
269.	5,223	3,000	3,000		3,000
270.	4,013	3,000	3,000		3,000
271.	4,013	3,000	3,000		3,000
272.	4,013	3,000	3,000		3,000
273.	4,936	3,000	3,000		3,000
274.	4,936	3,000	3,000		3,000
275.	4,936	3,000	3,000		3,000
276.	5,302	3,000	3,000		3,000
277.	5,302	3,000	3,000		3,000
278.	5,377	3,000	3,000		3,000
279.	5,377	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
280.	5,377	3,000	3,000		3,000
281.	4,985	3,000	3,000		3,000
282.	4,985	3,000	3,000		3,000
283.	4,985	3,000	3,000		3,000
284.	2,841	3,000	2,841		2,841
285.	4,257	3,000	3,000		3,000
286.	3,348	3,000	3,000		3,000
287.	2,699	3,000	2,699		2,699
288.	3,261	3,000	3,000		3,000
289.	3,247	3,000	3,000		3,000
290.	3,332	3,000	3,000		3,000
291.	4,993	3,000	3,000		3,000
292.	4,993	3,000	3,000		3,000
293.	4,993	3,000	3,000		3,000
294.	4,807	3,000	3,000		3,000
295.	4,807	3,000	3,000		3,000
296.	5,296	3,000	3,000		3,000
297.	5,296	3,000	3,000		3,000
298.	3,201	3,000	3,000		3,000
299.	3,201	3,000	3,000		3,000
300.	5,683	3,000	3,000		3,000
301.	3,089	3,000	3,000		3,000
302.	3,438	3,000	3,000		3,000
303.	3,726	3,000	3,000		3,000
304.	3,726	3,000	3,000		3,000
305.	3,726	3,000	3,000		3,000
306.	4,179	3,000	3,000		3,000
307.	3,630	3,000	3,000		3,000
308.	3,773	3,000	3,000		3,000
309.	3,773	3,000	3,000		3,000
310.	3,773	3,000	3,000		3,000
311.	3,407	3,000	3,000		3,000
312.	3,407	3,000	3,000		3,000
313.	4,701	3,000	3,000		3,000
314.	4,701	3,000	3,000		3,000
315.	4,303	3,000	3,000		3,000
316.	5,533	3,000	3,000		3,000
317.	4,454	3,000	3,000		3,000
318.	4,454	3,000	3,000		3,000
319.	3,429	3,000	3,000		3,000
320.	3,891	3,000	3,000		3,000
321.	3,405	3,000	3,000		3,000
322.	3,405	3,000	3,000		3,000
323.	6,057	3,000	3,000		3,000
324.	6,057	3,000	3,000		3,000
325.	4,796	3,000	3,000		3,000
326.	4,796	3,000	3,000		3,000
327.	3,134	3,000	3,000		3,000
328.	3,134	3,000	3,000		3,000
329.	3,134	3,000	3,000		3,000
330.	5,318	3,000	3,000		3,000
331.	5,318	3,000	3,000		3,000
332.	6,086	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
333.	5,575	3,000	3,000		3,000
334.	5,575	3,000	3,000		3,000
335.	3,284	3,000	3,000		3,000
336.	5,017	3,000	3,000		3,000
337.	5,017	3,000	3,000		3,000
338.	5,017	3,000	3,000		3,000
339.	3,994	3,000	3,000		3,000
340.	4,943	3,000	3,000		3,000
341.	4,943	3,000	3,000		3,000
342.	4,823	3,000	3,000		3,000
343.	5,490	3,000	3,000		3,000
344.	5,490	3,000	3,000		3,000
345.	4,472	3,000	3,000		3,000
346.	4,472	3,000	3,000		3,000
347.	4,472	3,000	3,000		3,000
348.	3,683	3,000	3,000		3,000
349.	3,683	3,000	3,000		3,000
350.	4,454	3,000	3,000		3,000
351.	4,454	3,000	3,000		3,000
352.	4,022	3,000	3,000		3,000
353.	6,258	3,000	3,000		3,000
354.	5,605	3,000	3,000		3,000
355.	3,567	3,000	3,000		3,000
356.	3,567	3,000	3,000		3,000
357.	3,528	3,000	3,000		3,000
358.	4,303	3,000	3,000		3,000
359.	3,757	3,000	3,000		3,000
360.	5,243	3,000	3,000		3,000
361.	5,243	3,000	3,000		3,000
362.	4,410	3,000	3,000		3,000
363.	4,410	3,000	3,000		3,000
364.	5,533	3,000	3,000		3,000
365.	3,840	3,000	3,000		3,000
366.	5,233	3,000	3,000		3,000
367.	5,233	3,000	3,000		3,000
368.	3,582	3,000	3,000		3,000
369.	3,582	3,000	3,000		3,000
370.	6,579	3,000	3,000		3,000
371.	5,849	3,000	3,000		3,000
372.	5,849	3,000	3,000		3,000
373.	8,347	3,000	3,000		3,000
374.	8,347	3,000	3,000		3,000
375.	3,308	3,000	3,000		3,000
376.	5,168	3,000	3,000		3,000
377.	5,168	3,000	3,000		3,000
378.	3,295	3,000	3,000		3,000
379.	4,889	3,000	3,000		3,000
380.	4,889	3,000	3,000		3,000
381.	4,410	3,000	3,000		3,000
382.	4,410	3,000	3,000		3,000
383.	3,118	3,000	3,000		3,000
384.	2,725	3,000	2,725		2,725
385.	4,654	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
386.	3,702	3,000	3,000		3,000
387.	3,702	3,000	3,000		3,000
388.	6,454	3,000	3,000		3,000
389.	5,446	3,000	3,000		3,000
390.	5,446	3,000	3,000		3,000
391.	6,648	3,000	3,000		3,000
392.	5,752	3,000	3,000		3,000
393.	5,752	3,000	3,000		3,000
394.	4,875	3,000	3,000		3,000
395.	4,875	3,000	3,000		3,000
396.	4,875	3,000	3,000		3,000
397.	4,456	3,000	3,000		3,000
398.	3,289	3,000	3,000		3,000
399.	4,422	3,000	3,000		3,000
400.	4,422	3,000	3,000		3,000
401.	3,238	3,000	3,000		3,000
402.	3,238	3,000	3,000		3,000
403.	4,124	3,000	3,000		3,000
404.	4,124	3,000	3,000		3,000
405.	2,725	3,000	2,725		2,725
406.	4,966	3,000	3,000		3,000
407.	4,966	3,000	3,000		3,000
408.	4,860	3,000	3,000		3,000
409.	4,135	3,000	3,000		3,000
410.	4,135	3,000	3,000		3,000
411.	4,135	3,000	3,000		3,000
412.	5,479	3,000	3,000		3,000
413.	5,479	3,000	3,000		3,000
414.	4,875	3,000	3,000		3,000
415.	5,017	3,000	3,000		3,000
416.	5,017	3,000	3,000		3,000
417.	5,017	3,000	3,000		3,000
418.	4,162	3,000	3,000		3,000
419.	4,583	3,000	3,000		3,000
420.	4,583	3,000	3,000		3,000
421.	4,836	3,000	3,000		3,000
422.	4,836	3,000	3,000		3,000
423.	4,836	3,000	3,000		3,000
424.	4,050	3,000	3,000		3,000
425.	6,478	3,000	3,000		3,000
426.	6,478	3,000	3,000		3,000
427.	3,903	3,000	3,000		3,000
428.	3,726	3,000	3,000		3,000
429.	3,726	3,000	3,000		3,000
430.	3,726	3,000	3,000		3,000
431.	4,273	3,000	3,000		3,000
432.	4,273	3,000	3,000		3,000
433.	3,134	3,000	3,000		3,000
434.	4,456	3,000	3,000		3,000
435.	4,050	3,000	3,000		3,000
436.	3,403	3,000	3,000		3,000
437.	4,065	3,000	3,000		3,000
438.	4,065	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
439.	4,065	3,000	3,000		3,000
440.	4,250	3,000	3,000		3,000
441.	4,250	3,000	3,000		3,000
442.	4,250	3,000	3,000		3,000
443.	3,742	3,000	3,000		3,000
444.	4,836	3,000	3,000		3,000
445.	4,836	3,000	3,000		3,000
446.	4,815	3,000	3,000		3,000
447.	4,815	3,000	3,000		3,000
448.	4,338	3,000	3,000		3,000
449.	5,280	3,000	3,000		3,000
450.	4,306	3,000	3,000		3,000
451.	5,642	3,000	3,000		3,000
452.	5,642	3,000	3,000		3,000
453.	3,369	3,000	3,000		3,000
454.	3,946	3,000	3,000		3,000
455.	5,172	3,000	3,000		3,000
456.	5,172	3,000	3,000		3,000
457.	4,421	3,000	3,000		3,000
458.	4,869	3,000	3,000		3,000
459.	4,869	3,000	3,000		3,000
460.	4,869	3,000	3,000		3,000
461.	4,254	3,000	3,000		3,000
462.	4,254	3,000	3,000		3,000
463.	4,026	3,000	3,000		3,000
464.	4,026	3,000	3,000		3,000
465.	4,026	3,000	3,000		3,000
466.	5,480	3,000	3,000		3,000
467.	5,480	3,000	3,000		3,000
468.	4,050	3,000	3,000		3,000
469.	6,331	3,000	3,000		3,000
470.	6,331	3,000	3,000		3,000
471.	3,811	3,000	3,000		3,000
472.	3,811	3,000	3,000		3,000
473.	5,346	3,000	3,000		3,000
474.	6,636	3,000	3,000		3,000
475.	6,636	3,000	3,000		3,000
476.	3,289	3,000	3,000		3,000
477.	3,771	3,000	3,000		3,000
478.	5,483	3,000	3,000		3,000
479.	5,483	3,000	3,000		3,000
480.	4,365	3,000	3,000		3,000
481.	4,365	3,000	3,000		3,000
482.	4,072	3,000	3,000		3,000
483.	4,055	3,000	3,000		3,000
484.	5,038	3,000	3,000		3,000
485.	5,234	3,000	3,000		3,000
486.	5,234	3,000	3,000		3,000
487.	12,902	3,000	3,000		3,000
488.	5,669	3,000	3,000		3,000
489.	4,055	3,000	3,000		3,000
490.	3,629	3,000	3,000		3,000
491.	3,629	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
492.	5,055	3,000	3,000		3,000
493.	5,055	3,000	3,000		3,000
494.	4,454	3,000	3,000		3,000
495.	4,454	3,000	3,000		3,000
496.	4,940	3,000	3,000		3,000
497.	4,940	3,000	3,000		3,000
498.	4,225	3,000	3,000		3,000
499.	4,225	3,000	3,000		3,000
500.	4,991	3,000	3,000		3,000
501.	4,130	3,000	3,000		3,000
502.	4,050	3,000	3,000		3,000
503.	4,303	3,000	3,000		3,000
504.	3,322	3,000	3,000		3,000
505.	6,372	3,000	3,000		3,000
506.	4,005	3,000	3,000		3,000
507.					

Ontario co-operative education tax credit (total of amounts in column K) 500 1,516,774 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... ______ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009* or the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
Selma Yam	(416) 345-6827

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 788,867,244

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/ trade name **405**	C Name of apprentice **410**
1.	309a	Electrician-Construction and Maintenance	Apprentice 1
2.	309a	Electrician-Construction and Maintenance	Apprentice 2
3.	309a	Electrician-Construction and Maintenance	Apprentice 3
4.	309a	Electrician-Construction and Maintenance	Apprentice 4
5.	309a	Electrician-Construction and Maintenance	Apprentice 5
6.	433a	Industrial Mechanic (Millwright)	Apprentice 6
7.	434a	Powerline Technician	Apprentice 7
8.	444B	Utility Arborist	Apprentice 8
9.	403a	General Carpenter	Apprentice 9
10.	434a	Powerline Technician	Apprentice 10
11.	434a	Powerline Technician	Apprentice 11
12.	444B	Utility Arborist	Apprentice 12
13.	444B	Utility Arborist	Apprentice 13
14.	309a	Electrician-Construction and Maintenance	Apprentice 14
15.	434a	Powerline Technician	Apprentice 15
16.	434a	Powerline Technician	Apprentice 16
17.	434a	Powerline Technician	Apprentice 17
18.	434a	Powerline Technician	Apprentice 18
19.	434a	Powerline Technician	Apprentice 19
20.	434a	Powerline Technician	Apprentice 20
21.	434a	Powerline Technician	Apprentice 21
22.	434a	Powerline Technician	Apprentice 22
23.	434a	Powerline Technician	Apprentice 23
24.	434a	Powerline Technician	Apprentice 24
25.	434a	Powerline Technician	Apprentice 25
26.	434a	Powerline Technician	Apprentice 26
27.	434a	Powerline Technician	Apprentice 27

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
28.	434a	Powerline Technician	Apprentice 28
29.	434a	Powerline Technician	Apprentice 29
30.	309a	Electrician-Construction and Maintenance	Apprentice 30
31.	309a	Electrician-Construction and Maintenance	Apprentice 31
32.	309a	Electrician-Construction and Maintenance	Apprentice 32
33.	309a	Electrician-Construction and Maintenance	Apprentice 33
34.	444B	Utility Arborist	Apprentice 34
35.	444B	Utility Arborist	Apprentice 35
36.	444B	Utility Arborist	Apprentice 36
37.	434a	Powerline Technician	Apprentice 37
38.	434a	Powerline Technician	Apprentice 38
39.	434a	Powerline Technician	Apprentice 39
40.	434a	Powerline Technician	Apprentice 40
41.	434a	Powerline Technician	Apprentice 41
42.	434a	Powerline Technician	Apprentice 42
43.	434a	Powerline Technician	Apprentice 43
44.	434a	Powerline Technician	Apprentice 44
45.	434a	Powerline Technician	Apprentice 45
46.	434a	Powerline Technician	Apprentice 46
47.	434a	Powerline Technician	Apprentice 47
48.	434a	Powerline Technician	Apprentice 48
49.	434a	Powerline Technician	Apprentice 49
50.	434a	Powerline Technician	Apprentice 50
51.	434a	Powerline Technician	Apprentice 51
52.	434a	Powerline Technician	Apprentice 52
53.	434a	Powerline Technician	Apprentice 53
54.	434a	Powerline Technician	Apprentice 54
55.	444B	Utility Arborist	Apprentice 55
56.	444B	Utility Arborist	Apprentice 56
57.	434a	Powerline Technician	Apprentice 57
58.	403a	General Carpenter	Apprentice 58
59.	309a	Electrician-Construction and Maintenance	Apprentice 59
60.	309a	Electrician-Construction and Maintenance	Apprentice 60
61.	434a	Powerline Technician	Apprentice 61
62.	434a	Powerline Technician	Apprentice 62
63.	434a	Powerline Technician	Apprentice 63
64.	434a	Powerline Technician	Apprentice 64
65.	434a	Powerline Technician	Apprentice 65
66.	434a	Powerline Technician	Apprentice 66
67.	434a	Powerline Technician	Apprentice 67
68.	434a	Powerline Technician	Apprentice 68
69.	434a	Powerline Technician	Apprentice 69
70.	434a	Powerline Technician	Apprentice 70
71.	434a	Powerline Technician	Apprentice 71
72.	434a	Powerline Technician	Apprentice 72
73.	309a	Electrician-Construction and Maintenance	Apprentice 73
74.	309a	Electrician-Construction and Maintenance	Apprentice 74
75.	309a	Electrician-Construction and Maintenance	Apprentice 75
76.	309a	Electrician-Construction and Maintenance	Apprentice 76
77.	309a	Electrician-Construction and Maintenance	Apprentice 77
78.	434a	Powerline Technician	Apprentice 78
79.	309a	Electrician-Construction and Maintenance	Apprentice 79
80.	434a	Powerline Technician	Apprentice 80
81.	434a	Powerline Technician	Apprentice 81
82.	434a	Powerline Technician	Apprentice 82

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
83.	434a	Powerline Technician	Apprentice 83
84.	434a	Powerline Technician	Apprentice 84
85.	434a	Powerline Technician	Apprentice 85
86.	434a	Powerline Technician	Apprentice 86
87.	434a	Powerline Technician	Apprentice 87
88.	309a	Electrician-Construction and Maintenance	Apprentice 88
89.	309a	Electrician-Construction and Maintenance	Apprentice 89
90.	434a	Powerline Technician	Apprentice 90
91.	434a	Powerline Technician	Apprentice 91
92.	309a	Electrician-Construction and Maintenance	Apprentice 92
93.	309a	Electrician-Construction and Maintenance	Apprentice 93
94.	309a	Electrician-Construction and Maintenance	Apprentice 94
95.	309a	Electrician-Construction and Maintenance	Apprentice 95
96.	434a	Powerline Technician	Apprentice 96
97.	434a	Powerline Technician	Apprentice 97
98.	444B	Utility Arborist	Apprentice 98
99.	434a	Powerline Technician	Apprentice 99
100.	434a	Powerline Technician	Apprentice 100
101.	434a	Powerline Technician	Apprentice 101
102.	434a	Powerline Technician	Apprentice 102
103.	434a	Powerline Technician	Apprentice 103
104.	434a	Powerline Technician	Apprentice 104
105.	434a	Powerline Technician	Apprentice 105
106.	434a	Powerline Technician	Apprentice 106
107.	434a	Powerline Technician	Apprentice 107
108.	434a	Powerline Technician	Apprentice 108
109.	434a	Powerline Technician	Apprentice 109
110.	434a	Powerline Technician	Apprentice 110
111.	434a	Powerline Technician	Apprentice 111
112.	309a	Electrician-Construction and Maintenance	Apprentice 112
113.	444B	Utility Arborist	Apprentice 113
114.	444B	Utility Arborist	Apprentice 114
115.	444B	Utility Arborist	Apprentice 115
116.	444B	Utility Arborist	Apprentice 116
117.	444B	Utility Arborist	Apprentice 117
118.	444B	Utility Arborist	Apprentice 118
119.	444B	Utility Arborist	Apprentice 119
120.	444B	Utility Arborist	Apprentice 120
121.	444B	Utility Arborist	Apprentice 121
122.	444B	Utility Arborist	Apprentice 122
123.	444B	Utility Arborist	Apprentice 123
124.	444B	Utility Arborist	Apprentice 124
125.	444B	Utility Arborist	Apprentice 125
126.	444B	Utility Arborist	Apprentice 126
127.	309a	Electrician-Construction and Maintenance	Apprentice 127
128.	403a	General Carpenter	Apprentice 128
129.	309a	Electrician-Construction and Maintenance	Apprentice 129
130.	403a	General Carpenter	Apprentice 130
131.	403a	General Carpenter	Apprentice 131
132.	309a	Electrician-Construction and Maintenance	Apprentice 132
133.	309a	Electrician-Construction and Maintenance	Apprentice 133
134.	309a	Electrician-Construction and Maintenance	Apprentice 134
135.	309a	Electrician-Construction and Maintenance	Apprentice 135
136.	434a	Powerline Technician	Apprentice 136
137.	434a	Powerline Technician	Apprentice 137

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
138.	434a	Powerline Technician	Apprentice 138
139.	434a	Powerline Technician	Apprentice 139
140.	434a	Powerline Technician	Apprentice 140
141.	434a	Powerline Technician	Apprentice 141
142.	434a	Powerline Technician	Apprentice 142
143.	434a	Powerline Technician	Apprentice 143
144.	434a	Powerline Technician	Apprentice 144
145.	434a	Powerline Technician	Apprentice 145
146.	434a	Powerline Technician	Apprentice 146
147.	309a	Electrician-Construction and Maintenance	Apprentice 147
148.	309a	Electrician-Construction and Maintenance	Apprentice 148
149.	444B	Utility Arborist	Apprentice 149
150.	309a	Electrician-Construction and Maintenance	Apprentice 150
151.	309a	Electrician-Construction and Maintenance	Apprentice 151
152.	309a	Electrician-Construction and Maintenance	Apprentice 152
153.	309a	Electrician-Construction and Maintenance	Apprentice 153
154.	309a	Electrician-Construction and Maintenance	Apprentice 154
155.	309a	Electrician-Construction and Maintenance	Apprentice 155
156.	309a	Electrician-Construction and Maintenance	Apprentice 156
157.	309a	Electrician-Construction and Maintenance	Apprentice 157
158.	309a	Electrician-Construction and Maintenance	Apprentice 158
159.	309a	Electrician-Construction and Maintenance	Apprentice 159
160.	309a	Electrician-Construction and Maintenance	Apprentice 160
161.	309a	Electrician-Construction and Maintenance	Apprentice 161
162.	309a	Electrician-Construction and Maintenance	Apprentice 162
163.	309a	Electrician-Construction and Maintenance	Apprentice 163
164.	309a	Electrician-Construction and Maintenance	Apprentice 164
165.	309a	Electrician-Construction and Maintenance	Apprentice 165
166.	309a	Electrician-Construction and Maintenance	Apprentice 166
167.	309a	Electrician-Construction and Maintenance	Apprentice 167
168.	309a	Electrician-Construction and Maintenance	Apprentice 168
169.	434a	Powerline Technician	Apprentice 169
170.	434a	Powerline Technician	Apprentice 170
171.	434a	Powerline Technician	Apprentice 171
172.	434a	Powerline Technician	Apprentice 172
173.	434a	Powerline Technician	Apprentice 173
174.	434a	Powerline Technician	Apprentice 174
175.	434a	Powerline Technician	Apprentice 175
176.	434a	Powerline Technician	Apprentice 176
177.	434a	Powerline Technician	Apprentice 177
178.	434a	Powerline Technician	Apprentice 178
179.	434a	Powerline Technician	Apprentice 179
180.	309a	Electrician-Construction and Maintenance	Apprentice 180
181.	434a	Powerline Technician	Apprentice 181
182.	434a	Powerline Technician	Apprentice 182
183.	434a	Powerline Technician	Apprentice 183
184.	434a	Powerline Technician	Apprentice 184
185.	434a	Powerline Technician	Apprentice 185
186.	434a	Powerline Technician	Apprentice 186
187.	434a	Powerline Technician	Apprentice 187
188.	434a	Powerline Technician	Apprentice 188
189.	434a	Powerline Technician	Apprentice 189
190.	434a	Powerline Technician	Apprentice 190
191.	434a	Powerline Technician	Apprentice 191
192.	434a	Powerline Technician	Apprentice 192

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
193.	434a	Powerline Technician	Apprentice 193
194.	434a	Powerline Technician	Apprentice 194
195.	434a	Powerline Technician	Apprentice 195
196.	309a	Electrician-Construction and Maintenance	Apprentice 196
197.	309a	Electrician-Construction and Maintenance	Apprentice 197
198.	444B	Utility Arborist	Apprentice 198
199.	434a	Powerline Technician	Apprentice 199
200.	309a	Electrician-Construction and Maintenance	Apprentice 200
201.	309a	Electrician-Construction and Maintenance	Apprentice 201
202.	309a	Electrician-Construction and Maintenance	Apprentice 202
203.	444B	Utility Arborist	Apprentice 203
204.	309a	Electrician-Construction and Maintenance	Apprentice 204
205.	309a	Electrician-Construction and Maintenance	Apprentice 205
206.	309a	Electrician-Construction and Maintenance	Apprentice 206
207.	309a	Electrician-Construction and Maintenance	Apprentice 207
208.	309a	Electrician-Construction and Maintenance	Apprentice 208
209.	444B	Utility Arborist	Apprentice 209
210.	444B	Utility Arborist	Apprentice 210
211.	444B	Utility Arborist	Apprentice 211
212.	444B	Utility Arborist	Apprentice 212
213.	444B	Utility Arborist	Apprentice 213
214.	444B	Utility Arborist	Apprentice 214
215.	444B	Utility Arborist	Apprentice 215
216.	444B	Utility Arborist	Apprentice 216
217.	444B	Utility Arborist	Apprentice 217
218.	444B	Utility Arborist	Apprentice 218
219.	444B	Utility Arborist	Apprentice 219
220.	309a	Electrician-Construction and Maintenance	Apprentice 220
221.	309a	Electrician-Construction and Maintenance	Apprentice 221
222.	309a	Electrician-Construction and Maintenance	Apprentice 222
223.	309a	Electrician-Construction and Maintenance	Apprentice 223
224.	309a	Electrician-Construction and Maintenance	Apprentice 224
225.	309a	Electrician-Construction and Maintenance	Apprentice 225
226.	309a	Electrician-Construction and Maintenance	Apprentice 226
227.	309a	Electrician-Construction and Maintenance	Apprentice 227
228.	309a	Electrician-Construction and Maintenance	Apprentice 228
229.	309a	Electrician-Construction and Maintenance	Apprentice 229
230.	309a	Electrician-Construction and Maintenance	Apprentice 230
231.	309a	Electrician-Construction and Maintenance	Apprentice 231
232.	309a	Electrician-Construction and Maintenance	Apprentice 232
233.	309a	Electrician-Construction and Maintenance	Apprentice 233
234.	309a	Electrician-Construction and Maintenance	Apprentice 234
235.	309a	Electrician-Construction and Maintenance	Apprentice 235
236.	309a	Electrician-Construction and Maintenance	Apprentice 236
237.	309a	Electrician-Construction and Maintenance	Apprentice 237
238.	433a	Industrial Mechanic (Millwright)	Apprentice 238
239.	433a	Industrial Mechanic (Millwright)	Apprentice 239
240.	433a	Industrial Mechanic (Millwright)	Apprentice 240
241.	433a	Industrial Mechanic (Millwright)	Apprentice 241
242.	434a	Powerline Technician	Apprentice 242
243.	309a	Electrician-Construction and Maintenance	Apprentice 243
244.	444B	Utility Arborist	Apprentice 244
245.	434a	Powerline Technician	Apprentice 245
246.	434a	Powerline Technician	Apprentice 246
247.	434a	Powerline Technician	Apprentice 247

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
248.	434a	Powerline Technician	Apprentice 248
249.	434a	Powerline Technician	Apprentice 249
250.	434a	Powerline Technician	Apprentice 250
251.	434a	Powerline Technician	Apprentice 251
252.	309a	Electrician-Construction and Maintenance	Apprentice 252
253.	444b	Utility Arborist	Apprentice 253
254.	434a	Powerline Technician	Apprentice 254
255.	444B	Utility Arborist	Apprentice 255
256.	309a	Electrician-Construction and Maintenance	Apprentice 256
257.	309a	Electrician-Construction and Maintenance	Apprentice 257
258.	309a	Electrician-Construction and Maintenance	Apprentice 258
259.	309a	Electrician-Construction and Maintenance	Apprentice 259
260.	309a	Electrician-Construction and Maintenance	Apprentice 260
261.	309a	Electrician-Construction and Maintenance	Apprentice 261
262.	309a	Electrician-Construction and Maintenance	Apprentice 262
263.	309a	Electrician-Construction and Maintenance	Apprentice 263
264.	309a	Electrician-Construction and Maintenance	Apprentice 264
265.	309a	Electrician-Construction and Maintenance	Apprentice 265
266.	309a	Electrician-Construction and Maintenance	Apprentice 266
267.	444B	Utility Arborist	Apprentice 267
268.	434a	Powerline Technician	Apprentice 268
269.	434a	Powerline Technician	Apprentice 269
270.	434a	Powerline Technician	Apprentice 270
271.	434a	Powerline Technician	Apprentice 271
272.	434a	Powerline Technician	Apprentice 272
273.	434a	Powerline Technician	Apprentice 273
274.	434a	Powerline Technician	Apprentice 274
275.	434a	Powerline Technician	Apprentice 275
276.	434a	Powerline Technician	Apprentice 276
277.	434a	Powerline Technician	Apprentice 277
278.	434a	Powerline Technician	Apprentice 278
279.	434a	Powerline Technician	Apprentice 279
280.	434a	Powerline Technician	Apprentice 280
281.	434a	Powerline Technician	Apprentice 281
282.	434a	Powerline Technician	Apprentice 282
283.	434a	Powerline Technician	Apprentice 283
284.	309a	Electrician-Construction and Maintenance	Apprentice 284
285.	403a	General Carpenter	Apprentice 285
286.	444B	Utility Arborist	Apprentice 286
287.	444B	Utility Arborist	Apprentice 287
288.	444B	Utility Arborist	Apprentice 288
289.	444B	Utility Arborist	Apprentice 289
290.	444B	Utility Arborist	Apprentice 290
291.	444B	Utility Arborist	Apprentice 291
292.	444B	Utility Arborist	Apprentice 292
293.	444B	Utility Arborist	Apprentice 293
294.	444B	Utility Arborist	Apprentice 294
295.	444B	Utility Arborist	Apprentice 295
296.	434a	Powerline Technician	Apprentice 296
297.	434a	Powerline Technician	Apprentice 297
298.	434a	Powerline Technician	Apprentice 298
299.	434a	Powerline Technician	Apprentice 299
300.	434a	Powerline Technician	Apprentice 300
301.	434a	Powerline Technician	Apprentice 301
302.	434a	Powerline Technician	Apprentice 302

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
303.	434a	Powerline Technician	Apprentice 303
304.	434a	Powerline Technician	Apprentice 304
305.	434a	Powerline Technician	Apprentice 305
306.	434a	Powerline Technician	Apprentice 306
307.	434a	Powerline Technician	Apprentice 307
308.	434a	Powerline Technician	Apprentice 308
309.	434a	Powerline Technician	Apprentice 309
310.	434a	Powerline Technician	Apprentice 310
311.	434a	Powerline Technician	Apprentice 311
312.	434a	Powerline Technician	Apprentice 312
313.	309a	Electrician-Construction and Maintenance	Apprentice 313
314.	444B	Utility Arborist	Apprentice 314
315.	309a	Electrician-Construction and Maintenance	Apprentice 315
316.	309a	Electrician-Construction and Maintenance	Apprentice 316
317.	309a	Electrician-Construction and Maintenance	Apprentice 317
318.	309a	Electrician-Construction and Maintenance	Apprentice 318
319.	309a	Electrician-Construction and Maintenance	Apprentice 319
320.	309a	Electrician-Construction and Maintenance	Apprentice 320
321.	309a	Electrician-Construction and Maintenance	Apprentice 321
322.	434a	Powerline Technician	Apprentice 322
323.	434a	Powerline Technician	Apprentice 323
324.	434a	Powerline Technician	Apprentice 324
325.	434a	Powerline Technician	Apprentice 325
326.	434a	Powerline Technician	Apprentice 326
327.	434a	Powerline Technician	Apprentice 327
328.	434a	Powerline Technician	Apprentice 328
329.	434a	Powerline Technician	Apprentice 329
330.	434a	Powerline Technician	Apprentice 330
331.	434a	Powerline Technician	Apprentice 331
332.	434a	Powerline Technician	Apprentice 332
333.	434a	Powerline Technician	Apprentice 333
334.	434a	Powerline Technician	Apprentice 334
335.	434a	Powerline Technician	Apprentice 335
336.	434a	Powerline Technician	Apprentice 336
337.	434a	Powerline Technician	Apprentice 337
338.	309a	Electrician-Construction and Maintenance	Apprentice 338
339.	309a	Electrician-Construction and Maintenance	Apprentice 339
340.	434a	Powerline Technician	Apprentice 340
341.	434a	Powerline Technician	Apprentice 341
342.	434a	Powerline Technician	Apprentice 342
343.	434a	Powerline Technician	Apprentice 343
344.	434a	Powerline Technician	Apprentice 344
345.	434a	Powerline Technician	Apprentice 345
346.	434a	Powerline Technician	Apprentice 346
347.	434a	Powerline Technician	Apprentice 347
348.	434a	Powerline Technician	Apprentice 348
349.	434a	Powerline Technician	Apprentice 349
350.	434a	Powerline Technician	Apprentice 350
351.	434a	Powerline Technician	Apprentice 351
352.	434a	Powerline Technician	Apprentice 352
353.	434a	Powerline Technician	Apprentice 353
354.	434a	Powerline Technician	Apprentice 354
355.	434a	Powerline Technician	Apprentice 355
356.	310t	Truck And Coach Technician	Apprentice 356
357.	310t	Truck And Coach Technician	Apprentice 357

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
358.	310t	Truck And Coach Technician	Apprentice 358
359.	310t	Truck And Coach Technician	Apprentice 359
360.	310t	Truck And Coach Technician	Apprentice 360
361.	310t	Truck And Coach Technician	Apprentice 361
362.	444B	Utility Arborist	Apprentice 362
363.	444B	Utility Arborist	Apprentice 363
364.	309a	Electrician-Construction and Maintenance	Apprentice 364
365.	309a	Electrician-Construction and Maintenance	Apprentice 365
366.	309a	Electrician-Construction and Maintenance	Apprentice 366
367.	309a	Electrician-Construction and Maintenance	Apprentice 367
368.	309a	Electrician-Construction and Maintenance	Apprentice 368
369.	309a	Electrician-Construction and Maintenance	Apprentice 369
370.	309a	Electrician-Construction and Maintenance	Apprentice 370
371.	309a	Electrician-Construction and Maintenance	Apprentice 371
372.	309a	Electrician-Construction and Maintenance	Apprentice 372
373.	309a	Electrician-Construction and Maintenance	Apprentice 373
374.	310t	Truck And Coach Technician	Apprentice 374
375.	434a	Powerline Technician	Apprentice 375
376.	434a	Powerline Technician	Apprentice 376
377.	434a	Powerline Technician	Apprentice 377
378.	434a	Powerline Technician	Apprentice 378
379.	434a	Powerline Technician	Apprentice 379
380.	434a	Powerline Technician	Apprentice 380
381.	434a	Powerline Technician	Apprentice 381
382.	434a	Powerline Technician	Apprentice 382
383.	434a	Powerline Technician	Apprentice 383
384.	434a	Powerline Technician	Apprentice 384
385.	434a	Powerline Technician	Apprentice 385
386.	434a	Powerline Technician	Apprentice 386
387.	434a	Powerline Technician	Apprentice 387
388.	434a	Powerline Technician	Apprentice 388
389.	309a	Electrician-Construction and Maintenance	Apprentice 389
390.	309a	Electrician-Construction and Maintenance	Apprentice 390
391.	434a	Powerline Technician	Apprentice 391
392.	434a	Powerline Technician	Apprentice 392
393.	434a	Powerline Technician	Apprentice 393
394.	434a	Powerline Technician	Apprentice 394
395.	434a	Powerline Technician	Apprentice 395
396.	434a	Powerline Technician	Apprentice 396
397.	434a	Powerline Technician	Apprentice 397
398.	434a	Powerline Technician	Apprentice 398
399.	434a	Powerline Technician	Apprentice 399
400.	434a	Powerline Technician	Apprentice 400
401.	434a	Powerline Technician	Apprentice 401
402.	434a	Powerline Technician	Apprentice 402
403.	434a	Powerline Technician	Apprentice 403
404.	434a	Powerline Technician	Apprentice 404
405.	434a	Powerline Technician	Apprentice 405
406.	434a	Powerline Technician	Apprentice 406
407.	434a	Powerline Technician	Apprentice 407
408.	434a	Powerline Technician	Apprentice 408
409.	434a	Powerline Technician	Apprentice 409
410.	434a	Powerline Technician	Apprentice 410
411.	434a	Powerline Technician	Apprentice 411
412.	434a	Powerline Technician	Apprentice 412

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
413.	434a	Powerline Technician	Apprentice 413
414.	434a	Powerline Technician	Apprentice 414
415.	434a	Powerline Technician	Apprentice 415
416.	434a	Powerline Technician	Apprentice 416
417.	434a	Powerline Technician	Apprentice 417
418.	434a	Powerline Technician	Apprentice 418
419.	434a	Powerline Technician	Apprentice 419
420.	434a	Powerline Technician	Apprentice 420
421.	434a	Powerline Technician	Apprentice 421
422.	434a	Powerline Technician	Apprentice 422
423.	434a	Powerline Technician	Apprentice 423
424.	434a	Powerline Technician	Apprentice 424
425.	434a	Powerline Technician	Apprentice 425
426.	434a	Powerline Technician	Apprentice 426
427.	434a	Powerline Technician	Apprentice 427
428.	434a	Powerline Technician	Apprentice 428
429.	434a	Powerline Technician	Apprentice 429
430.	434a	Powerline Technician	Apprentice 430
431.	434a	Powerline Technician	Apprentice 431
432.	434a	Powerline Technician	Apprentice 432
433.	434a	Powerline Technician	Apprentice 433
434.	434a	Powerline Technician	Apprentice 434
435.	434a	Powerline Technician	Apprentice 435
436.	434a	Powerline Technician	Apprentice 436
437.	434a	Powerline Technician	Apprentice 437
438.	434a	Powerline Technician	Apprentice 438
439.	434a	Powerline Technician	Apprentice 439
440.	434a	Powerline Technician	Apprentice 440
441.	434a	Powerline Technician	Apprentice 441
442.	434a	Powerline Technician	Apprentice 442
443.	434a	Powerline Technician	Apprentice 443
444.	434a	Powerline Technician	Apprentice 444
445.	434a	Powerline Technician	Apprentice 445
446.	434a	Powerline Technician	Apprentice 446
447.	434a	Powerline Technician	Apprentice 447
448.	434a	Powerline Technician	Apprentice 448
449.	434a	Powerline Technician	Apprentice 449
450.	434a	Powerline Technician	Apprentice 450
451.	434a	Powerline Technician	Apprentice 451
452.	434a	Powerline Technician	Apprentice 452
453.	309a	Electrician-Construction and Maintenance	Apprentice 453
454.	309a	Electrician-Construction and Maintenance	Apprentice 454
455.	309a	Electrician-Construction and Maintenance	Apprentice 455
456.	434a	Powerline Technician	Apprentice 456
457.	434a	Powerline Technician	Apprentice 457
458.	434a	Powerline Technician	Apprentice 458
459.	434a	Powerline Technician	Apprentice 459
460.	434a	Powerline Technician	Apprentice 460
461.	434a	Powerline Technician	Apprentice 461
462.	434a	Powerline Technician	Apprentice 462
463.	434a	Powerline Technician	Apprentice 463
464.	434a	Powerline Technician	Apprentice 464
465.	434a	Powerline Technician	Apprentice 465
466.	403a	General Carpenter	Apprentice 466
467.	309a	Electrician-Construction and Maintenance	Apprentice 467

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
468.	309a	Electrician-Construction and Maintenance	Apprentice 468
469.	309a	Electrician-Construction and Maintenance	Apprentice 469
470.	309a	Electrician-Construction and Maintenance	Apprentice 470
471.	309a	Electrician-Construction and Maintenance	Apprentice 471
472.	309a	Electrician-Construction and Maintenance	Apprentice 472
473.	309a	Electrician-Construction and Maintenance	Apprentice 473
474.	309a	Electrician-Construction and Maintenance	Apprentice 474
475.	309a	Electrician-Construction and Maintenance	Apprentice 475
476.	309a	Electrician-Construction and Maintenance	Apprentice 476
477.	309a	Electrician-Construction and Maintenance	Apprentice 477
478.	309a	Electrician-Construction and Maintenance	Apprentice 478
479.	309a	Electrician-Construction and Maintenance	Apprentice 479
480.	309a	Electrician-Construction and Maintenance	Apprentice 480
481.	309a	Electrician-Construction and Maintenance	Apprentice 481
482.	309a	Electrician-Construction and Maintenance	Apprentice 482
483.	433a	Industrial Mechanic (Millwright)	Apprentice 483
484.	433a	Industrial Mechanic (Millwright)	Apprentice 484
485.	434a	Powerline Technician	Apprentice 485
486.	434a	Powerline Technician	Apprentice 486
487.	434a	Powerline Technician	Apprentice 487
488.	434a	Powerline Technician	Apprentice 488
489.	434a	Powerline Technician	Apprentice 489
490.	434a	Powerline Technician	Apprentice 490
491.	434a	Powerline Technician	Apprentice 491
492.	434a	Powerline Technician	Apprentice 492
493.	434a	Powerline Technician	Apprentice 493
494.	434a	Powerline Technician	Apprentice 494
495.	309a	Electrician-Construction and Maintenance	Apprentice 495
496.	309a	Electrician-Construction and Maintenance	Apprentice 496
497.	309a	Electrician-Construction and Maintenance	Apprentice 497
498.	309a	Electrician-Construction and Maintenance	Apprentice 498
499.	309a	Electrician-Construction and Maintenance	Apprentice 499
500.	310t	Truck And Coach Technician	Apprentice 500
501.	310t	Truck And Coach Technician	Apprentice 501
502.	444B	Utility Arborist	Apprentice 502
503.	444B	Utility Arborist	Apprentice 503
504.	444B	Utility Arborist	Apprentice 504
505.	444B	Utility Arborist	Apprentice 505
506.	444B	Utility Arborist	Apprentice 506
507.	444B	Utility Arborist	Apprentice 507
508.	434a	Powerline Technician	Apprentice 508
509.	434a	Powerline Technician	Apprentice 509
510.	434a	Powerline Technician	Apprentice 510
511.	434a	Powerline Technician	Apprentice 511
512.	434a	Powerline Technician	Apprentice 512
513.	434a	Powerline Technician	Apprentice 513
514.	434a	Powerline Technician	Apprentice 514
515.	434a	Powerline Technician	Apprentice 515
516.	434a	Powerline Technician	Apprentice 516
517.	434a	Powerline Technician	Apprentice 517
518.	434a	Powerline Technician	Apprentice 518
519.	309a	Electrician-Construction and Maintenance	Apprentice 519
520.	309a	Electrician-Construction and Maintenance	Apprentice 520
521.	444B	Utility Arborist	Apprentice 521
522.	444B	Utility Arborist	Apprentice 522

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
523.	444B	Utility Arborist	Apprentice 523
524.	444B	Utility Arborist	Apprentice 524
525.	444B	Utility Arborist	Apprentice 525
526.	444B	Utility Arborist	Apprentice 526
527.	444B	Utility Arborist	Apprentice 527
528.	444B	Utility Arborist	Apprentice 528
529.	444B	Utility Arborist	Apprentice 529
530.	444B	Utility Arborist	Apprentice 530
531.	444B	Utility Arborist	Apprentice 531
532.	444B	Utility Arborist	Apprentice 532
533.	444B	Utility Arborist	Apprentice 533
534.	309a	Electrician-Construction and Maintenance	Apprentice 534
535.	309a	Electrician-Construction and Maintenance	Apprentice 535
536.	309a	Electrician-Construction and Maintenance	Apprentice 536
537.	309a	Electrician-Construction and Maintenance	Apprentice 537
538.	309a	Electrician-Construction and Maintenance	Apprentice 538
539.	309a	Electrician-Construction and Maintenance	Apprentice 539
540.	309a	Electrician-Construction and Maintenance	Apprentice 540
541.	309a	Electrician-Construction and Maintenance	Apprentice 541
542.	309a	Electrician-Construction and Maintenance	Apprentice 542
543.	309a	Electrician-Construction and Maintenance	Apprentice 543
544.	309a	Electrician-Construction and Maintenance	Apprentice 544
545.	309a	Electrician-Construction and Maintenance	Apprentice 545
546.	309a	Electrician-Construction and Maintenance	Apprentice 546
547.	434a	Powerline Technician	Apprentice 547
548.	434a	Powerline Technician	Apprentice 548
549.	434a	Powerline Technician	Apprentice 549
550.	434a	Powerline Technician	Apprentice 550
551.	434a	Powerline Technician	Apprentice 551
552.	434a	Powerline Technician	Apprentice 552
553.	434a	Powerline Technician	Apprentice 553
554.	434a	Powerline Technician	Apprentice 554
555.	434a	Powerline Technician	Apprentice 555
556.	434a	Powerline Technician	Apprentice 556
557.	434a	Powerline Technician	Apprentice 557
558.	434a	Powerline Technician	Apprentice 558
559.	434a	Powerline Technician	Apprentice 559
560.	434a	Powerline Technician	Apprentice 560
561.	403a	General Carpenter	Apprentice 561
562.	444b	Utility Arborist	Apprentice 562
563.	444B	Utility Arborist	Apprentice 563
564.	444B	Utility Arborist	Apprentice 564
565.	444B	Utility Arborist	Apprentice 565
566.	444B	Utility Arborist	Apprentice 566
567.	444B	Utility Arborist	Apprentice 567
568.	444B	Utility Arborist	Apprentice 568
569.	444B	Utility Arborist	Apprentice 569
570.	444B	Utility Arborist	Apprentice 570
571.	444B	Utility Arborist	Apprentice 571
572.	444B	Utility Arborist	Apprentice 572
573.	444B	Utility Arborist	Apprentice 573
574.	444B	Utility Arborist	Apprentice 574
575.	444b	Utility Arborist	Apprentice 575
576.	444B	Utility Arborist	Apprentice 576
577.	434a	Powerline Technician	Apprentice 577

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
578.	434a	Powerline Technician	Apprentice 578
579.	434a	Powerline Technician	Apprentice 579
580.	434a	Powerline Technician	Apprentice 580
581.	434a	Powerline Technician	Apprentice 581
582.	434a	Powerline Technician	Apprentice 582
583.	434a	Powerline Technician	Apprentice 583
584.	434a	Powerline Technician	Apprentice 584
585.	434a	Powerline Technician	Apprentice 585
586.	434a	Powerline Technician	Apprentice 586
587.	434a	Powerline Technician	Apprentice 587
588.	434a	Powerline Technician	Apprentice 588
589.	434a	Powerline Technician	Apprentice 589
590.	434a	Powerline Technician	Apprentice 590
591.	434a	Powerline Technician	Apprentice 591
592.	434a	Powerline Technician	Apprentice 592
593.	309a	Electrician-Construction and Maintenance	Apprentice 593
594.	309a	Electrician-Construction and Maintenance	Apprentice 594
595.	309a	Electrician-Construction and Maintenance	Apprentice 595
596.	309a	Electrician-Construction and Maintenance	Apprentice 596
597.	309a	Electrician-Construction and Maintenance	Apprentice 597
598.	309a	Electrician-Construction and Maintenance	Apprentice 598
599.	309a	Electrician-Construction and Maintenance	Apprentice 599
600.	309a	Electrician-Construction and Maintenance	Apprentice 600
601.	309a	Electrician-Construction and Maintenance	Apprentice 601
602.	309a	Electrician-Construction and Maintenance	Apprentice 602
603.	309a	Electrician-Construction and Maintenance	Apprentice 603
604.	309a	Electrician-Construction and Maintenance	Apprentice 604
605.	310t	Truck And Coach Technician	Apprentice 605
606.	310t	Truck And Coach Technician	Apprentice 606
607.	310t	Truck And Coach Technician	Apprentice 607
608.	309a	Electrician-Construction and Maintenance	Apprentice 608
609.	434a	Powerline Technician	Apprentice 609
610.	434a	Powerline Technician	Apprentice 610
611.	434a	Powerline Technician	Apprentice 611
612.	434a	Powerline Technician	Apprentice 612
613.	434a	Powerline Technician	Apprentice 613
614.	434a	Powerline Technician	Apprentice 614
615.	434a	Powerline Technician	Apprentice 615
616.	434a	Powerline Technician	Apprentice 616
617.	434a	Powerline Technician	Apprentice 617
618.	434a	Powerline Technician	Apprentice 618
619.	434a	Powerline Technician	Apprentice 619
620.	434a	Powerline Technician	Apprentice 620
621.	434a	Powerline Technician	Apprentice 621
622.	434a	Powerline Technician	Apprentice 622
623.	434a	Powerline Technician	Apprentice 623
624.	434a	Powerline Technician	Apprentice 624
625.	434a	Powerline Technician	Apprentice 625
626.	309a	Electrician-Construction and Maintenance	Apprentice 626
627.	309a	Electrician-Construction and Maintenance	Apprentice 627
628.	309a	Electrician-Construction and Maintenance	Apprentice 628
629.	309a	Electrician-Construction and Maintenance	Apprentice 629
630.	434a	Powerline Technician	Apprentice 630
631.	434a	Powerline Technician	Apprentice 631
632.	434a	Powerline Technician	Apprentice 632

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
633.	434a	Powerline Technician	Apprentice 633
634.	434a	Powerline Technician	Apprentice 634
635.	434a	Powerline Technician	Apprentice 635
636.	434a	Powerline Technician	Apprentice 636
637.	434a	Powerline Technician	Apprentice 637
638.	434a	Powerline Technician	Apprentice 638
639.	434a	Powerline Technician	Apprentice 639
640.	434a	Powerline Technician	Apprentice 640
641.	434a	Powerline Technician	Apprentice 641
642.	434a	Powerline Technician	Apprentice 642
643.	434a	Powerline Technician	Apprentice 643
644.	434a	Powerline Technician	Apprentice 644
645.	434a	Powerline Technician	Apprentice 645
646.	434a	Powerline Technician	Apprentice 646
647.	309a	Electrician-Construction and Maintenance	Apprentice 647
648.	309a	Electrician-Construction and Maintenance	Apprentice 648
649.	309a	Electrician-Construction and Maintenance	Apprentice 649
650.	309a	Electrician-Construction and Maintenance	Apprentice 650
651.	309a	Electrician-Construction and Maintenance	Apprentice 651
652.	309a	Electrician-Construction and Maintenance	Apprentice 652
653.	309a	Electrician-Construction and Maintenance	Apprentice 653
654.	309a	Electrician-Construction and Maintenance	Apprentice 654
655.	309a	Electrician-Construction and Maintenance	Apprentice 655
656.	309a	Electrician-Construction and Maintenance	Apprentice 656
657.	309a	Electrician-Construction and Maintenance	Apprentice 657
658.	309a	Electrician-Construction and Maintenance	Apprentice 658
659.	434a	Powerline Technician	Apprentice 659
660.	434a	Powerline Technician	Apprentice 660
661.	434a	Powerline Technician	Apprentice 661
662.	434a	Powerline Technician	Apprentice 662
663.	434a	Powerline Technician	Apprentice 663
664.	434a	Powerline Technician	Apprentice 664
665.	434a	Powerline Technician	Apprentice 665
666.	434a	Powerline Technician	Apprentice 666
667.	434a	Powerline Technician	Apprentice 667
668.	434a	Powerline Technician	Apprentice 668
669.	309a	Electrician-Construction and Maintenance	Apprentice 669
670.	309a	Electrician-Construction and Maintenance	Apprentice 670
671.	444B	Utility Arborist	Apprentice 671
672.	444B	Utility Arborist	Apprentice 672
673.	444BN	Utility Arborist	Apprentice 673
674.	444B	Utility Arborist	Apprentice 674
675.	444B	Utility Arborist	Apprentice 675
676.	444B	Utility Arborist	Apprentice 676
677.	444B	Utility Arborist	Apprentice 677
678.	444B	Utility Arborist	Apprentice 678
679.	444B	Utility Arborist	Apprentice 679
680.	444B	Utility Arborist	Apprentice 680
681.	444B	Utility Arborist	Apprentice 681
682.	444B	Utility Arborist	Apprentice 682
683.	444B	Utility Arborist	Apprentice 683
684.	444B	Utility Arborist	Apprentice 684
685.	444B	Utility Arborist	Apprentice 685
686.	444B	Utility Arborist	Apprentice 686
687.	444B	Utility Arborist	Apprentice 687

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
688.	444B	Utility Arborist	Apprentice 688
689.	444B	Utility Arborist	Apprentice 689
690.	444B	Utility Arborist	Apprentice 690
691.	444B	Utility Arborist	Apprentice 691
692.	434a	Powerline Technician	Apprentice 692
693.	434a	Powerline Technician	Apprentice 693
694.	434a	Powerline Technician	Apprentice 694
695.	434a	Powerline Technician	Apprentice 695
696.	434a	Powerline Technician	Apprentice 696
697.	434a	Powerline Technician	Apprentice 697
698.	434a	Powerline Technician	Apprentice 698
699.	434a	Powerline Technician	Apprentice 699
700.	434a	Powerline Technician	Apprentice 700
701.	434a	Powerline Technician	Apprentice 701
702.	434a	Powerline Technician	Apprentice 702
703.	310t	Truck And Coach Technician	Apprentice 703
704.	310t	Truck And Coach Technician	Apprentice 704
705.	434a	Powerline Technician	Apprentice 705
706.	434a	Powerline Technician	Apprentice 706
707.	434a	Powerline Technician	Apprentice 707
708.	434a	Powerline Technician	Apprentice 708
709.	434a	Powerline Technician	Apprentice 709
710.	434a	Powerline Technician	Apprentice 710
711.	434a	Powerline Technician	Apprentice 711
712.	434a	Powerline Technician	Apprentice 712
713.	434a	Powerline Technician	Apprentice 713
714.	434a	Powerline Technician	Apprentice 714
715.	434a	Powerline Technician	Apprentice 715
716.	434a	Powerline Technician	Apprentice 716
717.	434a	Powerline Technician	Apprentice 717
718.	434a	Powerline Technician	Apprentice 718
719.	309a	Electrician-Construction and Maintenance	Apprentice 719
720.	309a	Electrician-Construction and Maintenance	Apprentice 720
721.	309a	Electrician-Construction and Maintenance	Apprentice 721
722.	444B	Utility Arborist	Apprentice 722
723.	444B	Utility Arborist	Apprentice 723
724.	444B	Utility Arborist	Apprentice 724
725.	444B	Utility Arborist	Apprentice 725
726.	444B	Utility Arborist	Apprentice 726
727.	444B	Utility Arborist	Apprentice 727
728.	444B	Utility Arborist	Apprentice 728
729.	444B	Utility Arborist	Apprentice 729
730.	444B	Utility Arborist	Apprentice 730
731.	444B	Utility Arborist	Apprentice 731
732.	444B	Utility Arborist	Apprentice 732
733.	444B	Utility Arborist	Apprentice 733
734.	444B	Utility Arborist	Apprentice 734
735.	444B	Utility Arborist	Apprentice 735
736.	309a	Electrician-Construction and Maintenance	Apprentice 736
737.	309a	Electrician-Construction and Maintenance	Apprentice 737
738.	309a	Electrician-Construction and Maintenance	Apprentice 738
739.	309a	Electrician-Construction and Maintenance	Apprentice 739
740.	309a	Electrician-Construction and Maintenance	Apprentice 740
741.	309a	Electrician-Construction and Maintenance	Apprentice 741
742.	309a	Electrician-Construction and Maintenance	Apprentice 742

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
743.	309a	Electrician-Construction and Maintenance	Apprentice 743
744.	309a	Electrician-Construction and Maintenance	Apprentice 744
745.	309a	Electrician-Construction and Maintenance	Apprentice 745
746.	309a	Electrician-Construction and Maintenance	Apprentice 746
747.	309a	Electrician-Construction and Maintenance	Apprentice 747
748.	309a	Electrician-Construction and Maintenance	Apprentice 748
749.	309a	Electrician-Construction and Maintenance	Apprentice 749
750.	309a	Electrician-Construction and Maintenance	Apprentice 750
751.	434a	Powerline Technician	Apprentice 751
752.	434a	Powerline Technician	Apprentice 752
753.	434a	Powerline Technician	Apprentice 753
754.	434a	Powerline Technician	Apprentice 754
755.	434a	Powerline Technician	Apprentice 755
756.	434a	Powerline Technician	Apprentice 756
757.	434a	Powerline Technician	Apprentice 757
758.	434a	Powerline Technician	Apprentice 758
759.	434a	Powerline Technician	Apprentice 759
760.	434a	Powerline Technician	Apprentice 760
761.	434a	Powerline Technician	Apprentice 761

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	AG9782	2009-01-05	2009-01-05	2013-01-05
2.	PB0246	2009-01-12	2009-01-12	2013-01-12
3.	PA3471	2009-01-12	2009-01-12	2013-01-12
4.	PB1924	2009-01-12	2009-06-04	2013-01-12
5.	PB0244	2009-01-12	2009-07-28	2013-01-12
6.	AD9948	2009-01-12	2009-01-12	2013-01-12
7.	PE3498	2013-02-25	2013-02-25	2013-03-13
8.	AD9900	2009-10-19	2009-10-19	2013-01-22
9.	468652	2011-04-26	2011-04-26	2013-01-23
10.	PF9082	2012-04-12	2012-04-12	2013-01-25
11.	PC1278	2009-03-26	2009-03-26	2013-01-29
12.	AG9928	2009-10-19	2009-10-19	2013-01-30
13.	AG9945	2009-10-19	2009-10-19	2013-02-01
14.	A78556	2012-05-31	2012-05-31	2013-02-01
15.	PB1930	2009-02-02	2009-02-02	2013-02-02
16.	PC2634	2009-02-02	2009-02-02	2013-02-02
17.	PB1921	2009-02-02	2009-02-02	2013-02-02
18.	PC2632	2009-02-02	2009-02-02	2013-02-02
19.	PC2635	2009-02-02	2009-02-02	2013-02-02
20.	PB0245	2009-02-02	2009-02-02	2013-02-02
21.	PB1925	2009-02-02	2009-02-02	2013-02-02
22.	PB1929	2009-02-02	2009-02-02	2013-02-02
23.	PB1928	2009-02-02	2009-02-02	2013-02-02
24.	PC2631	2009-02-02	2009-02-02	2013-02-02
25.	PB1931	2009-02-02	2009-02-02	2013-02-02
26.	PC2633	2009-02-02	2009-02-02	2013-02-02
27.	PB1926	2009-02-02	2009-02-02	2013-02-02
28.	PA4078	2009-02-02	2009-02-02	2013-02-02
29.	PB1932	2009-02-02	2009-02-02	2013-02-02

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
30.	PC1260	2009-02-02	2009-02-02	2013-02-02
31.	PC1259	2009-02-02	2009-02-02	2013-02-02
32.	A86038	2009-10-29	2009-10-29	2013-02-05
33.	PD3347	2011-03-10	2013-01-01	2013-12-31
34.	AG9954	2009-08-31	2009-08-31	2013-02-20
35.	AG9962	2009-08-31	2009-08-31	2013-02-21
36.	AG9796	2009-07-13	2009-07-13	2013-02-22
37.	PC2643	2009-02-23	2009-02-23	2013-02-23
38.	PC2649	2009-02-23	2009-02-23	2013-02-23
39.	PC2648	2009-02-23	2009-02-23	2013-02-23
40.	PC2637	2009-02-23	2009-02-23	2013-02-23
41.	PC2646	2009-02-23	2009-02-23	2013-02-23
42.	PC2641	2009-02-23	2009-02-23	2013-02-23
43.	PA6247	2009-02-23	2009-02-23	2013-02-23
44.	PC2647	2009-02-23	2009-02-23	2013-02-23
45.	PC2645	2009-02-23	2009-02-23	2013-02-23
46.	PA4122	2009-02-23	2009-02-23	2013-02-23
47.	PC2642	2009-02-23	2009-02-23	2013-02-23
48.	PC2650	2009-02-23	2009-02-23	2013-02-23
49.	PA6238	2009-02-23	2009-02-23	2013-02-23
50.	PC2638	2009-02-23	2009-02-23	2013-02-23
51.	PC2651	2009-02-23	2009-02-23	2013-02-23
52.	PC2639	2009-02-23	2009-02-23	2013-02-23
53.	PC2644	2009-02-23	2009-02-23	2013-02-23
54.	PC2665	2009-03-16	2009-03-16	2013-02-25
55.	AG9944	2009-10-19	2009-10-19	2013-02-25
56.	AG9931	2009-10-19	2009-10-19	2013-03-01
57.	PF9085	2012-04-12	2012-04-12	2013-03-11
58.	D24149	2012-05-31	2012-05-31	2013-03-11
59.	BA2655	2013-10-21	2013-10-21	2013-12-31
60.	BC2659	2013-10-21	2013-10-21	2013-12-31
61.	PA4079	2009-05-25	2009-05-25	2013-03-14
62.	PC2658	2009-03-16	2009-03-16	2013-03-16
63.	PC2659	2009-03-16	2009-03-16	2013-03-16
64.	PC2662	2009-03-16	2009-03-16	2013-03-16
65.	PC2654	2009-03-16	2009-03-16	2013-03-16
66.	PC2663	2009-03-16	2009-03-16	2013-03-16
67.	PC2657	2009-03-16	2009-03-16	2013-03-16
68.	PC2656	2009-03-16	2009-03-16	2013-03-16
69.	PC2661	2009-03-16	2009-03-16	2013-03-16
70.	PC2653	2009-03-16	2009-03-16	2013-03-16
71.	PC2655	2009-03-16	2009-03-16	2013-03-16
72.	PC2652	2009-03-16	2009-03-16	2013-03-16
73.	BA2658	2013-10-17	2013-10-17	2013-12-31
74.	BA2656	2013-10-17	2013-10-17	2013-12-31
75.	BE0780	2013-10-17	2013-10-17	2013-12-31
76.	BA2657	2013-10-17	2013-10-17	2013-12-31
77.	BC2646	2013-10-17	2013-10-17	2013-12-31
78.	PD8720	2009-05-25	2009-05-25	2013-03-20
79.	PD1197	2010-01-11	2010-01-11	2013-03-22
80.	PC1274	2009-03-26	2009-03-26	2013-03-26
81.	PC1269	2009-03-26	2009-03-26	2013-03-26
82.	PC1270	2009-03-26	2009-03-26	2013-03-26

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
83.	PC1273	2009-03-26	2009-03-26	2013-03-26
84.	PC1279	2009-03-26	2009-03-26	2013-03-26
85.	PA1238	2009-03-26	2009-03-26	2013-03-26
86.	PC1268	2009-03-26	2009-03-26	2013-03-26
87.	PC1272	2009-03-26	2009-03-26	2013-03-26
88.	PC1282	2009-03-30	2009-03-30	2013-03-30
89.	101325A	2013-09-19	2013-09-19	2013-12-31
90.	BE0774	2013-08-01	2013-08-01	2013-10-30
91.	PA1335	2013-09-19	2013-09-19	2013-12-31
92.	PE6959	2013-09-19	2013-09-19	2013-12-31
93.	BC2648	2013-09-19	2013-09-19	2013-12-31
94.	BC2647	2013-09-19	2013-09-19	2013-12-31
95.	BC2643	2013-09-19	2013-09-19	2013-12-31
96.	PC2671	2009-04-20	2009-04-20	2013-04-18
97.	PD8725	2009-05-25	2009-05-25	2013-04-18
98.	AG9935	2009-10-19	2009-10-19	2013-04-18
99.	PD8712	2009-04-20	2009-04-20	2013-04-20
100.	PC2679	2009-04-20	2009-04-20	2013-04-20
101.	PC2678	2009-04-20	2009-04-20	2013-04-20
102.	PC2672	2009-04-20	2009-04-20	2013-04-20
103.	PD8714	2009-04-20	2009-04-20	2013-04-20
104.	PC2677	2009-04-20	2009-04-20	2013-04-20
105.	PD8711	2009-04-20	2009-04-20	2013-04-20
106.	PC2675	2009-04-20	2009-04-20	2013-04-20
107.	PC2673	2009-04-20	2009-04-20	2013-04-20
108.	PD8713	2009-04-20	2009-04-20	2013-04-20
109.	PC2674	2009-04-20	2009-04-20	2013-04-20
110.	PC2666	2009-04-20	2009-04-20	2013-04-20
111.	PC2667	2009-04-20	2009-04-20	2013-04-20
112.	PG4569	2011-05-30	2011-05-30	2013-04-22
113.	BA3538	2013-09-09	2013-09-09	2013-12-31
114.	BA3542	2013-09-09	2013-09-09	2013-12-31
115.	BA3543	2013-09-09	2013-09-09	2013-12-31
116.	BA3536	2013-09-09	2013-09-09	2013-12-31
117.	BA3535	2013-09-09	2013-09-09	2013-12-31
118.	BA3537	2013-09-09	2013-09-09	2013-12-31
119.	BA3541	2013-09-09	2013-09-09	2013-12-31
120.	BA3540	2013-09-09	2013-09-09	2013-12-31
121.	BA3534	2013-09-09	2013-09-09	2013-12-31
122.	BA3533	2013-09-09	2013-09-09	2013-12-31
123.	BA3539	2013-09-09	2013-09-09	2013-12-31
124.	BA3544	2013-09-09	2013-09-09	2013-12-31
125.	AG9939	2009-10-19	2009-10-19	2013-04-30
126.	AG9952	2009-08-31	2009-08-31	2013-05-02
127.	PC6743	2013-06-27	2013-06-27	2013-11-01
128.	PF8806	2013-08-26	2013-08-26	2013-12-31
129.	PD8837	2009-06-01	2009-06-01	2013-05-10
130.	CA2225	2013-08-22	2013-08-22	2013-12-31
131.	78521	2012-08-23	2012-08-23	2013-05-16
132.	PD3371	2013-06-27	2013-06-27	2013-11-14
133.	BC2654	2013-08-15	2013-08-15	2013-12-31
134.	BC2640	2013-08-15	2013-08-15	2013-12-31
135.	PA6597	2011-05-30	2011-05-30	2013-05-23

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
136.	PD8717	2009-05-25	2009-05-25	2013-05-25
137.	PD8721	2009-05-25	2009-05-25	2013-05-25
138.	PD8718	2009-05-25	2009-05-25	2013-05-25
139.	PD8726	2009-05-25	2009-05-25	2013-05-25
140.	PD8724	2009-05-25	2009-05-25	2013-05-25
141.	PD8716	2009-05-25	2009-05-25	2013-05-25
142.	PD8715	2009-05-25	2009-05-25	2013-05-25
143.	PD8719	2009-05-25	2009-05-25	2013-05-25
144.	PD8722	2009-05-25	2009-05-25	2013-05-25
145.	PD8723	2009-05-25	2009-05-25	2013-05-25
146.	PD8729	2009-05-25	2009-05-25	2013-05-25
147.	PD8730	2009-06-01	2009-06-01	2013-05-27
148.	PD8871	2009-07-13	2009-07-13	2013-05-27
149.	AG9792	2009-07-13	2009-07-13	2013-05-30
150.	PC2797	2009-06-01	2009-06-01	2013-06-01
151.	PC9747	2009-06-01	2009-06-01	2013-06-01
152.	PD8830	2009-06-01	2009-06-01	2013-06-01
153.	PD8838	2009-06-01	2009-06-01	2013-06-01
154.	PC2799	2009-06-01	2009-06-01	2013-06-01
155.	PC7114	2009-06-01	2009-06-01	2013-06-01
156.	PD8833	2009-06-01	2009-06-01	2013-06-01
157.	PD8842	2009-06-01	2009-06-01	2013-06-01
158.	PC2804	2009-06-01	2009-06-01	2013-06-01
159.	PD8841	2009-06-01	2009-06-01	2013-06-01
160.	PD8839	2009-06-01	2009-06-01	2013-06-01
161.	PD8835	2009-06-01	2009-06-01	2013-06-01
162.	PD8843	2009-06-01	2009-06-01	2013-06-01
163.	PD8831	2009-06-01	2009-06-01	2013-06-01
164.	PC2798	2009-06-01	2009-06-01	2013-06-01
165.	PD8834	2009-06-01	2009-06-01	2013-06-01
166.	PD8832	2009-06-01	2009-06-01	2013-06-01
167.	PD8840	2009-06-01	2009-06-01	2013-06-01
168.	PD8836	2009-06-01	2009-06-01	2013-06-01
169.	BE0773	2013-08-01	2013-08-01	2013-12-31
170.	BE0769	2013-03-25	2013-08-01	2013-12-31
171.	BE0770	2013-03-25	2013-08-01	2013-12-31
172.	BE0768	2013-08-01	2013-08-01	2013-12-31
173.	BC2540	2013-08-01	2013-08-01	2013-12-31
174.	BE0771	2013-08-01	2013-08-01	2013-12-31
175.	BE0772	2013-08-01	2013-08-01	2013-12-31
176.	BE0775	2013-08-01	2013-08-01	2013-12-31
177.	BE0776	2013-08-01	2013-08-01	2013-12-31
178.	BE0777	2013-08-01	2013-08-01	2013-12-31
179.	BE0778	2013-08-01	2013-08-01	2013-12-31
180.	PE9351	2010-05-31	2010-05-31	2013-06-03
181.	BA7448	2013-03-25	2013-07-31	2013-12-31
182.	BA7450	2013-03-25	2013-07-31	2013-12-31
183.	BE0761	2013-03-25	2013-07-31	2013-12-31
184.	BE0763	2013-03-25	2013-07-31	2013-12-31
185.	BE0767	2013-03-25	2013-07-31	2013-12-31
186.	BA7452	2013-06-03	2013-07-31	2013-12-31
187.	BA7446	2013-07-31	2013-07-31	2013-12-31
188.	BC2662	2013-07-31	2013-07-31	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
189.	BA7451	2013-07-31	2013-07-31	2013-12-31
190.	BA7453	2013-07-31	2013-07-31	2013-12-31
191.	BA7454	2013-07-31	2013-07-31	2013-12-31
192.	BE0762	2013-07-31	2013-07-31	2013-12-31
193.	BE0764	2013-07-31	2013-07-31	2013-12-31
194.	BA0765	2013-07-31	2013-07-31	2013-12-31
195.	BE0766	2013-07-31	2013-07-31	2013-12-31
196.	PC1283	2009-06-11	2009-06-11	2013-06-11
197.	2641	2013-07-22	2013-07-22	2013-12-31
198.	BA3474	2013-04-08	2013-04-08	2013-12-31
199.	PE8720	2011-05-02	2011-05-02	2013-06-18
200.	BA7442	2013-06-27	2013-06-27	2013-12-31
201.	BA7443	2013-06-27	2013-06-27	2013-12-31
202.	7444	2013-06-27	2013-06-27	2013-12-31
203.	AG9799	2009-07-13	2009-07-13	2013-07-13
204.	PD8865	2009-07-13	2009-07-13	2013-07-13
205.	PD8866	2009-07-13	2009-07-13	2013-07-13
206.	PD8867	2009-07-13	2009-07-13	2013-07-13
207.	PD8868	2009-07-13	2009-07-13	2013-07-13
208.	PD8869	2009-07-13	2009-07-13	2013-07-13
209.	AG9942	2010-08-09	2010-08-09	2013-07-13
210.	BA3531	2013-06-10	2013-06-10	2013-12-31
211.	BA3532	2013-06-10	2013-06-10	2013-12-31
212.	BA3530	2013-06-10	2013-06-10	2013-12-31
213.	BA3528	2013-06-10	2013-06-10	2013-12-31
214.	BA3524	2013-06-10	2013-06-10	2013-12-31
215.	BA3526	2013-06-10	2013-06-10	2013-12-31
216.	BA3527	2013-06-10	2013-06-10	2013-12-31
217.	BA3523	2013-06-10	2013-06-10	2013-12-31
218.	BA3529	2013-06-10	2013-06-10	2013-12-31
219.	BA3525	2013-06-10	2013-06-10	2013-12-31
220.	BA3508	2013-06-03	2013-06-03	2013-12-31
221.	BA3511	2013-06-03	2013-06-03	2013-12-31
222.	BA3512	2013-06-03	2013-06-03	2013-12-31
223.	BA3522	2013-06-03	2013-06-03	2013-12-31
224.	BA3513	2013-06-03	2013-06-03	2013-12-31
225.	BA3515	2013-06-03	2013-06-03	2013-12-31
226.	BA3507	2013-06-03	2013-06-03	2013-12-31
227.	BA3505	2013-06-03	2013-06-03	2013-12-31
228.	BA3504	2013-06-03	2013-06-03	2013-12-31
229.	BA3519	2013-06-03	2013-06-03	2013-12-31
230.	BA3520	2013-06-03	2013-06-03	2013-12-31
231.	BA3516	2013-06-03	2013-06-03	2013-12-31
232.	BA3517	2013-06-03	2013-06-03	2013-12-31
233.	BA3503	2013-06-03	2013-06-03	2013-12-31
234.	BA3506	2013-06-03	2013-06-03	2013-12-31
235.	BA3501	2013-06-03	2013-06-03	2013-12-31
236.	BB5918	2013-06-03	2013-06-03	2013-12-31
237.	BA3500	2013-06-03	2013-06-03	2013-12-31
238.	BA3510	2013-06-03	2013-06-03	2013-12-31
239.	BA3518	2013-06-03	2013-06-03	2013-12-31
240.	BA3521	2013-06-03	2013-06-03	2013-12-31
241.	BA3502	2013-06-03	2013-06-03	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
242.	BA7435	2013-06-03	2013-06-03	2013-12-31
243.	PA4630	2010-06-14	2010-06-14	2013-08-01
244.	AG9947	2009-10-19	2009-10-19	2013-08-07
245.	BC2664	2010-09-27	2013-05-27	2013-12-31
246.	BA7431	2013-03-25	2013-05-27	2013-12-31
247.	BC2669	2013-05-27	2013-05-27	2013-12-31
248.	BA7430	2013-05-27	2013-05-27	2013-12-31
249.	BA7433	2013-05-27	2013-05-27	2013-12-31
250.	BA7434	2013-05-27	2013-05-27	2013-12-31
251.	BC2670	2013-05-27	2013-05-27	2013-12-31
252.	PC1262	2012-04-23	2012-04-23	2013-08-14
253.	AG9948	2009-10-19	2009-10-19	2013-08-17
254.	PF9113	2011-09-19	2011-09-19	2013-08-19
255.	AG9934	2009-10-19	2009-10-19	2013-08-20
256.	BA7425	2013-05-07	2013-05-02	2013-12-31
257.	PE6955	2013-05-02	2013-05-02	2013-12-31
258.	BA7133	2013-05-02	2013-05-02	2013-12-31
259.	BA7134	2013-05-02	2013-05-02	2013-12-31
260.	BA7135	2013-05-02	2013-05-02	2013-12-31
261.	BA7420	2013-05-02	2013-05-02	2013-12-31
262.	BA7421	2013-05-02	2013-05-02	2013-12-31
263.	BA7422	2013-05-02	2013-05-02	2013-12-31
264.	BA7423	2013-05-02	2013-05-02	2013-12-31
265.	PE6958	2013-05-02	2013-05-02	2013-12-31
266.	BC2665	2013-05-02	2013-05-02	2013-12-31
267.	AD9925	2010-08-09	2010-08-09	2013-09-03
268.	BA3488	2013-04-29	2013-04-29	2013-12-31
269.	BA3493	2013-04-29	2013-04-29	2013-12-31
270.	BA3486	2013-04-29	2013-04-29	2013-12-31
271.	BA3498	2013-04-29	2013-04-29	2013-12-31
272.	BA3494	2013-04-29	2013-04-29	2013-12-31
273.	BA3487	2013-04-29	2013-04-29	2013-12-31
274.	BA3489	2013-04-29	2013-04-29	2013-12-31
275.	BA3497	2013-04-29	2013-04-29	2013-12-31
276.	BA3491	2013-04-29	2013-04-29	2013-12-31
277.	BA3485	2013-04-29	2013-04-29	2013-12-31
278.	BA3496	2013-04-29	2013-04-29	2013-12-31
279.	BA3492	2013-04-29	2013-04-29	2013-12-31
280.	BA3490	2013-04-29	2013-04-29	2013-12-31
281.	BA3484	2013-04-29	2013-04-29	2013-12-31
282.	BA3495	2013-04-29	2013-04-29	2013-12-31
283.	PC7606	2012-04-26	2012-04-26	2013-09-12
284.	PD8880	2011-03-10	2011-03-10	2013-09-20
285.	PC7008	2009-09-22	2009-09-22	2013-09-22
286.	BA3473	2013-04-08	2013-04-08	2013-12-31
287.	BA3476	2013-04-08	2013-04-08	2013-12-31
288.	BA3477	2013-04-08	2013-04-08	2013-12-31
289.	BA3478	2013-04-08	2013-04-08	2013-12-31
290.	BA3479	2013-04-08	2013-04-08	2013-12-31
291.	BA3480	2013-04-08	2013-04-08	2013-12-31
292.	BA3472	2013-04-08	2013-04-08	2013-12-31
293.	BA3481	2013-04-08	2013-04-08	2013-12-31
294.	BA3482	2013-04-08	2013-04-08	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
295.	BA3483	2013-04-08	2013-04-08	2013-12-31
296.	BA3464	2013-04-08	2013-04-08	2013-12-31
297.	BA3466	2013-04-08	2013-04-08	2013-12-31
298.	BA3468	2013-04-08	2013-04-08	2013-12-31
299.	BA3469	2013-04-08	2013-04-08	2013-12-31
300.	BA3463	2013-04-08	2013-04-08	2013-12-31
301.	BA3456	2013-04-08	2013-04-08	2013-12-31
302.	BA3471	2013-04-08	2013-04-08	2013-12-31
303.	BA3461	2013-04-08	2013-04-08	2013-12-31
304.	BA3458	2013-04-08	2013-04-08	2013-12-31
305.	BA3465	2013-04-08	2013-04-08	2013-12-31
306.	BA3470	2013-04-08	2013-04-08	2013-12-31
307.	BA3455	2013-04-08	2013-04-08	2013-12-31
308.	BA3457	2013-04-08	2013-04-08	2013-12-31
309.	BA3460	2013-04-08	2013-04-08	2013-12-31
310.	BA3459	2013-04-08	2013-04-08	2013-12-31
311.	BA3467	2013-04-08	2013-04-08	2013-12-31
312.	BA3462	2013-04-08	2013-04-08	2013-12-31
313.	PC0432	2010-04-26	2010-04-26	2013-10-08
314.	AG9950	2009-10-19	2009-10-19	2013-10-19
315.	PD8878	2009-10-19	2009-10-19	2013-10-19
316.	PD8884	2009-10-29	2009-10-29	2013-10-29
317.	PD8887	2009-10-29	2009-10-29	2013-10-29
318.	PD8886	2009-10-29	2009-10-29	2013-10-29
319.	PD8883	2009-10-29	2009-10-29	2013-10-29
320.	PD8885	2009-10-29	2009-10-29	2013-10-29
321.	PD8882	2009-10-29	2009-10-29	2013-10-29
322.	PE3493	2013-02-25	2013-02-25	2013-12-31
323.	PE3489	2013-02-25	2013-02-25	2013-12-31
324.	PE3491	2013-02-25	2013-02-25	2013-12-31
325.	PE3496	2013-02-25	2013-02-25	2013-12-31
326.	PE3484	2013-02-25	2013-02-25	2013-12-31
327.	PE3486	2013-02-25	2013-02-25	2013-12-31
328.	PE3495	2013-02-25	2013-02-25	2013-12-31
329.	PE3494	2013-02-25	2013-02-25	2013-12-31
330.	PE3485	2013-02-25	2013-02-25	2013-12-31
331.	PE3487	2013-02-25	2013-02-25	2013-12-31
332.	PE3488	2013-02-25	2013-02-25	2013-12-31
333.	PE3490	2013-02-25	2013-02-25	2013-12-31
334.	PE3492	2013-02-25	2013-02-25	2013-12-31
335.	PE3497	2013-02-25	2013-02-25	2013-12-31
336.	PE3483	2013-02-25	2013-02-25	2013-12-31
337.	PF9124	2012-04-26	2012-02-07	2013-11-13
338.	PD8849	2009-11-16	2007-06-05	2013-11-16
339.	PC5463	2010-01-11	2010-01-11	2013-12-31
340.	PD8859	2010-01-11	2010-01-11	2013-12-31
341.	PE3482	2013-01-28	2013-01-28	2013-12-31
342.	PE3809	2013-01-28	2013-01-28	2013-12-31
343.	PE3813	2013-01-28	2013-01-28	2013-12-31
344.	PG4232	2013-01-28	2013-01-28	2013-12-31
345.	PE3803	2013-01-28	2013-01-28	2013-12-31
346.	PE3812	2013-01-28	2013-01-28	2013-12-31
347.	PE3806	2013-01-28	2013-01-28	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
348.	PE0337	2013-01-28	2013-01-28	2013-12-31
349.	PE3481	2013-01-28	2013-01-28	2013-12-31
350.	PE3807	2013-01-28	2013-01-28	2013-12-31
351.	PE3810	2013-01-28	2013-01-28	2013-12-31
352.	PE3811	2013-01-28	2013-01-28	2013-12-31
353.	PE3805	2013-01-28	2013-01-28	2013-12-31
354.	PE3802	2013-01-28	2013-01-28	2013-12-31
355.	PE3808	2013-01-28	2013-01-28	2013-12-31
356.	AJ8937	2013-01-28	2013-01-28	2013-12-31
357.	AJ8938	2013-01-28	2013-01-28	2013-12-31
358.	AQ1156	2013-01-28	2013-01-28	2013-12-31
359.	AY4001	2013-01-28	2013-01-28	2013-12-31
360.	AQ1155	2013-01-28	2013-01-28	2013-12-31
361.	AY4002	2013-01-28	2013-01-28	2013-12-31
362.	AD9918	2010-08-09	2010-08-09	2013-12-09
363.	AD9921	2010-08-09	2010-08-09	2013-12-09
364.	PD1200	2010-01-11	2010-01-11	2013-12-31
365.	PD1201	2010-01-11	2010-01-11	2013-12-31
366.	PD1199	2010-01-11	2010-01-11	2013-12-31
367.	PD1202	2010-01-11	2010-01-11	2013-12-31
368.	D24335	2010-01-11	2010-01-11	2013-12-31
369.	PD1204	2010-01-11	2010-01-11	2013-12-31
370.	PD1203	2010-01-11	2010-01-11	2013-12-31
371.	PD1206	2010-01-11	2010-01-11	2013-12-31
372.	PA3582	2010-01-11	2010-01-11	2013-12-31
373.	PD1207	2010-01-11	2010-01-11	2013-12-31
374.	AD9905	2010-01-11	2010-01-11	2013-12-31
375.	PD1190	2010-01-11	2010-01-11	2013-12-31
376.	PD8853	2010-01-11	2010-01-11	2013-12-31
377.	PD1194	2010-01-11	2010-01-11	2013-12-31
378.	PD1193	2010-01-11	2010-01-11	2013-12-31
379.	PD8855	2010-01-11	2010-01-11	2013-12-31
380.	PD8854	2010-01-11	2010-01-11	2013-12-31
381.	PD8860	2010-01-11	2010-01-11	2013-12-31
382.	PD8852	2010-01-11	2010-01-11	2013-12-31
383.	PD8857	2010-01-11	2010-01-11	2013-12-31
384.	PD1191	2010-01-11	2010-01-11	2013-12-31
385.	PD1192	2010-01-11	2010-01-11	2013-12-31
386.	PA9019	2010-01-11	2010-01-11	2013-12-31
387.	PD1195	2010-01-11	2010-01-11	2013-12-31
388.	PD8856	2010-01-11	2010-01-11	2013-12-31
389.	PD8890	2010-01-18	2010-01-18	2013-12-31
390.	D13161	2010-01-18	2010-01-18	2013-12-31
391.	PD1198	2010-01-25	2010-01-25	2013-12-31
392.	PD1210	2010-01-25	2010-01-25	2013-12-31
393.	PA4126	2010-01-25	2010-01-25	2013-12-31
394.	PD1214	2010-01-25	2010-01-25	2013-12-31
395.	PD1217	2010-01-25	2010-01-25	2013-12-31
396.	PD8851	2010-01-25	2010-01-25	2013-12-31
397.	PD1209	2010-01-25	2010-01-25	2013-12-31
398.	PD1220	2010-01-25	2010-01-25	2013-12-31
399.	PD1216	2010-01-25	2010-01-25	2013-12-31
400.	PD1196	2010-01-25	2010-01-25	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
401.	PD1218	2010-01-25	2010-01-25	2013-12-31
402.	PD1213	2010-01-25	2010-01-25	2013-12-31
403.	PD1219	2010-01-25	2010-01-25	2013-12-31
404.	PD1212	2010-01-25	2010-01-25	2013-12-31
405.	PD1211	2010-01-25	2010-01-25	2013-12-31
406.	PD1221	2010-01-25	2010-01-25	2013-12-31
407.	PD1227	2010-02-22	2010-02-22	2013-12-31
408.	PD1232	2010-02-22	2010-02-22	2013-12-31
409.	PD1235	2010-02-22	2010-02-22	2013-12-31
410.	PD1236	2010-02-22	2010-02-22	2013-12-31
411.	PD1229	2010-02-22	2010-02-22	2013-12-31
412.	PD1233	2010-02-22	2010-02-22	2013-12-31
413.	PD1223	2010-02-22	2010-02-22	2013-12-31
414.	PD1226	2010-02-22	2010-02-22	2013-12-31
415.	PD1228	2010-02-22	2010-02-22	2013-12-31
416.	PD1230	2010-02-22	2010-02-22	2013-12-31
417.	PD1225	2010-02-22	2010-02-22	2013-12-31
418.	PD1234	2010-02-22	2010-02-22	2013-12-31
419.	PD1231	2010-02-22	2010-02-22	2013-12-31
420.	PD1224	2010-02-22	2010-02-22	2013-12-31
421.	PA8734	2010-02-22	2010-02-22	2013-12-31
422.	PE8407	2010-03-08	2010-03-08	2013-12-31
423.	PD1244	2010-03-08	2010-03-08	2013-12-31
424.	PD1241	2010-03-08	2010-03-08	2013-12-31
425.	PE8410	2010-03-08	2010-03-08	2013-12-31
426.	PD1238	2010-03-08	2010-03-08	2013-12-31
427.	PE8409	2010-03-08	2010-03-08	2013-12-31
428.	PE8411	2010-03-08	2010-03-08	2013-12-31
429.	PD1237	2010-03-08	2010-03-08	2013-12-31
430.	PE8408	2010-03-08	2010-03-08	2013-12-31
431.	PE8406	2010-03-08	2010-03-08	2013-12-31
432.	PD1243	2010-03-08	2010-03-08	2013-12-31
433.	PE8412	2010-03-08	2010-03-08	2013-12-31
434.	PD1237	2010-03-08	2010-03-08	2013-12-31
435.	PD1242	2010-03-08	2010-03-08	2013-12-31
436.	PD1240	2010-03-08	2010-03-08	2013-12-31
437.	PE8405	2010-03-08	2010-03-08	2013-12-31
438.	PA7954	2010-04-12	2010-04-12	2013-12-31
439.	PE8425	2010-04-12	2010-04-12	2013-12-31
440.	PE8421	2010-04-12	2010-04-12	2013-12-31
441.	PE8420	2010-04-12	2010-04-12	2013-12-31
442.	PE8414	2010-04-12	2010-04-12	2013-12-31
443.	PA8742	2010-04-12	2010-04-12	2013-12-31
444.	PE8427	2010-04-12	2010-04-12	2013-12-31
445.	PE8415	2010-04-12	2010-04-12	2013-12-31
446.	PA4118	2010-04-12	2010-04-12	2013-12-31
447.	PE8424	2010-04-12	2010-04-12	2013-12-31
448.	PE8416	2010-04-12	2010-04-12	2013-12-31
449.	PE8419	2010-04-12	2010-04-12	2013-12-31
450.	PE8417	2010-04-12	2010-04-12	2013-12-31
451.	PE8426	2010-04-12	2010-04-12	2013-12-31
452.	PE8423	2010-04-12	2010-04-12	2013-12-31
453.	PD8601	2010-04-26	2010-04-26	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
454.	PD8899	2010-04-26	2010-04-26	2013-12-31
455.	PD8898	2010-04-26	2010-04-26	2013-12-31
456.	PE8413	2010-05-03	2010-05-03	2013-12-31
457.	PB1218	2010-05-03	2010-05-03	2013-12-31
458.	PE8435	2010-05-03	2010-05-03	2013-12-31
459.	PE8433	2010-05-03	2010-05-03	2013-12-31
460.	PE8431	2010-05-03	2010-05-03	2013-12-31
461.	PA0213	2010-05-03	2010-05-03	2013-12-31
462.	PE8430	2010-05-03	2010-05-03	2013-12-31
463.	PE8429	2010-05-03	2010-05-03	2013-12-31
464.	PE8432	2010-05-03	2010-05-03	2013-12-31
465.	PE8428	2010-05-03	2010-05-03	2013-12-31
466.	PA8514	2010-05-25	2010-05-25	2013-12-31
467.	PE8449	2010-05-31	2010-05-31	2013-12-31
468.	PE8441	2010-05-31	2010-05-31	2013-12-31
469.	PA4684	2010-05-31	2010-05-31	2013-12-31
470.	PE8448	2010-05-31	2010-05-31	2013-12-31
471.	PE8452	2010-05-31	2010-05-31	2013-12-31
472.	PE8442	2010-05-31	2010-05-31	2013-12-31
473.	PE8447	2010-05-31	2010-05-31	2013-12-31
474.	PE8443	2010-05-31	2010-05-31	2013-12-31
475.	PE8450	2010-05-31	2010-05-31	2013-12-31
476.	PE8440	2010-05-31	2010-05-31	2013-12-31
477.	PE8439	2010-05-31	2010-05-31	2013-12-31
478.	PE8454	2010-05-31	2010-05-31	2013-12-31
479.	PE8446	2010-05-31	2010-05-31	2013-12-31
480.	PE8451	2010-05-31	2010-05-31	2013-12-31
481.	PE8445	2010-05-31	2010-05-31	2013-12-31
482.	PE8444	2010-05-31	2010-05-31	2013-12-31
483.	AD9907	2010-05-31	2010-05-31	2013-12-31
484.	AD9906	2010-05-31	2010-05-31	2013-12-31
485.	PE8460	2010-05-31	2010-05-31	2013-12-31
486.	PE8462	2010-05-31	2010-05-31	2013-12-31
487.	PE8455	2010-05-31	2010-05-31	2013-12-31
488.	PE8461	2010-05-31	2010-05-31	2013-12-31
489.	PE8457	2010-05-31	2010-05-31	2013-12-31
490.	PA6251	2010-05-31	2010-05-31	2013-12-31
491.	PE8456	2010-05-31	2010-05-31	2013-12-31
492.	PE8436	2010-05-31	2010-05-31	2013-12-31
493.	PE8463	2010-05-31	2010-05-31	2013-12-31
494.	PE8459	2010-05-31	2010-05-31	2013-12-31
495.	PD8901	2010-06-07	2010-06-07	2013-12-31
496.	PD8903	2010-06-14	2010-06-14	2013-12-31
497.	PA9197	2010-06-14	2010-06-14	2013-12-31
498.	PD8895	2010-06-14	2010-06-14	2013-12-31
499.	PC7795	2010-06-14	2010-06-14	2013-12-31
500.	AD9913	2010-07-05	2010-07-05	2013-12-31
501.	AD9914	2010-07-05	2010-07-05	2013-12-31
502.	AD9923	2010-08-09	2010-08-09	2013-12-31
503.	AD9920	2010-08-09	2010-08-09	2013-12-31
504.	AD9917	2010-08-09	2010-08-09	2013-12-31
505.	AG9941	2010-08-09	2010-08-09	2013-12-31
506.	AD9919	2010-08-09	2010-08-09	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
507.	AD9924	2010-08-09	2010-08-09	2013-12-31
508.	PB1851	2010-08-16	2010-08-16	2013-12-31
509.	PF9066	2010-08-16	2010-08-16	2013-12-31
510.	PB1850	2010-08-16	2010-08-16	2013-12-31
511.	PF9071	2010-08-16	2010-08-16	2013-12-31
512.	PC7041	2010-08-16	2010-08-16	2013-12-31
513.	PF2888	2010-08-16	2010-08-16	2013-12-31
514.	PB1847	2010-08-16	2010-08-16	2013-12-31
515.	PC7616	2010-08-16	2010-08-16	2013-12-31
516.	PB1849	2010-08-16	2010-08-16	2013-12-31
517.	PF9072	2010-08-16	2010-08-16	2013-12-31
518.	PF9069	2010-08-16	2010-08-16	2013-12-31
519.	PD8905	2010-09-07	2010-09-07	2013-12-31
520.	PD8877	2010-09-07	2010-09-07	2013-12-31
521.	AD9942	2010-10-04	2010-10-04	2013-12-31
522.	AD9943	2010-10-04	2010-10-04	2013-12-31
523.	AD9947	2010-10-04	2010-10-04	2013-12-31
524.	AD9938	2010-10-04	2010-10-04	2013-12-31
525.	AD9945	2010-10-04	2010-10-04	2013-12-31
526.	AD9935	2010-10-04	2010-10-04	2013-12-31
527.	AD9937	2010-10-04	2010-10-04	2013-12-31
528.	AD9939	2010-10-04	2010-10-04	2013-12-31
529.	AD9941	2010-10-04	2010-10-04	2013-12-31
530.	AD9940	2010-10-04	2010-10-04	2013-12-31
531.	AD9944	2010-10-04	2010-10-04	2013-12-31
532.	AD9936	2010-10-04	2010-10-04	2013-12-31
533.	AD9946	2010-10-04	2010-10-04	2013-12-31
534.	PD8908	2010-10-04	2010-10-04	2013-12-31
535.	PD3343	2010-10-04	2010-10-04	2013-12-31
536.	PD8907	2010-10-04	2010-10-04	2013-12-31
537.	PD8911	2010-10-04	2010-10-04	2013-12-31
538.	PD8909	2010-10-04	2010-10-04	2013-12-31
539.	PD8910	2010-10-04	2010-10-04	2013-12-31
540.	PD3345	2010-10-25	2010-10-25	2013-12-31
541.	PD3346	2010-10-25	2010-10-25	2013-12-31
542.	PA3683	2011-01-10	2011-01-10	2013-12-31
543.	PD3359	2011-03-10	2011-03-10	2013-12-31
544.	PD3361	2011-03-10	2011-03-10	2013-12-31
545.	PD3354	2011-03-10	2011-03-10	2013-12-31
546.	PE8273	2011-03-10	2011-03-10	2013-12-31
547.	PE8458	2011-03-28	2011-03-28	2013-12-31
548.	PE8464	2011-03-28	2011-03-28	2013-12-31
549.	PE8711	2011-03-28	2011-03-28	2013-12-31
550.	PE8708	2011-03-28	2011-03-28	2013-12-31
551.	PE8710	2011-03-28	2011-03-28	2013-12-31
552.	PE8713	2011-03-28	2011-03-28	2013-12-31
553.	PE8707	2011-03-28	2011-03-28	2013-12-31
554.	PE8712	2011-03-28	2011-03-28	2013-12-31
555.	PE8717	2011-03-28	2011-03-28	2013-12-31
556.	PE8718	2011-03-28	2011-03-28	2013-12-31
557.	PE8715	2011-03-28	2011-03-28	2013-12-31
558.	PA8743	2011-03-28	2011-03-28	2013-12-31
559.	PE8465	2011-03-28	2011-03-28	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
560.	PE8716	2011-03-28	2011-03-28	2013-12-31
561.	PD9143	2011-04-12	2011-04-12	2013-12-31
562.	AJ8926	2011-04-18	2011-04-18	2013-12-31
563.	AJ8928	2011-04-18	2011-04-18	2013-12-31
564.	AD9929	2011-04-18	2011-04-18	2013-12-31
565.	AJ8930	2011-04-18	2011-04-18	2013-12-31
566.	AG9972	2011-04-18	2011-04-18	2013-12-31
567.	AD9932	2011-04-18	2011-04-18	2013-12-31
568.	AG9974	2011-04-18	2011-04-18	2013-12-31
569.	AJ8929	2011-04-18	2011-04-18	2013-12-31
570.	AJ8931	2011-04-18	2011-04-18	2013-12-31
571.	AD9931	2011-04-18	2011-04-18	2013-12-31
572.	AD9934	2011-04-18	2011-04-18	2013-12-31
573.	AD9930	2011-04-18	2011-04-18	2013-12-31
574.	AD9933	2011-04-18	2011-04-18	2013-12-31
575.	AG9973	2011-04-18	2011-04-18	2013-12-31
576.	AG9975	2011-04-18	2011-04-18	2013-12-31
577.	PA8727	2011-04-18	2011-04-18	2013-12-31
578.	PE8727	2011-05-02	2011-05-02	2013-12-31
579.	PE8722	2011-05-02	2011-05-02	2013-12-31
580.	PG4562	2011-05-02	2011-05-02	2013-12-31
581.	PG4564	2011-05-02	2011-05-02	2013-12-31
582.	PG4561	2011-05-02	2011-05-02	2013-12-31
583.	PE8721	2011-05-02	2011-05-02	2013-12-31
584.	PE8723	2011-05-02	2011-05-02	2013-12-31
585.	PE8725	2011-05-02	2011-05-02	2013-12-31
586.	PE8726	2011-05-02	2011-05-02	2013-12-31
587.	PG4563	2011-05-02	2011-05-02	2013-12-31
588.	PG4566	2011-05-02	2011-05-02	2013-12-31
589.	PE8729	2011-05-02	2011-05-02	2013-12-31
590.	PE8719	2011-05-02	2011-05-02	2013-12-31
591.	PE8728	2011-05-02	2011-05-02	2013-12-31
592.	PE8724	2011-05-02	2011-05-02	2013-12-31
593.	PE8731	2011-05-30	2011-05-30	2013-12-31
594.	PE8730	2011-05-30	2011-05-30	2013-12-31
595.	PG4573	2011-05-30	2011-05-30	2013-12-31
596.	PG4570	2011-05-30	2011-05-30	2013-12-31
597.	D13351	2011-05-30	2011-05-30	2013-12-31
598.	PB7400	2011-05-30	2011-05-30	2013-12-31
599.	PE8437	2011-05-30	2011-05-30	2013-12-31
600.	PG4572	2011-05-30	2011-05-30	2013-12-31
601.	PG4568	2011-05-30	2011-05-30	2013-12-31
602.	PF3034	2011-05-30	2011-05-30	2013-12-31
603.	PG4571	2011-05-30	2011-05-30	2013-12-31
604.	PG4574	2011-05-30	2011-05-30	2013-12-31
605.	AJ8934	2011-05-30	2011-05-30	2013-12-31
606.	AJ8932	2011-05-30	2011-05-30	2013-12-31
607.	AJ8935	2011-05-30	2011-05-30	2013-12-31
608.	PF2347	2011-07-14	2011-07-14	2013-12-31
609.	PF9114	2011-09-19	2011-09-19	2013-12-31
610.	PC7624	2012-01-30	2012-01-30	2013-12-31
611.	PG4580	2012-01-30	2012-01-30	2013-12-31
612.	PG4585	2012-01-30	2012-01-30	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
613.	PG4583	2012-01-30	2012-01-30	2013-12-31
614.	PG4575	2012-01-30	2012-01-30	2013-12-31
615.	PG4584	2012-01-30	2012-01-30	2013-12-31
616.	PD5713	2012-01-30	2012-01-30	2013-12-31
617.	PE6763	2012-01-30	2012-01-30	2013-12-31
618.	PG4577	2012-01-30	2012-01-30	2013-12-31
619.	PG4579	2012-01-30	2012-01-30	2013-12-31
620.	PG4582	2012-01-30	2012-01-30	2013-12-31
621.	PG4581	2012-01-30	2012-01-30	2013-12-31
622.	PG4576	2012-01-30	2012-01-30	2013-12-31
623.	PG4578	2012-01-30	2012-01-30	2013-12-31
624.	PE6764	2012-01-30	2012-01-30	2013-12-31
625.	PG4567	2012-01-30	2012-01-30	2013-12-31
626.	PD3363	2012-02-01	2012-03-29	2013-12-31
627.	101439A	2012-02-06	2012-02-06	2013-12-31
628.	PE6767	2012-02-06	2012-02-06	2013-12-31
629.	101449A	2012-02-06	2012-02-06	2013-12-31
630.	PE6782	2012-02-27	2012-02-27	2013-12-31
631.	PE6783	2012-02-27	2012-02-27	2013-12-31
632.	PE6779	2012-02-27	2012-02-27	2013-12-31
633.	PE6768	2012-02-27	2012-02-27	2013-12-31
634.	PE6775	2012-02-27	2012-02-27	2013-12-31
635.	PE6776	2012-02-27	2012-02-27	2013-12-31
636.	PE6778	2012-02-27	2012-02-27	2013-12-31
637.	PE6784	2012-02-27	2012-02-27	2013-12-31
638.	PB6677	2012-02-27	2012-02-27	2013-12-31
639.	PE6766	2012-02-27	2012-02-27	2013-12-31
640.	PE4038	2012-02-27	2012-02-27	2013-12-31
641.	PE6777	2012-02-27	2012-02-27	2013-12-31
642.	PE6765	2012-02-27	2012-02-27	2013-12-31
643.	PE6774	2012-02-27	2012-02-27	2013-12-31
644.	PE6781	2012-02-27	2012-02-27	2013-12-31
645.	PE6780	2012-02-27	2012-02-27	2013-12-31
646.	PE6773	2012-02-27	2012-02-27	2013-12-31
647.	PD3378	2012-03-29	2012-03-29	2013-12-31
648.	PD3379	2012-03-29	2012-03-29	2013-12-31
649.	PD3365	2012-03-29	2012-03-29	2013-12-31
650.	PD3368	2012-03-29	2012-03-29	2013-12-31
651.	PD3384	2012-03-29	2012-03-29	2013-12-31
652.	PD3348	2012-03-29	2012-03-29	2013-12-31
653.	PD3380	2012-03-29	2012-03-29	2013-12-31
654.	PE7852	2012-03-29	2012-03-29	2013-12-31
655.	PD3364	2012-03-29	2012-03-29	2013-12-31
656.	PD3382	2012-03-29	2012-03-29	2013-12-31
657.	PD3367	2012-03-29	2012-03-29	2013-12-31
658.	PD3383	2012-03-29	2012-03-29	2013-12-31
659.	PF9073	2012-04-12	2012-04-12	2013-12-31
660.	PF9112	2012-04-12	2012-04-12	2013-12-31
661.	PF9080	2012-04-12	2012-04-12	2013-12-31
662.	PF9115	2012-04-12	2012-04-12	2013-12-31
663.	PF9078	2012-04-12	2012-04-12	2013-12-31
664.	PF9116	2012-04-12	2012-04-12	2013-12-31
665.	PB1845	2012-04-12	2012-04-12	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
666.	PF9102	2012-04-12	2012-04-12	2013-12-31
667.	PF9117	2012-04-12	2012-04-12	2013-12-31
668.	PF9093	2012-04-12	2012-04-12	2013-12-31
669.	PB6254	2012-04-12	2012-04-12	2013-12-31
670.	PD8874	2012-04-12	2012-04-12	2013-12-31
671.	AJ8950	2012-04-16	2012-04-16	2013-12-31
672.	AQ1127	2012-04-16	2012-04-16	2013-12-31
673.	AJ8945	2012-04-16	2012-04-16	2013-12-31
674.	AQ1136	2012-04-16	2012-04-16	2013-12-31
675.	AJ8944	2012-04-16	2012-04-16	2013-12-31
676.	AQ1137	2012-04-16	2012-04-16	2013-12-31
677.	AQ1135	2012-04-16	2012-04-16	2013-12-31
678.	AQ1138	2012-04-16	2012-04-16	2013-12-31
679.	AQ1134	2012-04-16	2012-04-16	2013-12-31
680.	AQ1133	2012-04-16	2012-04-16	2013-12-31
681.	AJ8948	2012-04-16	2012-04-16	2013-12-31
682.	AJ8946	2012-04-16	2012-04-16	2013-12-31
683.	AJ8941	2012-04-16	2012-04-16	2013-12-31
684.	AJ8940	2012-04-16	2012-04-16	2013-12-31
685.	AQ1129	2012-04-16	2012-04-16	2013-12-31
686.	AJ8947	2012-04-16	2012-04-16	2013-12-31
687.	AJ8943	2012-04-16	2012-04-16	2013-12-31
688.	AQ1131	2012-04-16	2012-04-16	2013-12-31
689.	AJ8949	2012-04-16	2012-04-16	2013-12-31
690.	AQ1132	2012-04-16	2012-04-16	2013-12-31
691.	AJ8939	2012-04-16	2012-04-16	2013-12-31
692.	PA8750	2012-04-26	2012-04-26	2013-12-31
693.	PF9118	2012-04-26	2012-04-26	2013-12-31
694.	PF9126	2012-04-26	2012-04-26	2013-12-31
695.	PF9119	2012-04-26	2012-04-26	2013-12-31
696.	PC5967	2012-04-26	2012-04-26	2013-12-31
697.	PF9120	2012-04-26	2012-04-26	2013-12-31
698.	PE1669	2012-04-26	2012-04-26	2013-12-31
699.	PF9121	2012-04-26	2012-04-26	2013-12-31
700.	PF9122	2012-04-26	2012-04-26	2013-12-31
701.	PF1568	2012-04-30	2012-04-30	2013-12-31
702.	PF9127	2012-04-30	2012-04-30	2013-12-31
703.	AQ1140	2012-05-28	2012-05-28	2013-12-31
704.	AQ1139	2012-05-28	2012-05-28	2013-12-31
705.	PE6792	2012-05-28	2012-05-28	2013-12-31
706.	PG4983	2012-05-28	2012-05-28	2013-12-31
707.	PE6794	2012-05-28	2012-05-28	2013-12-31
708.	PE6790	2012-05-28	2012-05-28	2013-12-31
709.	PE6793	2012-05-28	2012-05-28	2013-12-31
710.	PE6797	2012-05-28	2012-05-28	2013-12-31
711.	PE6786	2012-05-28	2012-05-28	2013-12-31
712.	PC7890	2012-05-28	2012-05-28	2013-12-31
713.	PC7288	2012-05-28	2012-05-28	2013-12-31
714.	PE6787	2012-05-28	2012-05-28	2013-12-31
715.	PE6788	2012-05-28	2012-05-28	2013-12-31
716.	PE6789	2012-05-28	2012-05-28	2013-12-31
717.	PE6796	2012-05-28	2012-05-28	2013-12-31
718.	PE6795	2012-05-28	2012-05-28	2013-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
719.	PD3355	2012-05-31	2012-05-31	2013-12-31
720.	PD8879	2012-05-31	2012-05-31	2013-12-31
721.	PD3350	2012-05-31	2012-05-31	2013-12-31
722.	AQ1143	2012-07-09	2012-07-09	2013-12-31
723.	AQ1151	2012-07-09	2012-07-09	2013-12-31
724.	AQ1147	2012-07-09	2012-07-09	2013-12-31
725.	AQ1146	2012-07-09	2012-07-09	2013-12-31
726.	AQ1149	2012-07-09	2012-07-09	2013-12-31
727.	AQ1144	2012-07-09	2012-07-09	2013-12-31
728.	AQ1145	2012-07-09	2012-07-09	2013-12-31
729.	AQ1153	2012-07-09	2012-07-09	2013-12-31
730.	AQ1150	2012-07-09	2012-07-09	2013-12-31
731.	AQ1152	2012-07-09	2012-07-09	2013-12-31
732.	AQ1141	2012-07-09	2012-07-09	2013-12-31
733.	AQ1148	2012-07-09	2012-07-09	2013-12-31
734.	AQ1142	2012-07-09	2012-07-09	2013-12-31
735.	AQ1154	2012-07-09	2012-07-09	2013-12-31
736.	PD3389	2012-07-26	2012-07-26	2013-12-31
737.	PF5365	2012-08-23	2012-08-23	2013-12-31
738.	PE6952	2012-08-23	2012-08-23	2013-12-31
739.	PD3388	2012-08-23	2012-08-23	2013-12-31
740.	PD3387	2012-08-23	2012-08-23	2013-12-31
741.	PD3386	2012-08-23	2012-08-23	2013-12-31
742.	PC9315	2012-10-15	2012-10-15	2013-12-31
743.	PD3393	2012-10-15	2012-10-15	2013-12-31
744.	PB5840	2012-10-15	2012-10-15	2013-12-31
745.	PD3395	2012-10-15	2012-10-15	2013-12-31
746.	PE6951	2012-10-15	2012-10-15	2013-12-31
747.	PD3392	2012-10-15	2012-10-15	2013-12-31
748.	PD3344	2012-10-15	2012-10-15	2013-12-31
749.	PD3394	2012-10-15	2012-10-15	2013-12-31
750.	PD3391	2012-10-15	2012-10-15	2013-12-31
751.	PF9132	2012-11-08	2012-11-08	2013-12-31
752.	PF9133	2012-11-08	2012-11-08	2013-12-31
753.	PF9134	2012-11-08	2012-11-08	2013-12-31
754.	PF9135	2012-11-08	2012-11-08	2013-12-31
755.	PF9136	2012-11-08	2012-11-08	2013-12-31
756.	PF9109	2012-11-08	2012-11-08	2013-12-31
757.	PF9137	2012-11-08	2012-11-08	2013-12-31
758.	PF9138	2012-11-08	2012-11-08	2013-12-31
759.	PA1242	2012-11-08	2012-11-08	2013-12-31
760.	PF9140	2012-11-08	2012-11-08	2013-12-31
761.	PD1222	2010-02-22	2010-02-22	2013-12-31

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		5	5	137
2.		12	12	329
3.		12	12	329
4.		12	12	329
5.		12	12	329
6.		12	12	329
7.		17	17	466
8.		22	22	603
9.		23	23	630
10.		25	25	685
11.		29	29	795
12.		30	30	822
13.		32	32	877
14.		32	32	877
15.		33	33	904
16.		33	33	904
17.		33	33	904
18.		33	33	904
19.		33	33	904
20.		33	33	904
21.		33	33	904
22.		33	33	904
23.		33	33	904
24.		33	33	904
25.		33	33	904
26.		33	33	904
27.		33	33	904
28.		33	33	904
29.		33	33	904
30.		33	33	904
31.		33	33	904
32.		36	36	986
33.		365	365	10,000
34.		51	51	1,397
35.		52	52	1,425
36.		53	53	1,452
37.		53	53	1,452
38.		54	54	1,479
39.		54	54	1,479
40.		54	54	1,479
41.		54	54	1,479
42.		54	54	1,479
43.		54	54	1,479
44.		54	54	1,479
45.		54	54	1,479
46.		54	54	1,479
47.		54	54	1,479
48.		54	54	1,479
49.		54	54	1,479
50.		54	54	1,479
51.		54	54	1,479
52.		54	54	1,479

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	**H2** Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	**H3** Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	**I** Maximum credit amount for the tax year (see note 2 below) 445
53.		54	54	1,479
54.		56	56	1,534
55.		56	56	1,534
56.		60	60	1,644
57.		70	70	1,918
58.		70	70	1,918
59.		72	72	1,973
60.		72	72	1,973
61.		73	73	2,000
62.		75	75	2,055
63.		75	75	2,055
64.		75	75	2,055
65.		75	75	2,055
66.		75	75	2,055
67.		75	75	2,055
68.		75	75	2,055
69.		75	75	2,055
70.		75	75	2,055
71.		75	75	2,055
72.		75	75	2,055
73.		76	76	2,082
74.		76	76	2,082
75.		76	76	2,082
76.		76	76	2,082
77.		76	76	2,082
78.		79	79	2,164
79.		81	81	2,219
80.		85	85	2,329
81.		85	85	2,329
82.		85	85	2,329
83.		85	85	2,329
84.		85	85	2,329
85.		85	85	2,329
86.		85	85	2,329
87.		85	85	2,329
88.		89	89	2,438
89.		104	104	2,849
90.		91	91	2,493
91.		104	104	2,849
92.		104	104	2,849
93.		104	104	2,849
94.		104	104	2,849
95.		104	104	2,849
96.		108	108	2,959
97.		108	108	2,959
98.		108	108	2,959
99.		109	109	2,986
100.		109	109	2,986
101.		109	109	2,986
102.		109	109	2,986
103.		109	109	2,986
104.		109	109	2,986
105.		109	109	2,986

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
106.		109	109	2,986
107.		109	109	2,986
108.		109	109	2,986
109.		109	109	2,986
110.		109	109	2,986
111.		109	109	2,986
112.		112	112	3,068
113.		114	114	3,123
114.		114	114	3,123
115.		114	114	3,123
116.		114	114	3,123
117.		114	114	3,123
118.		114	114	3,123
119.		114	114	3,123
120.		114	114	3,123
121.		114	114	3,123
122.		114	114	3,123
123.		114	114	3,123
124.		114	114	3,123
125.		120	120	3,288
126.		122	122	3,342
127.		128	128	3,507
128.		128	128	3,507
129.		130	130	3,562
130.		132	132	3,616
131.		136	136	3,726
132.		141	141	3,863
133.		139	139	3,808
134.		139	139	3,808
135.		143	143	3,918
136.		144	144	3,945
137.		144	144	3,945
138.		144	144	3,945
139.		144	144	3,945
140.		144	144	3,945
141.		144	144	3,945
142.		144	144	3,945
143.		144	144	3,945
144.		144	144	3,945
145.		144	144	3,945
146.		144	144	3,945
147.		147	147	4,027
148.		147	147	4,027
149.		150	150	4,110
150.		151	151	4,137
151.		151	151	4,137
152.		151	151	4,137
153.		151	151	4,137
154.		151	151	4,137
155.		151	151	4,137
156.		151	151	4,137
157.		151	151	4,137
158.		151	151	4,137

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
159.		151	151	4,137
160.		151	151	4,137
161.		151	151	4,137
162.		151	151	4,137
163.		151	151	4,137
164.		151	151	4,137
165.		151	151	4,137
166.		151	151	4,137
167.		151	151	4,137
168.		152	152	4,164
169.		153	153	4,192
170.		153	153	4,192
171.		153	153	4,192
172.		153	153	4,192
173.		153	153	4,192
174.		153	153	4,192
175.		153	153	4,192
176.		153	153	4,192
177.		153	153	4,192
178.		153	153	4,192
179.		153	153	4,192
180.		154	154	4,219
181.		154	154	4,219
182.		154	154	4,219
183.		154	154	4,219
184.		154	154	4,219
185.		154	154	4,219
186.		154	154	4,219
187.		154	154	4,219
188.		154	154	4,219
189.		154	154	4,219
190.		154	154	4,219
191.		154	154	4,219
192.		154	154	4,219
193.		154	154	4,219
194.		154	154	4,219
195.		154	154	4,219
196.		162	162	4,438
197.		163	163	4,466
198.		268	268	7,342
199.		169	169	4,630
200.		188	188	5,151
201.		188	188	5,151
202.		188	188	5,151
203.		194	194	5,315
204.		194	194	5,315
205.		194	194	5,315
206.		194	194	5,315
207.		194	194	5,315
208.		194	194	5,315
209.		194	194	5,315
210.		205	205	5,616
211.		205	205	5,616

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
212.		205	205	5,616
213.		205	205	5,616
214.		205	205	5,616
215.		205	205	5,616
216.		205	205	5,616
217.		205	205	5,616
218.		205	205	5,616
219.		205	205	5,616
220.		212	212	5,808
221.		212	212	5,808
222.		212	212	5,808
223.		212	212	5,808
224.		212	212	5,808
225.		212	212	5,808
226.		212	212	5,808
227.		212	212	5,808
228.		212	212	5,808
229.		212	212	5,808
230.		212	212	5,808
231.		212	212	5,808
232.		212	212	5,808
233.		212	212	5,808
234.		212	212	5,808
235.		212	212	5,808
236.		212	212	5,808
237.		212	212	5,808
238.		212	212	5,808
239.		212	212	5,808
240.		212	212	5,808
241.		212	212	5,808
242.		212	212	5,808
243.		213	213	5,836
244.		219	219	6,000
245.		219	219	6,000
246.		219	219	6,000
247.		219	219	6,000
248.		219	219	6,000
249.		219	219	6,000
250.		219	219	6,000
251.		219	219	6,000
252.		226	226	6,192
253.		229	229	6,274
254.		231	231	6,329
255.		232	232	6,356
256.		239	239	6,548
257.		244	244	6,685
258.		244	244	6,685
259.		244	244	6,685
260.		244	244	6,685
261.		244	244	6,685
262.		244	244	6,685
263.		244	244	6,685
264.		244	244	6,685

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	**H2** Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	**H3** Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	**I** Maximum credit amount for the tax year (see note 2 below) 445
265.		244	244	6,685
266.		244	244	6,685
267.		246	246	6,740
268.		247	247	6,767
269.		247	247	6,767
270.		247	247	6,767
271.		247	247	6,767
272.		247	247	6,767
273.		247	247	6,767
274.		247	247	6,767
275.		247	247	6,767
276.		247	247	6,767
277.		247	247	6,767
278.		247	247	6,767
279.		247	247	6,767
280.		247	247	6,767
281.		247	247	6,767
282.		247	247	6,767
283.		255	255	6,986
284.		263	263	7,205
285.		265	265	7,260
286.		268	268	7,342
287.		268	268	7,342
288.		268	268	7,342
289.		268	268	7,342
290.		268	268	7,342
291.		268	268	7,342
292.		268	268	7,342
293.		268	268	7,342
294.		268	268	7,342
295.		268	268	7,342
296.		268	268	7,342
297.		268	268	7,342
298.		268	268	7,342
299.		268	268	7,342
300.		268	268	7,342
301.		268	268	7,342
302.		268	268	7,342
303.		268	268	7,342
304.		268	268	7,342
305.		268	268	7,342
306.		268	268	7,342
307.		268	268	7,342
308.		268	268	7,342
309.		268	268	7,342
310.		268	268	7,342
311.		268	268	7,342
312.		268	268	7,342
313.		281	281	7,699
314.		292	292	8,000
315.		292	292	8,000
316.		302	302	8,274
317.		302	302	8,274

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
318.		302	302	8,274
319.		302	302	8,274
320.		302	302	8,274
321.		302	302	8,274
322.		310	310	8,493
323.		310	310	8,493
324.		310	310	8,493
325.		310	310	8,493
326.		310	310	8,493
327.		310	310	8,493
328.		310	310	8,493
329.		310	310	8,493
330.		310	310	8,493
331.		310	310	8,493
332.		310	310	8,493
333.		310	310	8,493
334.		310	310	8,493
335.		310	310	8,493
336.		310	310	8,493
337.		317	317	8,685
338.		320	320	8,767
339.		365	365	10,000
340.		365	365	10,000
341.		338	338	9,260
342.		338	338	9,260
343.		338	338	9,260
344.		338	338	9,260
345.		338	338	9,260
346.		338	338	9,260
347.		338	338	9,260
348.		338	338	9,260
349.		338	338	9,260
350.		338	338	9,260
351.		338	338	9,260
352.		338	338	9,260
353.		338	338	9,260
354.		338	338	9,260
355.		338	338	9,260
356.		338	338	9,260
357.		338	338	9,260
358.		338	338	9,260
359.		338	338	9,260
360.		338	338	9,260
361.		338	338	9,260
362.		343	343	9,397
363.		343	343	9,397
364.		365	365	10,000
365.		365	365	10,000
366.		365	365	10,000
367.		365	365	10,000
368.		365	365	10,000
369.		365	365	10,000
370.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
371.		365	365	10,000
372.		365	365	10,000
373.		365	365	10,000
374.		365	365	10,000
375.		365	365	10,000
376.		365	365	10,000
377.		365	365	10,000
378.		365	365	10,000
379.		365	365	10,000
380.		365	365	10,000
381.		365	365	10,000
382.		365	365	10,000
383.		365	365	10,000
384.		365	365	10,000
385.		365	365	10,000
386.		365	365	10,000
387.		365	365	10,000
388.		365	365	10,000
389.		365	365	10,000
390.		365	365	10,000
391.		365	365	10,000
392.		365	365	10,000
393.		365	365	10,000
394.		365	365	10,000
395.		365	365	10,000
396.		365	365	10,000
397.		365	365	10,000
398.		365	365	10,000
399.		365	365	10,000
400.		365	365	10,000
401.		365	365	10,000
402.		365	365	10,000
403.		365	365	10,000
404.		365	365	10,000
405.		365	365	10,000
406.		365	365	10,000
407.		365	365	10,000
408.		365	365	10,000
409.		365	365	10,000
410.		365	365	10,000
411.		365	365	10,000
412.		365	365	10,000
413.		365	365	10,000
414.		365	365	10,000
415.		365	365	10,000
416.		365	365	10,000
417.		365	365	10,000
418.		365	365	10,000
419.		365	365	10,000
420.		365	365	10,000
421.		365	365	10,000
422.		365	365	10,000
423.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	**H2** Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	**H3** Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	**I** Maximum credit amount for the tax year (see note 2 below) 445
424.		365	365	10,000
425.		365	365	10,000
426.		365	365	10,000
427.		365	365	10,000
428.		365	365	10,000
429.		365	365	10,000
430.		365	365	10,000
431.		365	365	10,000
432.		365	365	10,000
433.		365	365	10,000
434.		365	365	10,000
435.		365	365	10,000
436.		365	365	10,000
437.		365	365	10,000
438.		365	365	10,000
439.		365	365	10,000
440.		365	365	10,000
441.		365	365	10,000
442.		365	365	10,000
443.		365	365	10,000
444.		365	365	10,000
445.		365	365	10,000
446.		365	365	10,000
447.		365	365	10,000
448.		365	365	10,000
449.		365	365	10,000
450.		365	365	10,000
451.		365	365	10,000
452.		365	365	10,000
453.		365	365	10,000
454.		365	365	10,000
455.		365	365	10,000
456.		365	365	10,000
457.		365	365	10,000
458.		365	365	10,000
459.		365	365	10,000
460.		365	365	10,000
461.		365	365	10,000
462.		365	365	10,000
463.		365	365	10,000
464.		365	365	10,000
465.		365	365	10,000
466.		365	365	10,000
467.		365	365	10,000
468.		365	365	10,000
469.		365	365	10,000
470.		365	365	10,000
471.		365	365	10,000
472.		365	365	10,000
473.		365	365	10,000
474.		365	365	10,000
475.		365	365	10,000
476.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
477.		365	365	10,000
478.		365	365	10,000
479.		365	365	10,000
480.		365	365	10,000
481.		365	365	10,000
482.		365	365	10,000
483.		365	365	10,000
484.		365	365	10,000
485.		365	365	10,000
486.		365	365	10,000
487.		365	365	10,000
488.		365	365	10,000
489.		365	365	10,000
490.		365	365	10,000
491.		365	365	10,000
492.		365	365	10,000
493.		365	365	10,000
494.		365	365	10,000
495.		365	365	10,000
496.		365	365	10,000
497.		365	365	10,000
498.		365	365	10,000
499.		365	365	10,000
500.		365	365	10,000
501.		365	365	10,000
502.		365	365	10,000
503.		365	365	10,000
504.		365	365	10,000
505.		365	365	10,000
506.		365	365	10,000
507.		365	365	10,000
508.		365	365	10,000
509.		365	365	10,000
510.		365	365	10,000
511.		365	365	10,000
512.		365	365	10,000
513.		365	365	10,000
514.		365	365	10,000
515.		365	365	10,000
516.		365	365	10,000
517.		365	365	10,000
518.		365	365	10,000
519.		365	365	10,000
520.		365	365	10,000
521.		365	365	10,000
522.		365	365	10,000
523.		365	365	10,000
524.		365	365	10,000
525.		365	365	10,000
526.		365	365	10,000
527.		365	365	10,000
528.		365	365	10,000
529.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
530.		365	365	10,000
531.		365	365	10,000
532.		365	365	10,000
533.		365	365	10,000
534.		365	365	10,000
535.		365	365	10,000
536.		365	365	10,000
537.		365	365	10,000
538.		365	365	10,000
539.		365	365	10,000
540.		365	365	10,000
541.		365	365	10,000
542.		365	365	10,000
543.		365	365	10,000
544.		365	365	10,000
545.		365	365	10,000
546.		365	365	10,000
547.		365	365	10,000
548.		365	365	10,000
549.		365	365	10,000
550.		365	365	10,000
551.		365	365	10,000
552.		365	365	10,000
553.		365	365	10,000
554.		365	365	10,000
555.		365	365	10,000
556.		365	365	10,000
557.		365	365	10,000
558.		365	365	10,000
559.		365	365	10,000
560.		365	365	10,000
561.		365	365	10,000
562.		365	365	10,000
563.		365	365	10,000
564.		365	365	10,000
565.		365	365	10,000
566.		365	365	10,000
567.		365	365	10,000
568.		365	365	10,000
569.		365	365	10,000
570.		365	365	10,000
571.		365	365	10,000
572.		365	365	10,000
573.		365	365	10,000
574.		365	365	10,000
575.		365	365	10,000
576.		365	365	10,000
577.		365	365	10,000
578.		365	365	10,000
579.		365	365	10,000
580.		365	365	10,000
581.		365	365	10,000
582.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
583.		365	365	10,000
584.		365	365	10,000
585.		365	365	10,000
586.		365	365	10,000
587.		365	365	10,000
588.		365	365	10,000
589.		365	365	10,000
590.		365	365	10,000
591.		365	365	10,000
592.		365	365	10,000
593.		365	365	10,000
594.		365	365	10,000
595.		365	365	10,000
596.		365	365	10,000
597.		365	365	10,000
598.		365	365	10,000
599.		365	365	10,000
600.		365	365	10,000
601.		365	365	10,000
602.		365	365	10,000
603.		365	365	10,000
604.		365	365	10,000
605.		365	365	10,000
606.		365	365	10,000
607.		365	365	10,000
608.		365	365	10,000
609.		365	365	10,000
610.		365	365	10,000
611.		365	365	10,000
612.		365	365	10,000
613.		365	365	10,000
614.		365	365	10,000
615.		365	365	10,000
616.		365	365	10,000
617.		365	365	10,000
618.		365	365	10,000
619.		365	365	10,000
620.		365	365	10,000
621.		365	365	10,000
622.		365	365	10,000
623.		365	365	10,000
624.		365	365	10,000
625.		365	365	10,000
626.		365	365	10,000
627.		365	365	10,000
628.		365	365	10,000
629.		365	365	10,000
630.		365	365	10,000
631.		365	365	10,000
632.		365	365	10,000
633.		365	365	10,000
634.		365	365	10,000
635.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
636.		365	365	10,000
637.		365	365	10,000
638.		365	365	10,000
639.		365	365	10,000
640.		365	365	10,000
641.		365	365	10,000
642.		365	365	10,000
643.		365	365	10,000
644.		365	365	10,000
645.		365	365	10,000
646.		365	365	10,000
647.		365	365	10,000
648.		365	365	10,000
649.		365	365	10,000
650.		365	365	10,000
651.		365	365	10,000
652.		365	365	10,000
653.		365	365	10,000
654.		365	365	10,000
655.		365	365	10,000
656.		365	365	10,000
657.		365	365	10,000
658.		365	365	10,000
659.		365	365	10,000
660.		365	365	10,000
661.		365	365	10,000
662.		365	365	10,000
663.		365	365	10,000
664.		365	365	10,000
665.		365	365	10,000
666.		365	365	10,000
667.		365	365	10,000
668.		365	365	10,000
669.		365	365	10,000
670.		365	365	10,000
671.		365	365	10,000
672.		365	365	10,000
673.		365	365	10,000
674.		365	365	10,000
675.		365	365	10,000
676.		365	365	10,000
677.		365	365	10,000
678.		365	365	10,000
679.		365	365	10,000
680.		365	365	10,000
681.		365	365	10,000
682.		365	365	10,000
683.		365	365	10,000
684.		365	365	10,000
685.		365	365	10,000
686.		365	365	10,000
687.		365	365	10,000
688.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
689.		365	365	10,000
690.		365	365	10,000
691.		365	365	10,000
692.		365	365	10,000
693.		365	365	10,000
694.		365	365	10,000
695.		365	365	10,000
696.		365	365	10,000
697.		365	365	10,000
698.		365	365	10,000
699.		365	365	10,000
700.		365	365	10,000
701.		365	365	10,000
702.		365	365	10,000
703.		365	365	10,000
704.		365	365	10,000
705.		365	365	10,000
706.		365	365	10,000
707.		365	365	10,000
708.		365	365	10,000
709.		365	365	10,000
710.		365	365	10,000
711.		365	365	10,000
712.		365	365	10,000
713.		365	365	10,000
714.		365	365	10,000
715.		365	365	10,000
716.		365	365	10,000
717.		365	365	10,000
718.		365	365	10,000
719.		365	365	10,000
720.		365	365	10,000
721.		365	365	10,000
722.		365	365	10,000
723.		365	365	10,000
724.		365	365	10,000
725.		365	365	10,000
726.		365	365	10,000
727.		365	365	10,000
728.		365	365	10,000
729.		365	365	10,000
730.		365	365	10,000
731.		365	365	10,000
732.		365	365	10,000
733.		365	365	10,000
734.		365	365	10,000
735.		365	365	10,000
736.		365	365	10,000
737.		365	365	10,000
738.		365	365	10,000
739.		365	365	10,000
740.		365	365	10,000
741.		365	365	10,000

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
742.		365	365	10,000
743.		365	365	10,000
744.		365	365	10,000
745.		365	365	10,000
746.		365	365	10,000
747.		365	365	10,000
748.		365	365	10,000
749.		365	365	10,000
750.		365	365	10,000
751.		365	365	10,000
752.		365	365	10,000
753.		365	365	10,000
754.		365	365	10,000
755.		365	365	10,000
756.		365	365	10,000
757.		365	365	10,000
758.		365	365	10,000
759.		365	365	10,000
760.		365	365	10,000
761.		365	365	10,000

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		95,494	95,494	33,423
2.		117,952	117,952	41,283
3.		111,697	111,697	39,094
4.		76,322	76,322	26,713
5.		94,146	94,146	32,951
6.		84,859	84,859	29,701
7.		46,294	46,294	16,203
8.		76,746	76,746	26,861
9.		1,910	1,910	669
10.		4,227	4,227	1,479
11.		104,851	104,851	36,698
12.		81,086	81,086	28,380
13.		79,072	79,072	27,675
14.		80,562	80,562	28,197
15.		92,584	92,584	32,404
16.		103,301	103,301	36,155
17.		101,164	101,164	35,407
18.		139,024	139,024	48,658
19.		115,011	115,011	40,254
20.		148,125	148,125	51,844
21.		145,183	145,183	50,814
22.		122,333	122,333	42,817
23.		134,332	134,332	47,016
24.		126,666	126,666	44,333
25.		48,439	48,439	16,954
26.		117,227	117,227	41,029

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
27.		140,748	140,748	49,262
28.		123,516	123,516	43,231
29.		102,082	102,082	35,729
30.		75,556	75,556	26,445
31.		74,998	74,998	26,249
32.		93,165	93,165	32,608
33.		2,896	2,896	1,014
34.		86,561	86,561	30,296
35.		85,044	85,044	29,765
36.		86,562	86,562	30,297
37.		118,351	118,351	41,423
38.		130,170	130,170	45,560
39.		87,971	87,971	30,790
40.		136,598	136,598	47,809
41.		113,983	113,983	39,894
42.		131,182	131,182	45,914
43.		115,232	115,232	40,331
44.		31,740	31,740	11,109
45.		112,704	112,704	39,446
46.		121,791	121,791	42,627
47.		110,094	110,094	38,533
48.		116,613	116,613	40,815
49.		115,553	115,553	40,444
50.		126,599	126,599	44,310
51.		138,984	138,984	48,644
52.		106,205	106,205	37,172
53.		125,195	125,195	43,818
54.		116,518	116,518	40,781
55.		82,797	82,797	28,979
56.		85,494	85,494	29,923
57.		14,791	14,791	5,177
58.		74,010	74,010	25,904
59.		9,542	9,542	3,340
60.		5,955	5,955	2,084
61.		124,443	124,443	43,555
62.		110,245	110,245	38,586
63.		106,104	106,104	37,136
64.		106,572	106,572	37,300
65.		113,854	113,854	39,849
66.		144,347	144,347	50,521
67.		132,489	132,489	46,371
68.		103,052	103,052	36,068
69.		89,077	89,077	31,177
70.		108,762	108,762	38,067
71.		112,908	112,908	39,518
72.		105,504	105,504	36,926
73.		7,296	7,296	2,554
74.		8,178	8,178	2,862
75.		8,178	8,178	2,862
76.		7,231	7,231	2,531
77.		9,390	9,390	3,287
78.		95,105	95,105	33,287
79.		101,145	101,145	35,401

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
80.		46,081	46,081	16,128
81.		52,204	52,204	18,271
82.		115,526	115,526	40,434
83.		74,740	74,740	26,159
84.		56,649	56,649	19,827
85.		81,755	81,755	28,614
86.		23,073	23,073	8,076
87.		18,658	18,658	6,530
88.		58,298	58,298	20,404
89.		7,018	7,018	2,456
90.		7,897	7,897	2,764
91.		39,867	39,867	13,953
92.		11,762	11,762	4,117
93.		11,586	11,586	4,055
94.		16,951	16,951	5,933
95.		10,568	10,568	3,699
96.		108,610	108,610	38,014
97.		107,839	107,839	37,744
98.		83,015	83,015	29,055
99.		98,813	98,813	34,585
100.		99,612	99,612	34,864
101.		80,102	80,102	28,036
102.		101,493	101,493	35,523
103.		95,482	95,482	33,419
104.		108,326	108,326	37,914
105.		62,205	62,205	21,772
106.		119,717	119,717	41,901
107.		106,047	106,047	37,116
108.		99,154	99,154	34,704
109.		93,200	93,200	32,620
110.		90,069	90,069	31,524
111.		95,196	95,196	33,319
112.		61,348	61,348	21,472
113.		36,120	36,120	12,642
114.		37,791	37,791	13,227
115.		38,887	38,887	13,610
116.		30,058	30,058	10,520
117.		14,561	14,561	5,096
118.		34,756	34,756	12,165
119.		12,345	12,345	4,321
120.		50,325	50,325	17,614
121.		29,672	29,672	10,385
122.		52,543	52,543	18,390
123.		36,016	36,016	12,606
124.		38,356	38,356	13,425
125.		94,290	94,290	33,002
126.		73,173	73,173	25,611
127.		19,748	19,748	6,912
128.		13,404	13,404	4,691
129.		107,939	107,939	37,779
130.		21,107	21,107	7,387
131.		60,223	60,223	21,078
132.		10,764	10,764	3,767

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
133.		21,447	21,447	7,506
134.		16,490	16,490	5,772
135.		97,652	97,652	34,178
136.		94,526	94,526	33,084
137.		101,861	101,861	35,651
138.		83,282	83,282	29,149
139.		95,941	95,941	33,579
140.		77,904	77,904	27,266
141.		75,671	75,671	26,485
142.		87,181	87,181	30,513
143.		87,050	87,050	30,468
144.		87,799	87,799	30,730
145.		76,774	76,774	26,871
146.		103,634	103,634	36,272
147.		107,299	107,299	37,555
148.		71,630	71,630	25,071
149.		69,456	69,456	24,310
150.		108,613	108,613	38,015
151.		83,002	83,002	29,051
152.		84,034	84,034	29,412
153.		57,054	57,054	19,969
154.		121,930	121,930	42,676
155.		89,964	89,964	31,487
156.		133,092	133,092	46,582
157.		25,571	25,571	8,950
158.		109,109	109,109	38,188
159.		77,154	77,154	27,004
160.		88,299	88,299	30,905
161.		75,610	75,610	26,464
162.		83,315	83,315	29,160
163.		77,947	77,947	27,281
164.		104,682	104,682	36,639
165.		78,144	78,144	27,350
166.		72,914	72,914	25,520
167.		61,161	61,161	21,406
168.		90,679	90,679	31,738
169.		71,818	71,818	25,136
170.		45,514	45,514	15,930
171.		45,437	45,437	15,903
172.		18,044	18,044	6,315
173.		19,944	19,944	6,980
174.		19,091	19,091	6,682
175.		17,139	17,139	5,999
176.		19,779	19,779	6,923
177.		18,091	18,091	6,332
178.		17,898	17,898	6,264
179.		17,868	17,868	6,254
180.		102,282	102,282	35,799
181.		49,747	49,747	17,411
182.		50,723	50,723	17,753
183.		54,967	54,967	19,238
184.		51,632	51,632	18,071
185.		47,784	47,784	16,724

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
186.		36,552	36,552	12,793
187.		30,795	30,795	10,778
188.		28,942	28,942	10,130
189.		27,496	27,496	9,624
190.		19,902	19,902	6,966
191.		27,627	27,627	9,669
192.		26,788	26,788	9,376
193.		22,895	22,895	8,013
194.		18,527	18,527	6,484
195.		20,937	20,937	7,328
196.		60,973	60,973	21,341
197.		14,758	14,758	5,165
198.		12,846	12,846	4,496
199.		69,859	69,859	24,451
200.		33,827	33,827	11,839
201.		17,316	17,316	6,061
202.		19,538	19,538	6,838
203.		19,094	19,094	6,683
204.		57,972	57,972	20,290
205.		50,868	50,868	17,804
206.		60,126	60,126	21,044
207.		43,588	43,588	15,256
208.		71,116	71,116	24,891
209.		75,426	75,426	26,399
210.		42,694	42,694	14,943
211.		37,999	37,999	13,300
212.		24,200	24,200	8,470
213.		41,740	41,740	14,609
214.		17,436	17,436	6,103
215.		24,457	24,457	8,560
216.		22,919	22,919	8,022
217.		22,654	22,654	7,929
218.		30,269	30,269	10,594
219.		22,708	22,708	7,948
220.		24,641	24,641	8,624
221.		31,483	31,483	11,019
222.		34,415	34,415	12,045
223.		17,399	17,399	6,090
224.		25,838	25,838	9,043
225.		24,843	24,843	8,695
226.		37,142	37,142	13,000
227.		25,571	25,571	8,950
228.		21,313	21,313	7,460
229.		26,591	26,591	9,307
230.		23,414	23,414	8,195
231.		25,345	25,345	8,871
232.		22,418	22,418	7,846
233.		26,790	26,790	9,377
234.		36,050	36,050	12,618
235.		35,825	35,825	12,539
236.		59,244	59,244	20,735
237.		24,422	24,422	8,548
238.		35,618	35,618	12,466

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
239.		35,409	35,409	12,393
240.		62,646	62,646	21,926
241.		47,234	47,234	16,532
242.		35,524	35,524	12,433
243.		69,292	69,292	24,252
244.		72,908	72,908	25,518
245.		64,000	64,000	22,400
246.		38,931	38,931	13,626
247.		25,042	25,042	8,765
248.		41,446	41,446	14,506
249.		28,627	28,627	10,019
250.		26,711	26,711	9,349
251.		32,433	32,433	11,352
252.		66,873	66,873	23,406
253.		36,395	36,395	12,738
254.		42,964	42,964	15,037
255.		70,634	70,634	24,722
256.		28,610	28,610	10,014
257.		26,367	26,367	9,228
258.		20,722	20,722	7,253
259.		26,103	26,103	9,136
260.		19,949	19,949	6,982
261.		25,913	25,913	9,070
262.		26,504	26,504	9,276
263.		30,077	30,077	10,527
264.		28,192	28,192	9,867
265.		30,762	30,762	10,767
266.		25,924	25,924	9,073
267.		82,452	82,452	28,858
268.		38,595	38,595	13,508
269.		33,933	33,933	11,877
270.		33,510	33,510	11,729
271.		33,892	33,892	11,862
272.		37,119	37,119	12,992
273.		36,271	36,271	12,695
274.		34,227	34,227	11,979
275.		32,680	32,680	11,438
276.		39,271	39,271	13,745
277.		53,176	53,176	18,612
278.		35,134	35,134	12,297
279.		35,522	35,522	12,433
280.		32,646	32,646	11,426
281.		37,339	37,339	13,069
282.		45,452	45,452	15,908
283.		55,647	55,647	19,476
284.		71,880	71,880	25,158
285.		49,281	49,281	17,248
286.		31,924	31,924	11,173
287.		32,951	32,951	11,533
288.		37,956	37,956	13,285
289.		33,032	33,032	11,561
290.		30,900	30,900	10,815
291.		31,007	31,007	10,852

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
292.		28,599	28,599	10,010
293.		28,835	28,835	10,092
294.		28,151	28,151	9,853
295.		32,200	32,200	11,270
296.		41,166	41,166	14,408
297.		46,540	46,540	16,289
298.		46,238	46,238	16,183
299.		43,609	43,609	15,263
300.		67,242	67,242	23,535
301.		43,079	43,079	15,078
302.		43,871	43,871	15,355
303.		44,633	44,633	15,622
304.		41,580	41,580	14,553
305.		42,129	42,129	14,745
306.		37,994	37,994	13,298
307.		39,518	39,518	13,831
308.		51,044	51,044	17,865
309.		32,347	32,347	11,321
310.		44,050	44,050	15,418
311.		35,215	35,215	12,325
312.		44,199	44,199	15,470
313.		62,312	62,312	21,809
314.		63,654	63,654	22,279
315.		71,194	71,194	24,918
316.		52,776	52,776	18,472
317.		77,421	77,421	27,097
318.		60,080	60,080	21,028
319.		65,095	65,095	22,783
320.		66,676	66,676	23,337
321.		64,045	64,045	22,416
322.		82,699	82,699	28,945
323.		42,336	42,336	14,818
324.		54,664	54,664	19,132
325.		49,646	49,646	17,376
326.		53,205	53,205	18,622
327.		54,908	54,908	19,218
328.		44,728	44,728	15,655
329.		49,157	49,157	17,205
330.		45,272	45,272	15,845
331.		49,237	49,237	17,233
332.		55,491	55,491	19,422
333.		51,551	51,551	18,043
334.		39,212	39,212	13,724
335.		44,065	44,065	15,423
336.		54,714	54,714	19,150
337.		63,950	63,950	22,383
338.		97,307	97,307	34,057
339.		25,345	25,345	8,871
340.		25,448	25,448	8,907
341.		51,200	51,200	17,920
342.		52,153	52,153	18,254
343.		44,763	44,763	15,667
344.		59,883	59,883	20,959

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
345.		50,073	50,073	17,526
346.		55,112	55,112	19,289
347.		48,770	48,770	17,070
348.		55,240	55,240	19,334
349.		54,199	54,199	18,970
350.		50,855	50,855	17,799
351.		50,141	50,141	17,549
352.		48,439	48,439	16,954
353.		46,177	46,177	16,162
354.		58,464	58,464	20,462
355.		47,626	47,626	16,669
356.		46,981	46,981	16,443
357.		50,184	50,184	17,564
358.		47,182	47,182	16,514
359.		41,822	41,822	14,638
360.		56,856	56,856	19,900
361.		41,993	41,993	14,698
362.		79,966	79,966	27,988
363.		78,862	78,862	27,602
364.		96,974	96,974	33,941
365.		119,784	119,784	41,924
366.		58,543	58,543	20,490
367.		70,126	70,126	24,544
368.		56,562	56,562	19,797
369.		71,716	71,716	25,101
370.		72,305	72,305	25,307
371.		78,909	78,909	27,618
372.		54,523	54,523	19,083
373.		57,749	57,749	20,212
374.		73,959	73,959	25,886
375.		48,603	48,603	17,011
376.		104,873	104,873	36,706
377.		91,374	91,374	31,981
378.		90,492	90,492	31,672
379.		77,974	77,974	27,291
380.		90,698	90,698	31,744
381.		101,463	101,463	35,512
382.		85,143	85,143	29,800
383.		91,180	91,180	31,913
384.		81,710	81,710	28,599
385.		96,323	96,323	33,713
386.		89,344	89,344	31,270
387.		49,725	49,725	17,404
388.		98,206	98,206	34,372
389.		48,278	48,278	16,897
390.		72,708	72,708	25,448
391.		101,118	101,118	35,391
392.		95,027	95,027	33,259
393.		86,478	86,478	30,267
394.		108,605	108,605	38,012
395.		94,898	94,898	33,214
396.		88,151	88,151	30,853
397.		119,731	119,731	41,906

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
398.		108,837	108,837	38,093
399.		87,762	87,762	30,717
400.		82,669	82,669	28,934
401.		90,561	90,561	31,696
402.		96,412	96,412	33,744
403.		85,809	85,809	30,033
404.		89,198	89,198	31,219
405.		87,315	87,315	30,560
406.		38,261	38,261	13,391
407.		78,955	78,955	27,634
408.		83,263	83,263	29,142
409.		76,568	76,568	26,799
410.		79,626	79,626	27,869
411.		97,045	97,045	33,966
412.		82,447	82,447	28,856
413.		108,468	108,468	37,964
414.		81,651	81,651	28,578
415.		77,877	77,877	27,257
416.		79,260	79,260	27,741
417.		86,938	86,938	30,428
418.		94,507	94,507	33,077
419.		90,988	90,988	31,846
420.		78,164	78,164	27,357
421.		93,771	93,771	32,820
422.		100,986	100,986	35,345
423.		88,410	88,410	30,944
424.		90,831	90,831	31,791
425.		110,047	110,047	38,516
426.		95,892	95,892	33,562
427.		86,446	86,446	30,256
428.		107,224	107,224	37,528
429.		98,234	98,234	34,382
430.		81,457	81,457	28,510
431.		74,587	74,587	26,105
432.		102,299	102,299	35,805
433.		89,390	89,390	31,287
434.		81,460	81,460	28,511
435.		96,553	96,553	33,794
436.		84,113	84,113	29,440
437.		92,312	92,312	32,309
438.		91,042	91,042	31,865
439.		115,165	115,165	40,308
440.		43,279	43,279	15,148
441.		69,764	69,764	24,417
442.		86,809	86,809	30,383
443.		97,314	97,314	34,060
444.		109,387	109,387	38,285
445.		90,611	90,611	31,714
446.		93,824	93,824	32,838
447.		73,030	73,030	25,561
448.		93,811	93,811	32,834
449.		96,579	96,579	33,803
450.		98,641	98,641	34,524

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
451.		83,594	83,594	29,258
452.		82,056	82,056	28,720
453.		44,772	44,772	15,670
454.		57,347	57,347	20,071
455.		54,418	54,418	19,046
456.		76,304	76,304	26,706
457.		95,688	95,688	33,491
458.		81,919	81,919	28,672
459.		83,070	83,070	29,075
460.		100,794	100,794	35,278
461.		92,751	92,751	32,463
462.		87,055	87,055	30,469
463.		93,531	93,531	32,736
464.		92,364	92,364	32,327
465.		80,304	80,304	28,106
466.		68,093	68,093	23,833
467.		65,249	65,249	22,837
468.		53,911	53,911	18,869
469.		63,642	63,642	22,275
470.		68,900	68,900	24,115
471.		82,845	82,845	28,996
472.		77,736	77,736	27,208
473.		67,019	67,019	23,457
474.		67,235	67,235	23,532
475.		66,238	66,238	23,183
476.		64,117	64,117	22,441
477.		78,961	78,961	27,636
478.		66,508	66,508	23,278
479.		74,774	74,774	26,171
480.		72,130	72,130	25,246
481.		63,009	63,009	22,053
482.		64,904	64,904	22,716
483.		136,884	136,884	47,909
484.		82,554	82,554	28,894
485.		82,699	82,699	28,945
486.		96,130	96,130	33,646
487.		75,452	75,452	26,408
488.		83,729	83,729	29,305
489.		69,083	69,083	24,179
490.		89,879	89,879	31,458
491.		121,941	121,941	42,679
492.		104,957	104,957	36,735
493.		113,504	113,504	39,726
494.		77,193	77,193	27,018
495.		59,103	59,103	20,686
496.		69,137	69,137	24,198
497.		79,166	79,166	27,708
498.		63,502	63,502	22,226
499.		62,345	62,345	21,821
500.		83,544	83,544	29,240
501.		71,038	71,038	24,863
502.		71,692	71,692	25,092
503.		77,741	77,741	27,209

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
504.		69,802	69,802	24,431
505.		69,214	69,214	24,225
506.		69,798	69,798	24,429
507.		60,946	60,946	21,331
508.		70,926	70,926	24,824
509.		93,430	93,430	32,701
510.		73,645	73,645	25,776
511.		79,573	79,573	27,851
512.		81,074	81,074	28,376
513.		92,961	92,961	32,536
514.		35,056	35,056	12,270
515.		71,168	71,168	24,909
516.		83,402	83,402	29,191
517.		75,088	75,088	26,281
518.		84,005	84,005	29,402
519.		46,477	46,477	16,267
520.		67,102	67,102	23,486
521.		64,903	64,903	22,716
522.		69,607	69,607	24,362
523.		76,131	76,131	26,646
524.		63,852	63,852	22,348
525.		77,817	77,817	27,236
526.		65,645	65,645	22,976
527.		66,616	66,616	23,316
528.		71,620	71,620	25,067
529.		55,728	55,728	19,505
530.		71,624	71,624	25,068
531.		66,965	66,965	23,438
532.		71,456	71,456	25,010
533.		55,272	55,272	19,345
534.		57,004	57,004	19,951
535.		63,395	63,395	22,188
536.		50,284	50,284	17,599
537.		48,436	48,436	16,953
538.		56,096	56,096	19,634
539.		53,633	53,633	18,772
540.		58,382	58,382	20,434
541.		73,348	73,348	25,672
542.		80,391	80,391	28,137
543.		58,904	58,904	20,616
544.		57,775	57,775	20,221
545.		33,832	33,832	11,841
546.		46,364	46,364	16,227
547.		63,438	63,438	22,203
548.		78,694	78,694	27,543
549.		85,379	85,379	29,883
550.		72,722	72,722	25,453
551.		74,249	74,249	25,987
552.		78,689	78,689	27,541
553.		72,402	72,402	25,341
554.		79,196	79,196	27,719
555.		80,514	80,514	28,180
556.		78,342	78,342	27,420

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	**J2** Eligible expenditures after March 26, 2009 (see note 3 below) 452	**J3** Eligible expenditures for the tax year (column J1 **plus** column J2) 450	**K** Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
557.		74,197	74,197	25,969
558.		80,489	80,489	28,171
559.		80,665	80,665	28,233
560.		71,283	71,283	24,949
561.		50,672	50,672	17,735
562.		66,627	66,627	23,319
563.		58,013	58,013	20,305
564.		55,740	55,740	19,509
565.		61,611	61,611	21,564
566.		63,304	63,304	22,156
567.		66,523	66,523	23,283
568.		72,455	72,455	25,359
569.		57,303	57,303	20,056
570.		65,387	65,387	22,885
571.		72,276	72,276	25,297
572.		64,938	64,938	22,728
573.		67,495	67,495	23,623
574.		74,315	74,315	26,010
575.		57,478	57,478	20,117
576.		63,863	63,863	22,352
577.		83,233	83,233	29,132
578.		72,337	72,337	25,318
579.		66,831	66,831	23,391
580.		88,186	88,186	30,865
581.		68,711	68,711	24,049
582.		65,243	65,243	22,835
583.		61,591	61,591	21,557
584.		33,798	33,798	11,829
585.		64,687	64,687	22,640
586.		85,075	85,075	29,776
587.		75,374	75,374	26,381
588.		83,231	83,231	29,131
589.		69,564	69,564	24,347
590.		71,601	71,601	25,060
591.		67,200	67,200	23,520
592.		42,312	42,312	14,809
593.		66,265	66,265	23,193
594.		60,331	60,331	21,116
595.		66,638	66,638	23,323
596.		57,372	57,372	20,080
597.		58,701	58,701	20,545
598.		99,634	99,634	34,872
599.		67,588	67,588	23,656
600.		62,421	62,421	21,847
601.		58,246	58,246	20,386
602.		61,198	61,198	21,419
603.		50,559	50,559	17,696
604.		65,414	65,414	22,895
605.		51,785	51,785	18,125
606.		63,453	63,453	22,209
607.		50,235	50,235	17,582
608.		53,545	53,545	18,741
609.		58,309	58,309	20,408

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
610.		84,154	84,154	29,454
611.		63,350	63,350	22,173
612.		62,333	62,333	21,817
613.		62,750	62,750	21,963
614.		59,755	59,755	20,914
615.		62,729	62,729	21,955
616.		66,307	66,307	23,207
617.		58,930	58,930	20,626
618.		65,974	65,974	23,091
619.		66,093	66,093	23,133
620.		66,230	66,230	23,181
621.		66,575	66,575	23,301
622.		63,288	63,288	22,151
623.		80,380	80,380	28,133
624.		65,131	65,131	22,796
625.		59,454	59,454	20,809
626.		51,309	51,309	17,958
627.		52,505	52,505	18,377
628.		56,157	56,157	19,655
629.		52,143	52,143	18,250
630.		64,950	64,950	22,733
631.		64,004	64,004	22,401
632.		58,593	58,593	20,508
633.		65,460	65,460	22,911
634.		62,244	62,244	21,785
635.		62,217	62,217	21,776
636.		66,960	66,960	23,436
637.		43,525	43,525	15,234
638.		56,005	56,005	19,602
639.		44,439	44,439	15,554
640.		71,750	71,750	25,113
641.		58,867	58,867	20,603
642.		64,715	64,715	22,650
643.		62,310	62,310	21,809
644.		55,840	55,840	19,544
645.		59,587	59,587	20,855
646.		53,773	53,773	18,821
647.		45,465	45,465	15,913
648.		34,371	34,371	12,030
649.		35,639	35,639	12,474
650.		55,025	55,025	19,259
651.		39,521	39,521	13,832
652.		56,942	56,942	19,930
653.		55,263	55,263	19,342
654.		45,721	45,721	16,002
655.		31,194	31,194	10,918
656.		42,644	42,644	14,925
657.		50,820	50,820	17,787
658.		36,170	36,170	12,660
659.		75,794	75,794	26,528
660.		57,710	57,710	20,199
661.		81,237	81,237	28,433
662.		47,590	47,590	16,657

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
663.		42,321	42,321	14,812
664.		54,431	54,431	19,051
665.		73,127	73,127	25,594
666.		55,572	55,572	19,450
667.		53,895	53,895	18,863
668.		73,897	73,897	25,864
669.		46,739	46,739	16,359
670.		67,090	67,090	23,482
671.		46,237	46,237	16,183
672.		55,150	55,150	19,303
673.		43,322	43,322	15,163
674.		46,371	46,371	16,230
675.		44,539	44,539	15,589
676.		41,688	41,688	14,591
677.		45,274	45,274	15,846
678.		55,059	55,059	19,271
679.		53,898	53,898	18,864
680.		55,615	55,615	19,465
681.		36,809	36,809	12,883
682.		48,062	48,062	16,822
683.		51,811	51,811	18,134
684.		58,405	58,405	20,442
685.		61,537	61,537	21,538
686.		48,390	48,390	16,937
687.		50,028	50,028	17,510
688.		56,873	56,873	19,906
689.		46,933	46,933	16,427
690.		52,051	52,051	18,218
691.		45,371	45,371	15,880
692.		75,161	75,161	26,306
693.		63,419	63,419	22,197
694.		70,006	70,006	24,502
695.		59,423	59,423	20,798
696.		94,338	94,338	33,018
697.		67,835	67,835	23,742
698.		75,086	75,086	26,280
699.		60,204	60,204	21,071
700.		66,029	66,029	23,110
701.		64,529	64,529	22,585
702.		69,789	69,789	24,426
703.		29,504	29,504	10,326
704.		38,889	38,889	13,611
705.		52,501	52,501	18,375
706.		66,196	66,196	23,169
707.		62,589	62,589	21,906
708.		50,382	50,382	17,634
709.		54,675	54,675	19,136
710.		60,503	60,503	21,176
711.		92,083	92,083	32,229
712.		49,944	49,944	17,480
713.		86,584	86,584	30,304
714.		59,012	59,012	20,654
715.		64,273	64,273	22,496

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
716.		65,908	65,908	23,068
717.		54,992	54,992	19,247
718.		51,612	51,612	18,064
719.		40,063	40,063	14,022
720.		59,256	59,256	20,740
721.		44,485	44,485	15,570
722.		58,794	58,794	20,578
723.		49,474	49,474	17,316
724.		47,505	47,505	16,627
725.		48,687	48,687	17,040
726.		48,024	48,024	16,808
727.		52,042	52,042	18,215
728.		55,013	55,013	19,255
729.		47,396	47,396	16,589
730.		49,447	49,447	17,306
731.		44,407	44,407	15,542
732.		47,514	47,514	16,630
733.		60,614	60,614	21,215
734.		53,081	53,081	18,578
735.		63,526	63,526	22,234
736.		45,262	45,262	15,842
737.		52,278	52,278	18,297
738.		39,210	39,210	13,724
739.		43,755	43,755	15,314
740.		49,963	49,963	17,487
741.		56,724	56,724	19,853
742.		53,093	53,093	18,583
743.		36,362	36,362	12,727
744.		61,131	61,131	21,396
745.		46,185	46,185	16,165
746.		34,485	34,485	12,070
747.		34,146	34,146	11,951
748.		51,620	51,620	18,067
749.		51,200	51,200	17,920
750.		33,240	33,240	11,634
751.		50,996	50,996	17,849
752.		53,329	53,329	18,665
753.		50,488	50,488	17,671
754.		50,968	50,968	17,839
755.		46,097	46,097	16,134
756.		53,001	53,001	18,550
757.		46,906	46,906	16,417
758.		47,317	47,317	16,561
759.		49,669	49,669	17,384
760.		47,001	47,001	16,450
761.		97,306	97,306	34,057

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	137		137
2.	329		329
3.	329		329
4.	329		329
5.	329		329
6.	329		329
7.	466		466
8.	603		603
9.	630		630
10.	685		685
11.	795		795
12.	822		822
13.	877		877
14.	877		877
15.	904		904
16.	904		904
17.	904		904
18.	904		904
19.	904		904
20.	904		904
21.	904		904
22.	904		904
23.	904		904
24.	904		904
25.	904		904
26.	904		904
27.	904		904
28.	904		904
29.	904		904
30.	904		904
31.	904		904
32.	986		986
33.	1,014		1,014
34.	1,397		1,397
35.	1,425		1,425
36.	1,452		1,452
37.	1,452		1,452
38.	1,479		1,479
39.	1,479		1,479
40.	1,479		1,479
41.	1,479		1,479
42.	1,479		1,479
43.	1,479		1,479
44.	1,479		1,479
45.	1,479		1,479
46.	1,479		1,479
47.	1,479		1,479
48.	1,479		1,479
49.	1,479		1,479
50.	1,479		1,479
51.	1,479		1,479
52.	1,479		1,479
53.	1,479		1,479

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
54.	1,534		1,534
55.	1,534		1,534
56.	1,644		1,644
57.	1,918		1,918
58.	1,918		1,918
59.	1,973		1,973
60.	1,973		1,973
61.	2,000		2,000
62.	2,055		2,055
63.	2,055		2,055
64.	2,055		2,055
65.	2,055		2,055
66.	2,055		2,055
67.	2,055		2,055
68.	2,055		2,055
69.	2,055		2,055
70.	2,055		2,055
71.	2,055		2,055
72.	2,055		2,055
73.	2,082		2,082
74.	2,082		2,082
75.	2,082		2,082
76.	2,082		2,082
77.	2,082		2,082
78.	2,164		2,164
79.	2,219		2,219
80.	2,329		2,329
81.	2,329		2,329
82.	2,329		2,329
83.	2,329		2,329
84.	2,329		2,329
85.	2,329		2,329
86.	2,329		2,329
87.	2,329		2,329
88.	2,438		2,438
89.	2,456		2,456
90.	2,493		2,493
91.	2,849		2,849
92.	2,849		2,849
93.	2,849		2,849
94.	2,849		2,849
95.	2,849		2,849
96.	2,959		2,959
97.	2,959		2,959
98.	2,959		2,959
99.	2,986		2,986
100.	2,986		2,986
101.	2,986		2,986
102.	2,986		2,986
103.	2,986		2,986
104.	2,986		2,986
105.	2,986		2,986
106.	2,986		2,986

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
107.	2,986		2,986
108.	2,986		2,986
109.	2,986		2,986
110.	2,986		2,986
111.	2,986		2,986
112.	3,068		3,068
113.	3,123		3,123
114.	3,123		3,123
115.	3,123		3,123
116.	3,123		3,123
117.	3,123		3,123
118.	3,123		3,123
119.	3,123		3,123
120.	3,123		3,123
121.	3,123		3,123
122.	3,123		3,123
123.	3,123		3,123
124.	3,123		3,123
125.	3,288		3,288
126.	3,342		3,342
127.	3,507		3,507
128.	3,507		3,507
129.	3,562		3,562
130.	3,616		3,616
131.	3,726		3,726
132.	3,767		3,767
133.	3,808		3,808
134.	3,808		3,808
135.	3,918		3,918
136.	3,945		3,945
137.	3,945		3,945
138.	3,945		3,945
139.	3,945		3,945
140.	3,945		3,945
141.	3,945		3,945
142.	3,945		3,945
143.	3,945		3,945
144.	3,945		3,945
145.	3,945		3,945
146.	3,945		3,945
147.	4,027		4,027
148.	4,027		4,027
149.	4,110		4,110
150.	4,137		4,137
151.	4,137		4,137
152.	4,137		4,137
153.	4,137		4,137
154.	4,137		4,137
155.	4,137		4,137
156.	4,137		4,137
157.	4,137		4,137
158.	4,137		4,137
159.	4,137		4,137

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
160.	4,137		4,137
161.	4,137		4,137
162.	4,137		4,137
163.	4,137		4,137
164.	4,137		4,137
165.	4,137		4,137
166.	4,137		4,137
167.	4,137		4,137
168.	4,164		4,164
169.	4,192		4,192
170.	4,192		4,192
171.	4,192		4,192
172.	4,192		4,192
173.	4,192		4,192
174.	4,192		4,192
175.	4,192		4,192
176.	4,192		4,192
177.	4,192		4,192
178.	4,192		4,192
179.	4,192		4,192
180.	4,219		4,219
181.	4,219		4,219
182.	4,219		4,219
183.	4,219		4,219
184.	4,219		4,219
185.	4,219		4,219
186.	4,219		4,219
187.	4,219		4,219
188.	4,219		4,219
189.	4,219		4,219
190.	4,219		4,219
191.	4,219		4,219
192.	4,219		4,219
193.	4,219		4,219
194.	4,219		4,219
195.	4,219		4,219
196.	4,438		4,438
197.	4,466		4,466
198.	4,496		4,496
199.	4,630		4,630
200.	5,151		5,151
201.	5,151		5,151
202.	5,151		5,151
203.	5,315		5,315
204.	5,315		5,315
205.	5,315		5,315
206.	5,315		5,315
207.	5,315		5,315
208.	5,315		5,315
209.	5,315		5,315
210.	5,616		5,616
211.	5,616		5,616
212.	5,616		5,616

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
213.	5,616		5,616
214.	5,616		5,616
215.	5,616		5,616
216.	5,616		5,616
217.	5,616		5,616
218.	5,616		5,616
219.	5,616		5,616
220.	5,808		5,808
221.	5,808		5,808
222.	5,808		5,808
223.	5,808		5,808
224.	5,808		5,808
225.	5,808		5,808
226.	5,808		5,808
227.	5,808		5,808
228.	5,808		5,808
229.	5,808		5,808
230.	5,808		5,808
231.	5,808		5,808
232.	5,808		5,808
233.	5,808		5,808
234.	5,808		5,808
235.	5,808		5,808
236.	5,808		5,808
237.	5,808		5,808
238.	5,808		5,808
239.	5,808		5,808
240.	5,808		5,808
241.	5,808		5,808
242.	5,808		5,808
243.	5,836		5,836
244.	6,000		6,000
245.	6,000		6,000
246.	6,000		6,000
247.	6,000		6,000
248.	6,000		6,000
249.	6,000		6,000
250.	6,000		6,000
251.	6,000		6,000
252.	6,192		6,192
253.	6,274		6,274
254.	6,329		6,329
255.	6,356		6,356
256.	6,548		6,548
257.	6,685		6,685
258.	6,685		6,685
259.	6,685		6,685
260.	6,685		6,685
261.	6,685		6,685
262.	6,685		6,685
263.	6,685		6,685
264.	6,685		6,685
265.	6,685		6,685

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
266.	6,685		6,685
267.	6,740		6,740
268.	6,767		6,767
269.	6,767		6,767
270.	6,767		6,767
271.	6,767		6,767
272.	6,767		6,767
273.	6,767		6,767
274.	6,767		6,767
275.	6,767		6,767
276.	6,767		6,767
277.	6,767		6,767
278.	6,767		6,767
279.	6,767		6,767
280.	6,767		6,767
281.	6,767		6,767
282.	6,767		6,767
283.	6,986		6,986
284.	7,205		7,205
285.	7,260		7,260
286.	7,342		7,342
287.	7,342		7,342
288.	7,342		7,342
289.	7,342		7,342
290.	7,342		7,342
291.	7,342		7,342
292.	7,342		7,342
293.	7,342		7,342
294.	7,342		7,342
295.	7,342		7,342
296.	7,342		7,342
297.	7,342		7,342
298.	7,342		7,342
299.	7,342		7,342
300.	7,342		7,342
301.	7,342		7,342
302.	7,342		7,342
303.	7,342		7,342
304.	7,342		7,342
305.	7,342		7,342
306.	7,342		7,342
307.	7,342		7,342
308.	7,342		7,342
309.	7,342		7,342
310.	7,342		7,342
311.	7,342		7,342
312.	7,342		7,342
313.	7,699		7,699
314.	8,000		8,000
315.	8,000		8,000
316.	8,274		8,274
317.	8,274		8,274
318.	8,274		8,274

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
319.	8,274		8,274
320.	8,274		8,274
321.	8,274		8,274
322.	8,493		8,493
323.	8,493		8,493
324.	8,493		8,493
325.	8,493		8,493
326.	8,493		8,493
327.	8,493		8,493
328.	8,493		8,493
329.	8,493		8,493
330.	8,493		8,493
331.	8,493		8,493
332.	8,493		8,493
333.	8,493		8,493
334.	8,493		8,493
335.	8,493		8,493
336.	8,493		8,493
337.	8,685		8,685
338.	8,767		8,767
339.	8,871		8,871
340.	8,907		8,907
341.	9,260		9,260
342.	9,260		9,260
343.	9,260		9,260
344.	9,260		9,260
345.	9,260		9,260
346.	9,260		9,260
347.	9,260		9,260
348.	9,260		9,260
349.	9,260		9,260
350.	9,260		9,260
351.	9,260		9,260
352.	9,260		9,260
353.	9,260		9,260
354.	9,260		9,260
355.	9,260		9,260
356.	9,260		9,260
357.	9,260		9,260
358.	9,260		9,260
359.	9,260		9,260
360.	9,260		9,260
361.	9,260		9,260
362.	9,397		9,397
363.	9,397		9,397
364.	10,000		10,000
365.	10,000		10,000
366.	10,000		10,000
367.	10,000		10,000
368.	10,000		10,000
369.	10,000		10,000
370.	10,000		10,000
371.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
372.	10,000		10,000
373.	10,000		10,000
374.	10,000		10,000
375.	10,000		10,000
376.	10,000		10,000
377.	10,000		10,000
378.	10,000		10,000
379.	10,000		10,000
380.	10,000		10,000
381.	10,000		10,000
382.	10,000		10,000
383.	10,000		10,000
384.	10,000		10,000
385.	10,000		10,000
386.	10,000		10,000
387.	10,000		10,000
388.	10,000		10,000
389.	10,000		10,000
390.	10,000		10,000
391.	10,000		10,000
392.	10,000		10,000
393.	10,000		10,000
394.	10,000		10,000
395.	10,000		10,000
396.	10,000		10,000
397.	10,000		10,000
398.	10,000		10,000
399.	10,000		10,000
400.	10,000		10,000
401.	10,000		10,000
402.	10,000		10,000
403.	10,000		10,000
404.	10,000		10,000
405.	10,000		10,000
406.	10,000		10,000
407.	10,000		10,000
408.	10,000		10,000
409.	10,000		10,000
410.	10,000		10,000
411.	10,000		10,000
412.	10,000		10,000
413.	10,000		10,000
414.	10,000		10,000
415.	10,000		10,000
416.	10,000		10,000
417.	10,000		10,000
418.	10,000		10,000
419.	10,000		10,000
420.	10,000		10,000
421.	10,000		10,000
422.	10,000		10,000
423.	10,000		10,000
424.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
425.	10,000		10,000
426.	10,000		10,000
427.	10,000		10,000
428.	10,000		10,000
429.	10,000		10,000
430.	10,000		10,000
431.	10,000		10,000
432.	10,000		10,000
433.	10,000		10,000
434.	10,000		10,000
435.	10,000		10,000
436.	10,000		10,000
437.	10,000		10,000
438.	10,000		10,000
439.	10,000		10,000
440.	10,000		10,000
441.	10,000		10,000
442.	10,000		10,000
443.	10,000		10,000
444.	10,000		10,000
445.	10,000		10,000
446.	10,000		10,000
447.	10,000		10,000
448.	10,000		10,000
449.	10,000		10,000
450.	10,000		10,000
451.	10,000		10,000
452.	10,000		10,000
453.	10,000		10,000
454.	10,000		10,000
455.	10,000		10,000
456.	10,000		10,000
457.	10,000		10,000
458.	10,000		10,000
459.	10,000		10,000
460.	10,000		10,000
461.	10,000		10,000
462.	10,000		10,000
463.	10,000		10,000
464.	10,000		10,000
465.	10,000		10,000
466.	10,000		10,000
467.	10,000		10,000
468.	10,000		10,000
469.	10,000		10,000
470.	10,000		10,000
471.	10,000		10,000
472.	10,000		10,000
473.	10,000		10,000
474.	10,000		10,000
475.	10,000		10,000
476.	10,000		10,000
477.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
478.	10,000		10,000
479.	10,000		10,000
480.	10,000		10,000
481.	10,000		10,000
482.	10,000		10,000
483.	10,000		10,000
484.	10,000		10,000
485.	10,000		10,000
486.	10,000		10,000
487.	10,000		10,000
488.	10,000		10,000
489.	10,000		10,000
490.	10,000		10,000
491.	10,000		10,000
492.	10,000		10,000
493.	10,000		10,000
494.	10,000		10,000
495.	10,000		10,000
496.	10,000		10,000
497.	10,000		10,000
498.	10,000		10,000
499.	10,000		10,000
500.	10,000		10,000
501.	10,000		10,000
502.	10,000		10,000
503.	10,000		10,000
504.	10,000		10,000
505.	10,000		10,000
506.	10,000		10,000
507.	10,000		10,000
508.	10,000		10,000
509.	10,000		10,000
510.	10,000		10,000
511.	10,000		10,000
512.	10,000		10,000
513.	10,000		10,000
514.	10,000		10,000
515.	10,000		10,000
516.	10,000		10,000
517.	10,000		10,000
518.	10,000		10,000
519.	10,000		10,000
520.	10,000		10,000
521.	10,000		10,000
522.	10,000		10,000
523.	10,000		10,000
524.	10,000		10,000
525.	10,000		10,000
526.	10,000		10,000
527.	10,000		10,000
528.	10,000		10,000
529.	10,000		10,000
530.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
531.	10,000		10,000
532.	10,000		10,000
533.	10,000		10,000
534.	10,000		10,000
535.	10,000		10,000
536.	10,000		10,000
537.	10,000		10,000
538.	10,000		10,000
539.	10,000		10,000
540.	10,000		10,000
541.	10,000		10,000
542.	10,000		10,000
543.	10,000		10,000
544.	10,000		10,000
545.	10,000		10,000
546.	10,000		10,000
547.	10,000		10,000
548.	10,000		10,000
549.	10,000		10,000
550.	10,000		10,000
551.	10,000		10,000
552.	10,000		10,000
553.	10,000		10,000
554.	10,000		10,000
555.	10,000		10,000
556.	10,000		10,000
557.	10,000		10,000
558.	10,000		10,000
559.	10,000		10,000
560.	10,000		10,000
561.	10,000		10,000
562.	10,000		10,000
563.	10,000		10,000
564.	10,000		10,000
565.	10,000		10,000
566.	10,000		10,000
567.	10,000		10,000
568.	10,000		10,000
569.	10,000		10,000
570.	10,000		10,000
571.	10,000		10,000
572.	10,000		10,000
573.	10,000		10,000
574.	10,000		10,000
575.	10,000		10,000
576.	10,000		10,000
577.	10,000		10,000
578.	10,000		10,000
579.	10,000		10,000
580.	10,000		10,000
581.	10,000		10,000
582.	10,000		10,000
583.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
584.	10,000		10,000
585.	10,000		10,000
586.	10,000		10,000
587.	10,000		10,000
588.	10,000		10,000
589.	10,000		10,000
590.	10,000		10,000
591.	10,000		10,000
592.	10,000		10,000
593.	10,000		10,000
594.	10,000		10,000
595.	10,000		10,000
596.	10,000		10,000
597.	10,000		10,000
598.	10,000		10,000
599.	10,000		10,000
600.	10,000		10,000
601.	10,000		10,000
602.	10,000		10,000
603.	10,000		10,000
604.	10,000		10,000
605.	10,000		10,000
606.	10,000		10,000
607.	10,000		10,000
608.	10,000		10,000
609.	10,000		10,000
610.	10,000		10,000
611.	10,000		10,000
612.	10,000		10,000
613.	10,000		10,000
614.	10,000		10,000
615.	10,000		10,000
616.	10,000		10,000
617.	10,000		10,000
618.	10,000		10,000
619.	10,000		10,000
620.	10,000		10,000
621.	10,000		10,000
622.	10,000		10,000
623.	10,000		10,000
624.	10,000		10,000
625.	10,000		10,000
626.	10,000		10,000
627.	10,000		10,000
628.	10,000		10,000
629.	10,000		10,000
630.	10,000		10,000
631.	10,000		10,000
632.	10,000		10,000
633.	10,000		10,000
634.	10,000		10,000
635.	10,000		10,000
636.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
637.	10,000		10,000
638.	10,000		10,000
639.	10,000		10,000
640.	10,000		10,000
641.	10,000		10,000
642.	10,000		10,000
643.	10,000		10,000
644.	10,000		10,000
645.	10,000		10,000
646.	10,000		10,000
647.	10,000		10,000
648.	10,000		10,000
649.	10,000		10,000
650.	10,000		10,000
651.	10,000		10,000
652.	10,000		10,000
653.	10,000		10,000
654.	10,000		10,000
655.	10,000		10,000
656.	10,000		10,000
657.	10,000		10,000
658.	10,000		10,000
659.	10,000		10,000
660.	10,000		10,000
661.	10,000		10,000
662.	10,000		10,000
663.	10,000		10,000
664.	10,000		10,000
665.	10,000		10,000
666.	10,000		10,000
667.	10,000		10,000
668.	10,000		10,000
669.	10,000		10,000
670.	10,000		10,000
671.	10,000		10,000
672.	10,000		10,000
673.	10,000		10,000
674.	10,000		10,000
675.	10,000		10,000
676.	10,000		10,000
677.	10,000		10,000
678.	10,000		10,000
679.	10,000		10,000
680.	10,000		10,000
681.	10,000		10,000
682.	10,000		10,000
683.	10,000		10,000
684.	10,000		10,000
685.	10,000		10,000
686.	10,000		10,000
687.	10,000		10,000
688.	10,000		10,000
689.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
690.	10,000		10,000
691.	10,000		10,000
692.	10,000		10,000
693.	10,000		10,000
694.	10,000		10,000
695.	10,000		10,000
696.	10,000		10,000
697.	10,000		10,000
698.	10,000		10,000
699.	10,000		10,000
700.	10,000		10,000
701.	10,000		10,000
702.	10,000		10,000
703.	10,000		10,000
704.	10,000		10,000
705.	10,000		10,000
706.	10,000		10,000
707.	10,000		10,000
708.	10,000		10,000
709.	10,000		10,000
710.	10,000		10,000
711.	10,000		10,000
712.	10,000		10,000
713.	10,000		10,000
714.	10,000		10,000
715.	10,000		10,000
716.	10,000		10,000
717.	10,000		10,000
718.	10,000		10,000
719.	10,000		10,000
720.	10,000		10,000
721.	10,000		10,000
722.	10,000		10,000
723.	10,000		10,000
724.	10,000		10,000
725.	10,000		10,000
726.	10,000		10,000
727.	10,000		10,000
728.	10,000		10,000
729.	10,000		10,000
730.	10,000		10,000
731.	10,000		10,000
732.	10,000		10,000
733.	10,000		10,000
734.	10,000		10,000
735.	10,000		10,000
736.	10,000		10,000
737.	10,000		10,000
738.	10,000		10,000
739.	10,000		10,000
740.	10,000		10,000
741.	10,000		10,000
742.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
743.	10,000		10,000
744.	10,000		10,000
745.	10,000		10,000
746.	10,000		10,000
747.	10,000		10,000
748.	10,000		10,000
749.	10,000		10,000
750.	10,000		10,000
751.	10,000		10,000
752.	10,000		10,000
753.	10,000		10,000
754.	10,000		10,000
755.	10,000		10,000
756.	10,000		10,000
757.	10,000		10,000
758.	10,000		10,000
759.	10,000		10,000
760.	10,000		10,000
761.	10,000		10,000

Ontario apprenticeship training tax credit (total of amounts in column N) 500 5,692,313 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = ... ________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 568

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2013-12-31

- Use this schedule to claim the Ontario business-research institute tax credit (OBRITC) under section 97 of the *Taxation Act, 2007* (Ontario).
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our website. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The criteria for a corporation to be eligible for the OBRITC include the eligibility requirements in Part 1 of this schedule.
- The annual qualified expenditure limit is $20 million. If a corporation is associated with other corporations at any time in the calendar year, the $20 million limit must be allocated among the associated corporations.
- Qualifying corporations are defined in subsection 97(3) of the *Taxation Act, 2007* (Ontario).
- For each eligible contract, you must complete a separate Schedule 569, *Ontario Business-Research Institute Tax Credit Contract Information*.
- Keep the eligible contract to support your claim. Do not submit the contract with the *T2 Corporation Income Tax Return*.
- To claim the OBRITC, include the following with the *T2 Corporation Income Tax Return*:
  – a completed copy of this schedule; and
  – a completed copy of Schedule 569 for each eligible contract.

Part 1 – Eligibility

1. Did the corporation, for the tax year, carry on business in Ontario through a permanent establishment in Ontario? . . . . **100** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax for the tax year under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **105** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, the corporation is **not eligible** for the OBRITC.

Part 2 – Qualified expenditure limit for the tax year

Was the corporation associated at any time in the tax year with another corporation? . . . . **200** 1 Yes [X] 2 No [ ]

If the corporation answered **no** at line 200, enter $20,000,000 on line 205. If the corporation answered **yes** at line 200, complete Part 3 and enter on line 205 the expenditure limit allocated to the corporation in column 310 in Part 3.

Qualified expenditure limit . . . . **205** 20,000,000 A

If the tax year is 51 weeks or more, enter amount A on line 210.

If the tax year of the filing corporation is less than 51 weeks, complete the following proration calculation:

Amount A 20,000,000 x (days in the tax year 365 / 365) = ... ________ B

Qualified expenditure limit for the tax year (amount A or amount B, whichever applies) . . . . **210** 20,000,000 C

Part 3 – Allocation of the $20 million expenditure limit between associated corporations

Use this part to allocate the $20 million expenditure limit to the filing corporation and all its associated corporations for each of their tax years ending in the calendar year. See subsection 38(4) of Ontario Regulation 37/09 for expenditure limit allocation rules for associated corporations. Attach additional schedules if you need more space.

	Name of all associated corporations, including the filing corporation (include the associated corporations that have a tax year that ends in the calendar year) 300	Business Number (enter "NR" if corporation is not registered) 305	Expenditure limit allocated 310
1.	Hydro One Networks Inc.	87086 5821 RC0001	20,000,000
2.	Hydro One Inc.	86999 4731 RC0001	
3.	Hydro One Remote Communities Inc.	87083 6269 RC0001	
4.	Hydro One Telecom Inc.	86800 1066 RC0001	
5.	Hydro One Telecom Link Limited	88786 7513 RC0001	
6.	Hydro One Brampton Networks Inc.	86486 7635 RC0001	
7.	Hydro One Lake Erie Link Management Inc	87892 1519 RC0001	
8.	Hydro One Lake Erie Link Company Inc.	87560 6519 RC0001	
9.	Hydro One B2M LP Inc.	81838 2046 RC0001	
10.	B2M GP INC.	81838 1840 RC0001	
11.	Hydro One B2M Holdings Inc.	82217 7531 RC0001	
12.	1908872 Ontario Inc	82581 6838 RC0001	
13.	1908873 Ontario Inc.	83392 0978 RC0001	
14.	1893080 Ontario Inc.	82217 7333 RC0001	

Total expenditure limit (cannot exceed $20 million) 315 20,000,000 D

Enter the expenditure limit allocated to the corporation on line 205 in Part 2.

Part 4 – Calculation of the Ontario business-research institute tax credit

Total number of eligible contracts used to determine the OBRITC for this tax year 400 4

Total qualified expenditures for all eligible contracts identified on line 400 for this tax year (total of amounts on line 310 in Part 3 of each **Schedule 569**) . . . . . 405 875,000 E

Qualified expenditure limit for the tax year (amount C in Part 2) . . . . . 20,000,000 F

Qualified expenditures for the OBRITC for the tax year (amount E or F, whichever is less) 410 875,000

Ontario business-research Institute tax credit (line 410 x 20 %) . . . . . 175,000 G

Enter amount G on line 470 of Schedule 5, *Tax Calculation Supplementary – Corporations*.

STANDARD &POOR'S

Standard & Poor's Research

Summary:

Hydro One Inc.

Primary Credit Analyst:
Gavin Macfarlane, Toronto (1) 416-507-2545; gavin.macfarlane@standardandpoors.com

Secondary Contact:
Stephen R Goltz, Toronto (1) 416-507-2592; stephen.goltz@standardandpoors.com

Table Of Contents

1163593 | 300642892

Summary:
Hydro One Inc.

Corporate Credit Rating	A+/Negative/A-1

Profile Assessments

BUSINESS RISK	EXCELLENT	Vulnerable — Excellent
FINANCIAL RISK	SIGNIFICANT	Highly leveraged — Minimal

Likelihood Of Extraordinary Government Support

Standard & Poor's Ratings Services bases its 'A+' rating on Hydro One Inc.'s stand-alone credit risk profile of 'a' and its opinion that there is a "high" likelihood that its owner, the Province of Ontario (AA-/Negative/A-1+), would provide timely and sufficient extraordinary support in the event of financial distress.

Rationale

Business Risk: Excellent	Financial Risk: Significant
• Relatively stable regulatory regime • Natural monopoly service provider • Limited commodity-price risk and low volume-risk exposure • Supportive shareholder	• Stable, regulated cash flow • Weak credit metrics that leave no cushion at the current ratings • Large capital program

Outlook: Negative

The negative outlook reflects the outlook on Ontario. We still expect continued predictable regulatory support despite Hydro One's large capital expenditure program and negative free operating cash flows.

Downside scenario

Based on our criteria for government-related entities, given a high likelihood of extraordinary support, a SACP of 'a' for Hydro One, and our 'AA-' rating on the province, a one- or two-notch downgrade on the province would affect the ratings on Hydro One, but likely not more than one notch given the company's underlying credit strength. In the event of lower-than-expected cash flows and earnings, we expect the utility to maintain its leverage within the deemed capital structure of 60% reported debt-to-capital, adjusted funds from operations (AFFO)-to-debt of about 12%, and AFFO interest coverage of about 3x, by curtailing its capital spending and additional debt financing. In our view, there is no cushion for Hydro One to deteriorate from our expectations on its key credit measures to maintain the ratings.

Any sustained deterioration of financial measures beyond our expectations, a material adverse regulatory ruling, or market restructuring (such as the assumption of the obligation to supply, not just deliver, electricity) could lead us to lower the 'a' SACP and consequently the ratings, regardless of any changes to the ratings on the province.

Upside scenario

An improvement in the company's SACP is unlikely without the assurance of a much stronger balance sheet and stronger cash flow-interest and debt coverage ratios (such as higher than 30% AFFO-to debt). If we revise the outlook on Ontario to stable and affirm the issuer credit rating, we will also revise the outlook on Hydro One to stable at the current rating.

Standard & Poor's Base-Case Scenario

The key driver in our analysis continues to be the regulatory framework and the utility's performance within it.

Assumptions

- The regulatory regime continues to be relatively stable and Hydro One does not experience any material, adverse regulatory decisions
- The company continues to earn close to its allowed return on equity (ROE) of about 9% on its deemed capital structure
- Financial policies continue to be stable, with Hydro One targeting the deemed capital structure established by the regulator that includes 60% debt

Key Metrics

	2012A	2013E	2014E
AFFO/debt	12%	11%-13%	11%-13%
Debt-to-debt and equity	63%	60%-65%	60%-65%

Note: Standard & Poor's-adjusted ratios.
AFFO--Adjusted funds from operations. A--Actual.
E--Estimated.

Business Risk: Excellent

In our opinion, the Ontario Energy Board's regulatory framework continues to support stable cash flow, a key credit strength. The framework allows for the recovery of prudent costs and the opportunity to earn a modest return. We believe that rates for the transmission business will continue to be set based cost on regular cost of service applications. Distribution rates for 2013 were established under an incentive rate mechanism (IRM) with an incremental capital module supporting the capital program. We expect the company to have its distribution rates reset under a cost-of-service methodology in 2015. The regulatory framework limits Hydro One's exposure to commodity risk and associated cash flow volatility. While the distribution business must bill customers for the commodity delivered, the cost is a flow-through. The company has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements, which reduces operating risk. Supporting the "excellent" business risk profile is Hydro One's natural monopoly position in its service territories and the asset-intensive nature of electricity distribution that limit competitive risk. We believe that the company's customer base supports the overall stability of its revenues and severely limits exposure to any particular customer or customer class. In the transmission business, municipally owned investment grade electricity distribution companies collect transmission revenues and forward them to Hydro One through the Independent Electricity System Operator. The company's distribution business collects revenues from a relatively stable customer base that is dominated by residential and commercial customers. We view the economy of Ontario, which the transmission business services, as large, wealthy, and well-diversified. Hydro One's operating efficiency does not raise any credit concerns. We do not believe the company has ever paid any penalties that could affect credit quality. Its excellent business risk profile is similar to that of most Canadian regulated utilities. We characterize both the industry and the country of operation as stable, with generally low-risk factors that do not limit the rating.

Financial Risk: Significant

We expect Hydro One will continue generating stable cash flow, a key credit strength. Underpinning this stability, FFO consists primarily of an allowed ROE that is the product of the rate base, deemed capital structure and the allowed ROE, and depreciation. We believe the company has stable financial policies that support ongoing stable credit metrics. A cornerstone of Hydro One's financial policies is a target capital structure broadly in line with the deemed capital structure established by the regulator, which includes about 60% debt. Nevertheless, our forecast credit metrics leave no headroom at the current rating. While the company has a large capital program of about C$1.4 billion in 2013 and increasing in 2014, we believe that it will maintain its target capital structure, curtailing dividends as required. We expect both the more frequent transmission cost-of-service applications and the expectation of a custom incentive rate mechanism application in the distribution business to provide cash flow support to credit metrics, largely offsetting the affect the large capital program has on the metrics.

Liquidity: Adequate

The short-term rating on Hydro One is 'A-1' and the company continues to have "adequate" liquidity, in our view. We expect that liquidity sources will be adequate to cover uses more than 1.2x in the next 12 months. We expect that in the event of a 15% EBITDA decline, Hydro One's sources of funds would still exceed its uses. In our view, the company has sound relationships with its banks and generally prudent financial risk management. We continue to believe that the company would have considerable flexibility regarding dividend payments in a highly unexpected financial stress situation and have therefore not included it as a use of cash in our liquidity calculations.

Principal Liquidity Sources	Principal Liquidity Uses
• Projected FFO of about C$1.3 billion • C$1.4 billion of available committed credit facilities at March 31, 2013, expiring in June 2018 • About C$250 million of notes issued by the province that Hydro One could liquidate if needed	• Capital spending of about C$ 1.5 billion • Debt maturities of about C$600 million within the next 12 months

Related Criteria And Research

- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk					
Business Risk	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	B- or below

Note: These rating outcomes are shown for guidance purposes only. The ratings indicated in each cell of the matrix are the midpoints of the likely rating possibilities. There can be small positives and negatives that would lead to an outcome of one notch higher or lower than the typical matrix outcome. Moreover, there will be exceptions that go beyond a one-notch divergence. For example, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). Other rating outcomes that are more than one notch off the matrix may occur for companies that have liquidity that we judge as "less than adequate" or "weak" under our criteria, or companies with "satisfactory" or better business risk profiles that have extreme debt burdens due to leveraged buyouts or other reasons. For government-related entities (GREs), the indicated rating would apply to the standalone credit profile, before giving any credit for potential government support.

MOODY'S
INVESTORS SERVICE

Credit Opinion: Hydro One Inc.

Global Credit Research - 08 Nov 2013

Toronto, Ontario, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	A1
Commercial Paper	P-1

Contacts

Analyst	Phone
Macfarlane, Gavin/Toronto	1.416.214.3864
William L. Hess/New York City	212.553.3837

Key Indicators

[1]**Hydro One Inc.**

	LTM 06/30/2013	2012	2011	2010
(CFO Pre-W/C + Interest) / Interest Expense	4.1x	4.0x	3.9x	3.7x
(CFO Pre-W/C) / Debt	14.4%	13.6%	14.1%	13.9%
(CFO Pre-W/C - Dividends) / Debt	12.4%	10.1%	12.4%	13.7%
Debt / Book Capitalization	56.6%	57.6%	56.4%	59.2%

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Interrelationship with the Province of Ontario (Province, Aa2/Stable) and the influence of government policy/actions.

Large, low-risk regulated electric transmission and distribution (T&D) utility with no commodity price risk

Relatively supportive regulatory environment

Predictable cash flow generation

Continued high capital expenditure could place pressure on financial metrics

Corporate Profile

Hydro One Inc. (HOI) began operations on 1 April 1999, pursuant to the Electricity Act, 1998, as a commercial corporation 100% owned by the Province of Ontario when the former Ontario Hydro was restructured into five entities: Ontario Power Generation Inc. (OPG), the Independent Electricity System Operator (IESO), Ontario Electricity Financial Corporation (OEFC), the Electricity Safety Authority and HOI. Virtually all of HOI's revenue and cash flow comes from its electricity transmission and distribution businesses, both of which are regulated by the Ontario Energy Board (OEB). HOI owns and operates virtually all of Ontario's electricity transmission system and a substantial portion of the province's electricity distribution assets. The Province does not explicitly guarantee HOI's debt obligations.

SUMMARY RATING RATIONALE

As a government related issuer, HOI's A1 rating reflects its baseline credit assessment (BCA) of baa1 with a three notch uplift attributable to high default dependence and high probability of extraordinary support from the Province of Ontario (Aa2). HOI's BCA of baa1 is indicated by our Regulated Electric and Gas Utility rating methodology, reflecting lower risk and lack of commodity price risk inherent in the transmission and distribution sector, coupled with a relatively supportive regulatory environment. We expect cash flow from operations to remain predictable. Credit metrics are forecast to remain relatively weak for the ratings as a result of the existing allowed return on equity and deemed capital structure established by the regulator and HOI's ongoing large capital program. We expect the company to have limited headroom above credit metric levels we associate with a reduction in the company's BCA. Potential risk exists for HOI from government policy initiatives; for example, those related to the restructuring of Ontario's electricity sector or those that delay or inhibit cost recovery.

DETAILED RATING CONSIDERATIONS

INTERRELATIONSHIP WITH THE PROVINCE AND THE INFLUENCE OF GOVERNMENT POLICY/ACTIONS

In accordance with Moody's Government Related Issuer (GRI) rating methodology, HOI's A1 rating reflects the following:

Aa2 local currency rating of the Province of Ontario.

High default dependence as a result of HOI's exposure to virtually all facets of the provincial economy and its operational and financial proximity to the government.

High probability of extraordinary support from the Province reflecting the strategic importance of HOI to the provincial economy and as an essential component of the government's energy policy; as well as the Province's history of targeting a 60:40 deemed capital structure by modulating dividends payable each year.

HOI's BCA reflects the following:

Large, low-risk regulated monopoly electric transmission and distribution (T&D) utility with no commodity price risk underpins credit strength. We expect the regulatory environment to remain relatively transparent, predictable and broadly credit supportive. Rates for the transmission business are established using cost of service principles with relatively frequent cost of service rate resets. Distribution rates are established through an incentive rate mechanism, with periodic cost of service rate resets. The company does not have any direct commodity risk exposure since commodity costs are a pass through for the distribution businesses. The company does have some exposure to volume risk that is typically driven by weather variability and the underlying performance of the economies in its service territories. The company continues to benefit from its competitive position as a monopoly service provider. While a competitor recently won a competitive bid for a transmission project in ON, we do not believe this will weaken the company's competitive position or its ability to generate cash flow from its assets. The business has inherently lower risk as a T&D business compared to the price, volume, operational or environmental risks typically associated with generation activities. The company does not have any supply obligations.

We expect the company to continue to generate stable cash flow, a key credit strength. Underpinning this stability, cash flow from operations is generally a function of the company's rate base, its deemed capital structure (established by the regulator), the allowed return on equity (currently about 9%) and depreciation. We have assumed that the company continues to perform broadly in line with the levels established by the regulator. While the company continues to move forward with a large capital program that could exceed C$3bn in 2013-2014, we believe that a combination of frequent cost of service rate resets in the transmission business and incremental capital module applications in the distribution business will mitigate some of the downward pressure the large capital program continues to place on credit metrics. CFO pre w/c debt (3 year average) of 13-14% provides limited headroom above Moody's investment grade thresholds for this regulated sector. We believe the company will be able to maintain its capital structure broadly in line with that established by the regulator by adjusting the dividends it pays to the province as required.

Liquidity Profile

We believe Hydro One has adequate liquidity.

Hydro One has demonstrated its ability to readily access capital markets. Up to $1 billion can be issued under the commercial paper (CP) program. The CP program is backstopped by $1.75 billion of liquidity support, which consist of a bank syndicate committed revolver of $1.5 billion maturing in June 2018 and $250 million Province of Ontario floating rate notes. At June 30, 2013, $118 million was drawn from the revolver, leaving $1,382 million available.

Hydro One relies in part on debt to finance its ongoing capex. The company recently completed debt issuances of about $1.2 billion. Annual gross borrowings are projected to be about$1.5 billion in 2014. Part of these borrowings are to refinance debt maturities of $600 million in the remainder of 2013 and $750 million in 2014. We believe these refinancings are manageable given Hydro One's good capital markets access.

Rating Outlook

HOI's rating outlook is stable given the T&D nature of its business model coupled with the historically supportive regulatory environmental in which it operates.

What Could Change the Rating - Up

We consider an upward revision in HOI's A1 rating to be unlikely in the near term. However, the company's senior unsecured rating could be positively impacted by a two notch improvement in its BCA to a2, or by a change in the facts and circumstances that cause us to believe that the probability of extraordinary support should be higher than we currently believe it is. An improvement in HOI's BCA to a2 would require both a sustainable improvement in financial ratios (such as CFO pre-WC to Interest exceeding 4.5x, CFO pre-WC to Debt exceeding 22% and CFO pre-WC less Dividends to Debt exceeding 17%) and a more favorable assessment of HOI's regulatory and cost recovery environment.

What Could Change the Rating - Down

HOI's A1 senior unsecured rating could be negatively impacted by one or more of the following:

A reduction in both the Province's rating and HOI's BCA, or

A material reduction in the perceived probability of extraordinary support due to changes in the ownership, governance or management structures or other factors.

A one notch reduction in HOI's BCA to baa2 could follow a sustained weakening of cash flow metrics such as CFO pre-WC to Interest coverage below 3.3x, CFO pre-WC to Debt below 13% and/or CFO pre-WC less Dividends to Debt below 9% combined with a deterioration in HOI's regulated ability to recover its costs and earn an appropriate return.

Rating Factors

Hydro One Inc.

Regulated Electric and Gas Utilities Industry [1][2]	**LTM 06/30/2013**			**Moody's 12-18 month Forward View* As of November 2013**	
Factor 1: Regulatory Framework (25%)	Measure	Score		Measure	Score
a) Regulatory Framework		A			A
Factor 2: Ability To Recover Costs And Earn Returns (25%)					

a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)				
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	3.9x	Baa	3.8x - 3.9x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	14.0%	Baa	13 - 14%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	11.6%	Baa	10 - 11%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	57.4%	Ba	57 - 59%	Ba
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 06/30/2013(LTM); Source: Moody's Financial Metrics

Hydro One Inc.

Rating

Debt Rated	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Commercial Paper	R-1 (middle)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable

Rating Update

DBRS has confirmed the Issuer Rating and the Senior Unsecured Debentures rating of Hydro One Inc. (Hydro One or the Company) at A (high), and the Commercial Paper rating at R-1 (middle). All trends are Stable. The ratings confirmation is underpinned by the Company's low business risk profile, a supportive regulatory framework in Ontario and a strong financial profile sustained by stable earnings and cash flows. The Stable trend assumes that the regulatory regime under the Renewed Regulatory Framework will continue to remain reasonable, allowing the Company to earn adequate returns and pass through prudently incurred costs on a timely basis.

Hydro One's business risk profile is indicative of an A (high) rating as the Company operates in an extensive franchise area, with regulated transmission and distribution businesses in Ontario accounting for substantially all its earnings. DBRS continues to view the regulatory framework in Ontario as reasonable for regulated transmission and distribution operators (refer to Assessment of Hydro One's Regulatory Environment on Page 8). In late 2013, the Ontario Energy Board (OEB) released a final report on its Renewed Regulatory Framework, setting out policies and approaches to the rate adjustment parameters for incentive rate (IR) setting and the benchmarking of total cost performance. DBRS views the parameters of the Custom Incentive Rate-setting option under the Renewed Regulatory Framework as modestly positive for Hydro One's distribution business (35% of EBIT) as it provides greater clarity for recovery and pass through of capital costs to ratepayers, and it reduces pressure on utilities to meet operating efficiency targets. However, this is somewhat offset by the modestly higher regulatory lag under the Custom IR regime, which the Company will operate under, as it has a minimum term of five years as compared with the previous three-year rate setting process. It also remains to be seen how operating expenses and capex will be scrutinized as the Company proceeds under the Custom IR framework.

Hydro One's financial profile reflects an A (high) rating as key credit metrics have remained in the upper range of the "A" rating category. Hydro One's ratings are on a stand-alone basis but are constrained by the rating of the Province of Ontario (the Province; rated AA (low)), which acts as a ceiling. DBRS assumes that Hydro One's rate base will continue to grow and provide incremental cash flow to fund the majority of capex and maintain debt-to-capital at around 55%, with minimal regulatory lag and no significant cost-overruns.

Rating Considerations

Strengths

(1) Low business risk
(2) Strong financial profile
(3) Extensive franchise area
(4) Indirect support from the province of Ontario

Challenges

(1) High level of planned capex
(2) Project construction risk
(3) Significant external financing requirements
(4) Limited access to equity markets

Financial Information

Hydro One Inc.	**For the year ended December 31**				
(CAD millions where applicable)	**2013**	**2012**	**2011**	**2010**	**2009**
EBIT gross interest coverage (times)	3.06	2.91	2.75	2.42	2.23
Total debt in capital structure	55.1%	55.5%	55.5%	56.5%	56.2%
Cash flow/Total debt	15.3%	15.4%	14.6%	13.9%	13.8%
(Cash flow-dividends)/Capex (times)	0.83	0.65	0.70	0.67	0.50
Net income before non-recurring items	795	736	632	579	470
Cash flow from operations	1,390	1,313	1,176	1,080	964

Rating Considerations

Strengths

(1) **Low business risk.** Substantially all of the Company's earnings are contributed by its low-risk regulated distribution and transmission businesses, which operate under a reasonable regulatory framework.

(2) **Strong financial profile.** The Company continues to maintain strong credit metrics and a healthy balance sheet (debt-to-capital ratio at 55.1%, EBIT interest coverage at 3.06 times and cash flow-to-debt at 15.3%, for 2013).

(3) **Extensive franchise area.** Hydro One owns the largest transmission and distribution businesses in Ontario. The Company serves approximately 96.8% of the Province's transmission throughput, including servicing 47 Local Distribution Companies (LDCs). The distribution component of the Company spans approximately 75% of the Province, serving approximately 1.4 million customers (rural and urban).

(4) **Indirect support from the Province.** The Province provides indirect support to Hydro One with respect to the flexibility of its dividends, which allows Hydro One to maintain its leverage below the 60% set by the OEB.

Challenges

(1) **High level of planned capex.** Hydro One is currently in the midst of an aggressive build-out program that will continue over the next several years. Capex is expected to be approximately $1.6 billion in each of the next two years ($950 million for Transmission and $650 million for Distribution in the first year). Therefore, DBRS expects the Company to generate free cash flow deficits over this time frame. These sizable free cash flow deficits, combined with lengthy construction times, will continue to put temporary pressure on the balance sheet and coverage ratios during the build-out.

(2) **Project construction risk.** The size and magnitude of Hydro One's upcoming designated projects, combined with the continued increases in material and labour costs and the significant number of interveners involved, could potentially expose Hydro One to rising project costs beyond the amounts forecasted in its regulatory applications. There is no assurance that cost overruns beyond the regulatory-approved amounts will be recovered if deemed imprudent by the OEB. However, DBRS notes that Hydro One is experienced in managing projects and is focused on mitigating the risk of cost overruns.

(3) **Significant external funding requirements.** Significant external funding is required to finance the potentially sizable free cash flow deficits expected over the near to medium term. Maintaining adequate access to the public debt markets (term and commercial paper) is critical to the Company during this key build-out phase.

(4) **Limited access to equity markets.** Hydro One's ownership structure (100% owned by the Province) limits its ability to access the equity markets directly. As a result, Hydro One's additional cash flow needs are being financed largely through its retained earnings and short- and long-term debt issuances.

Hydro One Inc.

Report Date:
April 10, 2014

Earnings and Outlook

(CAD millions where applicable)	For the year ended December 31 2013	2012	2011	2010	2009
Net Sales	3,054	2,954	2,843	2,650	2,418
EBITDA	1,948	1,883	1,751	1,572	1,361
EBIT	1,272	1,224	1,135	989	824
Gross interest expense	416	421	412	409	369
Earning before taxes	901	854	779	630	516
Net income before non-recurring items	795	736	632	579	470
Reported net income	803	745	641	591	470
Return on equity	11.2%	11.1%	10.2%	10.2%	8.9%

	2013	2012	2011	2010	2009
Transmission rate base (CAD billions)	9.35	8.80	7.90	7.60	7.00
Distribution rate base (CAD billions)	NA	NA	5.10	4.80	NA

NA = rate base was not adjusted

Segmented Information (CAD millions)	For the year ended December 31 2013	2012	2011	2010	2009
Net Sales					
Transmission	1,529	1,482	1,389	1,307	1,147
Distribution	1,464	1,410	1,391	1,280	1,208
Other	61	62	63	63	63
Total Revenues	3,054	2,954	2,843	2,650	2,418
EBIT by segment					
Transmission	827	760	665	618	469
Distribution	452	473	478	378	357
Other	(7)	(9)	(8)	(7)	(2)
Total EBIT	1,272	1,224	1,135	989	824

2013 Summary

- Hydro One's earnings have continued to increase over the past five years, mainly as a result of the Company's increased regulatory asset base, driven by high capex.

2014 Outlook

- Earnings are expected to increase modestly in line with rate base increases over the near to medium term, given the high level of planned capex. Capex will be mainly spent to service the Company's aging infrastucture in the trasmission and distribution businesses and to interconnect new facilities to the grid.

Financial Profile

	For the year ended December 31				
(CAD millions where applicable)	2013	2012	2011	2010	2009
Net income before non-recurring items	795	736	632	579	470
Depreciation & amortization	597	589	550	526	487
Deferred income taxes and other	(2)	(12)	(6)	(25)	7
Cash flow from operations	1,390	1,313	1,176	1,080	964
Dividends paid	(218)	(370)	(168)	(28)	(188)
Capital expenditures	(1,412)	(1,454)	(1,447)	(1,570)	(1,566)
Free cash flow (bef. working cap. changes)	(240)	(511)	(439)	(518)	(790)
Changes in non-cash work. cap. items	11	(40)	184	94	(38)
Changes in regulatory assets	3	12	47	(10)	(34)
Net Free Cash Flow	(226)	(539)	(208)	(434)	(862)
Acquisitions & long-term investments	0	0	0	(250)	0
Short-term investments	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0
Amount to be financed	(226)	(539)	(208)	(684)	(862)
Net equity change	0	0	0	0	0
Net debt change	574	488	239	845	805
Other	22	18	25	37	15
Change in cash	370	(33)	56	198	(42)
Total debt	9,088	8,521	8,047	7,778	6,962
Cash and equivalents	565	195	228	172	0
Total debt in capital structure	55.1%	55.5%	55.5%	56.5%	56.2%
Cash flow/Total debt	15.3%	15.4%	14.6%	13.9%	13.8%
EBIT gross interest coverage (times)	3.06	2.91	2.75	2.42	2.23
Dividend payout ratio	27.4%	50.3%	26.6%	4.8%	40.0%

2013 Summary

- Overall, Hydro One has maintained a strong financial profile with key credit metrics, including leverage, interest coverage and cash flow ratios, remaining within the A (high) rating category.
- Cash flow from operations remains strong, improving over time in line with an increasing rate base.
- Cash flow deficits persist primarily because of increased capex related to infrastructure upgrades and developing system reliability. Free cash flow deficits have been mainly funded by debt and dividend management.
- Unlike other provincially and municipally owned distributors, Hydro One benefits from a flexible dividend program, unrestricted by any earnings threshold level.
- As the equity base has grown at a similar pace as debt, leverage has remained stable at 55% over the past three years.

2014 Outlook

- DBRS expects free cash flow deficits to continue as the Company plans to incur capital expenditures of approximately $1.6 billion in each year from 2014 to 2016, to build critical infrastructure and expenditures to address Company’s aging power system infrastructure.
- DBRS anticipates that free cash flow deficits will be funded prudently through debt issuance and dividend management in order to maintain debt leverage in the 55% to 60% range
- Key credit metrics are expected to remain reasonable for the current rating category during this period of high capex, given that cash flow from operations is expected to grow over the medium to long term as capital projects are included in the rate base.

Hydro One Inc.

Report Date:
April 10, 2014

Long-Term Debt Maturities and Bank Lines

- The Company's liquidity profile remains reasonable and provides it with sufficient funds for normal operating requirements.

(CAD millions - As at December 31, 2013)	Amount	Draw/LOCs	Available	Maturity
Cash & Cash Equivalents	565		565	
Committed Revolving Facility	1,500	-	1,500	Jun-18
Ontario Floating Rate Notes	251	-	251	Nov-14
Total	**2,316**	-	**2,316**	

- Hydro One has access to a $1.0 billion commercial paper program. This is supported by a revolving facility ($1.5 billion) and a $251 million holding in Province of Ontario Floating-Rate Notes.
- On May 31, 2013, Hydro One increased the size of its revolving credit facility to $1.5 billion from $1.25 billion and extended the maturity date from June 2017 to June 2018.
- Under the credit facility, Hydro One cannot exceed 75% of total capitalization, and third-party debt issued by its subsidiaries cannot exceed 10% of total book value of its assets. Hydro One was in compliance with these covenants as at December 31, 2013.
- Hydro One's continued access to the capital markets through its Medium-Term Notes (MTN) and commercial paper programs will be crucial over the next few years, given its infrastructure upgrade mandate.
- In October 2013, Hydro One issued $1,185 million of notes with a $750 million five-year tranche and a $435 million 30-year tranche. The proceeds were used to fund the retirement of $600 million of long-term debt and to fund a portion of its capex.
- Under its $3 billion MTN shelf prospectus, $1,640 million is available for issuance until October 2015.
- Hydro One completed a 50-year, $50 million MTN offering in January 2014 and a $125 million five-year Floating-Rate Note in March 2014.

Long-term Debt Maturities

(CAD millions - As at December 31, 2013)	2014	2015	2016	2017	2018	Thereafter	Total
Principal Repayments	750	550	500	600	750	6,070	9,220
% of Total	8%	6%	5%	7%	8%	66%	100%

- Hydro One has existing debt maturities of $750 million in 2014 and $550 million in 2015.
- DBRS expects Hydro One to refinance its debt maturities in the medium term, despite the frequency of maturities.

Major Projects (Potential and Under Construction)

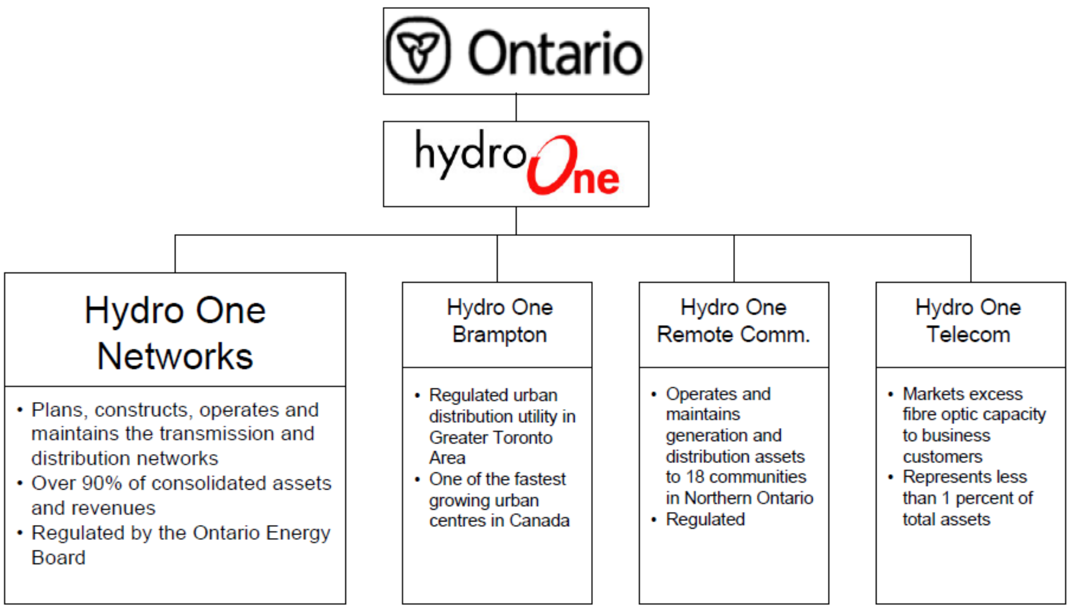
- On April 2, 2013, Hydro One reached an agreement with The Corporation of Norfolk County to acquire 100% of the common shares of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Norfolk Power will be approximately $93 million, and the transaction is anticipated to close by mid-2014.
- Capital investments for the next few years will include expenditures required to build critical infrastructure (Development capex – $450 million to $500 million annually) identified in the Long-Term Energy Plan, which is based on recommendations from the Ontario Power Authority, and expenditures to address aging power system infrastructure mainly in the distribution business (Sustainment capex – $900 million).*
- Development projects include the inter-area network upgrades that reflect supply mix policies, local area supply improvements, the Advanced Distribution System (ADS) project, new load and generation connections and requirements to enable Distributed Generation (DG), and customer demand work.
- Development future capital investments include the Clarington Transmission Station Project to install additional auto-transformer capacity in the east Greater Toronto Area; the Guelph Area Transmission

Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph; investments in ADS; requirements to enable DG; and up to four other transmission station upgrades, which when combined with the new Hearn Switching Station, will collectively enable up to 600 megawatts (MW) of new generation capacity in the Niagara, Toronto and Ottawa areas.

- West of London Transmission Lines: The aim of the projects is to add between 500 MW and 1,000 MW to the grid. These projects are in the early stages, with an expected completion date in 2017, contingent on the necessary regulatory approvals. Estimated costs range from $300 million to $450 million.
- Other capital expenditures include investments in operating infrastructure integration, IT, fleet services and facilities, and real estate.

*The figures above are released by the Ontario Power Authority and are still in the early stages.

Organizational Chart



Source: Hydro One investor presentation

Description of Operations

- Earnings are principally generated from its regulated transmission and distribution businesses.
- Largest electricity transmission and distribution company in Ontario.
- Hydro One Telecom Inc. is the unregulated operation of the Company that accounts for less than 1% of total assets. It markets dark and lit fibre optic capacity to commercial and telecommunication carriers.
- Operates two principal distinct business segments:

(1) Transmission

- One of the largest in North America as measured by assets.
- Owns and operates approximately 96.8% of transmission capacity in Ontario as measured by revenues.
- Has a 29,000 circuit kilometer high-voltage network, serving its own distribution network as well as 47 LDCs and 92 transmission connected companies.

(2) Distribution

- Largest distribution system in the Province based on assets, covering about 75% of Ontario.
- Distributes electricity over 120,500 kilometers, reaching approximately 1.4 million customers in a number of municipalities and rural areas.
- Approximately 60% of the distribution revenues are earned from residential customers.

Regulation

Regulatory Overview

- Hydro One's transmission and distribution businesses are licensed and regulated by the OEB. DBRS has assessed the regulatory environment to be satisfactory. (Refer to Assessment of Hydro One's Regulatory Environment on Page 8)
- Under the cost-of-service methodology, Hydro One is provided a reasonable opportunity to recover its forecast costs, including operating expenses, depreciation, costs of debt and taxes.
- In 2012, the OEB issued its report, *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*. This report established a new rate-setting policy that contains three rate-setting methods: 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements) and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). Each distributor may select the rate-setting method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis beginning with 2014 rates.
- In December 2013, the OEB released its final report on parameters related to the Renewed Regulatory Framework, which sets out the OEB's policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance. DBRS views the implementation of the Custom Incentive Rate-setting option under the Renewed Regulatory Framework as modestly positive for Hydro One as it provides (1) greater clarity with respect to a company's ability to recover high capital costs, (2) a much less onerous operating efficiency target and (3) the ability for companies to reopen regulatory rate cases should unexpected increases in operating costs occur before the end of the regulatory term. However, utilities are required to operate under the Custom IR framework for a longer period (five years), which modestly increases regulatory lag.
- On January 9, 2014, the OEB approved Hydro One's 2014 transmission revenue requirement for use in setting the 2014 Ontario Uniform Transmission Rates of $1446.4 million ($1,390.8 million in 2013) and an allowed 2014 return on equity (ROE) of 9.36% (8.93% in 2013). DBRS views this ROE increase as modestly postive.
- Hydro One is responsible for delivering electricity and billing customers at approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all purchased power costs and other approved regulatory charges are settled through the Independent Electricity System Operator (IESO), which facilitates payments to generators, and the Ontario Electricity Financial Corporation (OEFC).
- Under the Ontario electricity market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP), and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure, with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time of Use (TOU) thresholds. Virtually all of Hydro One's RPP customers are now on TOU billing.
- The OEB uses a deemed debt-to-common equity structure of 60% to 40% for both transmission and distribution. Debt is divided into 56% long term and 4% short term.

Assessment of Hydro One's Regulatory Environment

Criteria	Score	Analysis
(1) Deemed Equity	Excellent Good Satisfactory Below Average Poor	The OEB allows Hydro One to have a deemed equity of 40%, which has been consistent historically.
(2) Allowed ROE	Excellent Good Satisfactory Below Average Poor	The OEB approved a revenue requirement of $1446.4 million ($1,390.8 million in 2013) and an allowed return on equity (ROE) for transmission business of 9.36% (8.93% in 2013) for 2014. ROE for distribution business has averaged between 9.5% and 10% in the past few years.
(3) Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	No power price risk as the Company is allowed to pass through the entire cost of purchased power used by its customers. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory accounts over specified timeframes.
(4) COS vs. IRM	Excellent Good Satisfactory Below Average Poor	Hydro One is regulated under an incentive rate mechanism (IRM). Distribution rates are set based on five-year custom rate application with the OEB with rate rebasing each year. Transmission rates are based on cost-of-service (COS) application rate orders approved by the OEB annually.
(5) Capital Cost Recovery	Excellent Good Satisfactory Below Average Poor	Major capital costs are pre-approved by the OEB and added to rate base after the completion.

Criteria	Score	Analysis
(6) Political Interference	Excellent Good Satisfactory Below Average Poor	After years of a relatively stable political and regulatory environment, the utility sector in Ontario could face growing challenges. As generation costs potentially rise above and ultimately test the political ceiling (10% increase of the total bill annually), it may be difficult for the utilities to pass costs onto the ratepayers.
(7) Retail Rate	Excellent Good Satisfactory Below Average Poor	Retail rates in Ontario are at the mid-range of rates in other Canadian provinces. In 2013, Hydro One customers paid between 12.4cents/kWh to 12.9 cent/kWh on peak rates, which were 1.3% higher than 2012. Ontario's real GDP grew by 2.3% in 2013.
(8) Stranded Cost Recovery	Excellent Good Satisfactory Below Average Poor	Hydro One has limited history of stranded costs. Most prudently incurred or budgeted capital expenditures are approved by the OEB. DBRS notes that there can be some regulatory lag in the approval of capital expenditures.
(9) Rate Freeze	Excellent Good Satisfactory Below Average Poor	From 2002 to 2005, due to rising rates during Ontario's experimental utility deregulation phase, a distribution rate freeze was imposed province-wide. There have been no subsequent province-wide rate freezes.
(10) Market Structure (Deregulation)	Excellent Good Satisfactory Below Average Poor	Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. Hydro One is not a fully integrated utility as it does not generate electricity.

Hydro One Inc.

Balance Sheet (CAD millions)	Dec. 31 2013	Dec. 31 2012	Dec. 31 2011		Dec. 31 2013	Dec. 31 2012	Dec. 31 2011
Assets				**Liabilities & Equity**			
Cash & equivalents	565	195	228	S.T. borrowings	31	42	39
Accounts receivable	923	845	805	Accounts payable	62	140	154
Inventories	23	23	25	Current portion L.T.D.	756	600	600
Prepaid expenses & other	547	223	219	Other current liab.	1,148	974	1,027
Total Current Assets	2,058	1,286	1,277	**Total Current Liab.**	1,997	1,756	1,820
Net fixed assets	16,431	15,707	14,903	Long-term debt	8,301	7,879	7,408
Future income tax assets	11	14	17	Deferred income taxes	1,129	944	758
Goodwill & intangibles	446	400	357	Provisions	2,586	3,173	2,192
Regulatory assets	2,636	3,098	1,966	Regulatory liabilities	163	181	169
Investments & others	43	306	316	L.T. Payables & Other L.T. l	34	48	35
				Preferred shares	323	323	323
				Common equity	7,092	6,507	6,131
Total Assets	21,625	20,811	18,836	**Total Liab. & SE**	21,625	20,811	18,836

Balance Sheet & Liquidity & Capital Ratios	For the year ended December 31 2013	2012	2011	2010	2009
Current ratio	1.03	0.73	0.70	0.77	0.59
Total debt in capital structure	55.1%	55.5%	55.5%	56.5%	56.2%
Cash flow/Total debt	15.3%	15.4%	14.6%	13.9%	13.8%
(Cash flow-dividends)/Capex (times)	0.83	0.65	0.70	0.67	0.50
Dividend payout ratio	27.4%	50.3%	26.6%	4.8%	40.0%
Coverage Ratios (times)					
EBIT gross interest coverage	3.06	2.91	2.75	2.42	2.23
EBITDA gross interest coverage	4.68	4.47	4.25	3.84	3.69
Fixed-charges coverage	3.04	2.89	2.75	2.41	2.24
Profitability Ratios					
EBITDA margin	63.8%	63.7%	61.6%	59.3%	56.3%
EBIT margin	41.7%	41.4%	39.9%	37.3%	34.1%
Profit margin	26.0%	24.9%	22.2%	21.9%	19.4%
Return on equity	11.2%	11.1%	10.2%	10.2%	8.9%
Return on capital	6.6%	6.7%	6.3%	6.3%	5.7%

Hydro One Inc.

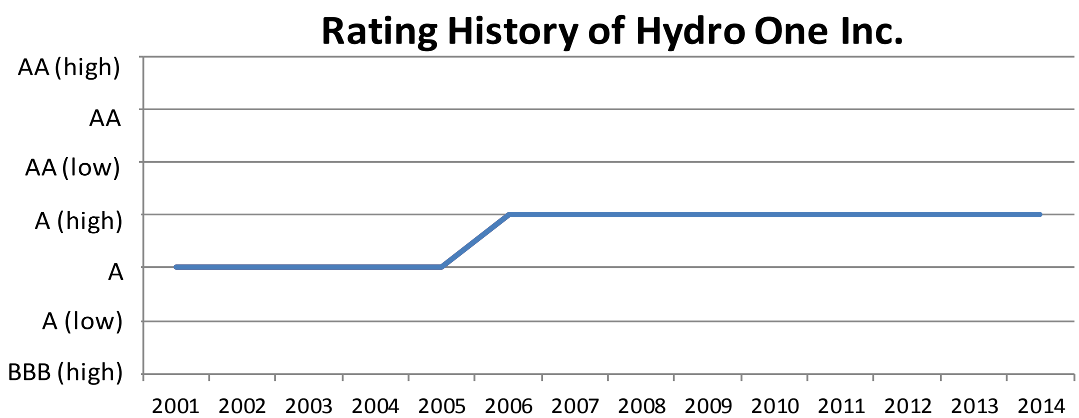
Report Date:
April 10, 2014

Ratings

Debt Rated	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Commercial Paper	R-1 (middle)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable

Rating History

	Current	2013	2012	2011	2010	2009
Issuer Rating	A (high)	A (high)	A (high)	NR	NR	NR
Commercial Paper	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)
Senior Unsecured Debentures	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)



Note:
All figures are in Canadian dollars unless otherwise noted.

PROSPECTUS FOR MOST RECENT FINANCING

Refer to Attachment 1.

This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities. All shelf information omitted from this shelf prospectus will be contained in one or more shelf prospectus supplements that will be delivered to purchasers together with the base shelf prospectus.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada*. Each shelf prospectus supplement will be incorporated by reference into this shelf prospectus for the purposes of securities legislation as of the date of the shelf prospectus supplement and only for the purposes of the distribution of the securities to which the shelf prospectus supplement pertains. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of Hydro One Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario, M5G 2P5, (416) 345-6044 and are also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

<u>*New Issue*</u> September 4, 2013

hydro One

HYDRO ONE INC.
$3,000,000,000
Medium Term Notes
(unsecured)

Hydro One Inc. ("our company," "we" or "us") may offer and issue from time to time medium term notes (the "Notes") in an aggregate principal amount of up to $3.0 billion in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) during the twenty-five months from the date of issuance of the receipt for this short form prospectus.

The Notes will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes.

Notes issued hereunder will be direct unsecured obligations of our company, will be issued under a trust indenture in any number of series or separate issues thereof, and will at their respective dates of issue rank *pari passu* with all other unsecured and unsubordinated Indebtedness (as defined below) of our company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of our company.

The specific variable terms of an offering of Notes (including the aggregate principal amount of the Notes being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling our company to extend the maturity date of the Notes, the name(s) of the dealer(s) offering the Notes, the commission payable to such dealer(s), the method of distribution and the net proceeds to our company) will be set forth in a prospectus supplement or pricing supplement which will accompany this short form prospectus. Unless otherwise indicated in a prospectus supplement or pricing supplement, the Notes will not be listed on any securities exchange.

This short form prospectus does not qualify the issuance of Notes: (i) entitling the holder to exchange or convert the Notes into other securities issued by our company or into securities issued by another entity; or (ii) in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to one or more underlying interests including, for example, an equity or debt security, a statistical measure of economic or financial performance including, but not limited to, any currency, consumer price or mortgage index, or the price or value of one or more commodities, indices or other items, or any other item or formula, or any combination or basket of the foregoing items. For greater certainty, however, this short form prospectus does qualify for issuance Notes in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to published rates of a central banking authority or one or more financial institutions, such as a prime rate or a bankers' acceptance rate, or to recognized market benchmark interest rates, such as CDOR, LIBOR or EURIBOR. For purposes of applicable Canadian securities laws, this short form prospectus only qualifies the distribution of the Notes in each of the provinces of Canada.

We are permitted, under a multijurisdictional disclosure system adopted by the United States and Canada, to prepare this short form prospectus in accordance with the disclosure requirements of Canada. Prospective investors should be aware that such requirements are different from those of the United States.

Prospective investors should be aware that the acquisition of the Notes may have tax consequences to them. Such consequences may not be described fully herein or in any prospectus supplement or pricing supplement. Prospective investors should review the tax disclosure contained in this short form prospectus, which may be amended or supplemented in any prospectus supplement or pricing supplement, and should consult with their tax advisors before purchasing the Notes.

The enforcement by investors of civil liabilities under the federal securities laws of the United States may be affected adversely by the fact that we are incorporated under the laws of the Province of Ontario, that all of our officers and directors are Canadian residents, that all of the experts named in the Registration Statement (as defined below) are Canadian residents and that substantially all of our assets and the assets of said persons may be located outside of the United States.

THE NOTES OFFERED HEREBY HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION (THE "SEC") OR ANY STATE OR PROVINCIAL SECURITIES COMMISSION OR REGULATOR NOR HAS THE SEC OR ANY STATE OR PROVINCIAL SECURITIES COMMISSION OR REGULATOR PASSED UPON THE ACCURACY OR ADEQUACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

Investing in the Notes involves risks. See the section entitled "Risk Factors" in this short form prospectus, which may be amended or supplemented in any prospectus supplement or pricing supplement.

Unless otherwise indicated in a prospectus supplement or pricing supplement, there is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this short form prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities, and the extent of issuer regulation. See "Risk Factors".

Prospective investors should rely only on the information contained in or incorporated by reference into this short form prospectus and any prospectus supplement or pricing supplement. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any jurisdiction where the offer is not permitted. Prospective investors should not assume that the information contained in this base shelf prospectus and any prospectus supplement or pricing supplement is accurate as of any date other than the date on the front of those documents.

RATES ON APPLICATION

The Notes may be offered severally by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to the dealer agreement referred to under the heading "Plan of Distribution" or such other dealers as may be selected from time to time by our company (the "Dealers"), in each case acting as agent of our company or as principal. Where the Notes are offered by the Dealer(s) as agent, the commissions payable in connection with sales of such Notes shall be agreed from time to time between our company and any such Dealers. Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between our company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. In each case, the commissions payable, if any, will be set forth in a prospectus supplement or pricing supplement that will accompany and be incorporated by reference in this short form prospectus. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to our company. We may also offer the Notes directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and our company.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders (the "Lenders") that have made an unsecured revolving credit facility available to our company (the "Credit Facility"). As of September 4, 2013, there is no outstanding indebtedness under the Credit Facility. However, if and when there is outstanding indebtedness to any of the Lenders under the Credit Facility or under any future credit facility with one or more of the Lenders, our company may be considered a connected issuer of those Dealers who are affiliates of such Lenders for purposes of securities laws in Canada. See "Plan of Distribution".

The offering of Notes is subject to the approval of certain legal matters on behalf of our company by Osler, Hoskin & Harcourt LLP in respect of both Canadian and United States legal matters and on behalf of the Dealers by Blake, Cassels & Graydon LLP in respect of Canadian legal matters and by Skadden, Arps, Slate, Meagher & Flom LLP in respect of United States legal matters.

Our company's head and registered office is located at 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario, M5G 2P5.

Our consolidated financial statements incorporated by reference in this short form prospectus have been prepared in accordance with US generally accepted accounting principles. Unless otherwise specified or the context otherwise requires, all references herein to currency are references to Canadian dollars.

TABLE OF CONTENTS

DOCUMENTS FILED AS PART OF THE REGISTRATION STATEMENT

The following documents are being filed with the SEC as part of the Registration Statement (as defined below): (i) the documents referred to under the heading "Documents Incorporated by Reference"; (ii) the consent of KPMG LLP; (iii) the Trust Indenture described under the heading "Description of the Notes", including any applicable supplements thereto; and (iv) the powers of attorney from our directors and officers.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions and similar regulatory authorities in Canada and with the SEC.

The following documents, which have been filed with the securities commission or similar regulatory authority in each of the provinces of Canada, and filed with or furnished to the SEC, are specifically incorporated by reference in this short form prospectus:

(a) the annual information form of our company dated March 28, 2013;

(b) the comparative audited consolidated financial statements of our company, and the notes thereto, as at and for the fiscal years ended December 31, 2012 and 2011, together with the report of the auditors thereon dated February 14, 2013;

(c) management's discussion and analysis of financial results ("MD&A") for the year ended December 31, 2012; and

(d) the comparative unaudited consolidated financial statements of our company, and the notes thereto, as at June 30, 2013 and for the three and six month periods ended June 30, 2013 and June 30, 2012 together with MD&A for those periods.

Updated earnings coverage ratios, as required, will be filed quarterly with the appropriate securities regulatory authorities either as prospectus supplements or as part of our company's unaudited interim and audited annual consolidated financial statements and will be deemed to be incorporated by reference into this short form prospectus for the purposes of the offering of Notes hereunder.

Any documents of the type required by National Instrument 44-101 – *Short Form Prospectus Distributions* to be incorporated by reference in a short form prospectus, including documents of the types referred to in paragraphs (a) through (d) above, and any material change reports (except confidential material change reports) and business acquisition reports filed by our company with the securities regulatory authorities in Canada since the end of the financial year in respect of which our then current annual information form is filed, shall be deemed to be incorporated by reference into this short form prospectus. Upon a new annual information form and new annual financial statements and related MD&A being filed by our company with, and where required, accepted by, the applicable securities regulatory authorities during the currency of this short form prospectus, the previous annual information form, previous annual financial statements and related MD&A, and all previous interim financial statements and related MD&A filed prior to the commencement of our company's financial year in which the new annual information form, new annual financial statements and related MD&A are filed shall be deemed no longer to be incorporated into this short form prospectus for purposes of future offers and sales of Notes hereunder. To the extent that any document or information incorporated by reference into this short form prospectus is included in a report that is filed with or furnished to the SEC, such document or information shall be deemed to be incorporated by reference as an exhibit to the Registration Statement (as defined below). In addition, any other report filed with or furnished to the SEC by our company shall be deemed to be incorporated by reference as an exhibit to the Registration Statement (as defined below), if and to the extent that such report expressly so provides.

A pricing supplement or prospectus supplement containing the specific variable terms for an issue of Notes will be delivered to purchasers of such Notes together with this short form prospectus and will be deemed to be incorporated by reference into this short form prospectus as of the date of the pricing supplement or prospectus supplement, solely for the purposes of the Notes issued under that pricing supplement or prospectus supplement. Any template version of marketing materials for an issue of Notes filed by our company with the securities regulatory authorities in Canada after the date of the pricing supplement or prospectus supplement in respect of such issue of Notes and before the termination of the distribution of such Notes will be deemed to be incorporated by reference into that pricing supplement or prospectus supplement.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded and not incorporated by reference, for purposes of this short form prospectus, to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not constitute a part of this short form prospectus, except as so modified or superseded.

AVAILABLE INFORMATION

This short form prospectus is part of a registration statement on Form F-10 relating to the Notes (the "Registration Statement") that we have filed with the SEC under the U.S. Securities Act of 1933, as amended (the "U.S. Securities Act"). This short form prospectus does not contain all of the information set forth in the Registration Statement, certain parts of which are omitted in accordance with the rules and regulations of the SEC. United States investors should refer to the Registration Statement and the exhibits to the Registration Statement for further information with respect to us and the Notes. We will file annual and quarterly reports, material change reports and other documents with the securities commissions or similar regulatory authorities in each of the provinces of Canada and will file such documents with, or furnish such documents to, the SEC. Under a multi-jurisdictional disclosure system adopted by the United States and Canada, these reports and other documents (including financial statements) may be prepared in accordance with the disclosure requirements in Canada, which differ from those in the United States. Prospective investors may read and download any public document that we have filed with securities commissions or similar regulatory authorities in each of the provinces of Canada on the System for Electronic Document Analysis and Retrieval, which is commonly known by the acronym SEDAR, and which may be accessed at www.sedar.com. Prospective investors may read any document that we file with or furnish to the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C., 20549. Prospective investors may also obtain copies of the same documents from the SEC's public reference room by paying a fee. Please call the SEC at 1-800-SEC-0330 or contact it at www.sec.gov for further information on the public reference room. Documents that we file with or furnish to the SEC will also be electronically available from the SEC's Electronic Document Gathering and Retrieval System, which is commonly known by the acronym EDGAR, and which may be accessed at www.sec.gov, as well as from commercial document retrieval sources.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

This short form prospectus, including the documents incorporated by reference herein, contains "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 that are based on current expectations, estimates, forecasts and projections about the business of our company and the industry in which we operate and includes beliefs and assumptions made by the management of our company. Such information and statements include, but are not limited to, information and statements about the general development of our business, our strategy, future capital expenditures, and expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario. Additional forward-looking information and forward-looking statements are identified in the various documents incorporated by reference in this short form prospectus, including the section entitled "Forward-Looking Information" in our annual information form and the section entitled "Forward-Looking Statements and Information" in our MD&A. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", and variations of such words and similar expressions are intended to identify such forward-looking statements. The forward-looking information and forward-looking statements contained in this short form prospectus, including the documents incorporated by reference herein, are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. In particular, this forward-looking information and these forward-looking statements are based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the Ontario Energy Board and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining required approvals; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; no unfavourable changes in environmental regulation; the continued use and availability of U.S. GAAP; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to our company including information obtained by our company from third-party sources. Actual outcomes and results may differ materially from what is expressed, implied or forecasted in this forward-looking information and these forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information and forward-looking statements are discussed in more detail under "Risk Factors" in this short form prospectus and in any prospectus supplement or pricing supplement and in the sections entitled "Forward-Looking Information" and "Risk Factors" in our annual information form and the sections entitled "Risk Management and Risk Factors" and "Forward-Looking Statements and Information" in our MD&A. You should carefully consider these and other factors and not place undue reliance on forward-looking statements and forward-looking information.

We do not intend, and we disclaim any obligation, to update any forward-looking information or forward-looking statements, except as required by law.

ENFORCEABILITY OF CIVIL LIABILITIES

We exist under the laws of the Province of Ontario. All of our directors and officers and the experts named in this short form prospectus are residents of Canada or otherwise reside outside the United States, and substantially all of our assets and the assets of said persons may be located outside the United States. We have filed with the SEC, along with the Registration Statement, an appointment of agent for service of process on Form F-X. Under the Form F-X, we appointed CT Corporation System as our agent for service of process in the United States in connection with any investigation or administrative proceeding conducted by the SEC, and any civil suit or action brought against or involving us in a United States court arising out of or related to or concerning an offering of the Notes. Although we have appointed an agent for service of process in the United States, it may be difficult for holders of Notes who reside in the United States to effect service within the United States upon those directors, officers and experts who are not residents of the United States. It may also be difficult for holders of Notes who reside in the United States to realize in the United States upon judgments of courts of the United States predicated upon the civil liability of us and the civil liability of the directors, officers and experts under the United States federal securities laws.

OUR COMPANY

We are the leading electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 96.8% of Ontario's transmission capacity based on revenues approved by the Ontario Energy Board for the year ended December 31, 2012. Our transmission system is one of the largest in North America based on assets. Our distribution system is the largest in Ontario based on assets as at December 31, 2012 and serves approximately 1.4 million customers. We have three reportable segments: (1) our transmission business; (2) our distribution business; and (3) our other business.

Our transmission business, which represented approximately $11.6 billion of our total assets of $20.8 billion as at December 31, 2012, transmits electricity through an approximately 29,000 circuit-kilometre high-voltage network. We transmit electricity from generators to our own distribution network, to 47 local distribution companies and to 92 transmission connected companies. We also own and operate 26 facilities that interconnect our transmission system with systems in neighbouring provinces and states.

Our distribution business, which represented approximately $8.6 billion of our total assets of $20.8 billion as at December 31, 2012, distributes electricity through our low-voltage distribution system to municipalities and to rural areas. Customers of our distribution business include 23 local distribution companies that are not directly connected to our transmission system, another 33 local distribution companies that are connected to our transmission system, 30 customers with loads exceeding 5MW and approximately 1.4 million rural and urban customers. Hydro One Brampton Networks Inc. is our urban distribution company, serving approximately 142,000 customers in the Greater Toronto Area. We also operate, through our subsidiary Hydro One Remote Communities Inc., 19 small, regulated generation and distribution systems in 21 remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

Our other business segment is primarily represented by the operations of Hydro One Telecom Inc. This subsidiary markets dark and lit fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of this segment constituted approximately $0.6 billion of our total assets of $20.8 billion as at December 31, 2012.

The Ontario Energy Board regulates our transmission and distribution businesses and issues rate orders to establish the revenue requirements required to cover the approved cost of these businesses plus a specified rate of return.

The address of the head and registered office and principal place of business of our company is 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario, M5G 2P5.

EARNINGS COVERAGE RATIOS

For the twelve months ended December 31, 2012 and the twelve months ended June 30, 2013, our company's consolidated income before provision for payment in lieu of corporate income taxes and interest expense (net of capitalized interest) was $1,224 million and $1,264 million, respectively. Interest expense (net of capitalized interest) for these periods was $358 million and $362 million, respectively, and including capitalized interest, was $417 million and $412 million, respectively. Preferred share dividends declared for these periods were $18 million and $18 million, respectively.

The following table sets forth the earnings coverage ratio for our company for the twelve month period ended December 31, 2012, based on audited information, and for the twelve month period ended June 30, 2013, based on unaudited information, in each case without giving effect to any Notes to be issued under this short form prospectus:

	December 31, 2012	**June 30, 2013**
Earnings coverage on long-term debt obligations(1)	2.83	2.94

(1) The earnings coverage ratio has been calculated as the sum of net income, interest expense (net of capitalized interest) and provision for payments in lieu of corporate income taxes divided by the sum of interest expense (including capitalized interest) plus preferred dividends declared.

DESCRIPTION OF THE NOTES

General

The following is a summary of the material attributes and characteristics of the Notes, and does not purport to be complete and is qualified in its entirety by reference to the Notes and the Trust Indenture (as defined below).

The terms and conditions set forth in this section "Description of the Notes" will apply to each Note unless otherwise specified in the applicable prospectus supplement or pricing supplement. We reserve the right to set forth in a prospectus supplement or pricing supplement specific variable terms of or amendments to the Notes which are not within the options and parameters set forth in this short form prospectus. References in this section "Description of the Notes" refer to all medium term notes of our company which have previously been or are to be issued under the Trust Indenture.

This short form prospectus qualifies under applicable Canadian securities laws the distribution of $3.0 billion aggregate principal amount of Notes in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) which have been authorized for issue under the Trust Indenture. This amount is subject to amendment from time to time as determined by our company. Our company has previously issued $1.485 billion aggregate principal amount of medium term notes under our short form prospectus dated August 23, 2011, which was qualified under applicable Canadian securities laws. Upon the issuance of a final receipt for this short form prospectus, we will not qualify for distribution any additional Notes under the August 23, 2011 prospectus. Only Notes that meet the eligibility requirements for registration on Form F-10, as applicable to our company, shall be registered under the U.S. Securities Act pursuant to the Registration Statement.

Notes issued hereunder will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units at the time of issue) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes (as described under the subheading "Global Notes" below). Each interest-bearing Note will bear interest at either a fixed rate (a "Fixed Rate Note") or a floating rate (a "Floating Rate Note"). Notes will be issued from time to time at such rates of interest and at par, at a premium or at a discount, may be subject to redemption or repayment prior to maturity, and may include terms entitling our company to extend the maturity dates of the Notes, which terms shall be determined by our company based on a number of factors, including advice from the Dealers. The Notes will be unsecured and will, at their respective dates of issue, rank *pari passu* with all other unsecured and unsubordinated Indebtedness and obligations of our company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of our company. We may also, from time to time, issue debt securities and incur additional debt otherwise than through the issuance of Notes pursuant to this short form prospectus.

Neither the aggregate principal amount of Notes which will be issued and sold nor the issue price to the public of the Notes has been established as the Notes will be issued at such times, in such amounts and at such prices as our company determines from time to time. Notes issued hereunder will be offered and sold during the twenty-five months from the date of issuance of the receipt for this short form prospectus at prices negotiated with the purchasers, and the prices at which the Notes will be offered and sold may vary as between purchasers and during the distribution period. The Notes will be issued from time to time at the discretion of our company in an aggregate principal amount not to exceed $3.0 billion in Canadian currency, or the equivalent thereof calculated at the applicable rates of exchange prevailing at the time of issue of Notes issued in currencies other than Canadian currency.

The specific variable terms of any offering of Notes, including, in the case of Floating Rate Notes, the information necessary for the calculation of interest thereon, will be set forth in a prospectus supplement or pricing supplement to this short form prospectus. Where Notes are offered and sold in currencies other than Canadian dollars, the Canadian dollar equivalent of the offering price and the rate of exchange at the last feasible date will be included in the applicable prospectus supplement or pricing supplement.

Trust Indenture

The Notes will be issued under a trust indenture dated as of June 4, 2001, as supplemented or modified from time to time (collectively, the "Trust Indenture") between our company and Computershare Trust Company of Canada, as trustee (the "Trustee", which term shall include, unless the context otherwise requires, its successors and assigns). To the extent necessary in connection with offers and sales in the United States, a U.S. affiliate of the Trustee and the Transfer Agent (as defined below) may act as co-transfer agent for the Notes, but not as co-trustee. The following is a brief summary of the material attributes and characteristics of the Trust Indenture. This summary does not purport to be complete and reference should be made to the Trust Indenture for more detailed information.

The Trust Indenture is subject to and governed by the *Business Corporations Act* (Ontario) and, consequently, is exempt from certain provisions of the U.S. Trust Indenture Act of 1939, as amended (the "U.S. Trust Indenture Act"), by virtue of Rule 4d-9 thereunder.

The Trust Indenture permits the issuance from time to time of additional unsecured medium term notes without limitation as to aggregate principal amount, subject to compliance with the covenants contained therein.

The Notes will be direct obligations of our company and will rank *pari passu* with all other medium term notes from time to time issued and outstanding under the Trust Indenture and with other present and future unsubordinated and unsecured Indebtedness of our company, except as to any sinking fund which pertains exclusively to any particular Indebtedness of our company. The Notes will not be secured by any mortgage, pledge or charge, except in the circumstances referred to under the heading "Negative Pledge".

Negative Pledge

The Trust Indenture contains provisions to the effect that our company will not, nor will it permit any Designated Subsidiary (as defined below) to, create, assume or suffer to exist any Security Interest (as defined below) on any of our or the Designated Subsidiary's assets to secure any Obligation (as defined below) unless at the same time it shall secure all the Notes then outstanding on an equal basis. This covenant is, however, subject to the following exceptions:

- any Security Interest that secures the Obligations of a Designated Subsidiary which exists prior to the date on which it becomes a Designated Subsidiary and which (a) was not incurred in contemplation of that person becoming a Designated Subsidiary and (b) was not applicable to our company or any other Designated Subsidiary or the properties or assets of our company or any other Designated Subsidiary;

- any Security Interest granted by our company or a Designated Subsidiary to secure the Notes;

- any Purchase Money Mortgage (as defined below) or Capital Lease Obligation (as defined below) of our company or any Designated Subsidiary;

- any Security Interest on a property or asset acquired by our company or a Designated Subsidiary that secures the Obligations of a person, whether or not that Obligation is assumed by the acquiring person, which Security Interest exists at the time that property or asset is acquired and which (a) was not incurred in contemplation of that property or asset being acquired and (b) was not applicable to our company or any other Designated Subsidiary or the properties or assets of our company or any other Designated Subsidiary;

- any Security Interest given in the ordinary course of business by our company or a Designated Subsidiary to any bank or banks or other lenders to secure any Indebtedness payable on demand or maturing within 18 months of the date that Indebtedness is incurred or of the date of any renewal or extension of that Indebtedness;

- any Security Interest granted by any Designated Subsidiary in favour of our company or any Wholly-Owned Designated Subsidiary (as defined below);

- any Security Interest on or against cash or marketable debt securities pledged to secure any non-speculative Financial Instrument Obligation (as defined below) which hedges Indebtedness of our company or of a Designated Subsidiary;

- any Security Interest for taxes, assessments, government charges or claims that are being contested in good faith and in respect of which appropriate provision is made in our consolidated financial statements in accordance with GAAP;

- Security Interests securing appeal bonds or other similar Security Interests arising in connection with contracts, bids, tenders or court proceedings, including, without limitation, surety bonds, security for costs of litigation where required by law and letters of credit, or any other instruments serving a similar purpose;

- a Security Interest in cash or marketable debt securities in a sinking fund account established by our company in support of a series of Notes;

- a lien or deposit under workers' compensation, social security or similar legislation or good faith deposits in connection with bids, tenders, leases, contracts or expropriation proceedings, or deposits to secure public or statutory obligations or deposits of cash or obligations to secure surety and appeal bonds;

- any lien or privilege imposed by law, such as builders', carriers', warehousemen's, landlords', mechanics' and material men's liens and privileges, and any lien or privilege arising out of judgments or awards with respect to which our company or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending that appeal or proceedings for review; or any liens for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by our company or a Designated Subsidiary in good faith; or undetermined or inchoate lien privileges and charges incidental to current operations which have not at such time been filed pursuant to law against our company or a Designated Subsidiary or which relate to obligations not due or delinquent; or the deposit of cash or securities in connection with any lien or privilege referred to in this clause;

- any minor encumbrance, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions as to our company's use of real property, which do not in the aggregate materially detract from the value of that property or materially impair its use in the operation of the business of our company or a Designated Subsidiary;

- any right reserved to or vested in, whether by statutory provision or otherwise, any municipality or governmental or other public authority to terminate, purchase assets used in connection with or require annual or other periodic payments as a condition to the continuance of, any lease, license, franchise, grant or permit acquired by our company or a Designated Subsidiary;

- any lien or right of distress reserved in or exercisable under any lease for rent and for compliance with the terms of that lease;

- any Security Interest granted by our company or a Designated Subsidiary to a public utility or any municipality or governmental or other public authority when required by that utility, municipality or other authority in connection with the operations of our company or a Designated Subsidiary;

- any reservation, limitation, proviso or condition, if any, expressed in any original grants to our company or a Designated Subsidiary from the Crown; and

- any extension, renewal, alteration, substitution or replacement, in whole or in part, of any Security Interest referred to in the foregoing clauses, provided that the Security Interest is limited to all or part of the same property that secured the Security Interest, the principal amount of the secured Obligations is not increased by that action, the term of the secured Indebtedness is not shortened and the terms and conditions are no more restrictive in any material respect than the Security Interest so extended.

In addition to the Security Interests permitted above, our company or any Designated Subsidiary may create, assume or suffer to exist any Security Interest on any of its assets if, after giving effect to that Security Interest, the aggregate amount of Indebtedness secured by the Security Interests permitted only by this paragraph does not at that time exceed 5% of the Consolidated Net Worth (as defined below) of our company.

Limitation on Funded Obligations

So long as any of the Notes issued under the Trust Indenture remain outstanding, neither our company nor any of its Designated Subsidiaries will, directly or indirectly, guarantee, incur, issue or become liable for or in respect of any Funded Obligations (as defined below) unless after giving pro forma effect to that guarantee, incurrence, issuance or liability, including the application or use of the resulting net proceeds, the aggregate principal amount of Consolidated Funded Obligations (as defined below) does not exceed 75% of the Total Consolidated Capitalization (as defined below). This covenant, however, will not prevent the incurrence of Capital Lease Obligations, Purchase Money Obligations and non-speculative Financial Instrument Obligations.

Ceasing to be a Designated Subsidiary

The Board of Directors of our company may elect that any Designated Subsidiary cease to be a Designated Subsidiary, except that an election may not be made in respect of any Designated Subsidiary:

- if the Designated Subsidiary owns any Funded Obligations of our company or any shares, voting interests or Funded Obligations of any other Designated Subsidiary;

- if the Designated Subsidiary owns or has any ownership interest in any Principal Property (as defined below); or

- if, after giving effect to the election, our company would not be entitled to issue Funded Obligations in the principal amount of at least $1.00.

Mergers, Consolidations and Sales of Assets

Our company will not enter into any transaction in which all or substantially all of our property and assets would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless:

- our company shall be the surviving person, or the person, if other than our company, formed by the amalgamation, consolidation or into which our company is merged or that acquires by disposition all or substantially all of the property or assets of our company, shall be a company organized and validly existing under the federal laws of Canada or any of its provinces or territories and shall expressly assume, by a supplemental indenture executed and delivered to the

Trustee in form satisfactory to the Trustee, all of our company's obligations under the Trust Indenture;

- immediately before and after giving effect to the transaction, no Event of Default or event that with the passing of time or the giving of notice, or both, would constitute an Event of Default shall have occurred and be continuing; and

- neither our company nor any successor, either at the time of or immediately after the consummation of any such transaction, will be insolvent or generally fail to meet, or admit in writing its inability or unwillingness to meet, its obligations as they generally become due.

Events of Default

The following are Events of Default under the Trust Indenture with respect to Notes of any series:

(1) failure to pay any principal or premium, if any, on any Notes when due, at maturity, upon redemption or otherwise and the continuance of such default for a period of five days;

(2) failure to pay any interest on any Notes when due and the continuance of that default for a period of 45 days;

(3) the sale, transfer or other disposition of all or substantially all of our undertaking or assets other than in accordance with the covenant described above under "Mergers, Consolidations and Sales of Assets";

(4) default in the performance or breach of any other covenant or agreement of our company under the Trust Indenture, any supplemental indenture or the Notes and the continuance of that default for a period of 60 days after written notice to our company by the Trustee or by holders of at least 25% of all Notes issued under the Trust Indenture;

(5) default by our company or any Material Subsidiary (as defined below), whether as primary obligor, guarantor or surety, on any payment of principal, premium, if any, or interest on any Indebtedness, the outstanding principal amount of which Indebtedness exceeds $100 million in the aggregate, beyond any applicable grace period or failure to perform or observe any other agreement, term or condition contained in any agreement under which that Indebtedness is created, or if any default, failure or other event under that agreement shall occur and be continuing, and the effect of that default, failure or other event is to cause $100 million or more of that Indebtedness to become due or to be required to be repurchased prior to any stated maturity;

(6) the rendering of a judgment or judgments, not subject to appeal, against our company or any Material Subsidiary in an aggregate amount in excess of $100 million by a court or courts of competent jurisdiction, which judgment or judgments remain undischarged and unstayed for a period of 60 days; and

(7) specified events of bankruptcy, insolvency or reorganization affecting our company or any Material Subsidiary.

If an Event of Default applicable only to the issued and outstanding Notes of a series occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of Notes of that series then outstanding may declare the principal of, and interest and premium, if any, on all Notes of that series to be due and payable immediately.

If, however, an Event of Default applicable to all Notes issued and outstanding under the Trust Indenture, or an Event of Default described in clause (5), (6), or (7) above occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of all issued and outstanding Notes, treated as one class, may declare the principal amount of all the Notes then outstanding to be due and payable immediately.

Subject to the provisions of the Trust Indenture relating to the duties of the Trustee, in case an Event of Default applicable to any Notes shall occur and be continuing, the Trustee will be under no obligation to exercise any of its rights or powers under the Trust Indenture at the request or direction of any of the holders of those Notes, unless those holders shall have offered to the Trustee reasonable indemnity. Subject to such provisions for the indemnification of the Trustee, the holders of a majority in principal amount of Notes of all series affected by an Event of Default will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee in respect of the Notes of all series affected by that Event of Default.

Defeasance

The Trust Indenture requires the Trustee to release our company from its obligations under the Trust Indenture relating to a particular series of Notes if specified conditions are satisfied. Among other things, our company must deposit money or securities for the payment of all principal of and interest and any other amounts on that series of Notes as well as for the payment of the expenses of the Trustee. The deposited money or securities must be denominated in the currency in which principal of these Notes is payable and, in the case of deposited securities, must constitute direct obligations of Canada or specified provinces of Canada or an agency or instrumentality of Canada.

Amendments and Waivers

The Trust Indenture provides that our company and the Trustee may enter into supplemental indentures ("Supplemental Indentures") without the consent of the holders of the Notes of any or all series to:

- add limitations or restrictions to be observed upon the amount or issue of Notes, provided that such limitations or restrictions shall not be materially adverse to the interests of the holders of the Notes;
- add covenants for the protection of the holders of the Notes of any series;
- provide for any additional Events of Default;
- make such provisions not inconsistent with the Trust Indenture as may be necessary or desirable with respect to matters or questions arising thereunder, including the making of any modifications in the form of the Notes which do not affect the substance thereof and which it may be expedient to make, provided that such provisions and modifications will not adversely affect the holders of Notes;
- provide for the issue of Notes of any one or more series and establish the form and terms of any series of Notes;
- evidence the succession, or successive successions, of successors to our company and the covenants and obligations assumed by any such successor, in accordance with the provisions of the Trust Indenture; and
- giving effect to any extraordinary resolution or ordinary resolution of the holders of Notes in accordance with the Trust Indenture.

Other amendments and modifications of the Trust Indenture, Supplemental Indentures and Notes may be made by our company and the Trustee with the consent of the holders of not less than 66⅔% (and in certain circumstances, a majority) in principal amount of Notes of all series voting on such amendment or modification and, if the rights of holders of Notes of a particular series of Notes would be affected differently than rights of holders of Notes of other series, not less than 66⅔% (and, in certain circumstances, a majority) in principal amount of Notes of the series so affected by that modification or amendment voting on such amendment or modification, in each case, voting as one class. However, no modification or amendment may, without the consent of the holder of each outstanding Note of the affected series,

- reduce the principal amount at maturity of, extend the fixed maturity of, or alter the redemption provisions of, those Notes;

- change the currency in which those Notes or any premium or accrued interest is payable;

- reduce the percentage in principal amount at maturity outstanding of those Notes that must consent to an amendment, supplement or waiver or consent to take any action under the Trust Indenture, Supplemental Indenture or those Notes;

- impair the right to institute suit for the enforcement of any payment on or with respect to those Notes;

- waive a default in payment with respect to those Notes;

- reduce the rate or extend the time for payment of interest on those Notes;

- affect the ranking of those Notes in a manner adverse to the holders; or

- make any changes to the Trust Indenture, Supplemental Indentures or those Notes that would result in our company being required to make any withholding or deduction from payments made under or with respect to those Notes.

The holders of 66⅔% in principal amount of the Notes of all series with respect to which an Event of Default shall have occurred and be continuing, voting as one class, may waive any Event of Default, except in the case of a default in payment of principal with respect to the Notes or except, further, in respect of a covenant or provision which cannot be modified or amended without the consent of the holder of each outstanding Note affected.

In respect of any series of Notes that are offered for sale in the United States pursuant to the Registration Statement, the Supplemental Indenture entered into in respect of such series will provide that notwithstanding anything else contained in the Trust Indenture, the right of any holder of that series of Notes to receive payment of the principal of and interest on that series of Notes, on or after the respective due dates for such payments, or to institute suit for the enforcement of any such payment on or after such respective dates, shall not be impaired or affected without the consent of such holder, except to the extent permitted by Section 316(b) of the U.S. Trust Indenture Act.

Definitions

In addition to the definitions set out above, the Trust Indenture contains definitions substantially to the following effect:

"Capital Lease Obligation" means any monetary obligation of our company or a Designated Subsidiary under any leasing or similar arrangement which, in accordance with GAAP, would be classified as a capital lease and for the purposes of the Trust Indenture, the amount of Capital Lease Obligations will be the capitalized amount thereof, determined in accordance with GAAP;

"Consolidated Funded Obligations" means the aggregate amount of all Funded Obligations of our company and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP;

"Consolidated Net Worth" means, as at any date, the consolidated shareholders' equity of our company and its Designated Subsidiaries as at that date determined in accordance with GAAP;

"Contingent Liability" means any agreement, undertaking or arrangement by which any person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the Obligation of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other

person. The amount of any person's obligation under any Contingent Liability will, subject to any limitation contained in that Contingent Liability, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the debt, obligation or other liability guaranteed thereby;

"Designated Subsidiary" means any subsidiary which is designated as such by the directors of our company, provided that any such subsidiary may only be so designated if, after giving effect thereto, our company would be entitled under the Trust Indenture to issue Funded Obligations in the principal amount of at least $1.00 and further provided that a subsidiary cannot be so designated if any of its shares are owned by a subsidiary which is not itself a Designated Subsidiary;

"Financial Instrument Obligations" means, with respect to any person at any time, the obligations of that person under any transaction that is a rate swap, basis swap, forward rate transaction, commodity swap, commodity option, commodity future, equity or equity index swap or option, bond, note or bill option, interest rate option, forward foreign exchange transaction, cap, collar or floor transaction, currency swap, cross-currency rate swap, swaption, currency option or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing to the extent of the net amount due to or accruing due by the person under that obligation, determined by marking that obligation to market at that time in accordance with its terms;

"Funded Obligations" means all Indebtedness created, assumed or guaranteed, which matures by its terms on, or is renewable at the option of the obligor to, a date more than 18 months after the date of the original creation, assumption or guarantee thereof;

"GAAP" means as at any date of determination:

(1) accounting principles which are recognized as being generally accepted in Canada, if our company is then preparing its financial statements in accordance with such principles; or

(2) accounting principles which are recognized as being generally accepted in the United States, if our company is then preparing its financial statements in accordance with such principles;

"Indebtedness" means, without duplication, with respect to any person,

(1) all obligations of that person for borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations, excluding Preferred Securities issued by that person;

(2) all obligations issued or assumed by that person in connection with its acquisition of property in respect of the deferred purchase price of that property;

(3) all Capital Lease Obligations and Purchase Money Obligations of that person; and

(4) all Contingent Liabilities of that person in respect of any of the foregoing;

"Material Subsidiary" means, as at any date, a Designated Subsidiary,

(1) the total assets of which represent more than 10% of the total assets of our company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of our company; or

(2) the total revenues of which represent more than 10% of the total revenues of our company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of our company;

"Obligations" means, without duplication, with respect to any person, all items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of that person as of the date at which Obligations are to be determined, other than Preferred Securities issued by that person; and all Contingent Liabilities of that person in respect of any of the foregoing;

"*Preferred Securities*" means:

(1) securities which on the date of issue by a person (a) have a term to maturity of more than 30 years, (b) are unsecured and rank subordinate to the unsecured and unsubordinated Indebtedness of that person outstanding on that date, (c) entitle that person to satisfy the obligation to pay the principal or face amount by issuing common shares, (d) entitle that person to defer the payment of interest for more than four years without causing an event of default to occur, and (e) entitle that person to satisfy the obligation to make payments of interest by issuing common shares; and

(2) shares of any class in the capital of a corporation or securities representing ownership interests in any person other than a corporation which, in either case, are not common shares;

"*Principal Property*" means any of our company's and our subsidiaries' fixed assets used for the transmission, transformation and distribution of electricity in Ontario as of June 4, 2001 (the date of the Trust Indenture);

"*Purchase Money Mortgage*" means any security interest, mortgage, pledge, charge or other encumbrance created, issued or assumed by our company or a Designated Subsidiary to secure a Purchase Money Obligation; provided that the security interest, mortgage, pledge, charge or other encumbrance is limited to the property (including associated rights) acquired, constructed, installed or improved using the funds advanced to our company or a Designated Subsidiary in connection with that Purchase Money Obligation;

"*Purchase Money Obligation*" means Indebtedness of our company or a Designated Subsidiary incurred or assumed to finance the purchase price, in whole or in part, of any property (except any Indebtedness which constitutes a Funded Obligation and which was incurred or assumed to finance the purchase price, in whole or in part, of any shares, bonds or other securities) or incurred to finance the cost, in whole or in part, of construction or installation of or improvements to any real property or fixtures provided that such Indebtedness is incurred or assumed within 24 months after the purchase of such real property or fixtures or the completion of such construction, installation or improvements, as the case may be, and includes any extension, renewal or refunding of any such Indebtedness, so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

"*Security Interest*" means any assignment, mortgage, charge (whether fixed or floating), hypothec, pledge, lien, or other encumbrance on or interest in property or assets that secures payment of Indebtedness or Obligation;

"*Total Consolidated Capitalization*" means, at any time and from time to time, without duplication, the sum of (1) the principal amount of all Consolidated Funded Obligations at the time outstanding, and (2) the total share capital of our company at the time outstanding, based upon the stated capital on the books of our company, and (3) the principal amount of all outstanding Preferred Securities referred to in clause (1) of the definition of "Preferred Securities" plus the total amount of (or less the amount of any net deficits in) the contributed or capital surplus of our company and the retained earnings of our company and all Designated Subsidiaries in accordance with GAAP after adding back the amount shown on the consolidated balance sheet of our company and its Designated Subsidiaries for minority interests applicable to Designated Subsidiaries and eliminating all intercorporate items, plus the amount of any premium on capital of our company not included in its surplus, and less the amount, if any, by which the capital account of our company or the consolidated capital surplus account of our company and all Designated Subsidiaries (determined in the manner described above) has at any time been increased as a result of any write-up in the value of the shares of a subsidiary which is not a Designated Subsidiary to reflect the equity of our company in its retained earnings or otherwise, or as a result of a restatement of the amount at which any other assets of our company or any Designated Subsidiary are recorded on its books. The amount of Total Consolidated Capitalization of our company and all Designated Subsidiaries at any time shall be ascertained in Canadian dollars; and

"*Wholly-Owned Designated Subsidiary*" means a Designated Subsidiary, all of the outstanding shares in the capital of which are owned, directly or indirectly, by or for our company and/or by or for one or more other Wholly-Owned Designated Subsidiaries.

Global Notes

Notes may be issued in the form of fully registered global notes ("Global Notes") held by, or on behalf of, CDS Clearing and Depository Services Inc. ("CDS") or another corporation performing similar services that is acceptable to the Trustee (the "Depository") as custodian of the Global Notes and, in such event, Notes will be registered in the name of the Depository or its nominee (a "Nominee"). Where CDS acts as Depository for a series of Notes, The Depositary Trust Company ("DTC"), Euroclear Bank S.A./N.V., as operator of the Euroclear System ("Euroclear") and Clearstream Banking, société anonyme ("Clearstream, Luxembourg"), in each case as direct or indirect participants in CDS, will record beneficial ownership of such series of Notes on behalf of their respective accountholders or participants, to the extent we make such series of Notes eligible with DTC, Euroclear or Clearstream, Luxembourg, as applicable (and we specify as such in the prospectus supplement or pricing supplement with respect to the particular series of Notes).

Purchasers of Notes represented by Global Notes will not receive Notes in definitive form ("Definitive Notes"). Instead, ownership of such Notes will be constituted through beneficial interests in the Global Notes, and will be represented through book-entry accounts of institutions (including the Dealers), as direct and indirect participants of the Depository ("participants") which, to the extent the Depository is CDS, may include DTC, Euroclear and Clearstream, Luxembourg to the extent applicable as noted above, acting on behalf of the beneficial owners of such Notes. Each purchaser of a Note represented by a Global Note will receive a customer confirmation of purchase from the Dealer or other person from or through whom the Note is purchased in accordance with the practices and procedures of such Dealer or other person. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Notes.

If Global Note(s) are issued and the Depository notifies our company that it is unwilling or unable to continue as depository in connection with the Global Notes, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be depository and our company and the Trustee are unable to locate a qualified replacement, or if our company elects to terminate the book-entry system, beneficial owners of Notes represented by Global Notes will receive Definitive Notes.

DTC, Euroclear and Clearstream, Luxembourg

Where CDS acts as Depository for a series of Notes, to the extent we make such series of Notes eligible with DTC, Euroclear or Clearstream, Luxembourg (and we specify as such in the prospectus supplement or pricing supplement with respect to such series of Notes), holders may hold such series of Notes through the accounts maintained by DTC, Euroclear or Clearstream, Luxembourg, as applicable, as participants in CDS only if they are participants of those systems, or indirectly through organizations which are participants of those systems.

In such case, DTC, Euroclear and Clearstream, Luxembourg will hold omnibus book-entry positions on behalf of their participants through customers' securities accounts in their respective depositaries which in turn will hold such positions in customers' securities accounts in the names of the nominees of the depositaries on the books of CDS. All securities in DTC, Euroclear and Clearstream, Luxembourg are held on a fungible basis without attribution of specific certificates to specific securities clearance accounts.

Transfers of such Notes by persons holding through Euroclear or Clearstream, Luxembourg participants, as applicable, will be effected through CDS, in accordance with CDS rules, on behalf of the relevant European international clearing system by its depositaries; however, such transactions will require delivery of transfer instructions to the relevant European international clearing system by the participant in such system in accordance with its rules and procedures and within its established deadlines (European time). The relevant European international clearing system will, if the transfer meets its requirements, deliver instructions to its depositaries to take action to effect the transfer of the Notes on its behalf by delivering Notes through CDS and receiving payment in accordance with its normal procedures for next-day funds settlement. Payments with respect to the Notes held through Euroclear or Clearstream, Luxembourg will be credited to the cash accounts of Euroclear participants or Clearstream, Luxembourg participants in accordance with the relevant system's rules and procedures, to the extent received by its depositaries.

All information in this short form prospectus concerning CDS, DTC, Euroclear and Clearstream, Luxembourg, reflects our understanding of the policies of such organizations which may change at any time without notice.

Fixed Rate Notes

Each Fixed Rate Note will bear interest from its original issue date at the rate per annum on the face thereof until the principal amount thereof is paid or made available for payment. Interest on a Fixed Rate Note will be calculated and payable monthly, quarterly, semi-annually or annually in arrears on the dates specified in such Fixed Rate Note, or other such dates as may be agreed to between the purchaser of the Note and our company (each, an "Interest Payment Date") and at maturity or upon earlier redemption or repayment. Interest Payment Dates will be set forth in the applicable prospectus supplement or pricing supplement for the Fixed Rate Note. Each payment of interest in respect of an Interest Payment Date will include interest accrued to but excluding such Interest Payment Date.

Floating Rate Notes

Each Floating Rate Note will bear interest from its original issue date at rates described in the Floating Rate Note and specified in the applicable prospectus supplement or pricing supplement.

The rate of interest on each Floating Rate Note will be reset monthly, quarterly, or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Interest on each Floating Rate Note will be payable monthly, quarterly or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Unless otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement, our company will be the calculation agent with respect to the Floating Rate Notes. Upon request of the holder of any Floating Rate Note, our company will provide the interest rate then in effect.

Payment of Interest and Principal

Interest on each interest bearing Note will be payable on such periodic basis or at maturity and on such date or dates as may be agreed upon by our company and the purchaser of the Note. Payments of interest on each interest bearing Definitive Note will be made by cheque payable on the interest payment date and mailed to the address of, or if so directed by the holder, funds representing the interest payable will be forwarded by electronic funds transfer on the interest payment date to the account of, the holder appearing on the registers maintained by Computershare Trust Company of Canada, as registrar and transfer agent (the "Transfer Agent", which term shall include such other registrar or transfer agent (or co-registrar or co-transfer agent) as may from time to time be appointed by our company) at the close of business in the City of Toronto on the tenth business day (with "business day" being a day other than Saturday, Sunday, or a day on which financial institutions in Toronto, Ontario are authorized or obligated by law or regulation to close) prior to the interest payment date or such other day specified to the Trustee by our company and reflected in a Supplemental Indenture for a particular series of Notes. Payment of principal will be made at any branch in Canada of the bank designated in a Definitive Note against surrender of the Note.

Payment of interest and principal on each Global Note will be made to the Depository or the Nominee, as the case may be, as the registered holder of the Global Note. Interest payments on Global Notes will be made by wire transfer no later than the date interest is payable. Principal payments on Global Notes will be made by wire transfer on the maturity date delivered to the Depository or the Nominee, as the case may be, at maturity against receipt of the Global Note. As long as the Depository or the Nominee is the registered owner of a Global Note, the Depository or the Nominee, as the case may be, will be considered the sole owner of the Global Note for the purposes of receiving payment on the Note and for all other purposes under the Trust Indenture and the Note.

Our company expects that the Depository or Nominee, upon receipt of any payment of principal or interest in respect of a Global Note, will credit participants' accounts, on the date principal or interest is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Note as shown on the records of the Depository or the Nominee. Our company also expects that such payments of principal and interest by participants to the owners of beneficial interests in such Global Note held through such participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name" and will be the responsibility of such participants. The responsibility and liability of our company and the Trustee in respect of Notes represented by Global Notes is limited to making payment of any principal and interest due on such Global Notes to the Depository or the Nominee.

Except as noted below or unless otherwise specified in the applicable prospectus supplement or pricing supplement, payments of interest and principal will be made in the currency in which the Note is denominated. In respect of Notes denominated in Canadian dollars and held through DTC (in circumstances where CDS acts as Depository), although we will make all payments of principal and interest on such Notes in Canadian dollars, holders of Notes held through DTC will receive such payments in U.S. dollars, unless they elect, through procedures established from time to time by DTC and its participants, to receive Canadian dollar payments, in which case such Canadian dollar amounts will be transferred directly to Canadian dollar accounts designated by such holders to DTC. If no election is made, Canadian dollar payments received by CDS will be exchanged into U.S. dollars and paid directly to DTC in accordance with procedures established from time to time by CDS and DTC. All costs of conversion will be borne by holders of Notes held through DTC who receive payments in U.S. dollars.

If the payment date for any amount of principal or interest on any Note is not, at the place of payment, a business day such payment will be made on the next business day and the holder of such Note shall not be entitled to any further interest or other payment in respect of such delay.

Transfers

The registered holder of a Definitive Note may transfer such Note upon payment of taxes incidental thereto, if any, by executing the form of transfer provided on the reverse side of the Note and surrendering the Note to the Transfer Agent at its principal office in the City of Toronto, upon which one or more new Definitive Notes will be issued in authorized denominations in the same aggregate principal amount as the Note so transferred, registered in the name or names of the transferee or transferees.

Transfers of beneficial ownership in Notes represented by Global Notes will be effected through records maintained by the Depository for such Global Notes or the Nominee (with respect to the interest of participants) and on the records of participants (with respect to the interest of beneficial owners other than participants). Beneficial owners of an interest in a Note represented by a Global Note who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interests in Global Notes, may do so only through participants in the Depository's book-entry system. A purchaser's interest in a Note represented by a Global Note will only be exchangeable for Definitive Notes in the limited circumstances set forth under the subheading "Global Notes" above and in accordance with the procedures established by the Depository or the Nominee.

The ability of a beneficial owner of an interest in a Note represented by a Global Note to pledge the Note or otherwise take action with respect to such owner's interest therein other than through a participant may be limited due to the lack of a physical certificate.

No transfer of a Note will be registered during the 10 business days immediately preceding any date fixed for payment of interest on such Note or payment of the principal amount thereof.

PLAN OF DISTRIBUTION

The Notes may be offered for sale severally and on a continuous basis by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to an agreement dated September 4, 2013, among such dealers and our company (the "Dealer Agreement") or such other dealers as may be selected from time to time by our company, in each case acting as agent of our company or as principal. Where the Notes are offered by the Dealer(s) as agent(s), the commission payable by our company shall be agreed from time to time between our company and any such Dealer(s). Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between our company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to our company. The commission payable in connection with sales of Notes shall be no higher than 1.5% and shall be set forth in a prospectus supplement or pricing supplement that shall accompany this short form prospectus. The Dealers that participate in the distribution of Notes may be deemed to be underwriters within the meaning of the U.S. Securities Act. Our company has agreed to reimburse the Dealers for certain expenses and to indemnify each Dealer against certain liabilities including liabilities under the U.S. Securities Act and applicable Canadian securities laws.

The Notes may be offered and sold in each of the provinces of Canada pursuant to this short form prospectus in compliance with applicable registration requirements of Canadian securities law, may be offered and sold in the United States pursuant to the Registration Statement or in transactions exempt from the registration requirements of U.S. federal securities laws, in each case in compliance with the broker-dealer registration requirements of the United States Securities and Exchange Act of 1934, as amended and applicable state securities laws and may be offered and sold outside of Canada and the United States on a private placement basis with our consent but subject to compliance by the Dealers with all applicable legal requirements of those other jurisdictions.

Our company may also offer the Notes directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and our company.

Our company and, if applicable, the Dealers, reserve the right to reject any offer to purchase the Notes in whole or in part. Our company also reserves the right to withdraw, cancel or modify the offering of the Notes under this short form prospectus without notice. In addition, the obligations of the Dealers to purchase any particular issue of Notes as principal may be terminated at the discretion of the Dealers upon the occurrence of certain stated events as set out in detail in the Dealer Agreement. However, the Dealers are obligated to take up and pay for all Notes of a particular issue if any of the Notes of that issue are purchased under the Dealer Agreement by the Dealers as principal.

In connection with any offering of Notes, the Dealers may, when acting as an agent or purchasing as principal, over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Dealers may from time to time purchase and sell the Notes in the secondary market but are not obliged to do so. Unless otherwise indicated in a prospectus supplement or pricing supplement, there is no market through which Notes may be resold and purchasers may not be able to resell Notes purchased under this short form prospectus. The offering price and other selling terms for any sales in the secondary market may, from time to time, be varied by the Dealers.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders (the "Lenders") which are lenders to our company under an unsecured revolving credit facility of up to $1,500 million (as amended and restated from time to time, the "Credit Facility"). As of September 4, 2013, there is no outstanding indebtedness under the Credit Facility. Proceeds from the sale of particular series or issues of Notes in which such Dealers are acting as principals or agents may be used to repay indebtedness under the Credit Facility or any future credit facility to which our company may be a party with one or more of the Lenders. Consequently, if and when there is outstanding indebtedness to any of the Lenders under such facilities, our company may be considered a connected issuer of those Dealers who are affiliates of such Lenders for purposes of the securities laws of certain Canadian provinces. The decision to distribute the Notes will be made by our company and the terms and conditions of distribution will be determined through negotiations between our company and the Dealers. The Lenders will not have any involvement in such decision or determination. As of the date hereof, our company is in compliance with the terms of the Credit Facility. Other than payment of their portion of the commissions, if applicable, or as set forth above in respect of the Credit Facility, none of the proceeds of such offerings of Notes will be applied, directly or indirectly, for the benefit of BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. or their affiliates. See “Use of Proceeds”.

USE OF PROCEEDS

The net proceeds from the sale of Notes will be added to the general funds of our company and, together with funding from other sources, including internally generated funds and other external financings, will be used to finance our company’s working capital requirements, to repay outstanding bank loans (which may include indebtedness under the Credit Facility), debentures, notes or other Indebtedness, to make advances to subsidiaries of our company, to finance our company’s capital expenditure program, to make acquisitions and for other general corporate purposes. Where appropriate, a prospectus supplement or pricing supplement will contain more specific information about the use of proceeds from each sale of Notes. All expenses relating to an offering of Notes, including any compensation paid to the Dealers, will be paid out of our company’s general funds or netted out of the proceeds of the particular offering of Notes. Our company may from time to time issue debt instruments and incur additional Indebtedness otherwise than through the issue of Notes pursuant to this short form prospectus.

PRIOR SALES

In the 12-month period prior to the date hereof, our company issued the following tranches of medium term notes under our short form prospectus dated August 23, 2011:

Note	Date of Issuance	Principal Amount	Sale Price (per $100 principal amount)	Gross Proceeds
Series 27 (Floating Rate Note) due 2016	December 3, 2012	$50,000,000	$100.00	$50,000,000

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

General

The following summary describes the principal Canadian federal income tax considerations generally applicable to a purchaser who acquires Notes, including entitlement to all payments thereunder, as a beneficial owner pursuant to this short form prospectus and who, at all relevant times, for purposes of the application of the *Income Tax Act* (Canada) and the *Income Tax Regulations* (collectively, the “Tax Act”), deals at arm’s length with our company and holds Notes as capital property (a “Holder”). Generally, Notes will be capital property to a purchaser provided the purchaser does not acquire or hold those Notes in the course of carrying on a business or as part of an adventure or concern in the nature of trade. Certain purchasers resident in Canada may be entitled to make or may have already made the irrevocable election permitted by subsection 39(4) of the Tax Act the effect of which may be to deem to be capital property any Notes (and all other “Canadian securities”, as defined in the Tax Act) owned by such purchasers in the taxation year in which the election is made and in all subsequent taxation years. Purchasers whose Notes might not otherwise be considered to be capital property should consult their own tax advisors concerning this election.

This summary is based on the current provisions of the Tax Act and on counsel’s understanding of the current administrative policies and assessing practices of the Canada Revenue Agency published in writing prior to the date hereof. This summary takes into account all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the “Proposed Amendments”) and assumes that all Proposed Amendments will be enacted in the form proposed. However, no assurances can be given that the Proposed Amendments will be enacted as proposed, or at all. This summary does not otherwise take into account or anticipate any changes in law or administrative policy or assessing practice whether by legislative, administrative or judicial action nor does it take into account tax legislation or considerations of any province, territory or foreign jurisdiction, which may differ from those discussed herein.

Depending upon the terms of any offering of the Notes as set forth in an applicable prospectus supplement or pricing supplement, and upon whether our company continues to be a corporation to which any of paragraphs 149(1)(d) to (d.6) of the Tax Act applies at the time of such offering, the Canadian federal income tax considerations applicable to a Holder of the Notes at the time of such offering may be different from those described below. Such considerations may be described more particularly when such Notes are offered (and then only to the extent material) in the prospectus supplement or pricing supplement related thereto. In the event the Canadian federal income tax considerations are described in such prospectus supplement or pricing supplement, the description below will be superseded by the description in the prospectus supplement or pricing supplement to the extent indicated therein.

This summary is of a general nature only and is not, and is not intended to be, legal or tax advice to any particular purchaser. This summary is not exhaustive of all Canadian federal income tax considerations. Accordingly, prospective purchasers of Notes should consult their own tax advisors having regard to their own particular circumstances.

Currency Conversion

For purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of the Notes issued in a non-Canadian currency must be converted into Canadian dollars based on exchange rates as determined in accordance with the Tax Act. The amount of interest required to be included in the income of, and capital gains or capital losses realized by, a Holder may be affected by fluctuations in the applicable exchange rate.

Holders Resident in Canada

This portion of the summary is generally applicable to a Holder who, at all relevant times, for purposes of the application of the Tax Act, is, or is deemed to be resident in Canada, is not affiliated with our company and has not entered into and will not enter into, with respect to the Notes acquired by such Holder, a "derivative forward agreement" as that term is defined in proposed amendments contained in a Notice of Ways and Means Motion that accompanied the federal budget tabled by the Minister of Finance (Canada) on March 21, 2013 (a "Resident Holder").

This portion of the summary is not applicable to (i) a purchaser an interest in which is a "tax shelter investment", (ii) a purchaser that is, for purposes of certain rules (referred to as the mark-to-market rules) applicable to securities held by financial institutions, a "financial institution", or (iii) a purchaser that reports its "Canadian tax results" in a currency other than Canadian currency, each as defined in the Tax Act. Such purchasers should consult their own tax advisors.

Taxation of Interest and other Amounts

A Resident Holder that is a corporation, partnership, unit trust or any trust of which a corporation or partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on a Note that accrues or is deemed to accrue to such Resident Holder to the end of that taxation year, or becomes receivable or is received by the Resident Holder before the end of such year, to the extent that such interest was not included in computing the Resident Holder's income for a preceding taxation year.

Any other Resident Holder, including an individual, will be required to include in computing its income for a taxation year any interest on a Note that is received or receivable by such Resident Holder in that taxation year (depending on the method regularly followed by the Resident Holder in computing its income) to the extent that such interest was not included in computing the Resident Holder's income for a preceding taxation year. Such a Resident Holder may also be required to include in the Resident Holder's income, for any taxation year that includes an "anniversary day" (as defined in the Tax Act) of the Note, any interest or amount that is considered for the purposes of the Tax Act to be interest on the Note which accrues to the Resident Holder to the end of such day, to the extent that such interest was not otherwise included in computing the Resident Holder's income for the year or a preceding taxation year. For this purpose, an "anniversary day" means the day that is one year after the day immediately preceding the date of issue of a Note, the day that occurs at every successive one year interval from that day and the day on which a Note is disposed of.

Where a Resident Holder is required to include an amount on account of interest on a Note that accrued in respect of the period prior to its date of acquisition, the Resident Holder will be entitled to a deduction in computing income of an equivalent amount. The adjusted cost base to the Resident Holder of the Note will be reduced by the amount which is so deducted.

If a Note is issued by our company at a discount from its face value, a Resident Holder who acquires the Note may be required to include an additional amount in respect of such discount in computing its income for the taxation year in which the Resident Holder acquired the Note, in taxation years in which such amount accrues or in the taxation year in which such discount is received or receivable by the Resident Holder, depending on the significance of such discount and whether our company is a corporation that is exempt from income tax pursuant to section 149 of the Tax Act at the time the Note is issued. Resident Holders should consult their own tax advisors in these circumstances as the treatment of the discount may vary with the facts and circumstances giving rise to the discount.

Any amount paid by our company to a Resident Holder as a premium, penalty or bonus because of early repayment of all or part of the principal amount of a Note before its maturity will be deemed to be received by the Resident Holder as interest on the Note at that time and will be required to be included in computing the Resident Holder's income as described above, to the extent such amount can reasonably be considered to relate to, and does not exceed the value at the time of payment of, interest that, but for the repayment, would have been paid or payable by our company on the Note for a taxation year of our company ending after that time.

Disposition of Notes

On a disposition or deemed disposition of a Note, including a redemption, repayment prior to or on maturity or repurchase, a Resident Holder will generally be required to include in computing its income for the taxation year in which the disposition occurs the amount of interest that has accrued, or that has been deemed to have accrued, on the Note to that time except to the extent that such amount has otherwise been included in the Resident Holder's income for the year or a preceding taxation year.

Generally, on a disposition or deemed disposition of a Note, including a redemption, payment on maturity or purchase for cancellation, a Resident Holder will realize a capital gain (or capital loss) equal to the amount, if any, by which the proceeds of disposition, net of any amount included in the Resident Holder's income as interest and any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the Resident Holder of the Note immediately before the disposition or deemed disposition. Generally, a Resident Holder is required to include in computing its income for a taxation year one-half of the amount of any capital gain (a "taxable capital gain") realized in the year. Subject to and in accordance with the provisions of the Tax Act, a Resident Holder is required to deduct one-half of the amount of any capital loss (an "allowable capital loss") realized in a taxation year from taxable capital gains realized by the Resident Holder in the year and allowable capital losses in excess of taxable capital gains for the year may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years.

Holders Not Resident in Canada

This portion of the summary is generally applicable to a Holder who, at all relevant times, for purposes of the application of the Tax Act (1) is not, and is not deemed to be, resident in Canada, (2) deals at arm's length with any transferee resident (or deemed to be resident) in Canada to whom the Holder disposes of the Notes, and (3) does not use or hold, and is not deemed to use or hold, the Notes in a business carried on in Canada (a "Non-Resident Holder"). Special rules, which are not discussed in this summary, may apply to a Non-Resident Holder that is an insurer that carries on an insurance business in Canada and elsewhere.

This summary assumes that no interest paid on the Notes will be in respect of a debt or other obligation to pay an amount to a person with whom our company does not deal at arm's length, within the meaning of the Tax Act.

This portion of the summary is not applicable to a Non-Resident Holder that is a "specified shareholder" (as defined in subsection 18(5) the Tax Act) of our company or that does not deal at arm's length for purposes of the Tax Act with a "specified shareholder" of our company. Generally, for this purpose, a "specified shareholder" is a shareholder that owns or is deemed to own, either alone or together with persons with which the shareholder does not deal at arm's length for purposes of the Tax Act, shares of our capital stock that either (i) give such shareholders 25% or more of the votes that could be cast at an annual meeting of the shareholders or (ii) have a fair market value of 25% or more of the fair market value of all of the issued and outstanding shares of our capital stock. Such Non-Resident Holders should consult their own tax advisors.

No Canadian withholding tax will apply to interest, principal or premium paid or credited to a Non-Resident Holder by our company on a Note or to the proceeds received by a Non-Resident Holder on the disposition of a Note including a redemption, repayment prior to or on maturity or repurchase, unless all or any portion of such interest is contingent or dependent on the use of or production from property in Canada or is computed by reference to revenue, profit, cash flow, commodity price or any other similar criterion or by reference to dividends paid or payable to shareholders of any class of shares of the capital stock of a corporation (the "Participating Debt Interest"). The interest on Fixed Rate Notes, and on Floating Rate Notes in respect of which the payment of interest is determined by reference to published rates of a central banking authority or one or more financial institutions, or to recognized market benchmark interest rates, is not Participating Debt Interest and, as such, no Canadian withholding tax will apply to interest paid or credited or deemed to be paid or credited on such Notes.

Generally, no other Canadian federal taxes on income or gains will be payable by a Non-Resident Holder on interest, principal or premium paid or credited to a Non-Resident Holder by our company on a Note or on the proceeds received by a Non-Resident Holder on the disposition of a Note including a redemption, repayment prior to or on maturity or repurchase.

CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

General

The following disclosure has been prepared without regard to the particular terms of any Notes that you may purchase in the future and, therefore, is provided solely as a matter of general information. You should not rely upon the following disclosure with regard to an investment in any particular Note because the disclosure does not take into account the terms of any particular Note or the tax consequences of investing in or holding any particular Note. Any Note that you purchase may have terms that would result in a tax treatment that is materially different from the treatment described below. There may be features or terms of your Note that will cause this tax section to be inapplicable to your Note. To the extent we deem necessary, we may include tax disclosure relevant to any Note you may purchase in any prospectus supplement or pricing supplement relating to your Note, and, unless the prospectus supplement or pricing supplement indicates otherwise, you should not rely on the tax disclosure below in deciding whether to invest in any Note. Moreover, in all cases, you should consult with your own tax advisor concerning the consequences of investing in and holding any particular Note you propose to purchase.

This section describes certain of the material United States federal income tax consequences of owning certain Notes that we may offer. It applies to you only if you acquire Notes in an offering and you hold Notes as capital assets (generally, property held for investment) for tax purposes. This section does not apply to persons other than U.S. holders (as defined below). The ownership of Notes that pay interest from sources within the United States may give rise to material United States federal income tax consequences to persons other than U.S. holders. If a particular offering of Notes is expected to pay interest from sources within the United States, the applicable prospectus supplement or pricing supplement will specify that fact and may discuss the material United States federal income tax consequences to persons other than U.S. holders of owning such Notes. This section does not apply to you if you are a member of a special class of holders subject to special rules, including a dealer in securities or currencies, a trader in securities that elects to use a mark-to-market method of accounting for your securities holdings, a regulated investment company, a real estate investment trust, a tax-exempt organization (including a private foundation), an insurance company, a person that owns Notes that are a hedge or that are hedged against interest rate or currency risks, a person that holds Notes as part of a straddle, conversion transaction or a synthetic security or other integrated transactions for United States federal income tax purposes, a United States expatriate, a U.S. holder whose functional currency is not the U.S. dollar, a person subject to the alternative minimum tax, a financial institution, an entity or arrangement treated as a partnership for United States federal income tax purposes and its partners, a controlled foreign corporation or a passive foreign investment company.

This discussion does not address any tax consequences arising under United States federal gift and estate or other federal tax laws or under the tax laws of any state, local or non-United States jurisdiction. This discussion is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations, published rulings and court decisions, as well as on the income tax treaty between the United States of America and Canada. These laws are subject to differing interpretations or change, possibly on a retroactive basis. This discussion is not binding on the United States Internal Revenue Service (the “IRS”) or the courts.

If a partnership (including any entity treated as a partnership for United States federal income tax purposes) holds Notes, the United States federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding Notes should consult its tax advisor with regard to the United States federal income tax treatment of an investment in Notes.

You are urged to consult your own tax advisor regarding the United States federal, state and local and other tax consequences of owning and disposing of Notes offered under this short form prospectus in your particular circumstances.

U.S. Holders

This section describes certain of the material United States federal income tax consequences of the acquisition, ownership and disposition of Notes by a U.S. holder. You are a U.S. holder if you are a beneficial owner of Notes and you are (i) a citizen or resident of the United States, (ii) a corporation, or other entity classified as a corporation for United States federal income tax purposes, that is created or organized in or under the laws of the United States, any state in the United States or the District of Columbia, (iii) an estate whose income is subject to United States federal income tax regardless of its source, or (iv) a trust if (A) a United States court can exercise primary supervision over the trust’s administration and one or more United States persons are authorized to control all substantial decisions of the trust or (B) it has made a valid election under applicable United States Treasury regulations to be treated as a United States person.

This section deals only with Fixed Rate Notes (i) that are due to mature 30 years or less from the date on which they are issued, and (ii) that are purchased pursuant to the offering to which the applicable prospectus supplement or pricing supplement relates at the offering price on the cover page of the applicable prospectus supplement or pricing supplement. The United States federal income tax consequences of owning Notes with a term of more than 30 years, Floating Rate Notes, Notes that are issued with original issue discount for United States federal income tax purposes, Notes that are not treated as debt for United States federal tax purposes or Notes that are treated as contingent payment debt obligations for United States federal tax purposes will be discussed, if material, in the applicable prospectus supplement or pricing supplement and will not, unless otherwise specified in the applicable prospectus supplement or pricing supplement, be treated in accordance with the discussion in this section.

Payments of Interest

In general, you will be taxed on any interest on your Notes, whether payable in Canadian dollars or any other currency, as ordinary income at the time you receive the interest or when it accrues, depending on your method of accounting for United States tax purposes.

Unless the applicable prospectus supplement or pricing supplement states otherwise, Notes will, for United States federal income tax purposes, be accounted for as being issued by our company or one of its non-United States affiliates, rather than by a United States branch or subsidiary. Assuming this treatment is respected, interest paid by us on such Notes will generally be income from sources outside the United States, subject to the rules regarding the foreign tax credit allowable to a U.S. holder. Under the foreign tax credit rules, interest included in income from sources outside the United States will, depending on your circumstances, be either “passive” or “general” income for purposes of computing the foreign tax credit. If, on the contrary, a particular offering of Notes is expected to pay interest from sources within the United States, the applicable prospectus supplement or pricing supplement will state that fact, if material. Interest from sources within the United States is not foreign source income for purposes of computing the foreign tax credit.

Cash Basis Taxpayers. If you are a taxpayer that uses the cash receipts and disbursements method of accounting for tax purposes and you receive an interest payment that is denominated in, or determined by reference to, a currency other than the U.S. dollar, you must recognize income equal to the U.S. dollar value of the interest payment, based on the exchange rate in effect on the date of receipt, regardless of whether you actually convert the payment into U.S. dollars.

Accrual Basis Taxpayers. If you are a taxpayer that uses an accrual method of accounting for tax purposes, you may determine the amount of income that you recognize with respect to an interest payment denominated in, or determined by reference to, a currency other than the U.S. dollar by using one of two methods. Under the first method, you will determine the amount of income accrued based on the average exchange rate in effect during the interest accrual period or, with respect to an accrual period that spans two taxable years, that part of the period within the taxable year.

If you elect the second method, you would determine the amount of income accrued on the basis of the exchange rate in effect on the last day of the accrual period, or, in the case of an accrual period that spans two taxable years, the exchange rate in effect on the last day of the part of the period within the taxable year. Additionally, under this second method, if you receive a payment of interest within five business days of the last day of your accrual period or taxable year, you may instead translate the interest accrued into U.S. dollars at the exchange rate in effect on the day that you actually receive the interest payment. If you elect the second method, it will apply to all debt instruments that you hold at the beginning of the first taxable year to which the election applies and to all debt instruments that you subsequently acquire. You may not revoke this election without the consent of the IRS.

When you actually receive an interest payment, including a payment attributable to accrued but unpaid interest upon the sale or retirement of your Note, denominated in, or determined by reference to, a currency other than the U.S. dollar for which you accrued an amount of income, you will recognize ordinary income or loss measured by the difference, if any, between the exchange rate that you used to accrue interest income and the exchange rate in effect on the date of receipt, regardless of whether you actually convert the payment into U.S. dollars.

Purchase, Sale and Retirement of Notes

Your tax basis in your Note will generally be the U.S. dollar cost of your Note. If you purchase your Note with foreign currency, the U.S. dollar cost of your Note will generally be the U.S. dollar value of the purchase price on the date of purchase. However, if you are a cash basis taxpayer or an accrual basis taxpayer that so elects and your Note is traded on an established securities market, as defined in the applicable Treasury regulations, the U.S. dollar cost of your Note will be the U.S. dollar value of the purchase price on the settlement date of your purchase.

You will generally recognize capital gain or loss on the sale or retirement of your Note equal to the difference between the amount you realize on the sale or retirement (other than amounts attributable to accrued interest not previously included in income, which will be subject to tax as interest income as discussed above, and exchange gain or loss with respect to the principal amount of the Note, as discussed below) and your tax basis in your Note. If your Note is sold or retired for an amount in a non-United States currency, the amount you realize will be the U.S. dollar value of such amount on the date the Note is disposed of or retired, except that in the case of a Note that is traded on an established securities market, as defined in the applicable Treasury regulations, a cash basis taxpayer, or an accrual basis taxpayer that so elects, will determine the amount realized based on the U.S. dollar value of the foreign currency on the settlement date of the sale. Capital gain of a noncorporate U.S. holder is generally taxed at preferential rates where the property is held for more than one year. The deductibility of capital losses is subject to significant limitations.

You must treat any portion of the gain or loss that you recognize on the sale or retirement of a Note as ordinary income or loss to the extent attributable to changes in exchange rates. However, you take exchange gain or loss into account only to the extent of the total gain or loss you realize on the transaction.

Exchange of Amounts in other than U.S. Dollars

If you receive non-U.S. currency as interest on your Note or on the sale or retirement of your Note, your tax basis in such currency will equal its U.S. dollar value when the interest is received or at the time of the sale or retirement. If you purchase foreign currency, you generally will have a tax basis equal to the U.S. dollar value of such currency on the date of your purchase. If you sell or dispose of such currency, including if you use it to purchase Notes or exchange them for U.S. dollars, any gain or loss recognized generally will be ordinary income or loss.

Medicare Tax

For taxable years beginning after December 31, 2012, a U.S. holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, will be subject to a 3.8% tax on the lesser of (1) the U.S. holder's "net investment income" in the case of individuals, and the "undistributed net investment income" in the case of estates and trusts for the relevant taxable year and (2) the excess of the U.S. holder's modified adjusted gross income for the taxable year over a certain threshold (which in the case of individuals will be between $125,000 and $250,000, depending on the individual's circumstances). A holder's net investment income will generally include its interest income and its net gains from the disposition of Notes, unless such interest income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). If you are a U.S. holder that is an individual, estate or trust, you are urged to consult your tax advisors regarding the applicability of the Medicare tax to your income and gains in respect of your investment in Notes.

Information With Respect to Foreign Financial Assets

Under recently enacted legislation, individuals that own "specified foreign financial assets" with an aggregate value in excess of $50,000 in taxable years beginning after March 18, 2010 will generally be required to file an information report with respect to such assets with their tax returns. "Specified foreign financial assets" include any financial accounts maintained by foreign financial institutions, as well as any of the following, but only if they are not held in accounts maintained by financial institutions: (i) stocks and securities issued by non-United States persons, (ii) financial instruments and contracts held for investment that have non-United States issuers or counterparties, and (iii) interests in foreign entities. The Notes offered under this short form prospectus may be subject to these rules. U.S. holders that are individuals are urged to consult their tax advisors regarding the application of this legislation to their ownership of the Notes.

Information Reporting and Backup Withholding

In general, if you are a noncorporate U.S. holder, we and other payors may be required to report to the IRS all payments of principal, any premium and interest on a Note. In addition, we and other payors are required to report to the IRS any payment of proceeds of the sale of your Note before maturity within the United States. Additionally, backup withholding may apply to any payments, if you fail to provide an accurate taxpayer identification number, or if you are notified by the IRS that you have failed to report all interest and dividends required to be shown on your United States federal income tax returns. You generally may obtain a refund of any amounts withheld under the backup withholding rules that exceed your income tax liability by timely filing a refund claim with the IRS.

RISK FACTORS

In addition to the other information contained and incorporated by reference in this short form prospectus, a purchaser should consult its own financial and legal advisors and should carefully consider the following risk factors before investing in the Notes. Notes will not be an appropriate investment for a purchaser if the purchaser does not understand the terms of the Notes or financial matters in general. A purchaser should not purchase Notes unless the purchaser understands, and can bear, all of the investment risks involving the Notes. For a discussion of the risks to which our business and industry are subject, please see the section entitled "Risk Factors" in our company's annual information form and the section entitled "Risk Management and Risk Factors" in our annual MD&A. In addition to those risks, an investment in the Notes is subject to the following additional risks:

We Must Receive Dividends and Other Payments from Our Subsidiaries in Order to Make Payments to Holders of Notes

We are a holding company that has no significant assets or operations other than the debt and equity of our subsidiaries. Our most significant subsidiary is Hydro One Networks Inc., a regulated wholly-owned subsidiary which owns and operates our transmission and distribution assets. We are dependent on dividends, interest, loans and other payments from this and other subsidiaries to meet our debt service and other obligations.

Our subsidiaries are separate legal entities and have no obligation to pay any amounts due under the Notes and, except for their respective obligations under existing intercompany debt obligations owing to us, have no obligation to make funds available to us, whether by dividends, interest, loans or other payments. In addition, these subsidiaries have not guaranteed the Notes. In the event of bankruptcy, liquidation or reorganization of any of our subsidiaries, the creditors of these subsidiaries will generally be entitled to the payment of their claims before any assets are made available for distribution to us, except to the extent that we are recognized as a creditor of those subsidiaries.

Our subsidiaries currently are not restricted in terms of their ability to pay dividends or make other payments to us, other than by solvency provisions under generally applicable Ontario corporate law. However, they could become so restricted in the future by, among other things, other laws as well as agreements to which they may become parties in the future.

There May Be No Trading Market for the Notes and if One Develops, the Notes May Be Subject to Trading Price Fluctuations

The Notes are new issues of securities for which, unless otherwise indicated in a prospectus supplement or pricing supplement, there is no existing trading market. We cannot predict whether any active trading market will develop for the Notes, even if the Notes are listed on a stock exchange.

Even if an active trading market develops for the Notes, the Notes could trade at prices that may be higher or lower than their initial offering prices, depending on many factors, including prevailing interest rates, our results of operations and financial position, the ratings assigned to the Notes and our other debt securities, and the markets for similar debt securities.

If you sell any Notes before their maturity, you may have to do so at a substantial discount from the issue price, and as a result you may suffer substantial losses.

Investors May Be Subject to the Risk of Exchange Rate Fluctuations

An investment in Notes that are denominated or payable in a currency other than the functional currency of the investor entails significant risks that are not associated with a similar investment in a security denominated in the functional currency of the investor. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the two currencies, the possibility of the imposition or modification of foreign exchange controls in respect of one or both of the currencies, and potential illiquidity in the secondary market. These risks generally depend on circumstances over which we have no control including political events, government policy and macroeconomic conditions. These risks will vary depending upon the currency or currencies involved and, where appropriate, will be more fully described in a prospectus supplement or pricing supplement.

In certain circumstances, investors may receive payments in currencies other than the currency in which the Notes are denominated. This may subject investors to exchange rate risk in respect of the conversion of principal and interest payments on the Notes from the currency in which the Notes are denominated to the currency of the payment which they receive, and they may also bear any costs of conversion incurred in connection therewith. For example, United States investors who hold Notes through DTC where CDS acts as Depository and who do not elect to receive principal and interest payments in Canadian dollars will be subject to exchange rate risk in respect of the conversion of Canadian dollar principal and interest payments to U.S. dollars, and will also bear any costs of conversion incurred in connection therewith.

The Notes will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Note may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

This short form prospectus does not describe all the risks of an investment in the Notes denominated or payable in a currency other than an investor's functional currency, and prospective investors should consult their own financial and legal advisor as to the risks entailed with respect thereto. Notes denominated in currencies other than an investor's functional currency are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

Changes in Interest Rates Will Affect the Market Price or Value of the Notes

Generally, the market price or value of the Notes will decline as prevailing interest rates for comparable debt instruments rise, and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of our company which may adversely affect its creditworthiness. It is impossible to predict whether interest rates will rise or fall.

Changes in Creditworthiness or Credit Ratings May Affect the Market Price or Value of the Notes

The perceived creditworthiness of our company and changes in credit ratings of the Notes may affect the market price or value and the liquidity of the Notes. In addition, negative changes in our company's credit rating may affect the credit ratings of the Notes.

Floating Rate Notes Are, By Their Nature, Uncertain

Investments in Floating Rate Notes entail risks not associated with investments in Fixed Rate Notes. The resetting of the applicable rate on a Floating Rate Note may result in a lower interest rate as compared to a Fixed Rate Note issued at the same time. The applicable rate on a Floating Rate Note will fluctuate in accordance with fluctuations in the instrument or obligation or other measure on which the applicable rate is based, which in turn may fluctuate and be affected by a number of interrelated factors, including economic, financial and political events over which our company has no control.

The Notes May Be Subject to Early Redemption

Depending on the terms of the Notes, we may have the right to redeem them, or the Notes may be automatically redeemable under some circumstances. If the Notes are redeemed, depending on the market conditions at the time of redemption, you may not be able to reinvest the redemption proceeds in a security with a comparable return.

LEGAL MATTERS

Certain legal matters in connection with any offering hereunder will be passed upon by Osler, Hoskin & Harcourt LLP for our company in respect of both Canadian and United States legal matters and by Blake, Cassels & Graydon LLP for the Dealers in respect of Canadian legal matters and Skadden, Arps, Slate, Meagher & Flom LLP in respect of United States legal matters. The partners and associates of Osler, Hoskin & Harcourt LLP and Blake, Cassels & Graydon LLP beneficially own, directly or indirectly, less than one percent of the securities of our company or any associate or affiliate of our company.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of our company are KPMG LLP, Bay Adelaide Centre, 333 Bay Street, Suite 4600, Toronto, Ontario M5H 2S5. KPMG LLP is independent in Ontario in accordance with its rules of professional conduct.

Registers for the registration and transfer of the Notes issued in registered form are kept at the principal offices of the Transfer Agent in the City of Toronto. A U.S. affiliate of the Trustee and the Transfer Agent may also act as co-transfer agent for the Notes, but only to the extent necessary in connection with offers and sales of the Notes in the United States.

ELIGIBILITY FOR INVESTMENT

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to our company, and Blake, Cassels & Graydon LLP, Canadian counsel to the Dealers, unless otherwise specified in the applicable prospectus supplement or pricing supplement, the Notes, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) (the "Tax Act") and the regulations thereunder for a trust governed by a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan, registered disability savings plan, deferred profit sharing plan (other than a trust governed by a deferred profit sharing plan for which any employer is our company or an employer who does not deal with our company at arm's length, within the meaning of the Tax Act) or a tax-free savings account ("TFSA").

The Notes will not be a "prohibited investment" for a TFSA, RRSP or RRIF, provided that the holder of the TFSA or the annuitant under a RRSP or RRIF, (i) deals at arm's length with our company for purposes of the Tax Act, and (ii) does not have a "significant interest" ,within the meaning of the Tax Act, in (A) our company, or (B) in a corporation, partnership or trust with which our company does not deal at arm's length. Proposed amendments to the Tax Act released on December 21, 2012 would delete the condition in (ii)(B) above. Holders of a TFSA and annuitants under a RRSP or RRIF should consult their own tax advisors as to whether the Notes will be a "prohibited investment" for such TFSA, RRSP or RRIF in their particular circumstances.

CREDIT RATING INFORMATION FOR CANADIAN INVESTORS

As of the date of this prospectus, the Notes have been rated A+ by Standard & Poor's Ratings Services ("S&P"), A (high) by DBRS Limited ("DBRS") and A1 by Moody's Investors Services, Inc. ("Moody's"). The following information relating to credit ratings is based on information made available to the public by the rating agencies.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The rating agencies rate long-term debt instruments by rating categories ranging from a high of AAA to a low of D (C in the case of Moody's). Long-term debt instruments which are rated in the A category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. However, the obligor's capacity to meet its financial commitment on the obligations is still strong. S&P utilizes a plus or a minus modifier to indicate the relative standing within the rating category. Long-term debt instruments which are rated in the A category by DBRS are considered to be of a good credit quality, with substantial capacity for the payment of financial obligations. Entities in the A category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable. The "high" modifier indicates relative standing within this rating category by DBRS. Long-term debt instruments which are rated in the A category by Moody's are judged to be upper-medium grade and are subject to low credit risk. Moody's appends numerical modifiers to each generic rating classification from Aa through Caa. The modifier 1 indicates a ranking in the higher end of that generic rating category.

The ratings mentioned above are not a recommendation to purchase, sell or hold our company's debt securities including the Notes and do not comment as to market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by any or all of S&P, DBRS and Moody's at any time in the future if in their judgment circumstances so warrant.

Our company has made, and anticipates making, payments to each of S&P, DBRS and Moody's pursuant to the ratings agency services agreements entered into with such credit rating organizations with respect to the ratings assigned to the long-term debt of our company. In addition, as Notes are issued, our company expects to make payments to such credit rating organizations pursuant to the ratings agency services agreements entered into with such credit rating organizations for the ratings they assign to the Notes of a particular series. There have been no other services provided by any of such credit rating organizations to our company within the last two years.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revision of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

CERTIFICATE OF HYDRO ONE INC.

Dated: September 4, 2013

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all of the provinces of Canada.

(Signed) Carmine Marcello President and Chief Executive Officer	(Signed) Sandy Struthers Chief Administration Officer and Chief Financial Officer

On behalf of the Board of Directors:

(Signed) James Arnett Chair of the Board of Directors	(Signed) Michael Mueller Director

CERTIFICATE OF DEALERS

Dated: September 4, 2013

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

BMO NESBITT BURNS INC.	CASGRAIN & COMPANY LIMITED	CIBC WORLD MARKETS INC.
By: (Signed) Andrew Hainsworth	By: (Signed) Stephen McHarg	By: (Signed) David Williams
DESJARDINS SECURITIES INC.	HSBC SECURITIES (CANADA) INC.	LAURENTIAN BANK SECURITIES INC.
By: (Signed) Ryan Godfrey	By: (Signed) David Loh	By: (Signed) Barry Calhoun

NATIONAL BANK FINANCIAL INC.	RBC DOMINION SECURITIES INC.
By: (Signed) Tushar Kittur	By: (Signed) Robert M. Brown
SCOTIA CAPITAL INC.	TD SECURITIES INC.
By: (Signed) D. Gregory Lawrence	By: (Signed) Patrick Scace

REGIONAL PLANNING PROCESS

1.0 INTRODUCTION

On October 18, 2012, the Ontario Energy Board (the "Board") issued its *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (RRFE Board Report). The RRFE Board Report concluded a consultation process aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters.

One of the Board's conclusions in the RRFE was that effective Regional Infrastructure Planning would be best achieved by allowing relevant stakeholders a further opportunity to build on their practical experience and on the input received through the RRFE consultation process. The Board therefore convened a stakeholder working group, the Planning Process Working Group (PPWG) to prepare a report to the Board that sets out the details of appropriate Regional Infrastructure Planning processes, that defines the outputs of the planning process and identifies any changes to the Board's regulatory instruments that may be needed to support the process. The working group consisted of transmitters, distributors, and a number of industry associations and organizations.

The PPWG's report (PPWG Report) was endorsed by the Board on May 17, 2013.
On August 26, 2013, the Board also amended the Transmission System Code (TSC) and Distribution System Code (DSC) to implement a regional planning process in Ontario, as detailed in the PPWG Report.

The PPWG Report divides the province into 21 regions, each of which is placed into one of three groups in order to prioritize and manage the regional planning process. As stated in the PPWG Report, it is anticipated that regional plans for all 21 regions would be completed in five year cycles as a minimum. Hydro One is the lead transmitter for 19 of the province's 21 regions.

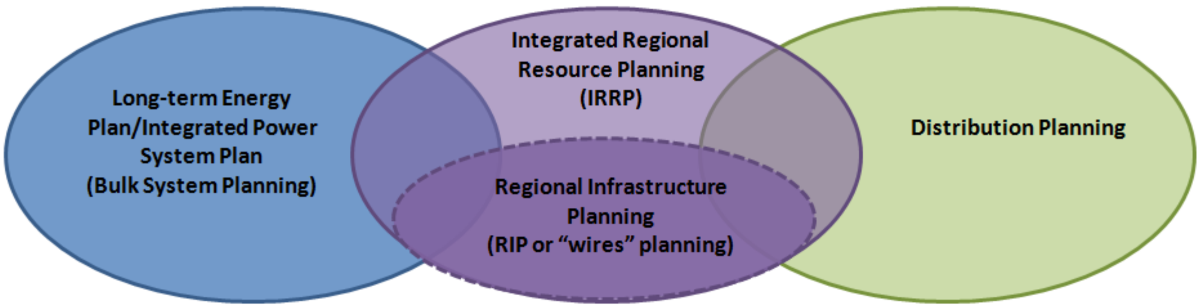
2.0 OVERVIEW OF PLANNING IN ONTARIO

Planning for the electricity system in Ontario is done at essentially three levels:

1. Bulk system planning
2. Regional system planning
3. Distribution system planning

These levels, as outlined in Figure 1, differ in the scope of impact on both the electricity system and the number of customers. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Figure 1: Three Levels of Planning in Ontario



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

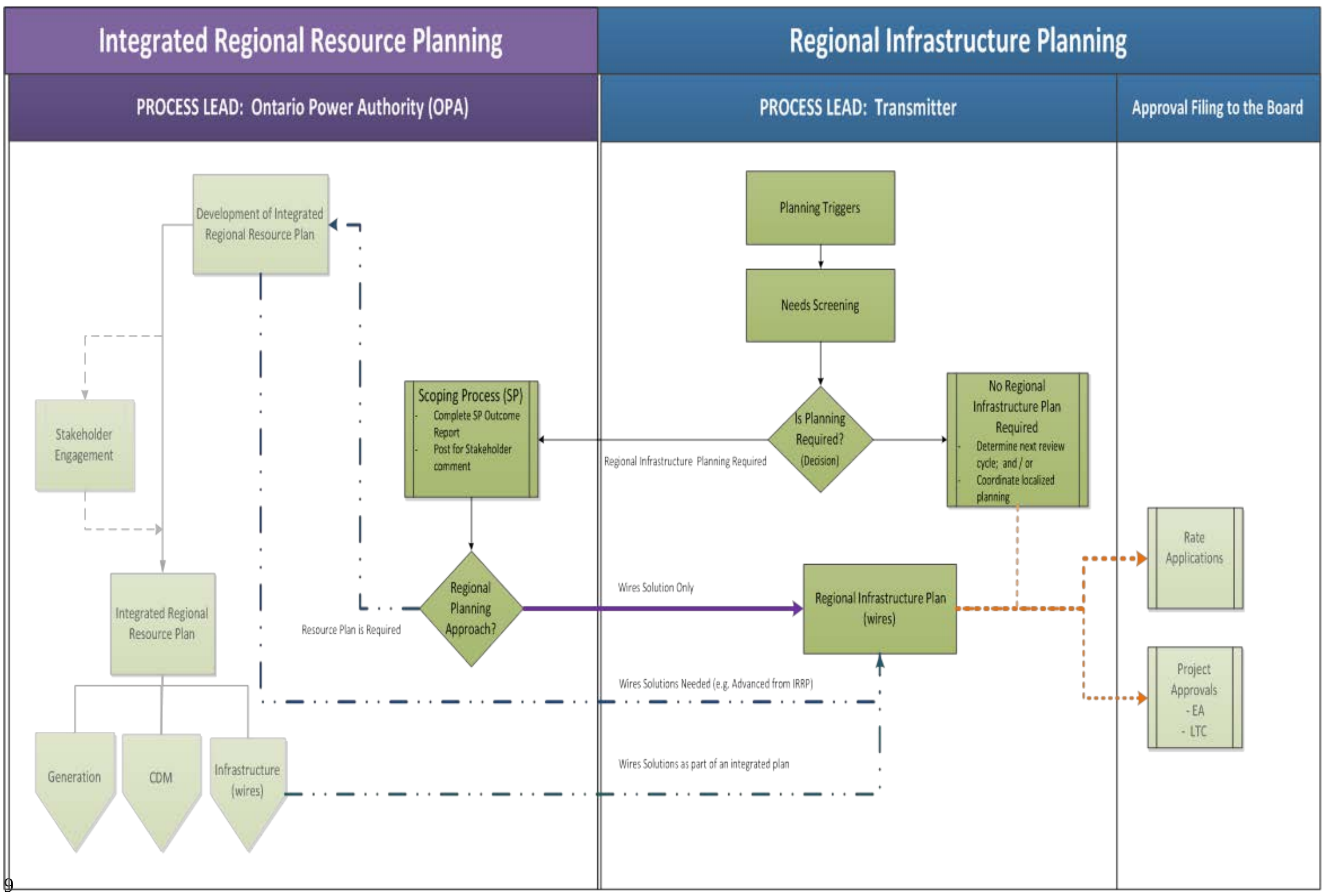
As depicted in Figure 1, regional planning can overlap with bulk system planning at interface points such as at the 230/500 kV auto-transformer stations, or where regional resource options affect the bulk system. Regional planning can also overlap with distribution planning which typically occurs at transformer load stations that deliver power to distributors and large directly-connected customers.

Regional planning is not a new concept in Ontario or for Hydro One for that matter. However, in the October 18, 2012 Report of the Board on a Renewed Regulatory Framework for Electricity Distributors, the Board concluded that a more structured approach is required to ensure the development of the provinces' electricity infrastructure in a cost-effective manner.
Moving forward, based on the PPWG report, there are four main steps in the planning processes that together will comprise regional planning:

1. Needs Assessment/Screening
2. Scoping Assessment
3. Integrated Regional Resource Planning process ("IRRP")
4. Regional Infrastructure Planning process ("RIP")

These steps are illustrated below in Figure 2.

Figure 2: Regional Planning Process



The Needs Screening and RIP are led by the transmitter in the region. Needs Screening is a high level assessment to determine if comprehensive and coordinated planning is required for the region or any of its subregions.

The Scoping Process, led by the OPA, establishes the scope of a planning study and determines if an IRRP or RIP or both are required to address the needs in the region or subregion. The IRRP process involves identification, evaluation and integration of available solutions (i.e. conservation and demand management, generation, and transmission and distribution options) at the regional or subregional level. The RIP process focuses on "wires" planning, mainly regional transmission and relevant distribution wires. The IRRP and RIP process are closely coordinated with each other.

3.0 THE REGIONAL INFRASTRUCTURE PLANNING (RIP) PROCESS

The Regional Planning process diagram shown in Figure 2 above illustrates the accountabilities for and the coordination between the RIP and IRRP processes. The Regional Infrastructure Planning process begins with a planning trigger. Potential triggers include regularly scheduled Needs Screening by the transmitter, a scheduled review specified in an existing Regional Infrastructure Plan, a Government directive, a significant change to codes and standards or an emergent need brought forward by the transmitter, distributors, customers, the OPA or the IESO that cannot wait until the next scheduled review.

The next stage involves a Needs Screening process which is led by the transmitter to determine if there are regional needs that require Regional Planning. At the end of the Needs Screening process, a decision is required as to whether Regional Planning is necessary to address any of the needs. If Regional Planning is not required, any necessary infrastructure investments for localized plans can be undertaken directly by the transmitter and distributor(s) or other transmission connected customer(s). In situations where identified needs require coordination at the regional or subregional levels, the transmitter determines the geographic scope and which distributor(s) should be involved. The determination of which distributors need to be involved is based on the information and load forecasts required from distributors and the issues (e.g., equipment end-of-life, reliability, etc.) brought forward in a predetermined region. At the conclusion of the Needs Screening, the transmitter produces a Needs Screening Summary Report that summarizes the data gathered, study assumptions, study findings, and recommendations. For needs that require coordination and integration of resources (i.e. CDM and generation) with wires solutions, the OPA initiates the Scoping Process.

During the Scoping Process, the OPA, in collaboration with the transmitter and impacted distributors, reviews the information collected as part of the Needs Screening phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate Regional Planning approach. The approach is either an IRRP led by the OPA, a RIP led by the transmitter, or both. In support of this process, the OPA will produce a Scoping Process Outcome Report, which will include the results of the Needs Screening process, a preliminary terms of reference identifying the various subregions that require study, and a list of the distributors to be involved. The IRRP process follows the Scoping Process and involves identification, evaluation and integration of available solutions (i.e. conservation and demand management, generation, and transmission and distribution options), along with broader engagement of stakeholders at the regional or subregional level.

Regional Infrastructure Planning (RIP) led by the transmitter begins after the completion of IRRP when it is established that a wires approach is required to address the needs of a region or subregion, and that coordination of the planning is needed at a regional level. At the conclusion of the RIP process, the transmitter will produce a finalized Regional Infrastructure Plan that will outline the scope of study, describe key assumptions, confirm needs at the regional or subregional level, evaluate alternatives to address those needs, explain the rationale for the wires solutions recommended, and propose an implementation plan. There may be cases where a wires solution is necessary to be implemented by the transmitter and/or LDC(s) to address a near-term need, as part of the development of an IRRP. In such cases, infrastructure solutions ultimately become part of the Regional Infrastructure Plan.

4.0 IMPLEMENTATION AND STATUS OF REGIONAL PLANNING PROCESS

As previously noted, the province has been divided into 21 electrical regions for the purposes of conducting assessments and developing regional plans. The 21 Regions have been assigned to one of three groups in order to prioritize and manage the regional planning process. Hydro One is the lead transmitter for 19 of the province's 21 planning regions, which will be assessed on a cyclical basis of five years as a minimum. As required by the Board's amendments to the TSC, Hydro One communicated with all Local Distribution Companies (LDCs) in these 19 regions, within 10 days of August 26th, 2013. The communication requested distributors' input about potential need for additional transmission capacity to support the needs of their distribution systems, including those of embedded distributors, and requested any other feedback pertinent to placement and prioritization of the regions to which they belong. Based on LDCs feedback and responses, the GTA East region was reprioritized from Group 2 to Group 1. The 19 regions for which Hydro One is the lead transmitter are listed below.

Group 1 Regions	Group 2 Regions	Group 3 Regions
- Burlington to Nanticoke	- London area	- Chatham/Lambton/Sarnia
- Greater Ottawa	- Peterborough to Kingston	- Greater Bruce/Huron
- GTA North	- South Georgian Bay/Muskoka	- Niagara
- GTA West	- Sudbury/Algoma	- North/East of Sudbury
- KWCG		- Renfrew
- Metro Toronto		- St. Lawrence
- Northwest Ontario		
- Windsor-Essex		
- GTA East*		

** Note: GTA East has been reassigned to Group 1 from Group 2*

The regional planning process for regions within Group 1 is currently underway; the status of regional planning activities for each region is described below in this exhibit. The regional planning process has not yet been initiated for the regions in Group 2 and Group 3. All of the regions will be assessed on a cyclical basis of five years as a minimum.

Transition to the new Regional Planning process

Planning studies, led by the OPA, for several regions and subregions were already in progress at the time of implementation of the new Regional Planning processes. These regional or subregional studies are continuing and are expected to culminate in an IRRP. For these regions or subregions, Needs Screening reports or Scoping Assessments were inherent as part of the study team planning process and are deemed complete. The planning studies for these regions or sub-regions may identify the need for a near-term wires solution in advance of the completion of an IRRP. In such cases, the OPA may provide Hydro One with a “handoff” letter, prior to the completion of an IRRP, to start a detailed assessment to develop wires options and recommend a preferred solution that meets a certain need for a particular region or subregion. Generally speaking, a handoff letter is provided to address a near-term need that can only be met by a transmission or distribution solution. These infrastructure solutions identified and/or implemented will ultimately become part of the RIP after an IRRP is complete.

Communication of the new Regional Planning process and Results

To facilitate the Regional Planning process, Hydro One and the OPA developed and launched Regional Planning websites. The two websites are interlinked and provide the geographical location of the regions, a brief description of their main characteristics and the current status of activities with regards to the Regional Planning process. Results such as final reports from the various steps of the Regional Planning process will be posted on the websites, as required by the TSC. A sample of the information provided on the Hydro One website for the Burlington to Nanticoke Region is provided in Figures 3 and 4.

Figure 3: Planning Region Description

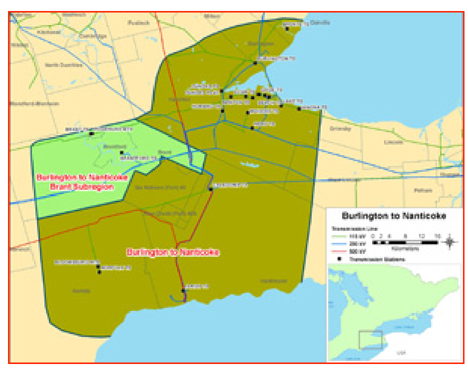
Burlington to Nanticoke

Region Overview

Burlington to Nanticoke Region comprises the municipalities of Burlington, Hamilton, Oakville, Brantford, Brant County, Haldimand County, and Norfolk.

Region's Local Distribution Companies

Brant County Power Inc.	Horizon Utilities Corporation
Brantford Power Inc.	Hydro One Networks Inc.
Burlington Hydro Inc.	Norfolk Power Distribution Inc.
Haldimand County Hydro Inc.	Oakville Hydro Electricity Distribution Inc.

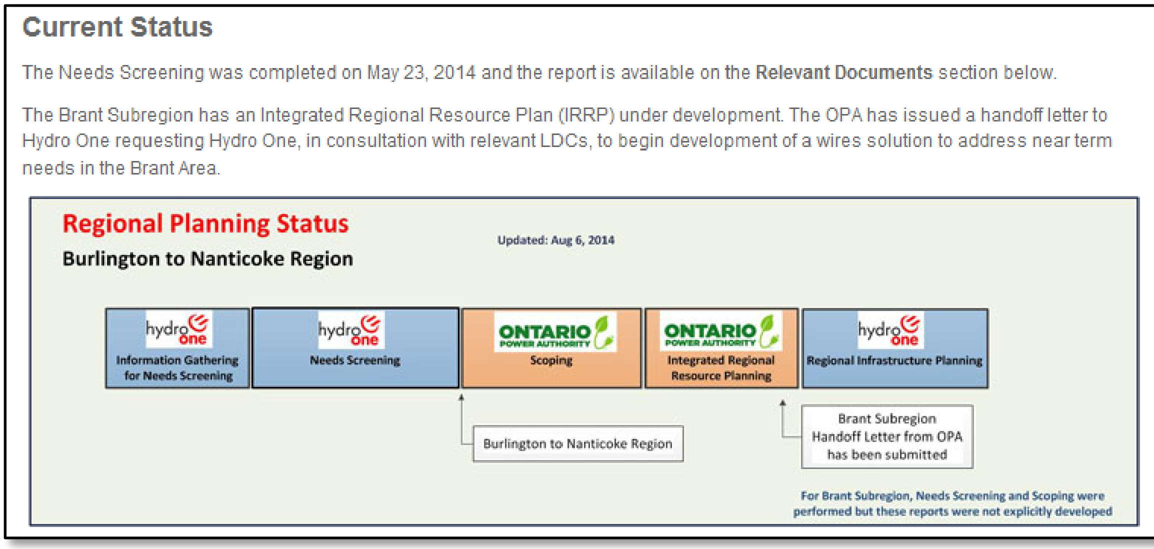


Brant Subregion

The area encompasses the County of Brant, City of Brantford and surrounding areas. This area has an estimated population of over 136,000 people, and the electricity demand mix is comprised of residential, commercial and industrial uses.

The electricity supply to this area is provided by three stepdown stations - Brant TS, Powerline MTS and Brantford TS. The coincident peak demand of the three stations in summer 2012 was approximately 250MW.

Figure 4: Regional Planning Status



4.1 Needs screening

Needs Screening is the first step in the Regional Planning process. In November 2013, Hydro One began organizing conference calls for the regions in Group 1, followed by meetings in January 2014 in order to outline the new regional planning process and discuss Needs Screening with relevant regional LDCs, the OPA and the IESO. As of April 2014, Needs Screening required for all of the regions or subregions in Group 1 has been initiated.

In the transition to the new regional planning process, the regions or subregions for which planning activities were already underway, the Needs Screening and Scoping Assessment are deemed complete, with the exception of the Northwest Region. These studies are in different stages of IRRP and further details are discussed in Section 4.2.

4.2 Status of regional planning activities

The status of regional planning activities for the Group 1 regions for which Hydro One is the lead transmitter is as follows:

<u>Regions in Group 1</u>

i) Burlington to Nanticoke

Hydro One requested and received, from distributors in the region, the OPA and the IESO, the data required to complete the Needs Screening for the Burlington to Nanticoke region. The Needs Screening for this region began on March 24, 2014 and was completed on May 23, 2014.

Brant Subregion (Burlington to Nanticoke)

The OPA is developing an IRRP for the Brant subregion and Hydro One is participating on these efforts. In light of new information that has been brought to light recently by relevant LDCs, LDCs must update their load forecasts. As a result, the timeline for the subregion's IRRP is being reviewed by the OPA. It is expected that the IRRP will be complete by the end of 2014. In addition, the OPA has issued a handoff letter to Hydro One requesting Hydro One, in consultation with relevant LDCs, to begin development of a wires solution to address near-term needs in the Brant area. This letter is included as Attachment 1 to this Exhibit.

ii) Greater Ottawa

The Greater Ottawa region consists of two subregions: the Outer Ottawa subregion and the Ottawa subregion.

Outer Ottawa Subregion

Hydro One requested and received information required for Needs Screening from LDCs in the Outer Ottawa subregion, the OPA and the IESO in May 2014..

The Needs Screening for this region began on May 26, 2014 and was completed on July 28, 2014.

Ottawa Subregion

The OPA is developing an IRRP for this subregion - it is expected that the IRRP will be complete by Q1 2015. A near-term need for a new transformer station has been identified. Hydro One has started planning for the construction of the new station, Orleans TS, in the Ottawa subregion.

iii) GTA North

The GTA North region consists of two subregions: the York subregion and the Western subregion.

Western Subregion

Hydro One requested and received the data required for Needs Screening from LDCs in the Western subregion, the OPA and the IESO. The Needs Screening for this region began on April 27, 2014 and was completed on June 27, 2014.

York Subregion

The OPA is developing an IRRP for the York subregion – it is expected that the IRRP will be complete by Q1 2015. Currently, IRRP assessments have identified two near-term wires solutions, and the OPA has issued a handoff letter to Hydro One requesting that the two proposed wires solutions be studied in more detail. This letter is included as Attachment 2 to this Exhibit. Hydro One is carrying out assessments and will be developing wires solutions to address near-term needs in the York subregion.

iv) GTA West

The GTA West region consists of two subregions: the Northwestern subregion and the Southern subregion.

Southern Subregion

Hydro One requested and received the data required for Needs Screening from LDCs in the Southern subregion, the OPA and the IESO. The Needs Screening for this region began on May 30, 2014 and was completed on June 1, 2014 and posted on the regional planning website.

Northwestern Subregion

The OPA is developing an IRRP for the Northwestern subregion - it is expected that the IRRP will be complete by Q2 2015.

v) GTA East

Hydro One requested and received the data required for Needs Screening from LDCs in the GTA East region, the OPA and the IESO. The Needs Screening for this region began on June 12, 2014 and was completed on August 11, 2014 and posted on the regional planning website.

vi) Kitchener-Waterloo-Cambridge-Guelph ("KWCG")

The OPA is developing an IRRP for the KWCG region – it is expected that the IRRP will be complete by Q4 2014. The OPA has issued a handoff letter to Hydro One, requesting that Hydro One undertake further assessment to develop transmission options and alternatives to address near and medium term needs in the region. This letter is included as Attachment 3 to this Exhibit. Two wires plans have been identified to address the near and medium term needs in this region: (1) the Guelph Area Transmission Reinforcement (GATR) project, and (2) the second Preston auto-transformer project. The GATR Leave to Construct application filed by Hydro One has been approved by the OEB. These assessments and any resulting investments in infrastructure solutions will ultimately become part of the RIP after an IRRP is complete. The GATR and Preston investments are included in this application in Exhibit D1, Tab 3, Schedule 3.

vii) Metro Toronto

The Metro Toronto region consists of two subregions: the Northern subregion and Central-Downtown subregion.

Northern Subregion

Hydro One has requested and received the data required for Needs Screening from LDCs in the Northern subregion, the OPA and the IESO. The Needs Screening for this region began on April 14, 2014 and was completed on June 11, 2014 and posted on the regional planning website.

Central-Downtown Subregion

The OPA is developing an IRRP for this subregion - it is expected that the IRRP will be complete by Q4 2014. The OPA has issued a handoff letter to Hydro One, requesting that Hydro One look at transmission options to address near-term needs of the subregion. This letter is included as Attachment 4 to this Exhibit. These assessments and any resulting investments in infrastructure solutions will ultimately become part of the RIP after the IRRP is complete.

viii) Northwest Ontario

The Northwest is a large region with diverse needs. The OPA is already leading planning activities in six sub-areas of the region and collecting information and load forecasts from relevant industrial proponents in these sub-areas.

Hydro One Transmission discussed the Regional Planning process and a formal Needs Screening for the Northwest Ontario Region with representatives from Kenora Hydro Electric Corp., Fort Frances Power Corp., Atikokan Hydro Inc., Sioux Lookout Hydro Inc., Thunder Bay Hydro Corp., Chapleau Public Utilities Corp., Hydro One Distribution, the OPA and the IESO. The participants recognized that significant planning work is already underway to address several needs in the region. Accordingly, with the agreement of study team Hydro One collected LDCs' specific information and updated load forecasts and moved the process directly to the OPA-led Scoping process. The data is provided to the OPA to augment studies in the Scoping Process phase of Regional Planning and for their assessments in developing a Northwest IRRP.

ix) Windsor Essex

The OPA and Hydro One have been monitoring developments in the Windsor-Essex region since 2011. The OPA is developing an IRRP for the region – it is expected that the IRRP will be complete by Q4 2014. Currently, the study has identified a new transformer station in Leamington, Leamington TS, to address near and medium-term needs of the area. To facilitate this project, Hydro One submitted a Leave to Construct application to the Board in January 2014, for construction of 13 km of new 230 kV double circuit line to supply the proposed Leamington TS and this investment is included in this application in Exhibit D1, Tab 3, Schedule 3.

Regions in Group 2 and Group 3

The Regional Planning process has not been initiated for the regions in groups 2 and 3. As was the case for the regions in group 1, Hydro One will engage the relevant stakeholders in each region prior to launching any regional planning activities. Regional planning activities for regions in Group 2 and Group 3 are expected to begin in the third quarter of 2014 and 2015 respectively.

4.3 Planning Status Letters

As required by the TSC, Hydro One has been providing Planning Status Letters to LDCs upon request, confirming the status of regional planning and detailing any planned investments in the relevant regions. The following LDCs have been issued Planning Status Letters by Hydro One as of April, 2014:

- Cambridge and North Dumfries Hydro Inc.
- Chapleau Public Utilities Corporation
- EnWin Utilities Inc.
- Fort Frances Power Corporation
- Haldimand County Hydro Inc.
- Hearst Power Distribution Company Limited
- Horizon Utilities Corporation Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Niagara-On-The-Lake Hydro Inc.
- Niagara Peninsula Energy Inc.
- North Bay Hydro Distribution Ltd.
- Oakville Hydro Electricity Distribution Inc.
- Oshawa PUC Networks Inc.
- Ottawa River Power Corporation
- Veridian Connections Inc.
- Woodstock Hydro Services Inc.

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

February 06, 2014

Mr. Bing Young
Director, Transmission System Development
Hydro One Networks
483 Bay Street
Toronto, Ontario M5G 2P5

Brant Area Regional Planning – Initiating the Implementation of the Near-Term Wire(s) Solution

Dear Bing:

The purpose of this letter is to request Hydro One Networks to initiate the implementation of a wire(s) solution - providing additional reactive support - to address the near-term supply need in the Brant Area.

The Brant Regional Planning Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One Transmission and Distribution, Brantford Power and Brant County Power has been conducting an Integrated Regional Resource Planning (IRRP) process for the Brant sub-region within the Burlington to Nanticoke Region. The IRRP process develops and analyzes forecast for demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC) and develops integrated solutions to address any needs that are identified.

While the IRRP for the Brant study area is not yet complete, the study has identified an urgent need to increase the load meeting capability (LMC) of the B12/13 circuits supplying Brant TS and Powerline MTS. The LMC for this supply was determined to be 104 MW based on voltage criteria. The peak loading on these circuits was approximately 118 MW in summer 2013 and is forecasted to reach 126 MW by 2016. Studies show that the installation of capacitor bank(s) at Powerline MTS will provide adequate relief to allow the circuits to be operated to their thermal capability, which will be approximately 125 MW. The load transfer among the Brant area stations will also allow effective use of the existing installed capacity. The Working Group believes that, along with the level of conservation expected to be achieved in this area, additional reactive support provides the most economic and effective solution for addressing this near-term need in this area.

Under the Ontario Energy Board's (OEB) recently endorsed regional planning process, in cases where an IRRP is still in progress but it has determined that a transmission and/or distribution wires solution is necessary to best address a near-term need, a "hand off" letter would be provided from the OPA to the lead transmitter, in this case Hydro One Networks, to initiate the implementation of a wire(s) solution. This is the case for the Brant Regional Planning Study.

The details associated with the near-term wire(s) solution will be determined by Hydro One Networks and relevant LDCs in the sub-region. The following information from the studies done and discussions had by the Working Group may be helpful to Hydro One Networks in the development of this project.

- The required date of this transmission reinforcement project is as soon as practical.
- The OPA studies considered a maximum of 30 MVar reactive compensation at Powerline MTS.
- The IESO has concern with excessive voltage change on switching a single 30 MVar capacitor bank at Powerline MTS.
- Hydro One and LDC(s) will develop optimum configuration of bank sizes and location, along with distribution transfer options.

We look forward to information, results and deliverables from this project as part of the Brant Working Group activities. We will continue to work with and support Hydro One and LDCs on the implementation of this work.

Regards,

R.F. Chow

Bob Chow
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

CC:
Brant Working Group members

Brantford Power Inc.
Mark Simpson
Steve Faulkner

Hydro One Distribution
Charlie Lee
Isabel Victal

IESO
Peter Drury

Brant County Power
Michael Desroches
Glen Fuller

Hydro One Networks
Farooq Qureshy
Devinder Bahra
Dhvani Shah
Ajay Garg

OPA
Kun Xiong
Wajiha Shoaib
Robert D'Ippolito

Luisa Da Rocha (OPA)
Charlene de Boer (OPA)
Richard Bassindale (Horizon Utilities Corporation)

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

June 14, 2013

Mr. Bing Young
Director, Transmission System Development
Hydro One Networks, Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Initiating a Regional Infrastructure Planning Process for Near-Term Transmission Projects in York Region

Dear Bing:

The purpose of this letter is to:

- Request that Hydro One initiate a Regional Infrastructure Planning (RIP) process to develop and implement the near-term transmission component of the integrated plan to meet the near- and medium-term reliability needs of York Region.

- Hand off from the Ontario Power Authority (OPA) the lead responsibility for the planning process associated with the near-term transmission component of the York Region Integrated Regional Resource Planning (IRRP) process to Hydro One to initiate the RIP process.

This is consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulatory Framework for Electricity.

The York Region Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One and the York Region local distribution companies, has been conducting an IRRP process for York Region. In combination with conservation and local generation options, the Working Group has identified two transmission projects for meeting the reliability needs of the area for the near and medium term. These projects are located at Holland TS, and along the Parkway Belt transmission corridor.

The Working Group has identified these projects for near-term implementation and has discussed preliminary options. However, more detailed study and development work is required before these projects can be implemented. Continued development of both projects is best accomplished through Hydro One's RIP process, guided by the information and requirements provided below from the IRRP process.

The objectives and scope of these two projects are provided in Attachment 1.

To facilitate the transition to the RIP process, the OPA will provide Hydro One with the following information:

- Relevant system base cases
- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

We look forward to information, results and deliverables from the York Region near-term transmission projects, as part of the York Region Working Group activities, and to continuing to work with and support Hydro One on the implementation of these projects.

Best Regards,

R.F. Chow

Bob Chow
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

CC York Region Working Group members:

PowerStream
Irv Klajman
Richard Wang
Riaz Shaikh

Newmarket-Tay Power
Larry Herod

Hydro One Distribution
Charlie Lee

Hydro One Networks
Farooq Qureshy
Paul Cook
E. Warren King

IESO
Peter Drury

OPA
Nicole Hopper
Bernice Chan
Alexandra Barrett
Kun Xiong
Joe Toneguzzo

Attachment 1 – Project Objectives and Scope

Holland TS Project Objectives:

The objectives of the Holland TS project are as follows:

- To increase the load-meeting capability of the Claireville-to-Brown Hill transmission line (B82V/B83V) to accommodate forecast load growth in northwest Vaughan and northern York Region in the near and medium term, and the connection of Vaughan #4 MTS, a new load supply station planned to be in service in spring 2017.

- To improve the capability to restore customer loads in northern York Region following a major outage affecting the main B82V/B83V transmission line, in accordance with the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC).

Holland TS Project Scope:

The Working Group has discussed options for meeting the above objectives and recommends proceeding with the following measures:

- Installation of two in-line breakers and associated motorized disconnect switches on the B82V/B83V circuits at, or near, the Holland TS property.

- Design and implementation of a Load Rejection (L/R) scheme for the stations connected to the B82V/B83V transmission line, or have available operational measures adequate for providing similar relief, as permitted by ORTAC.

Based on technical studies by the Working Group, with the addition of the in-line breakers and implementation of the L/R scheme described above, a load-meeting capability of 750 MW can be achieved for the system consisting of the B82V/B83V circuits and local generation (York Energy Centre). The switching facilities will also enable fast isolation of faulted line sections and allow restoration of customer loads, with York Energy Centre as a local supply source, following a major outage on the main transmission line, in accordance with ORTAC.

Hydro One will confirm the scope and cost of the above facilities to meet the identified reliability needs and to optimize their specifications and configuration.

Initiating these measures through the RIP process will allow restoration criteria to be met and provide sufficient capacity to supply forecast net load growth in Vaughan and northern York Region for the near and medium term. In the longer term (2020-2025 based on current load forecasts), the Working Group recognizes that a solution will be needed to support continued load growth in York Region and is planning engagement with affected communities, Aboriginal communities, and stakeholders on a long-term York Region Integrated Regional Resource Plan (IRRP).

The Holland TS project is needed in northern York Region to meet ORTAC restoration criteria today. In addition, it will be necessary to coordinate the development of this project with the connection of Vaughan #4 MTS to ensure there is sufficient capacity to supply this station when it connects in spring 2017. Therefore, the Holland TS project should be targeted to be in service by spring 2017.

Parkway Belt Project Objectives:

The objective of the Parkway Belt project is to improve the reliability of supply to customers supplied from the 230 kV "Parkway Belt" circuits (V71P/V75P), specifically in the following areas:

- To enable the Parkway Belt to meet ORTAC's 600 MW load security limit. Currently, the amount of load that could be lost by configuration in a double-circuit contingency exceeds 700 MW during peak demand conditions.

- To enable customer loads supplied from the Parkway Belt circuits to be restored following a major outage affecting the V71P/V75P circuits in accordance with ORTAC.

Parkway Belt Project Scope:

There are a number of options for meeting the above objectives, including a new switching station or line option, and the optimal solution has not been determined at this time. Development work, as part of the RIP, is required to assess the feasibility, cost and development timelines of the various options before the project can be fully scoped. There may be potential for a coordinated transmission and distribution solution.

This project is needed to meet ORTAC load security and restoration criteria today. As the project scope has yet to be defined, the in-service date will be established in accordance with the development timeline for the selected option.

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

May 29, 2013

Mr. Bing Young
Director, Transmission System Development
Hydro One Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Initiating a Regional Infrastructure Planning Process for a Near- and Medium-Term Transmission Project in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Area

Dear Bing:

The purpose of this letter is to:

- Request Hydro One to initiate a Regional Infrastructure Planning (RIP) process to develop and implement the remaining transmission component of the integrated plan to meet the near- and medium-term reliability needs of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area.

- Hand-off from the Ontario Power Authority (OPA) the lead responsibility for the planning process associated with the transmission component of the KWCG area Integrated Regional Resource Planning (IRRP) process to Hydro One.

This is consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulatory Framework for Electricity.

The KWCG Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One and local distribution companies in the KWCG area, has been conducting an IRRP process for the KWCG area. In combination with conservation and local generation options, the Working Group has identified two transmission projects for meeting the reliability needs of the area in the near- and medium- term. These projects are:

- the Guelph Area Transmission Refurbishment (GATR) project – Hydro One is currently proceeding with this project, including seeking the necessary OEB Leave-to-Construct approval; and
- the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive facilities (Preston Autotransformer Project) – the OPA has completed a preliminary assessment of this option as part of the IRRP process.

While the GATR project has advanced to the approval phase, more detailed study and development work is required for planning the Preston Autotransformer Project. This is best accomplished through Hydro One's RIP process guided by the information and requirements provided below from the IRRP process.

Objectives:

The objectives of the Preston Autotransformer Project are:

- To provide adequate load meeting capability to connect a future Cambridge & North Dumfries Hydro transformer station on the Kitchener-Guelph 115 kV system by about 2018

- To substantially improve the ability to restore electricity supply and minimize the potential impact of service interruptions to customers following a major transmission outage in the Cambridge area consistent with the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)

- To provide sufficient voltage support for the Kitchener-Guelph 115 kV system and Cambridge 230 kV system to comply with IESO requirements

- To facilitate the necessary measures to manage multiple outages conditions on the Kitchener-Guelph 115 kV system and Cambridge 230 kV system

Scope:

The Working Group has discussed various options for meeting the above objectives and recommends proceeding with the following measures:

- Installation of a second 230/115 kV autotransformer at Preston TS and associated 115 kV switching facilities

- Installation of low-voltage capacitor banks on the Kitchener-Guelph 115 kV and/or the Cambridge 230 kV system

- Design and implementation of a Load Rejection (L/R) scheme for the Kitchener-Guelph 115 kV system, or have available operational measures adequate to provide similar relief.

Hydro One will confirm the need, scope and costs of the above facilities to meet the identified reliability needs and to optimize their specifications and configuration. At this time, based on preliminary cost estimates provided by Hydro One, the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support are expected to be between $20 million and $35 million. However, further refinements to the cost will be provided as part of the RIP process. The costs may also vary due to any significant scope changes arising from new information that is substantively different to that used in the IRRP process to date.

Consistent with the support letter that was submitted to Hydro One on August 7, 2012, these measures will further leverage the system improvements gained through the GATR project to address the near- and medium-term needs of the KWCG area. The ability of the Preston Autotransformer Project to meet the above objectives is subject to the availability of the GATR facilities.

In coordination with and subject to the OEB approval of the GATR project, the second 230/115kV autotransformer at Preston TS and associated switching and reactive support should be in-service by the end of 2015.

Supporting Information:

To facilitate the transition to the RIP process, the OPA may provide Hydro One with the following information:

- Relevant system base cases
- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

We look forward to information, results and deliverables from the Preston Autotransformer RIP as part of the KWCG Working Group activities and to continuing to work with and support Hydro One on the implementation of this project.

Regards,

R.F. Chow

Bob Chow
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

CC KWCG Working Group members

Cambridge and North Dumfries Hydro Inc.
Ron Sinclair
Shawn Jackson

Guelph Hydro Electric Systems Inc.
Kazi Marouf
Michael Wittemund
Erik Veneman

Kitchener-Wilmot Hydro Inc.
Lloyd Frank
Shaun Wang
Greig Cameron

Waterloo North Hydro Inc.
Dorothy Moryc
David Wilkinson
Herbert Haller

Hydro One Distribution
Charlie Lee

Hydro One Networks
John Sabiston
Emeka Okongwu
Arthur Fisher
Jennifer Li

IESO
Peter Drury

OPA
Charlene de Boer
Bernice Chan

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

December 27, 2013

Mr. Bing Young
Director, Transmission System Development
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

RE: Initiating a Regional Infrastructure Planning Process for Near Term Transmission Projects in Central Toronto

Dear Bing:

The purpose of this letter is to:

- Request that Hydro One initiate a Regional Infrastructure Planning (RIP) process to develop and implement specific near term transmission and distribution (T&D) components of the integrated plan to meet near and medium term reliability needs of the central and downtown Toronto area, for which conservation and local generation are not technically viable alternatives.

- Hand off from the Ontario Power Authority (OPA), the lead responsibility for the planning process associated with specific near term T&D components of the Central Toronto Integrated Regional Resource Planning (IRRP) process to Hydro One.

This is consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulatory Framework for Electricity.

The Central Toronto IRRP Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One and Toronto Hydro, has been conducting an IRRP process for the central Toronto area including downtown. The IRRP process investigates conservation, local generation, as well as T&D options to meet the needs of an area.

The Working Group has established that certain near term reliability needs, based on the Independent Electricity System Operator's "Ontario Resource and Transmission Assessment Criteria" (ORTAC), cannot be met through the application of conservation and local generation solutions.

More detailed study and development work is required before recommended solutions can be proposed and implemented for these near term needs. Development of T&D components of the plan is best accomplished through the RIP process guided by the information and requirements provided below and in Attachment 1, from the IRRP process.

Supporting Information for Central Toronto Near-Term Projects:

The objectives and scope of the near term T&D components of the plan, which are to be subjected to the RIP process, are provided in Attachment 1.

To facilitate the transition to the RIP process, the OPA will provide Hydro One with the following information:

- Summary of the needs that have been established requiring RIP
- Relevant system base cases
- Demand forecasts
- Conservation and distributed generation forecasts
- Preliminary assessments of some options
- Other relevant information upon request from Hydro One

We look forward to information, results and deliverables from the Central Toronto RIP as part of the Working Group activities, and to continuing to work with and supporting Hydro One on the further development and implementation of these projects.

Best Regards,

Steve Norris, for:

Joe Toneguzzo
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

Copied: Central Toronto IRRP Working Group

Attachment 1

It should be noted that the following needs and observations have been established with the understanding that the supply for Horner TS would be changed from circuits R2K and R15K to circuits R2K and R13K, by the second quarter of 2014, as advised by Hydro One.

1.A Needs Requiring Immediate Implementation of Solutions

The near term need described in this section is based on the Independent Electricity System Operator's ORTAC, and it has been determined for this specific need, that CDM, local generation, or other electricity system initiatives are not technically feasible solutions.

- The outage of any two of the three 230/115 kV autotransformers at either the east or west yard of Manby TS can result in the overload of the remaining autotransformer. This outage can be caused by the failure of any of the following Manby TS breakers: A1H4, H1H4, or H2H3. Solutions are required as soon as possible to address the resulting overload to fulfill the requirements specified in ORTAC.

Some options that have been investigated on a preliminary basis by the Working Group include the following:

1. A Special Protection Scheme that can be armed if prevailing system conditions (normal and emergency) would result in loadings exceeding equipment ratings following the contingencies.
2. Re-termination of existing facilities at Manby TS to reduce the impact of breaker failure contingencies at Manby TS.

1.B Discretionary Near Term Observations to Enhance Supply to Downtown

- Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS can result in the loss of two of the three 230/115 kV autotransformers on the same half of Leaside TS. At present, if the steam-turbine generator at the Portlands Energy Centre is unavailable, and consequently is derated to the output of a single combustion unit, coincident with either of these double circuit contingencies, then curtailment of load would be required to respect the Long Term Rating of the remaining autotransformer. In addition, the voltage stability limit, based on 95% of the critical load of Leaside supplied facilities, is determined to be 1420 MW for this particular condition. This limit is forecast to be exceeded as early as 2021 (under a load forecast scenario which considers no new CDM beyond 2014), if limitations at Manby prevent load transfers to relieve Leaside autotransformer loading.

Some options that have been investigated on a preliminary basis by the Working Group include the following:

1. Re-termination of the incoming 230 kV Cherrywood to Leaside circuits to ensure that a C2L/C3L or a C16L/C17L double contingency does not result in the removal of two autotransformers from the same half of the Leaside 115 kV yard.
2. Modification of operating instructions to include closing the Leaside 115 kV bus-tie breakers following the loss of any two Cherrywood to Leaside circuits and/or two Leaside autotransformers if the Portlands Energy Centre steam turbine generator is unavailable.

It should also be noted that by addressing breaker failure contingencies at Manby TS, additional load transfer from Leaside to Manby would be available and could substantially reduce load curtailment requirements in the Leaside sector for C2L/C3L and C16L/C17L contingencies. Therefore, considerations for load transfer should be quantified and included in the assessments.

- The outage of two of the three Leaside to Bridgman circuits may result in overloading of the remaining circuit, and unacceptable voltages at Bridgman TS. This outage can be caused by the failure of breaker L14L15 at Leaside TS.

The following options have been investigated on a preliminary basis by the Working Group and include the following, which are not necessarily mutually exclusive:

1. Special Protection Scheme that can be armed if prevailing system conditions would result in loading exceeding equipment ratings following the outage of two Leaside to Bridgman circuits.
2. Re-termination of L14W or L15W to ensure that no two circuits supplying Bridgman share a common breaker.

1.C Other Observations and Assessments from the IRRP Review for Consideration

In addition to the above near term needs, a number of other observations are identified for consideration to enhance the level of service and should be considered in developing the T&D solutions to address the needs identified in 1.A. It should be noted that these observations do not represent criteria violations; however, consistent with ORTAC Section 7.4, the customer and transmitter can agree to a higher level of reliability "for technical, economic, safety, and environmental reasons."

These observations are:

1. Supply to Duplex TS, Glengrove TS, and Leaside DESNs in the event of the loss of Leaside TS, including considering feasible load transfers, operating measures, and/or the use of temporary facilities.

2. Supply to Manby DESNs for the loss of Manby TS, including considering feasible load transfers, operating measures, and/or the use of temporary facilities.

3. Enhance the transfer capability from the Leaside sector to Manby sector, including considering the uprating of the limiting sections of 115 kV circuit H2JK and/or providing additional 115 kV circuits between John TS and Hearn station.

4. Enhance the load-meeting capability to respect the loss of two adjacent 115 kV circuits on the multi-circuit 115 kV tower lines in the Manby East and West sectors, which are not anticipated to be defined as Bulk Electric System (BES) facilities by the NERC Transmission Planning Standards, to provide an equivalent standard of reliability as compared to those applied to the Leaside sector (largely anticipated to be BES).

5. Enhance load restoration capability, to mitigate the impact of extreme contingency events, such as the complete loss of Manby TS or Leaside TS.

==

END of LETTER

TRANSMISSION BUSINESS PERFORMANCE

1.0 INTRODUCTION

Hydro One is focused on the strategic goals and performance targets in the area of safety, customer satisfaction, reliability, shareholder value, and productivity. This Exhibit illustrates the historical business performance of Hydro One's Transmission Business in these areas with the exception of Productivity, which is addressed separately in Exhibit A, Tab 18, Schedule 1. Utility performance assessment also involves comparisons with other utilities which are a priority of the Board and stakeholder community. This Exhibit includes a brief discussion of the issues with benchmarking and provides a comparison to other utilities. These comparisons focus on the established Canadian Electricity Association (CEA) composite performance which is the aggregate performance of CEA participating transmission utilities. Other comparison perspectives that are evolving within the industry, on a North American scale, are also presented.

2.0 PERFORMANCE MEASUREMENT PROCESS

The first approach to establish Hydro One Transmission's performance levels entails monitoring actual performance over time. This Exhibit provides Hydro One's performance on its targeted areas, utilizing historical data drawn from Hydro One's own records.

The second approach involves comparison with other transmission utilities, particularly for reliability performance. This is a much more complex undertaking that requires careful consideration of following:

- measurement definition;
- data collection processes which impact on the consistency and accuracy of the reported measures; and
- variations such as climate, operating environment and system infrastructure among transmission companies that can influence the absolute performance of their transmission systems.

A way to reduce the effect of these factors is to observe year-over-year performance using consistent and precise measurement definitions. Although transmitters each have a slightly different approach when measuring their own transmission system performance, the Canadian Electricity Association (CEA) has had success in creating reliability performance definitions with sufficient precision and consistency over the years to permit some degree of multi-jurisdictional transmission system performance comparisons. The data, however, is not audited and the comparisons are used only to help identify opportunities for business improvement. This Exhibit presents Hydro One’s transmission system performance relative to a CEA composite performance where available.

3.0 HEALTH AND SAFETY PERFORMANCE

Health and Safety is the foundation of every action, every project, every day for all staff regardless of position or level. The Company continues to develop, implement and maintain progressive programs and initiatives for accident prevention with a concentrated focus on the elimination of serious injuries and “near-misses”. The goal is to create and maintain an injury-free workplace.

Hydro One has continued with the Journey to Zero safety initiative that was started in 2009. This initiative compares our approach to health and safety management with world class companies to identify gaps. Opportunities for improvement have been prioritized and action plans implemented. Some of the new initiatives currently being developed include but are not limited to:

- Develop a *work environment* whereby employees have more direct involvement into suggesting ways to improve safety both on the job, and in operational plans;
- Identify a framework to instill Health and Safety in the shared beliefs and actions of all employees for themselves and their co-workers. Ensure it is a way of life and a condition of employment in the Hydro One culture.; and
- Identify opportunities and recommend solutions to reduce exposure to safety risks of MVAs.

During 2013, there was a focus on the following areas:

- Journey to Zero initiatives (including a safety culture assessment by DuPont: a survey, site assessment, leadership interviews and focus groups);
- obtaining and maintaining OHSAS 18001 registration, skills and safety training;
- field coaching/mentoring, young and new worker safety; and
- a number of employee health and wellness initiatives.

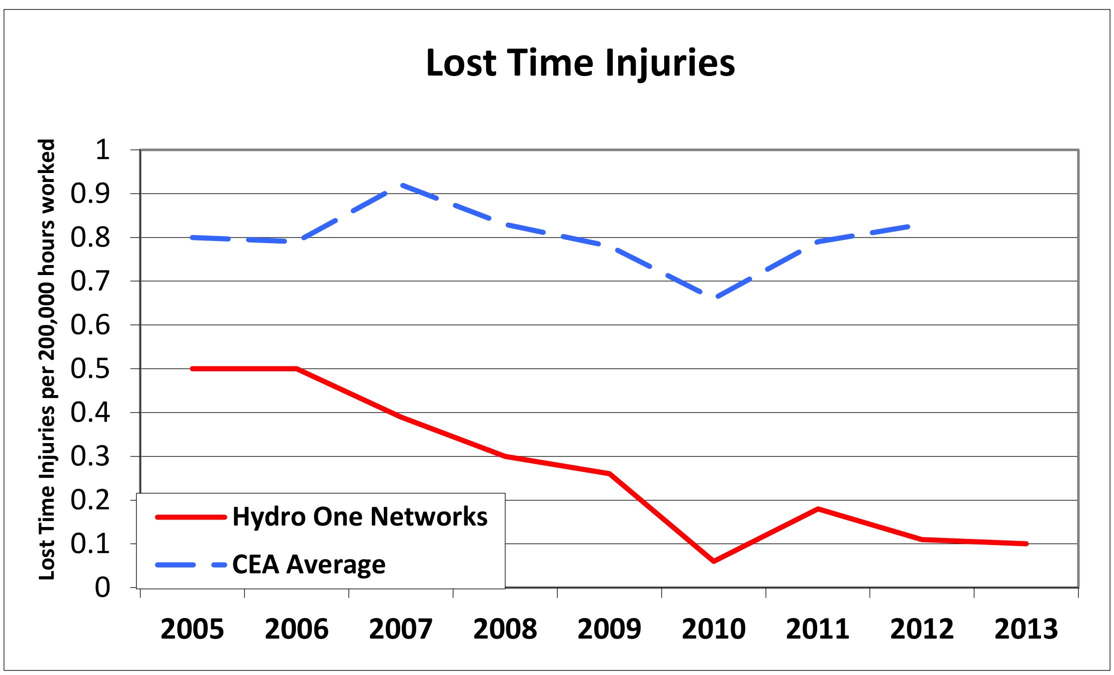
The successful OHSAS 18001 registration of the Hydro One Health, Safety and Environment Management System will enhance health & safety performance through a structured approach that drives continual improvement and effective risk and hazard assessment and management.

The Hydro One executive and senior management continue to demonstrate visible leadership to reinforce our health and safety vision through site visits and face-to-face discussions with employees.

Since the Hydro One safety program encompasses the entire company, safety performance is tracked throughout the company and performance measure results are not divided between the transmission and distribution businesses. The results presented in this evidence are for all of Hydro One.

As part of its safety program, Hydro One tracks a number of measures. Historically, the focus was on the Lost Time Injury measure. Lost Time Injuries are those injuries that result in Hydro One employees having to take time off to recover before they can return to work. Recent results have been included in Figure 1 to provide continuity to past results reported in previous rate filings. The Lost Time Injury measure has now been replaced by the Medical Attentions measure as the primary measure of safety performance.

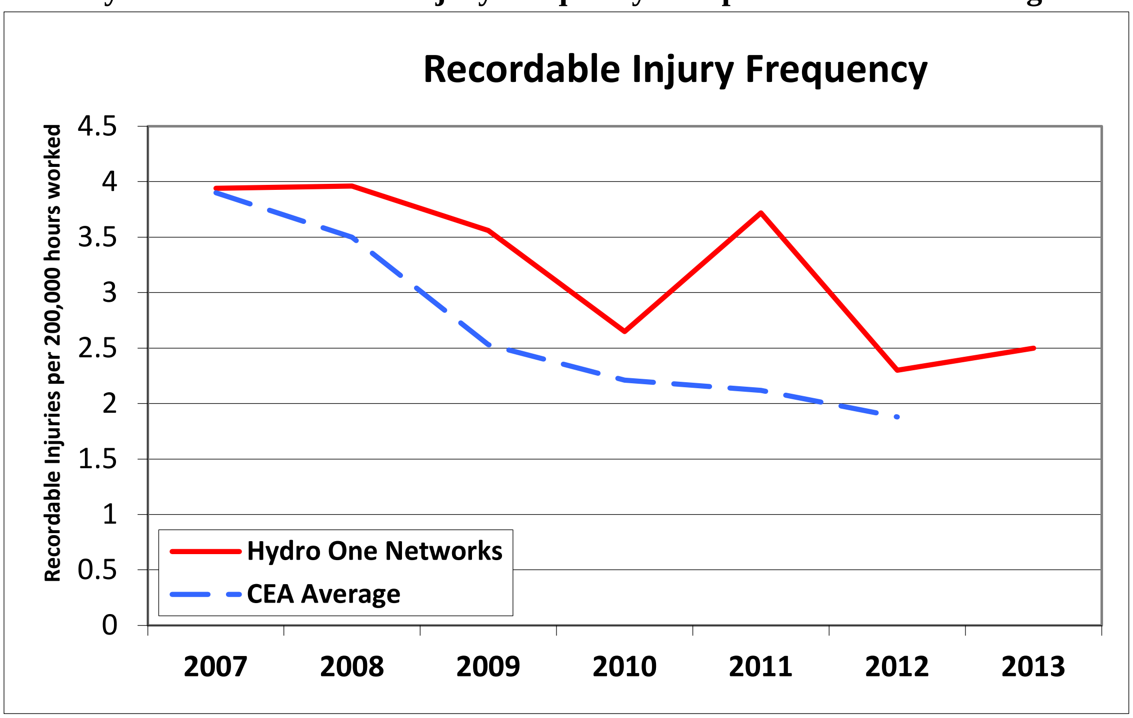
Figure 1:
Lost Time Injury Frequency Rate



In recent years, Hydro One has implemented the Medical Attentions measure in favour of the Lost Time Injury (LTI) metric as its primary Health and Safety performance measure. The Medical Attentions metric measures the number of injuries that require treatment by a medical practitioner (i.e. beyond first aid). The frequency of the LTI type measure occurrences is low and does not provide the best measure upon which to base Hydro One's improvement initiatives. The Medical Attentions measure captures a broader number of occurrences than LTI and in so doing, provides more opportunities to identify potential injury situations and their avoidance as part of the objective of having an injury-free workplace. This Medical Attentions metric will measure the impact that our planned improvement initiatives will have on the prevention of injuries that are more serious than requiring basic first aid.

The Medical Attention metric is aligned with the Canadian Electricity Association (CEA) recordable rate metric and the US Occupational Safety and Health Administration (OSHA) recordable metric. Hydro One can compare its performance to other Canadian utilities using the recordable injury metric as shown in Figure 2.

Figure 2:
Hydro One Recordable Injury Frequency Comparison to CEA Average

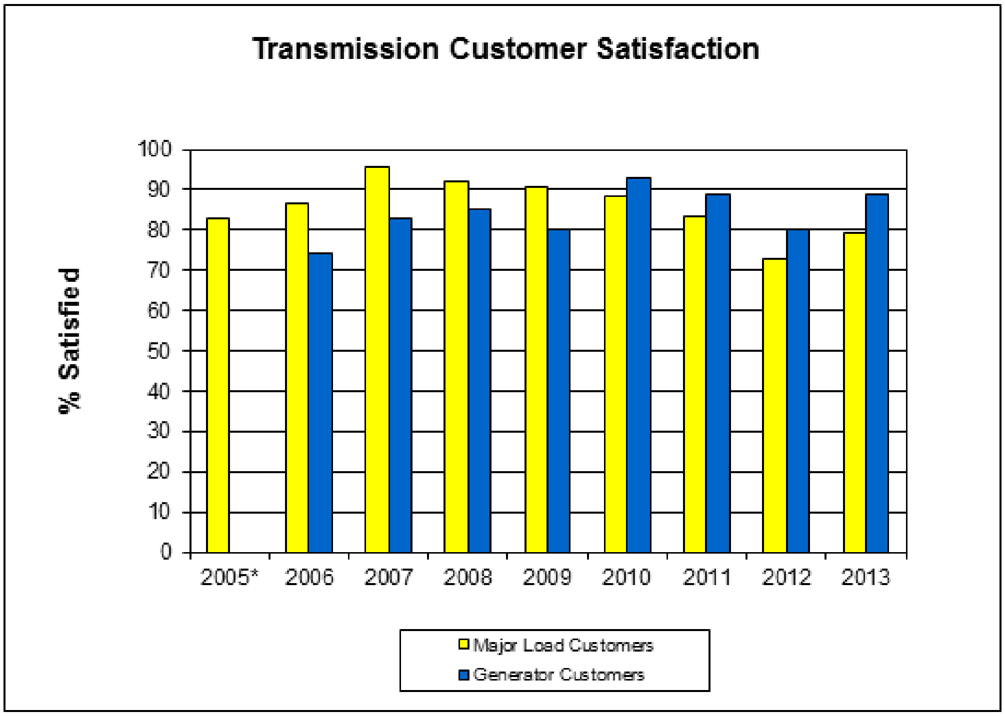


Hydro One continues to build on the strength of its achievements and focus on safety through its health and safety management program and Journey to Zero initiative to achieve an injury-free workplace.

4.0 CUSTOMER SERVICE PERFORMANCE

Hydro One is in business to serve its customers and as such, customer satisfaction is a high priority for the company. To gauge satisfaction, the company surveys customers on their satisfaction with the service that they have been receiving. Surveys are administered to both major load and generator customers, and survey questions are focused on areas of importance to customers such as reliability, communications, relationships, and responsiveness. Figure 3 illustrates the overall results from surveys that have been conducted in recent years.

Figure 3:
Transmission Customer Satisfaction



* Note: In 2005 there was no satisfaction survey carried out of the Generator Customers due to the Hydro One labour disruption.

As evidenced by the results in Figure 3, Hydro One's major load customers have indicated a relatively high satisfaction during the past several years, though a gradual decline in customer satisfaction in the major load customer sector since 2007 has been noted. This segment trend has seen its first year of improvement in 2013. This segment includes industrial customers and Local Distribution Companies (LDCs). Hydro One is actively addressing these results.

Reliability and more specifically power quality has been identified as a growing concern and that it is having a significant impact on the customers costs related to lost production or damage to product. Initiatives regarding customer engagement for power quality improvements can be found in Exhibit A, Tab, 4, Schedule 1.

Industrial customers have requested Hydro One to help them to reduce their costs through more effective management of planned outages on the transmission system. Efforts to bundle work programs on transformers and circuits to minimize transmission related outages are incorporated in the Hydro One's business plans going forward. See Exhibit A, Tab 16, Schedule 6 for more details on this effort.

LDCs are expressing concern over Hydro One's aging infrastructure and related reliability and the speed at which our work programs are addressing their concerns. Transformer and breaker replacement programs top the list of immediate concerns. Transformer capacity constraints in southern and eastern portions of the province are adding to the LDC stress, and a higher level of frustration was voiced by LDCs in the south at the inability to connect renewable generation projects within their service territories. Continual measurement of customer satisfaction and follow-up actions are examples of Hydro One's customer focus to meet and/or exceed customer expectations.

For generator customers, overall satisfaction with Hydro One is variable year over year but statistically fairly stable from the first survey conducted in 2004 through to including the latest 2013 survey results. The largest point of dissatisfaction with the generators is related to planned outages requiring them to reduce output or disconnect. Similar to the industrial customers, the generators will be included in the work bundling efforts to reduce these impacts. Hydro One staff are following up with those customers that indicated that they were either neutral or dissatisfied in order to gain specific feedback that will lead to ways of improving performance.

5.0 RELIABILITY PERFORMANCE

5.1 Transmission Reliability

Hydro One measures and actively monitors its transmission system reliability from two principle perspectives, namely: equipment performance and delivery performance. The equipment performance perspective enables Hydro One to assess the operational performance of transmission components, ensuring that the transmission equipment is functioning according to design. The delivery performance perspective establishes a measure of how reliably electricity is delivered to transmission customers such as Local Distribution Companies and large Industrial Customers. Being a customer focused organization, Hydro One considers delivery of electricity an important measure of transmission reliability and it strives to achieve a high level of performance in this area.

Transmission reliability is determined primarily using measures developed collaboratively with other transmission utilities across Canada at the Canadian Electricity Association (CEA). These measures have had success since they are well defined and understood by the participating member utilities and the definitions are of sufficient precision and consistency over years for multi-jurisdictional transmission performance comparisons.

5.2 Transmission Reliability Measures

Hydro One's service quality includes transmission system equipment performance and delivery of electricity performance measures. Four measures are listed in Table 1. Delivery Points are generally the interfaces between Hydro One's transmission system and its load customers. Delivery Points are either low voltage buses at Hydro One owned step-down transformer stations[1], or stations owned by transmission load customers, including Hydro One Distribution stations.

Delivery reliability is measured by frequency of delivery point interruptions, duration of delivery point interruptions and delivery point unreliability Index which is a normalized measure of unsupplied energy to customers. All interruptions caused by a forced outage are included in these measures. For transmission equipment reliability performance, transmission system forced unavailability is used.

[1] There are situations where a customer owns low voltage buses but these buses are still treated as Hydro One's transmission Delivery Points.

Table 1:

Transmission Reliability Measures

Reliability Perspective	Reliability Measure	Description
Reliability of Delivery of Electricity to Customers	*Frequency of Delivery Point Interruptions*	average number of interruptions experienced at delivery points
	Duration of Delivery Point Interruptions	average interruption durations in minutes experienced at delivery points
	Delivery Point Unreliability Index – a measure of unsupplied energy	energy not supplied to customers caused by interruptions, normalized by system peak load and presented in System Minutes
Reliability of Transmission Equipment	*Transmission Equipment Unavailability*	extent to which transmission equipment is not available for use by market participants due to forced outages

Hydro One uses these measures because:

- These are commonly used transmission reliability measures in industry to address transmission service quality perspectives important to customers and stakeholders.
- The benchmarking of these measures is meaningful as data collection and reporting practices among all CEA member utilities are consistent.
- These measures have been in place for over 10 years and it makes historical data available for assessing performance trends, setting targets and benchmarking.
- The limited number of measures keeps tracking and reporting requirements at a manageable and cost-effective level while still covering a broad transmission reliability performance spectrum.

A summary of delivery point performance according to the Hydro One Customer Delivery Point Performance (CDPP) Standards is discussed in Section 5.5. The standard, as attached in Appendix A, is described in a Hydro One exhibit previously filed with the OEB: Customer Delivery Point Performance (CDPP) Standard, EB-2002-0424. Appendix B provides definitions and detailed descriptions of these reliability measures. Appendix C provides historical performance of the measures as listed in Table 1.

5.3 Comparison of Hydro One Performance to Canadian Averages

Using data collected by the CEA, Hydro One is able to compare the reliability performance of its transmission system against Canadian average performance (CEA Composite). The comparison of delivery point reliability performance discussed in this section is at the system level that reflects the system average of all delivery points. Hydro One also focuses on multi-circuit supplied delivery point performance and that can be benchmarked with comparable Canadian utilities. In its efforts to achieve high performance, Hydro One establishes multi-circuit supplied delivery point performance targets in the first quartile ranking to comparable utilities in Canada.

Hydro One's comparative reliability performance at the system level is illustrated in the following Figures 4, 5, 6 and 7 for frequency of momentary interruptions, frequency of sustained interruptions, duration of sustained interruptions and delivery point unreliability index respectively. The CEA composite data is only available up to 2012. Hydro One 2013 data is provided in graphs where available.

Special notes for July 8th, 2013 Greater Toronto Area (GTA) Flooding Event:

Following the new CEA reporting criteria, the July 8th GTA rain flooding event is classified as a "Degree 4 Severity" event due to the significant customer impact. The criteria dictates that a local disturbance event will be treated separately when the total unsupplied energy caused by the event is more than 1 million MW-minutes. There was 1,406,218 MW-minutes unsupplied energy for July 8th event. The CEA generates two sets of numbers, with and without the event for load interruption related reliability meatuses. Such separation makes the performance comparison more meaningful among member utilities. The only two other events in the same category in the CEA transmission reliability reporting history were 1998 Eastern Ice Storm and 2003 Blackout. In order to have a meaningful comparison, all interruptions due to the July 8th event are excluded in this report.

Figure 4:

Comparison of Hydro One Frequency of Momentary Interruptions to CEA Composite

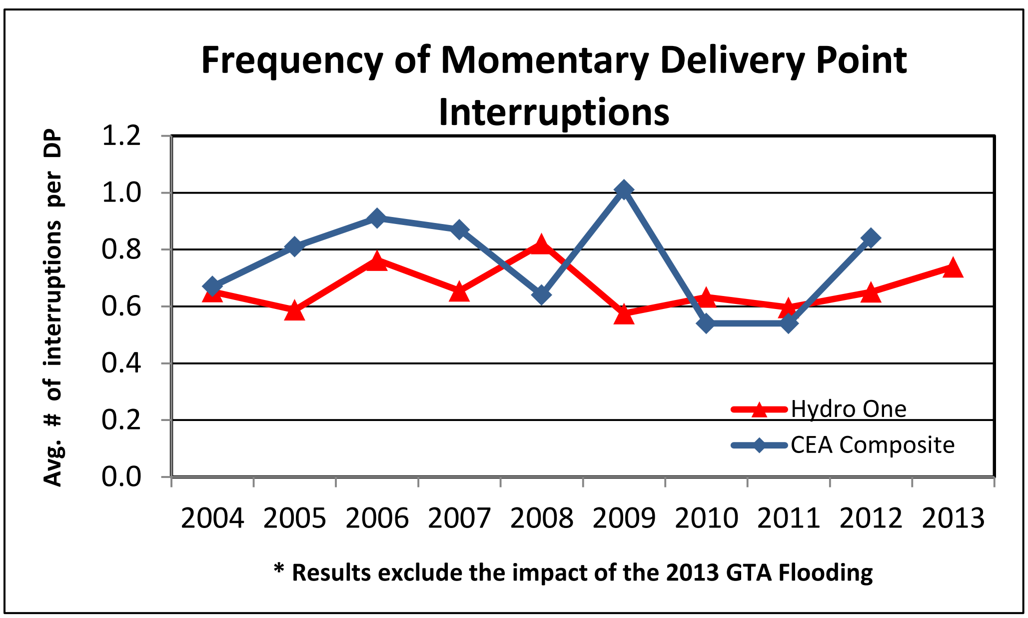


Figure 5:
Comparison of Hydro One Frequency of Sustained Interruptions to CEA Composite

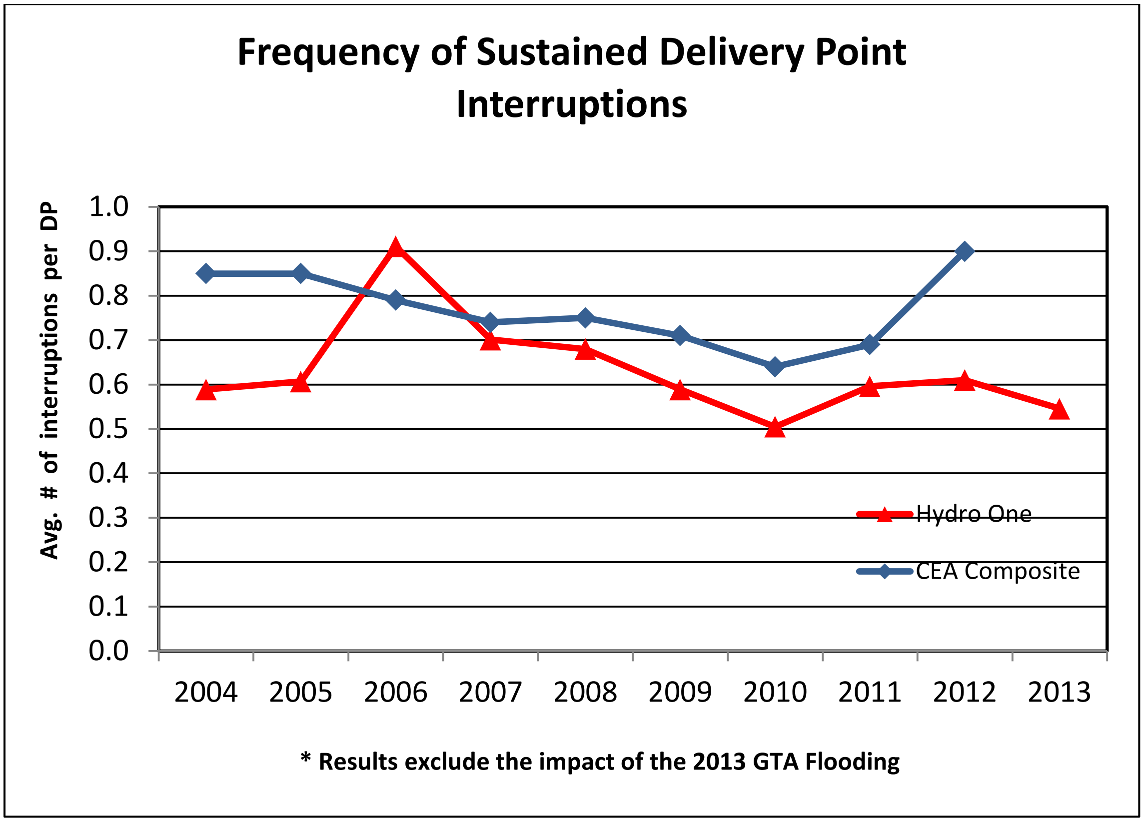


Figure 6:
Comparison of Hydro One Duration of Sustained Interruptions to CEA Composite

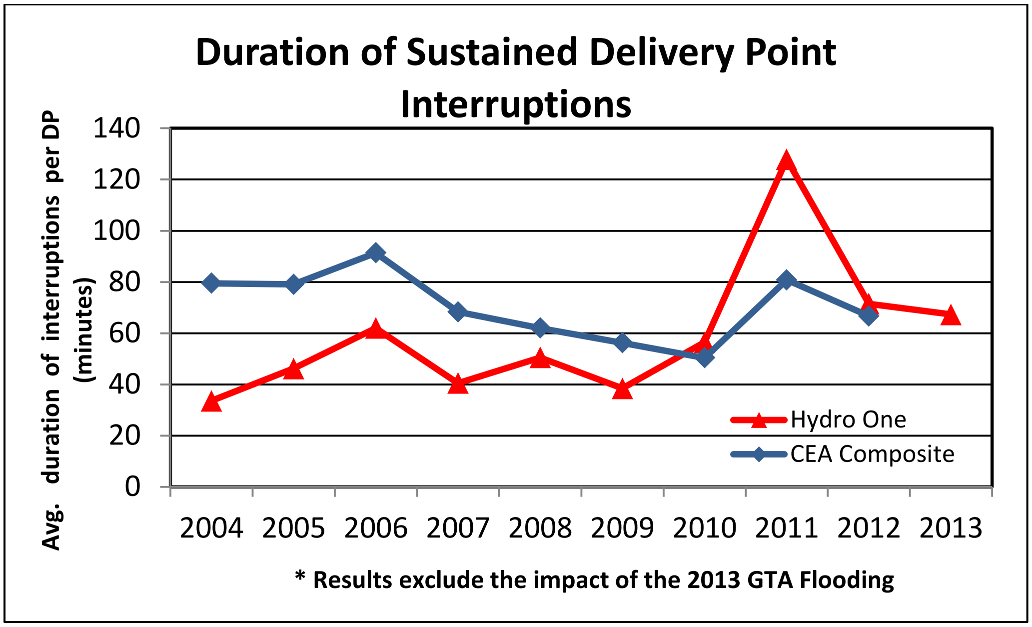
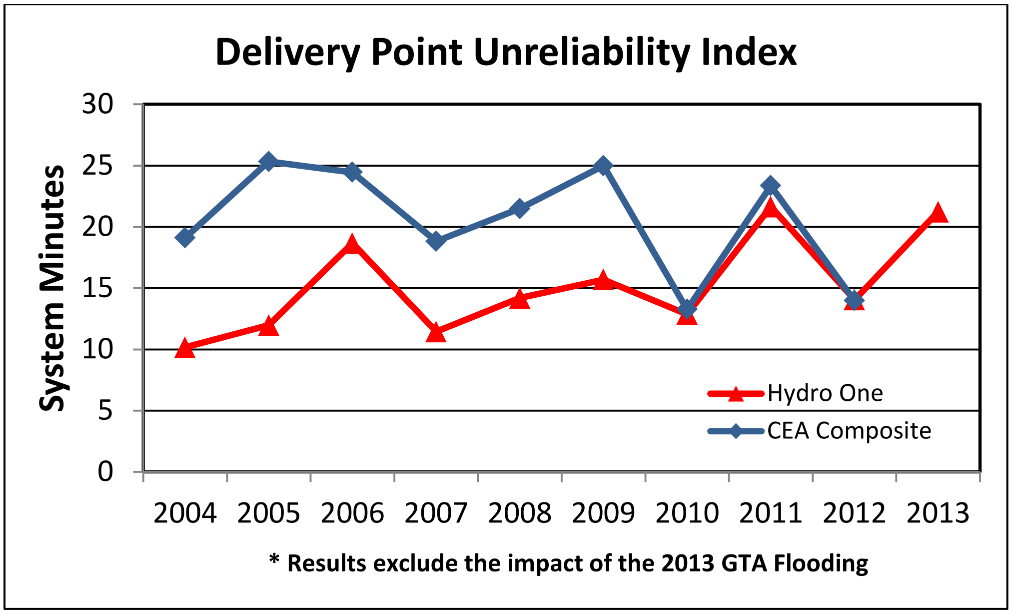


Figure 7:
Comparison of Hydro One Delivery Point Unreliability Index to CEA Composite



Delivery point interruption duration is the most critical index of measuring delivery reliability. A list of major events that significantly contributed to this measure are provided:

- In July 2013, an intense summer storm with high winds, lightning and torrential downpours in southern central Ontario contributed 7.9 minutes of 2013 duration of delivery point interruption measure.
- In December 2013, just before Christmas, an icy winter weather condition in most of southern Ontario contributed 5.0 minutes to 2013 duration of delivery point interruption measure.
- In November 2013, Armitage Transmission Station had a switch failure that contacted two 230 kV circuits. As a result, 7 delivery points normally supplied by these two circuits were interrupted. The event contributed 3.5 minutes to 2013 duration of delivery point interruption measure.
- In 2012, a forest fire in Dymond area, Northern Ontario significantly impacted the performance of the Hydro One grid. The event contributed 40.4 minutes to 2012 duration of delivery point interruption measure.
- In 2011, a forest fire in Northwestern Ontario damaged several wood pole structures and significantly impacted the performance of the Hydro One grid. The duration of delivery point interruptions was increased from 58.5 to 127.9 minutes per delivery point.
- In 2006, the Caledonia Event contributed 8.5 minutes to the Duration of Delivery Point Interruption measure as shown.
- In 2006, ice storms and electric storms significantly impacted the performance of the Hydro One grid. The frequency of sustained delivery point interruptions was increased from 0.78 to 0.91 interruptions per delivery point (Figure 5) and the duration of delivery point interruptions was increased from 54.6 to 62.0 minutes per delivery point.

Transmission system forced unavailability is split into Unavailability of Transmission Lines and Unavailability of Transmission Station Equipment. Station equipment includes power transformers, circuit breakers and capacitor banks. The Unavailability measure represents the extent to which the major transmission equipment is not available for use within the system. The detailed description of this measure is provided in Appendix B for both categories. Figures 8 and 9 illustrate historical performance of Hydro One lines and station equipment as compared to the CEA Composite which is a 5-year moving average performance of all the CEA member utilities. Figure 8 shows an increase in Transmission Line Unavailability from 2009 to 2011. The Hydro One measure indicates significant improvement in 2012 and 2013. The CEA All Canada numbers show a decrease in performance in 2012. Figure 9 shows similar trend for major Station Equipment and relatively better performance in 2013.

Figure 8:
Unavailability of Transmission Lines

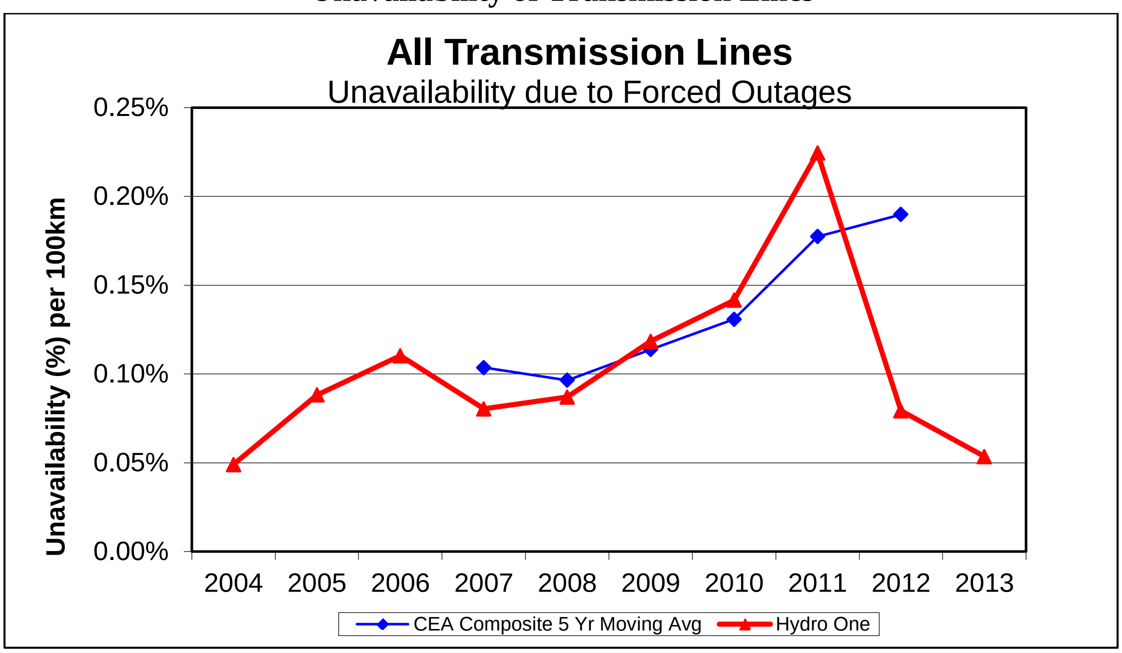
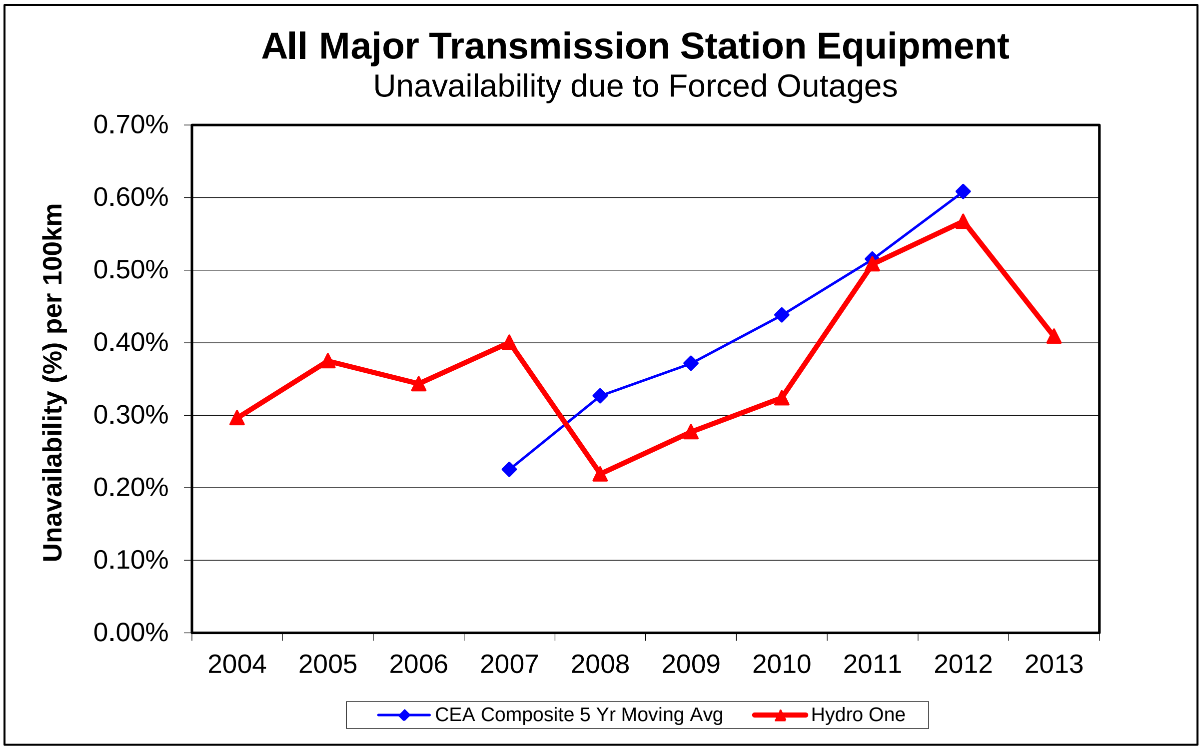


Figure 9:

Unavailability of Major Transmission Station Equipment



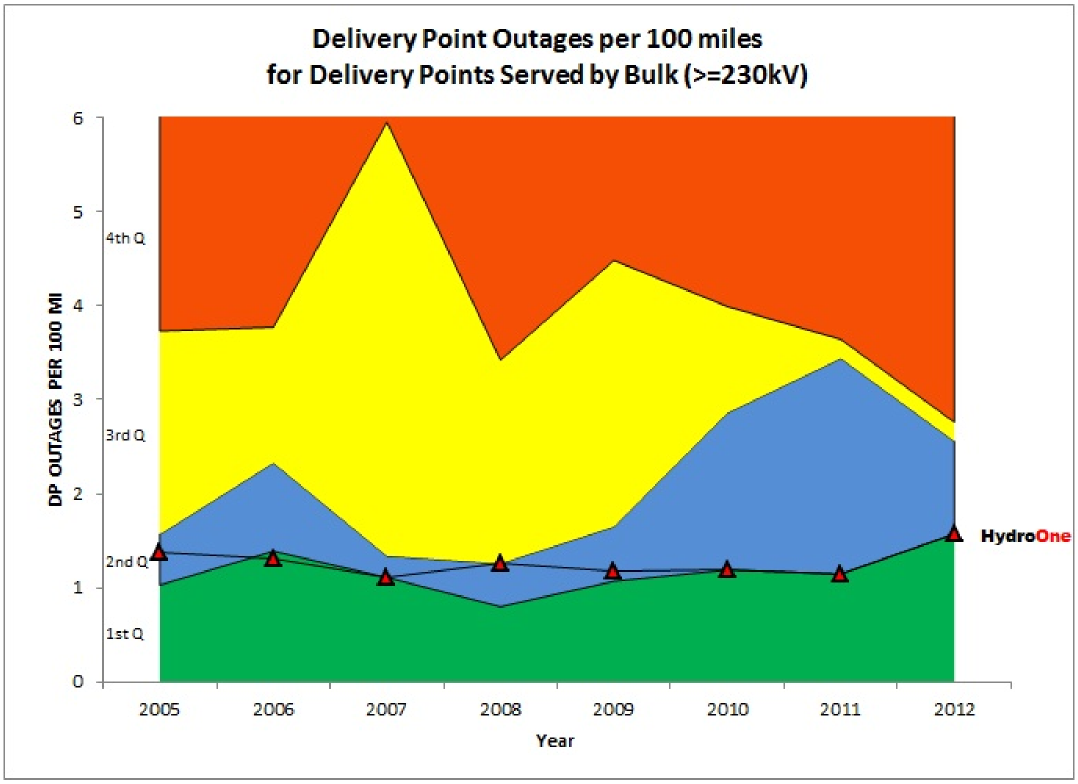
Performance of equipment is a leading indicator of system performance. Sustainment investments are made to preserve performance of critical asset groups by investing at the individual asset level and thereby preserving overall system performance.

Transmission system performance is one factor considered in the Hydro One Investment Plan Development (Exhibit A, Tab, 16, Schedule 3) and in the Investment Prioritization Process (Exhibit A, Tab 16, Schedule 4).

5.4 Performance Relative to Utilities in the USA

In order to provide additional reliability comparisons, Hydro One also participates in a transmission line reliability benchmarking study in the U.S., administered by SGS, a utility consultancy. Hydro One's delivery performance associated with transmission line outages are illustrated in Figures 10 and 11 below. The graphs show Hydro One's relative quartile performance compared to other transmission companies in the SGS study. Although there are some inconsistencies in both definitions and reporting practices within the study utilities, the results are considered accurate enough for broad, system performance comparisons. The measures are system averages for frequency and duration of forced interruptions to transmission delivery points. Results are normalized by line length to facilitate the measurement comparison. The results indicate that for 230kV and above systems, Hydro One is generally performing in the second quartile within this study group.

Figure 10:
Delivery Point Outages per 100 miles for Delivery Points Served by ≥ 230kV

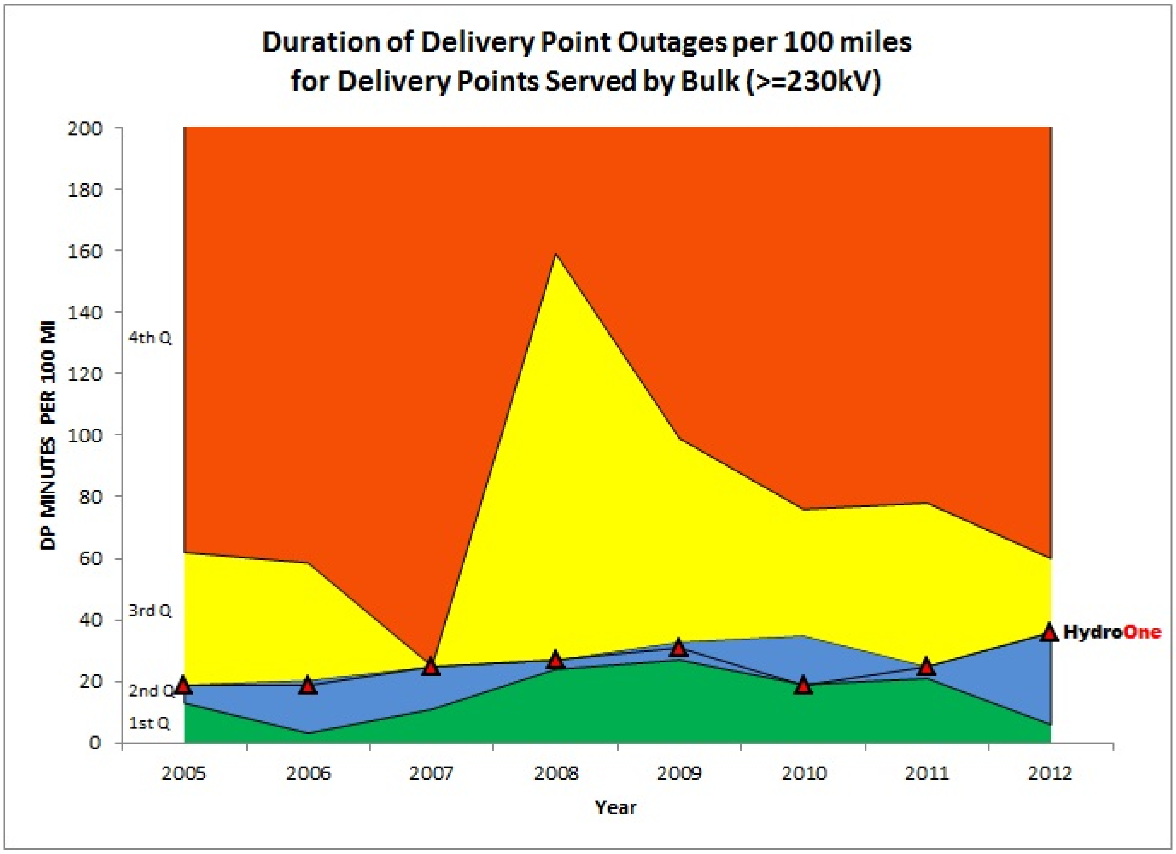


<u>Notes:</u>

(1) The quartile values are reported as part of the study results.

(2) Measures are system averages for frequency and include non-planned interruptions to transmission delivery points due to transmission line outages only.

Figure 11:
Delivery Point Outage Duration per 100 miles for Delivery Points Served by ≥ 230kV



Notes:

(1) The quartile values are reported as part of the study results.

(2) Measures are system averages for duration and include non-planned interruptions to transmission delivery points due to transmission outages only.

5.5 Delivery Point Performance Outliers

Delivery point performance is evaluated in accordance with the standard that Hydro One developed and filed with the OEB.[2] The performance standard is used as a trigger by Hydro One to initiate assessment and follow up with affected customers in order to:

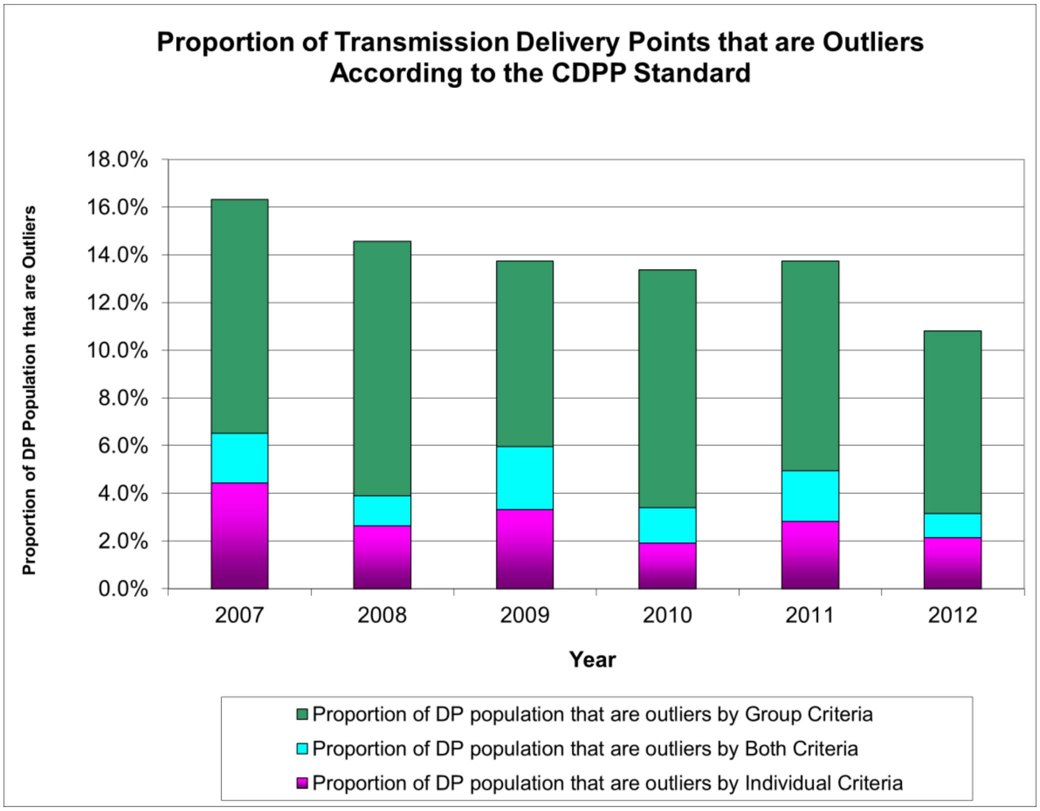
- Determine the root cause of unreliability;
- Perform technical and financial evaluations; and
- Decide on remedial action to improve reliability.

Figure 12 provides a summary of the transmission load delivery point performance outliers for the Group and Individual Customer Delivery Point Performance (CDPP) Standard criteria. Outliers due to Group and Individual CDPP Standard criteria are not mutually exclusive. This means that a delivery point can be both a group outlier and an individual outlier in same year.

[2] Customer Delivery Point Performance (CDPP) Standard, EB-2002-0424

Figure 12:

Transmission Load Delivery Point Performance Outliers



The delivery points found to continually be outliers according to the standard are incorporated into future investment programs. Hydro One endeavours to keep the number of outliers at 10% or less of the total population of delivery points. This will not always be the case as some delivery points are flagged as individual outliers even though they would normally experience better reliability performance than standard. One or two interruptions caused by isolated events may drive a specific delivery point as an individual outlier in a particular year. These delivery points would typically become a non-outlier in the following year with no incremental investment. Hydro One takes this into consideration in its assessments.

6.0 SHAREHOLDER PERFORMANCE

Delivering shareholder value is a key objective of any business and as such, Hydro One monitors related measures. A key measure in this area is the company's credit rating. Currently the company has a credit rating in the "A" category, which is in line with other large transmission companies in Canada. The goal is to maintain this credit rating in order to ensure ready access to long-term financing at reasonable rates, as Hydro One does not have access to equity markets and must use debt to fund capital requirements and investments. Table 1 of Exhibit B1, Tab 2, Schedule 1 provides credit ratings of Hydro One Inc.

Maintaining a good credit rating allows Hydro One to borrow at attractive interest rates, which benefits customers by minimizing the cost of capital.

Appendix A - Customer Delivery Point Performance Standards

1.0 INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop performance standards at the customer delivery point ("CDPP")[1] level, consistent with system wide standards, that:

- reflect typical transmission system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, load, and capacity levels;
- establish triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken; and
- establish any circumstances in which the performance standards will not apply.

On May 3, 2002, Hydro One filed proposed Customer Delivery Point Performance Standards to meet the requirements of the TSC with the OEB for review and approval. Subsequently, on September 8, 2004, as a result of stakeholder comments received, Hydro One filed amendments to its original CDPP Standards submission. On July 25, 2005, the OEB issued its Decision and Order (RP-1999-0057/EB-2002-0424) which approved Hydro One's proposed CDPP Standards subject to a number of changes directed by the Board.

[1] A Delivery Point is defined as a point of connection between a transmitter's transmission facilities and a customer's facilities.

The approved CDPP Standards apply to all existing transmission load customers (including customers that have signed a connection cost recovery agreement prior to market opening). For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement.

2.0 DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components;

- Group CDPP Standards that relate the reliability of supply to the size of load being served at the delivery point; and
- (2) Individual CDPP Standards that maintain a customer's individual historical delivery point performance.

Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unreliability and remedial action required to improve reliability. The CDPP Standards and triggers for each component are summarized in Sections 2.1 and 2.2.

2.1 Performance Standards Based on Size of Load Being Served: Group CDPP Standards

In this component, the CDPP Standards and the associated triggers are based on the size of load being served. For this purpose, the load is the delivery point's total average station gross load[2] as measured in megawatts. The CDPP Standards vary with the size of the load in groups or bands of 0 to 15 MW, greater than 15 up to 40 MW, greater than 40 up to 80 MW and greater than 80 MW, as shown in Table 1 below.

[2] Total Average Station Gross Load (MW) = (Total Energy Delivered to the Station (MWh) + Total Energy Generated at the Station Site (MWh)) / 8760 hours.

Table 1

Customer Delivery Point Performance Standards Based on Load Size

Performance Measure	Customer Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		>15 - 40 MW		>40 - 80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

These CDPP Standards are based on historical 1991-2000 performance, as measured by the frequency and duration of all momentary and sustained interruptions[3] caused by forced outages, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system. Included in this category of excluded events are the 1998 ice storm and the 2003 blackout.

[3] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Hydro One components causing load loss. Interruptions caused by Hydro One's customers are recorded but not charged against Hydro One's reliability performance for the customer initiating the interruption, but are charged against Hydro One's reliability performance for other interrupted customers.

2.1.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Group CDPP Standards

The minimum CDPP standards of performance, for each of the four load groups or bands, are used as triggers by Hydro One. The trigger occurs when the three-year rolling average of the delivery point performance falls below the minimum CDPP Standard for the delivery point of the load size group or band (referred to as a performance outlier or outlier) or when a delivery point customer indicates that analysis is required. When an outlier is identified, it is considered a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations in consultation with affected customers to determine the root cause of the unreliability and any remedial action required to improve the reliability.

2.2 Performance Standards to Maintain Historical Delivery Point Performance: Individual CDPP Standards

In this component, the CDPP Standards are intended to maintain the reliability performance levels at each customer delivery point. This is done by identifying customer delivery points with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1 above). Once identified, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is established for each delivery point based on the historical 1991-2000 average performance, plus one standard deviation (the “historical baseline”). The historical baselines exclude outages resulting from extraordinary events that have had “excessive” impact on the transmission system and strongly skew the historical trend of the measure such as the 1998 ice storm and the 2003 blackout. For delivery points that were placed in service after 1991, the in-service year is to be the first year of the 10-year period used to determine the performance baseline.

2.2.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Individual CDPP Standards

Delivery point performance that is worse than the historical baseline (for either frequency or duration) in two consecutive years is considered a performance outlier and a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and the remedial measures required to restore the historical reliability of the delivery point's performance.

2.3 Remedial Costs to Address Group and Individual Performance Outliers

For Group and Individual Performance outliers, Hydro One will cover the remedial costs of restoring and sustaining the inherent reliability performance of the existing assets. These costs include appropriate asset sustainment costs, on-going maintenance costs and costs associated with asset refurbishment or replacement. Historically, Hydro One has spent approximately $700 million per year on OM&A and Capital expenditures on the transmission system. About half of these expenditures are related to sustainment work to ensure that transmission assets are in "good" working order and able to perform as intended. These expenditures are made on an ongoing basis consistent with "good utility practices". No customer contribution formula is required for these normal sustainment expenditures.

For Individual Performance outliers, Hydro One will restore the delivery point to the historical level of performance. Hydro One's remedial work will not include capital improvements that significantly enhance the reliability inherent to the original system design or configuration of supply.

For Group Performance outliers, Hydro One's level of incremental investment for improving the performance of an outlier beyond what was designed originally will be limited to the present value of three years' worth of transformation and/or transmission line connection revenue[4]. Any funding shortfalls for improving delivery point reliability performance will be contributed by affected delivery point customers. In cases where specific transmission facilities are serving two or more customers in common with outlier performance, Hydro One will approach all affected customers to determine their willingness to contribute jointly to the reliability improvements.

Cost responsibility for these investments is to be consistent with the TSC, specifically:

1. Hydro One will not attribute the costs associated with network investment to any customer and any variance from this approach requires a determination by the Board;
2. The costs of preparing the final estimate for reliability improvements required to address performance outliers is the only portion of the technical and financial evaluation that is to be included as part of the cost of the remedial work; and
3. Where a customer contribution is required to improve or expand the transmission system to correct outlier performance, the customer will be given contracting privileges consistent with those applicable to contestability for new customer connections. In addition, affected delivery point customers are responsible for all of the costs associated with any new or modified facilities required on lines and stations they own to improve reliability. These financial and cost sharing arrangements are to be detailed in a connection and cost recovery agreement with the affected customers.

2.4 Process Timelines to Address Performance Outliers

The process and associated timelines to determine the preferred course of action to address performance outliers – both for Group and Individual outliers - is provided in Figure 1.

[4] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as a proxy in the revenue calculation.

Figure 1: Performance Outlier Process Map

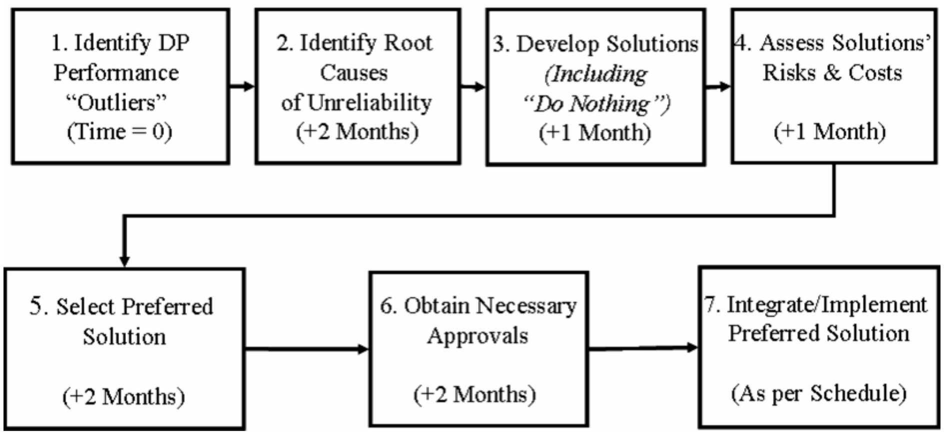


Figure 2: Performance Outlier Process

Step	Timeline	Action
1	0	Hydro One annually identifies delivery point performance "outliers" for both Group and Individual standards and notifies affected customers to solicit their feedback/issues/concerns on the reliability of supply.
2	< 2 months	Hydro One determines the root cause(s) of the reliability issue associated with each performance outlier identified in step1
3	< 1 month	Hydro One develops solutions to address performance outliers, including; (i) the restoration and sustainment of the original reliability performance of the assets; and (ii) for Group Performance outliers, discuss additional capital improvements required to improve the performance to within standard. Hydro One will discuss the proposed solutions with affected customers.
4	< 1 month	Hydro One determines the costs and assesses the risks of the solutions. Hydro One presents these costs to the customers for their review and assessment.

Step	Timeline	Action
5	< 2 months	Hydro One and customers select the preferred option and consider capital improvements that will require customer contributions identified in option (ii) above.
6	< 2 months	Hydro One and customers obtain the necessary approvals to proceed with the preferred solution.
7	Agreed to Schedule	Hydro One integrates the solution into the work program according to a mutually agreed schedule.

When Hydro One completes work to restore delivery point performance to standard, it continues to monitor the delivery point the year after the work is completed. If future performance suggests that the standard has not been met, Hydro One will review the work that has taken place and identify additional required corrective action(s).

Appendix B - Description of the Reliability Measures

Delivery Point

The delivery point is the point of supply where the energy from the Bulk Electricity System (115 kV and above) is transferred to the Distribution System or the retail customer. This point is generally taken as the low voltage bus at step-down transformer stations. For customer-owned stations supplied directly from the Transmission System, this point is generally taken as the interface between utility-owned equipment and the customer's equipment.

Forced Interruption

A Delivery Point interruption due to the disconnection as a result of an unplanned event.

Planned Interruption

A Delivery Point interruption due to the disconnection at a selected time for the purpose of construction/preventive maintenance

Momentary Interruption

Any loss of supply voltage to a delivery point that has a duration of less than one minute. These are interruptions generally restored by automatic reclosure facilities, which are of very short duration (of the order of a few seconds).

Sustained Interruption

Any loss of supply voltage to a delivery point that has a duration of one minute or more

Average Frequency of Delivery Point Interruptions

Average Frequency of Delivery Point Interruptions is an indicator of the average number of interruptions that customer experienced and presented as interruptions per delivery point per year. It is expressed mathematically as:

$$\textit{Average Frequency of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}\left(M_i + S_i\right)}{N}$$

Where:

- M_i is the total number of momentary interruptions experienced at Delivery Point i in a given year.
- S_i is the total number of sustained interruptions experienced at Delivery Point i in a given year.
- N is the equivalent total number of delivery points for a given year.

The frequency of power supply interruptions and indicators that track such performance are universally used in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption frequency indicator. Additionally, the Canadian Electricity Association (CEA) tracks the frequency of delivery point interruptions among the CEA transmission member utilities.

Average Duration of Delivery Point Interruptions

Average Duration of Delivery Point Interruptions is the average time that customers are interrupted from transmission system and presented as minutes per delivery point per year. It is expressed mathematically as:

$$\textit{Average Duration of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N} \left(\mathrm{D}_i\right)}{N}$$

Where:

- D_i is the total effective interruption duration of Sustained Interruptions experienced at Delivery Point i in a given year.
- N is the equivalent total number of delivery points for a given year.

The duration of delivery point interruptions has long been a concern to customers. It is almost universally used in some form in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption duration indicator. Additionally, the Canadian Electricity Association (CEA) tracks the duration of delivery point interruptions among the CEA transmission member utilities.

Unsupplied Energy

Unsupplied Energy is an indicator of total energy not supplied to customers due to delivery point interruptions. In order to make it comparable among different sizes of utilities, the unsupplied energy is normalized by the system peak. This measure is defined as Delivery Point Unreliability Index (DPUI). It is expressed mathematically as:

$$\textit{Delivery Point Unreliability Index} = \frac{\sum_{i=1}^{N} U_i \ x\ 60\,\mathrm{min/hr}}{Pk}$$

Where:

- U_i is the total unsupplied energy, expressed in MWh, at Delivery Point i in a given year.
- Pk is the system peak load in the year, expressed in MW.
- N is the equivalent total number of delivery points for a given year.

The unit of the measure of normalized unsupplied energy is expressed in "system minutes".

Transmission companies in Canada, the U.S., and Europe use indicators of this type to assess transmission system reliability.

<u>Transmission System Unavailability</u>

Transmission System Unavailability captures the total duration of transmission equipment out of service due to forced outages. Transmission System Unavailability due to forced outages is sub-categorized as (1) Transmission Line Unavailability, and (2) Station Equipment Unavailability, which are consistent to CEA reliability benchmarking programs.

These indicators are expressed mathematically as:

(1) Transmission Line Unavailability $= \left(\dfrac{\sum_{i=1}^{N_L} F_{L_i}}{T_L} \right) \text{x}\,100\%$

Where:

- F_{Li} is the annual forced outage duration in hours due to transmission line-related outages of circuit L_i.
- T_L is the inventory (expressed in 100 km-hours) of all in-service transmission circuits.
- N_L is the total number of in-service transmission circuits

(2) Station Equipment Unavailability $= \left(\dfrac{\sum_{i=1}^{N_S} F_{S_i}}{T_S} \right) \text{x}\,100\%$

Where:

- F_{Si} is the annual forced outage duration in hours for Major Transmission Station Equipment S_i.
- Ts is the inventory (expressed in hours) of all In-service Major Transmission Station Equipment
- N_s is the total number of in-service major transmission station equipment.

These indicators track the extent to which the transmission system including load and generation connection lines and interconnection lines is not available for use. These indicators are focused on the aspect of transmission service within Hydro One's control. It also puts the impact of outages in context with the availability of the transmission system as a whole and expresses the impact of outages in a single, easily understood indicator. Transmission companies in Canada, U.S., and in Europe use indicators of this type to assess transmission system reliability.

Appendix C - Reliability Measures Historical Performance

The latest 10 years of performance for the four reliability measures is provided in the figures below.

Figure C1
Historical Performance of Frequency of Delivery Point Interruptions

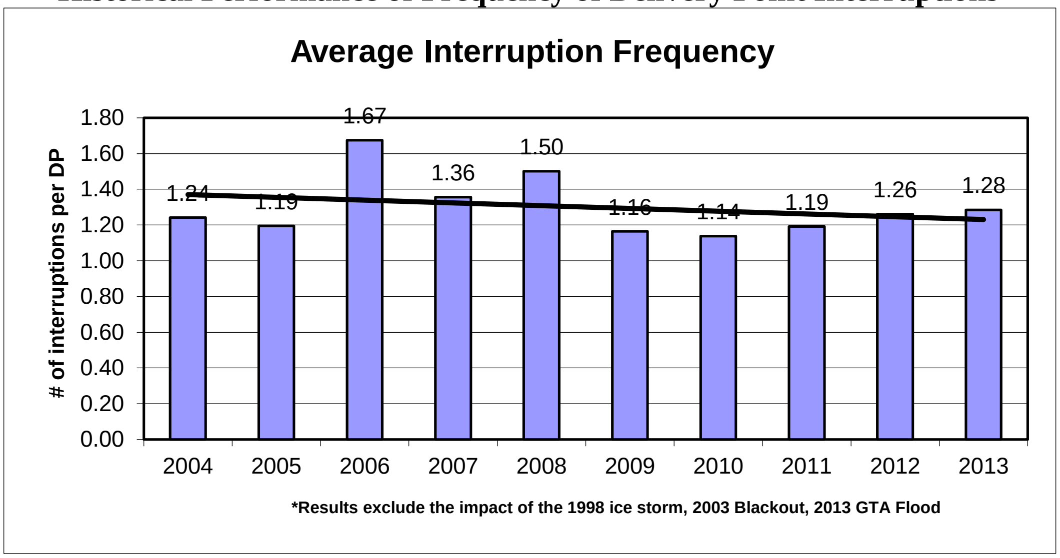


Figure C2
Historical Performance of Duration of Delivery Point Interruptions

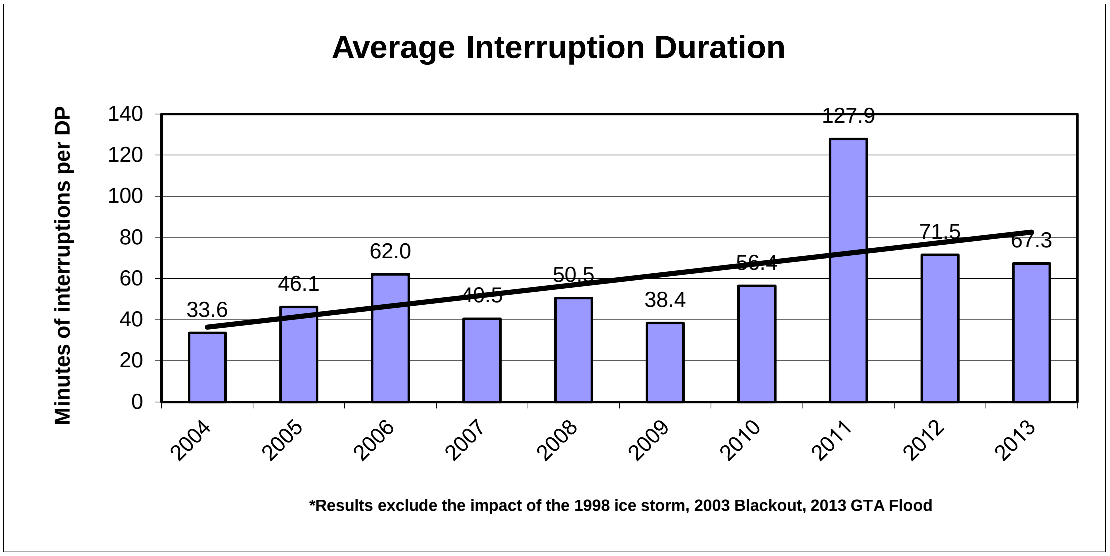


Figure C3
Historical Performance of Delivery Point Unreliability Index

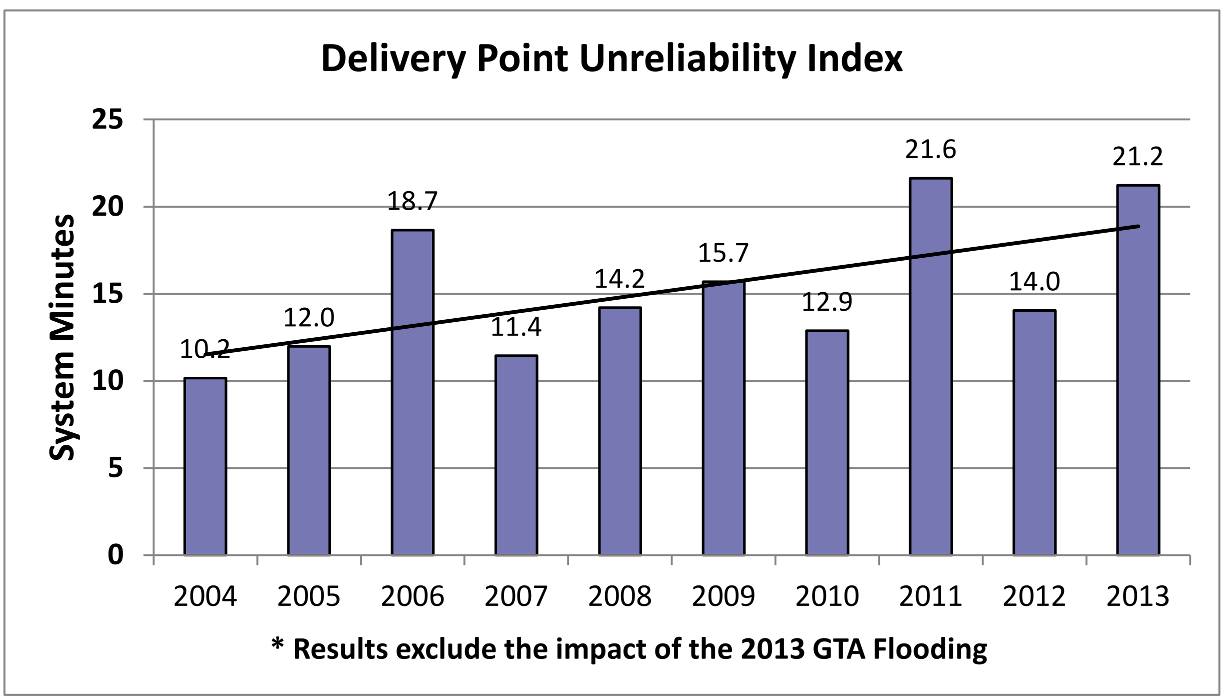


Figure C4
Historical Performance of Transmission Unavailability – Transmission Lines

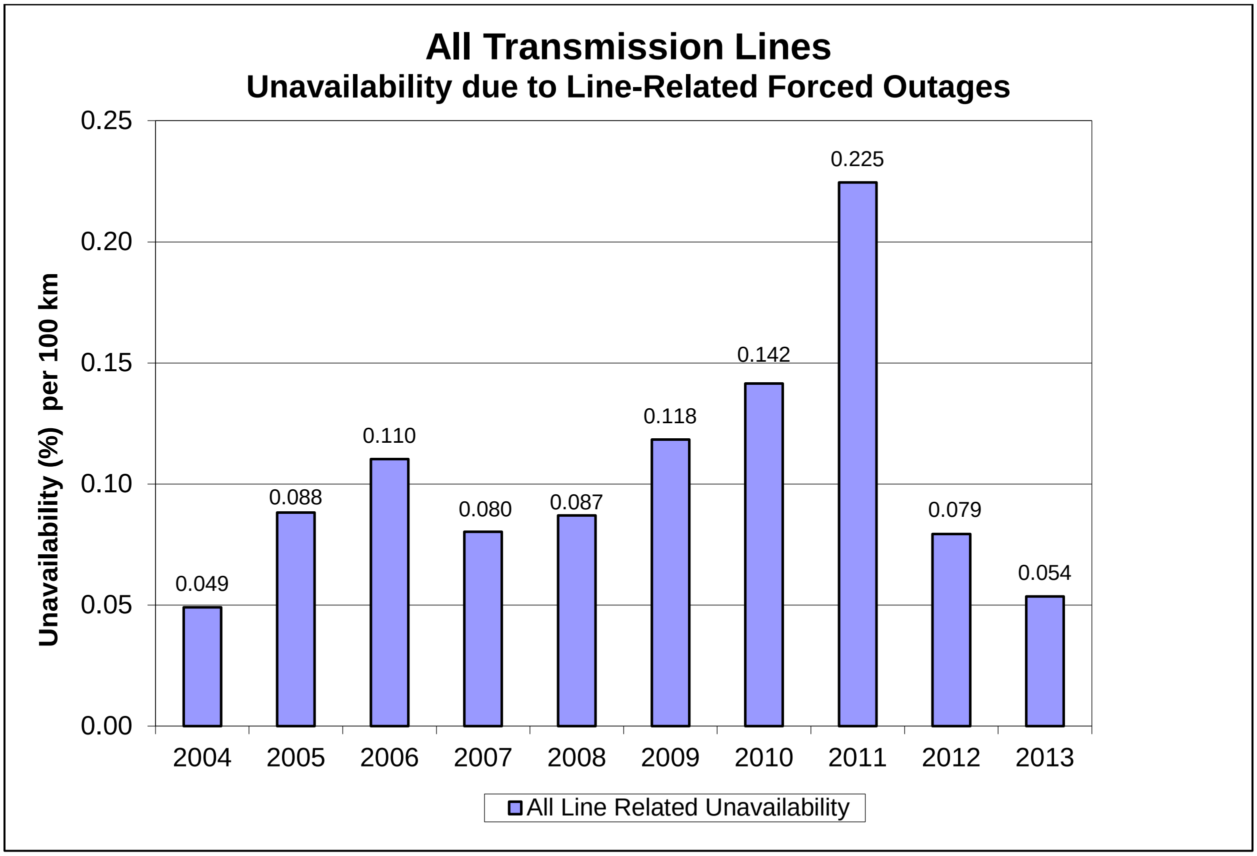
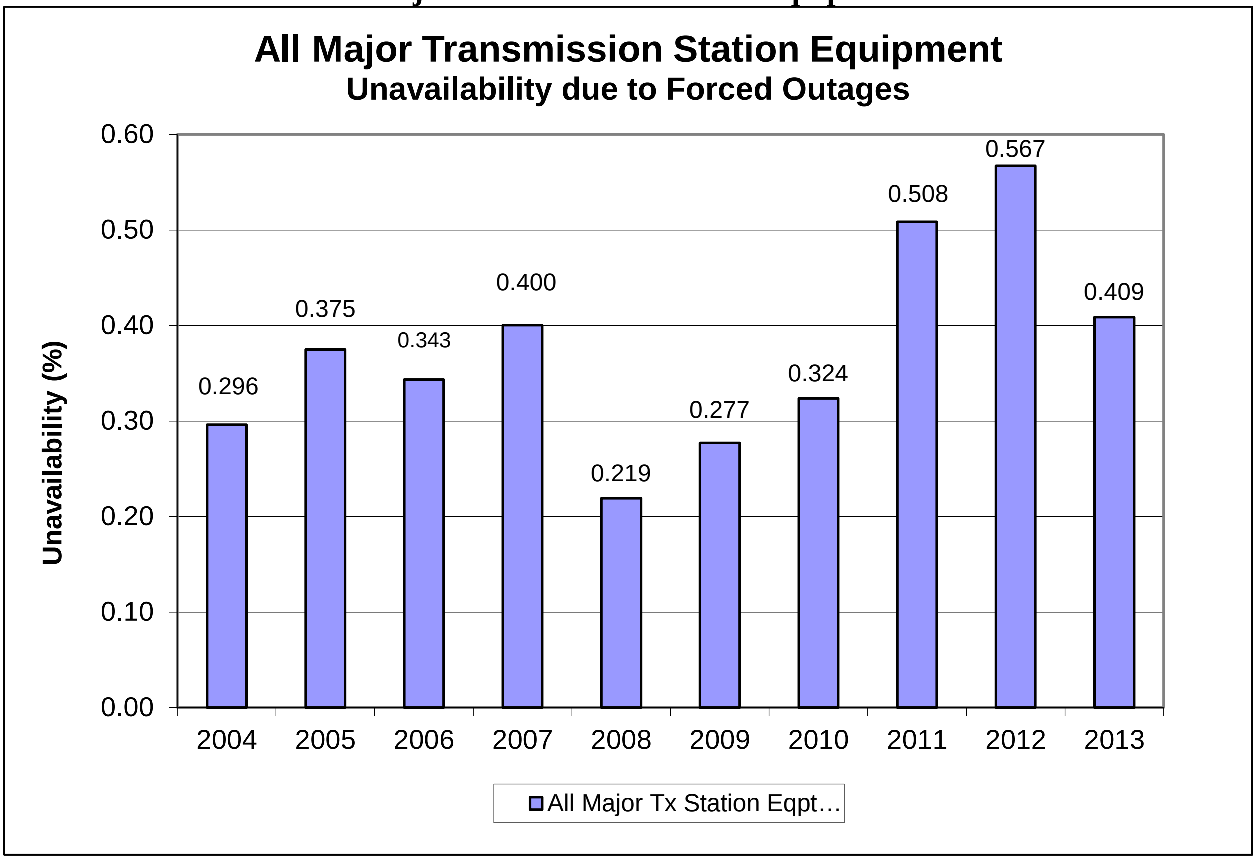


Figure C5
**Historical Performance of Transmission Unavailability **
– Major Transmission Station Equipment



OVERVIEW OF UNIFORM TRANSMISSION RATES

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002 as per the Board's Decision in Proceeding RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Ontario Uniform Transmission Rates (UTR) Schedules, which were effective on January 1, 2014 as part of the Board's Order under EB-2012-0031 issued January 9, 2014, are filed at Exhibit H2, Tab 1, Schedule 1 (Attachment 1).

Since rates are established on a uniform basis, Hydro One Transmission's requested revenue requirement for the 2015 and 2016 Test Years is a contributor to the total revenue requirement to be collected from the provincial UTRs. The revenue requirement for all the other transmitters in the province approved to participate in the UTRs must be added to that of Hydro One Transmission in order to calculate the total transmission revenue requirement for the province for the test years.[1]

The total revenue requirement from all transmitters must be allocated to the Network, Line Connection and Transformation Connection rate pools in order to establish uniform rates by pool. The revenue requirement allocated to each rate pool for the other transmitters is currently based on the proportions established by Hydro One Transmission's Cost Allocation process. Once the revenue requirement by rate pool has been established, rates are determined by applying the Provincial charge determinants for each pool to the total revenue for each pool. The Provincial charge determinants are the sum of all charge determinants, by rate pool, approved by the Board for each of the transmitters participating in the UTR.

[1] The other three transmitters currently included in the UTRs are Great Lakes Power Transmission Inc., Canadian Niagara Power Inc., and Five Nations Energy Inc.

A forecast of the 2015 and 2016 Uniform Transmission Rates is provided at Exhibit H2, Tab 1, Schedule 2 based on the values proposed for Hydro One Transmission in this application and maintaining the currently approved values for other transmitters.