

Hydro One Networks Inc.

8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

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

Susan Frank

Vice President and Chief Regulatory Officer
Regulatory Affairs



BY COURIER

November 21, 2012

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

Dear Ms. Walli:

EB-2012-0136 - Hydro One Networks Inc. 2013 IRM Distribution Rate Application – Hydro One Networks Responses to Technical Conference Questions and Update to Interrogatory Responses

Please find attached an electronic copy of written responses provided by Hydro One Networks to Technical Conference Questions. Ten (10) hard copy responses will be given to the Board prior to the Technical Conference.

I am also attaching an electronic copy of Hydro One Networks' update to Exhibit I, Tab 2, Schedule 5.05 VECC 8 page 2. Ten (10) hard copies of the blue page updates will be given to the Board prior to the Technical Conference.

Hydro One has provided written responses to Technical Conference questions that require data intensive responses. Hydro One Technical Conference participants will answer any other questions orally.

An electronic copy of the responses and the update have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Attach.

A detailed list of the Responses are provided below:

OEB Staff Question 1, Parts a, b, c	VECC Question 33
OEB Staff Question 6, Parts a, b	VECC Question 34
OEB Staff Question 10, Parts b, c	VECC Question 35
OEB Staff Question 12	VECC Question 36
OEB Staff Question 13	SEC Question 2
Energy Probe Question 5	SEC Question 4 c-d, f, g
Energy Probe Question 6, Parts a-e	SEC Question 5
Balsam Lake Coalition Question 1	SEC Question 5.1
Balsam Lake Coalition Question 2	SEC Question 7
Balsam Lake Coalition Question 3	SEC Question 8
VECC Questions 1	SEC Question 12
VECC Question 3	SEC Question 13
VECC Question 4 a-c, e, f	SEC Question 14
VECC Question 5	SEC Question 17
VECC Question 7	SEC Question 19
VECC Question 8 b-c	SEC Question 20
VECC Question 9	SEC Question 21
VECC Question 10	SEC Question 23
VECC Question 14	SEC Question 24
VECC Question 15	SEC Question 25
VECC Question 17	SEC Question 26
VECC Question 18	SEC Question 27
VECC Question 19	AMPCO Question 1
VECC Question 21	AMPCO Question 6
VECC Question 22	AMPCO Question 7
VECC Question 23	AMPCO Question 9
VECC Question 24	CCC Questions 1-6
VECC Question 27	CME Question 1
VECC Question 30	
VECC Question 31	
VECC Question 32	

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BY COURIER

October 11, 2012

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

Dear Ms. Walli:

EB-2012-0136 - Hydro One Networks Inc. 2013 IRM Distribution Rate Application – Hydro One Networks Responses to Interrogatory Questions

Please find attached an electronic copy of responses provided by Hydro One Networks to Interrogatory questions. Ten (10) hard copies will be sent to the Board shortly.

The Interrogatory Responses have been filed by Issue. Below is the Tab numbers for each Issue:

Tab 1	Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?
Tab 2	Issue 2 Should the proposed capital projects be approved for ICM treatment?
Tab 3	Issue 3 Is Hydro One's proposal with respect to the capital contribution allocated to Hydro One Transmission appropriate?
Tab 4	Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?
Tab 5	Issue 5 Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?
Tab 6	Issue 6 Is the proposed rate implementation for projects approved under the ICM, if any, appropriate?
Tab 7	Issue 7 Is the proposed calculation of the ICM rate rider, including the cost of capital parameters used in the calculation, appropriate?
Tab 8	Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and Variance Accounts appropriate?
Tab 9	Issue 9 Is Hydro One's proposed rate rider to share the impact of the income tax decrease with customers appropriate?
Tab 10	Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?
Tab 11	Issue 11 Are the proposed adjustments to the Retail Transmission Service rates appropriate?

Tab 12	Issue 12 Is Hydro One's proposal to implement the final adjustments of the Harmonization Plan in accordance with the Board's directions?
Tab 13	Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?
Tab 14	Issue 14 What is the appropriate effective date for new rates under this Application? If the effective date is prior to the date of actual implementation, what methods should be used to ensure that the amounts collected are consistent with the approved effective date?
Tab 15	Issue 15 If new rates cannot be implemented by January 1, 2013, should Hydro One's rates be declared interim, and if so, from and after what date?
Tab 16	Issue 16 What are the terms, if any, of any true-up between the amounts collected under the ICM rate rider and the actual revenue requirement associated with approved ICM projects, and how should any difference between the proposed effective date of January 1, 2013 and the actual effective date approved by the Board be reflected in that true-up calculation?
Tab 17	Issue 17 Is the proposed Tariff of Rates and Charges for 2013 appropriate?

An electronic copy of the Interrogatories and the updated exhibit, have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Attach.

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

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

Ref: Exhibit A/Tab8/Sch1 -Attachment 1

Following publication of the Notice of Application, the Board received a number of Letters of Comment from ratepayers. Please confirm whether a reply was sent from Hydro One to the authors of the letters. If confirmed, please file the replies. Please ensure that the author's contact information except for the name is redacted. If replies were not sent, please explain why responses were not sent and indicate if Hydro One intends to respond.

Response

Hydro One has responded to each individual communication sent to the Board in relation to Hydro One's Distribution Rate Change application. Redacted copies of the replies are provided as Attachment 1.

Hydro One notes that in certain cases, the concerns expressed are not directly related to the issues that will be dealt with in this Distribution IRM application but nonetheless are of concern to Ontario electricity customers, especially those on a fixed income or suffering economic hardship.

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Regulatory Affairs

Filed: October 11, 2012

EB-2012-0136

Exhibit I-1-1.01 Staff 1

Attachment 1

Page 1 of 9



BY FAX TO OEB

October 4, 2012

Dear Mr. Summers:

We are in receipt of your July 19, 2012 communication to the Ontario Energy Board regarding the recent Distribution Rate Change application.

In making our application to the OEB, the Company seeks to recover costs that will allow Hydro One to make prudent investments to meet customer needs, ensure regulatory compliance, and maintain and sustain the distribution assets system and to replace aging and end-of-life assets so that we can continue to provide safe and reliable power to the people of Ontario.

The OEB's hearing process, which was outlined in the Notice published in newspapers, provides you with ways to present your concerns and comments to the OEB. The OEB's Notice states that any comments filed on this application will be "provided to OEB members deciding the application" so you can be certain that your views will be part of the OEB's deliberations in deciding this application.

If you need more information on the review process and ways to participate, you can visit the OEB's website at <http://www.ontarioenergyboard.ca> or call the OEB's Consumer Relations Centre at 1-877-632-2727.

If you require further details of our application, Hydro One's complete application is available on our website at <http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx>.

Thank you,

ORIGINAL SIGNED BY SUSAN FRANK

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BY EMAIL

October 4, 2012

Dear Mr. Abramowitz:

We are in receipt of your July 26, 2012 email to the Ontario Energy Board regarding Hydro One's recent Distribution Rate Change application.

In making our application to the OEB, the Company seeks to recover costs that will allow Hydro One to make prudent investments to meet customer needs, ensure regulatory compliance, and maintain and sustain the distribution assets system and to replace aging and end-of-life assets so that we can continue to provide safe and reliable power to the people of Ontario.

The OEB's hearing process, which was outlined in the Notice published in newspapers, provides you with ways to present your concerns and comments to the OEB. The OEB's Notice states that any comments filed on this application will be "provided to OEB members deciding the application" so you can be certain that your views will be part of the OEB's deliberations in deciding this application.

If you need more information on the review process and ways to participate, you can visit the OEB's website at <http://www.ontarioenergyboard.ca> or call the OEB's Consumer Relations Centre at 1-877-632-2727.

If you require further details of our application, Hydro One's complete application is available on our website at <http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx>.

Thank you,

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BY LETTER

October 4, 2012

Al Aubry



Dear Mr. Aubry:

We are in receipt of your email dated July 16, 2012 to the Ontario Energy Board regarding the recent Distribution Rate Change application.

In making our application to the OEB, the Company seeks to recover costs that will allow Hydro One to make prudent investments to meet customer needs, ensure regulatory compliance, and maintain and sustain the distribution assets system so that we can continue to provide safe and reliable power to the people of Ontario.

In relation to your comments on seasonal customers, their delivery costs include fixed monthly delivery charges. These fixed charges are meant to recover, amongst other things, billing related costs, which are independent of your electricity consumption, as well as the cost of having assets such as poles and lines in place to deliver electricity when and as required.

Regarding your comments on line loss adjustments, these factors have been set in prior proceedings and will not be reviewed as part of the current application. HST is applied on customer bill line items according to Provincial Tax Rules.

The OEB's hearing process, which was outlined in the Notice published in newspapers, provides you with ways to present your concerns and comments to the OEB. The OEB's Notice states that any comments filed on this application will be "provided to OEB members deciding the application" so you can be certain that your views will be part of the OEB's deliberations in deciding this application.

If you need more information on the review process and ways to participate, you can visit the OEB's website at <http://www.ontarioenergyboard.ca> or call the OEB's Consumer Relations Centre at 1-877-632-2727.

If you require further details of our application, Hydro One's complete application is available on our website at <http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx>

Thank you,

ORIGINAL SIGNED BY SUSAN FRANK

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Regulatory Affairs



BY LETTER

October 4, 2012

Richard Bensch
[REDACTED]

Dear Mr. Bensch:

We are in receipt of your email dated July 20, 2012 to the Ontario Energy Board regarding the recent Distribution Rate Change application.

In making our application to the OEB, the Company seeks to recover costs that will allow Hydro One to make prudent investments to meet customer needs, ensure regulatory compliance, and maintain and sustain the distribution assets system and to replace aging and end-of-life assets so that we can continue to provide safe and reliable power to the people of Ontario.

Regarding your concerns on line loss adjustments, these factors have been set in prior proceedings and will not be reviewed as part of the current application.

The OEB's hearing process, which was outlined in the Notice published in newspapers, provides you with ways to present your concerns and comments to the OEB. The OEB's Notice states that any comments filed on this application will be "provided to OEB members deciding the application" so you can be certain that your views will be part of the OEB's deliberations in deciding this application.

If you need more information on the review process and ways to participate, you can visit the OEB's website at www.oeb.gov.on.ca or call the OEB's Consumer Relations Centre at 1-877-632-2727.

If you require further details of our application, Hydro One's complete application is available on our website at <http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx>

Thank you,

ORIGINAL SIGNED BY SUSAN FRANK

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BY LETTER

October 4, 2012

Peter King
[REDACTED]

Dear Mr King:

We are in receipt of your July 17, 2012 letter to the Ontario Energy Board regarding the recent Distribution Rate Change application.

In making our application to the OEB, the Company seeks to recover costs that will allow Hydro One to make prudent investments to meet customer needs, ensure regulatory compliance, and maintain and replace the Company's assets so that we can continue to provide safe and reliable power to the people of Ontario.

In regards to your specific billing situation, the delivery charges in each of the bills included in your communication include 3 months of fixed delivery charges. These fixed charges are meant to recover, amongst other things, billing related costs, which are independent of your electricity consumption, as well as the cost of having assets such as poles and lines in place to deliver electricity to you when and as required.

The OEB's hearing process, which was outlined in the Notice published in newspapers, provides you with ways to present your concerns and comments to the OEB. The OEB's Notice states that any comments filed on this application will be "provided to OEB members deciding the application" so you can be certain that your views will be part of the OEB's deliberations in deciding this application.

If you need more information on the review process and ways to participate, you can visit the OEB's website at <http://www.ontarioenergyboard.ca> or call the OEB's Consumer Relations Centre at 1-877-632-2727.

If you require further details of our application, Hydro One's complete application is available on our website at <http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx>

Thank you,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
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Susan Frank

Vice President and Chief Regulatory Officer
Regulatory Affairs



BY LETTER

October 4, 2012

Ms Diana Kwiatkowski
[REDACTED]

Dear Ms Kwiatkowski:

We are in receipt of your August 8, 2012 letter to the Ontario Energy Board regarding the recent Distribution Rate Change application.

In making our application to the OEB, the Company seeks to recover costs that will allow Hydro One to make prudent investments to meet customer needs, ensure regulatory compliance, and maintain and sustain the distribution assets system and to replace aging and end-of-life assets so that we can continue to provide safe and reliable power to the people of Ontario. We are very sensitive to the impact of rate increases on our customers so we are working to ensure that the level of funding requested balances system requirements with a concern for customer rate increases given the current economic climate.

In response to your specific questions about the Customer Information System project, the project was awarded through a public tendering process. The CIS capital expenditures will replace an outdated billing system. . The asset will be included in the base and this system will provide operational benefits and savings.

The OEB's hearing process, which was outlined in the Notice published in newspapers, provides you with ways to present your concerns and comments to the OEB. The OEB's Notice states that any comments filed on this application will be "provided to OEB members deciding the application" so you can be certain that your views will be part of the OEB's deliberations in deciding this application.

If you need more information on the review process and ways to participate, you can visit the OEB's website at <http://www.ontarioenergyboard.ca> or call the OEB's Consumer Relations Centre at 1-877-632-2727.

If you require further details of our application, Hydro One's complete application is available on our website at <http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx>.

Thank you,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
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Susan Frank

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Regulatory Affairs



BY LETTER

October 4, 2012

Jeremi Schembri
Town of Caledon



Dear Mr Schembri:

We are in receipt of your August 13, 2012 letter to the Ontario Energy Board (OEB) regarding the recent Distribution Rate Change application and your concerns about the proposed increase in the delivery costs for street lights accounts.

In making our application to the OEB, the Company seeks to recover costs that will allow Hydro One to make prudent investments to meet customer needs, ensure regulatory compliance, and maintain and sustain the distribution assets system and to replace aging and end-of-life assets so that we can continue to provide safe and reliable power to the people of Ontario.

In relation to your concerns about street lights accounts the OEB is studying the street lighting charges and any changes to the cost allocation would wait for the results of that study. The current Distribution Rate Change Application is based on an OEB approved model, which establishes the changes to all rate classes, including street lighting.

The OEB's hearing process, which was outlined in the Notice published in newspapers, provides you with ways to present your concerns and comments to the OEB. The OEB's Notice states that any comments filed on this application will be "provided to OEB members deciding the application" so you can be certain that your views will be part of the OEB's deliberations in deciding this application.

If you need more information on the review process and ways to participate, you can visit the OEB's website at <http://www.ontarioenergyboard.ca> or call the OEB's Consumer Relations Centre at 1-877-632-2727.

If you require further details of our application, Hydro One's complete application is available on our website at <http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx>.

Thank you,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Vice-President and Chief Regulatory Officer
Regulatory Affairs
Hydro One Networks Inc.

Energy Probe (EP) INTERROGATORY #1 List 1

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 1 – Threshold Test

- a) Please provide a table showing 2010 and 2011 Actual inputs to the formula-Rate base, Revenue Requirement, Depreciation.
- b) Please revise the Threshold calculation using 2011 Actuals as the base year inputs (except growth).

Response

- a) The table below sets out, as requested, the Rate Base and Depreciation for 2010 and 2011 actuals. Revenue Requirement is a forward looking calculation and is not applicable when reviewing actual results.

<i>Actuals (\$M)</i>	2010	2011
Rate Base	4,767.8	4,969.4
Depreciation	259.7	264.4

- b) Using actual 2011 depreciation and rate base, the revised threshold calculation yields an answer of \$308.4M.

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

Issue 1 **Has Hydro One appropriately applied the IRM mechanism as specified by the Board?**

Interrogatory

Reference: **Exhibit A, Tab 2, Schedule 1, page 3**

Preamble: The Application states -“the Applicant may seek meetings with Board staff in an attempt to identify and reach agreements to settle issues arising out of this Application”.

- a) To date has HON held any meetings with Board staff to discuss its Application? If yes, please indicate how these informed the preparation of the Application.
- b) Now that HON has filed its Application, what does HON consider to be role of Board staff in settling issues arising from the Application that meetings would be required?

Response

- a) Yes. Hydro One had held meetings with Board staff to discuss the timeline of this application. Detailed content of this application was not discussed and therefore these meetings did not affect the preparation of the application (other than timing and schedule).
- b) Hydro One believes that settling of issues does not require additional meetings with Board staff.

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

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, page 2

Preamble: HON states that its Application is substantially consistent with the requirements of the 2006 Electricity Distribution Rate Handbook and the Board's 2012 Filing Guidelines.

- a) Where, in HON's view, does the Application diverge from the requirements of the 2006 Rate Handbook and the 2012 Filing Guidelines?
- b) Is the Application fully consistent with the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors dated July 14, 2008 and the related Supplementary Reports and Addendums?
- c) If not, please indicate those specific areas where HON does not consider its Application to be consistent and explain why.

Response

- a) Hydro one believes that the application does not diverge from the requirements of the 2006 Rate Handbook. In respect to 2012 Filing Guidelines, please refer to Exhibit I, Tab 2, Schedule 1.05 Staff 6.
- b) c)
Hydro One believes that the application is consistent with the spirit and the intent of the approach that the Board provided in the July 2008 Report which is to provide a mechanism to fund non-discretionary capital to provide reliable and safe service to customers. Hydro One has also included the Density Study which is not considered by the July 2008 Report.

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

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

Reference: Exhibit A, Tab 5, Schedule 1

- a) Please provide a schedule that sets out the derivation of HON Distribution's actual 2011 rate base, return on rate base and return on equity.

Response

Actual results from 2011 showed a Rate Base of \$4,969.4M

Actual Common Equity is only available on a GAAP basis wherein Equity equals Assets less allocated Liabilities. Using this approach as has been done in previous proceedings, yields a Return on Rate Base of 4.7% and Return on Equity of 11.4%.

Power Workers Union (PWU) INTERROGATORY #1 List 1

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

Ref (1): Exhibit B/Tab 1/Schedule 2/Page 1/Lines 6-9 (Calculation of Incremental Capital Module Revenue Requirement).

In calculating the revenue requirement for the proposed ICM introduced in Exhibit B, Tab 1, Schedule 1, the methodology applied is generally consistent with Board requirements as outline in Chapter 3 of “the Filing Requirements for Transmission and Distribution Applications”, dated June 28, 2012.

Ref (2): Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications. Last Revised on June 28, 2012.1 Chapter 3, Pages 9-10.

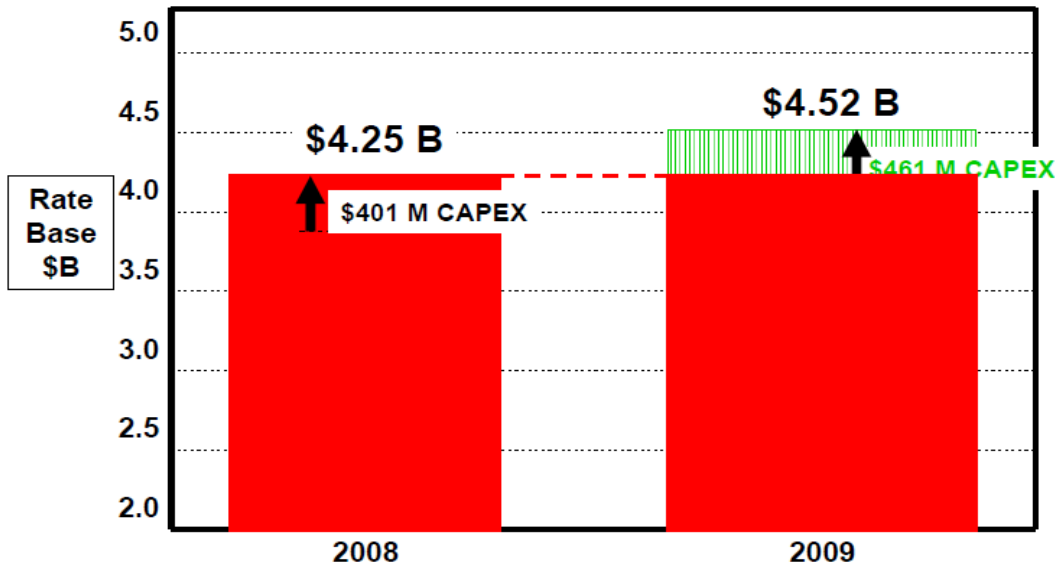
2.2.5 ICM Filing Guidelines

The Board requires that a distributor requesting relief for incremental capital during the IRM3 plan term must include comprehensive evidence to support the claimed need, which should include the following:

- 1. An analysis demonstrating that the materiality threshold test has been met ...**
- ...**
- 2. Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth);**
- ...**

Ref (3): EB-2008-0187/Exhibit K1.15/Page 1

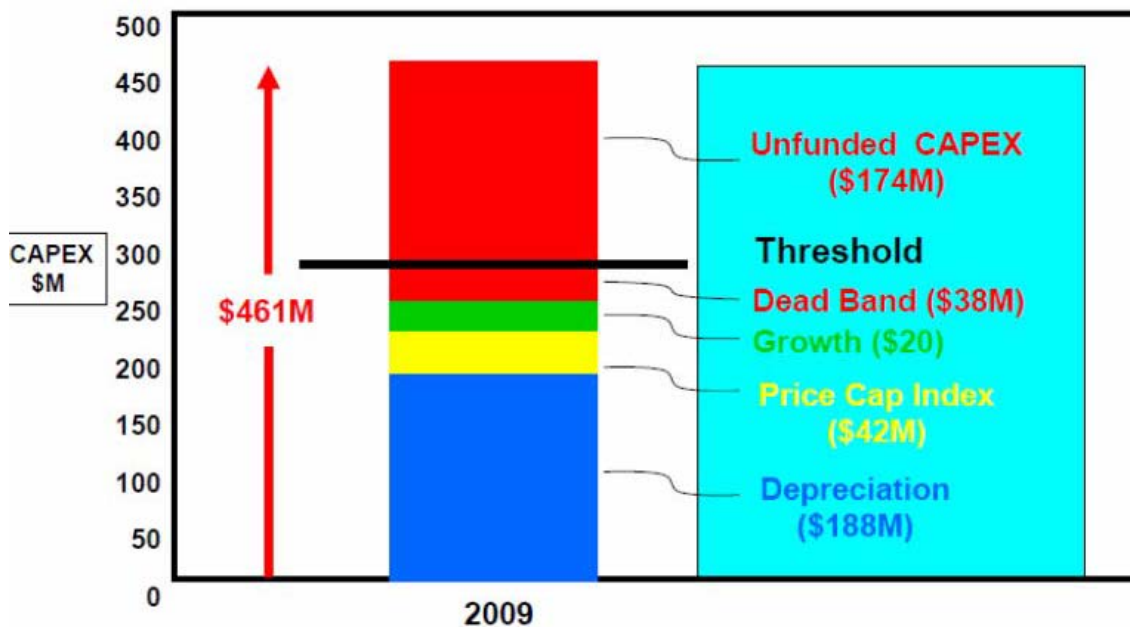
HYDRO ONE'S 3GIRM: CHANGE IN RATE BASE



1

1

HYDRO ONE'S 3GIRM: CALCULATION OF THRESHOLD



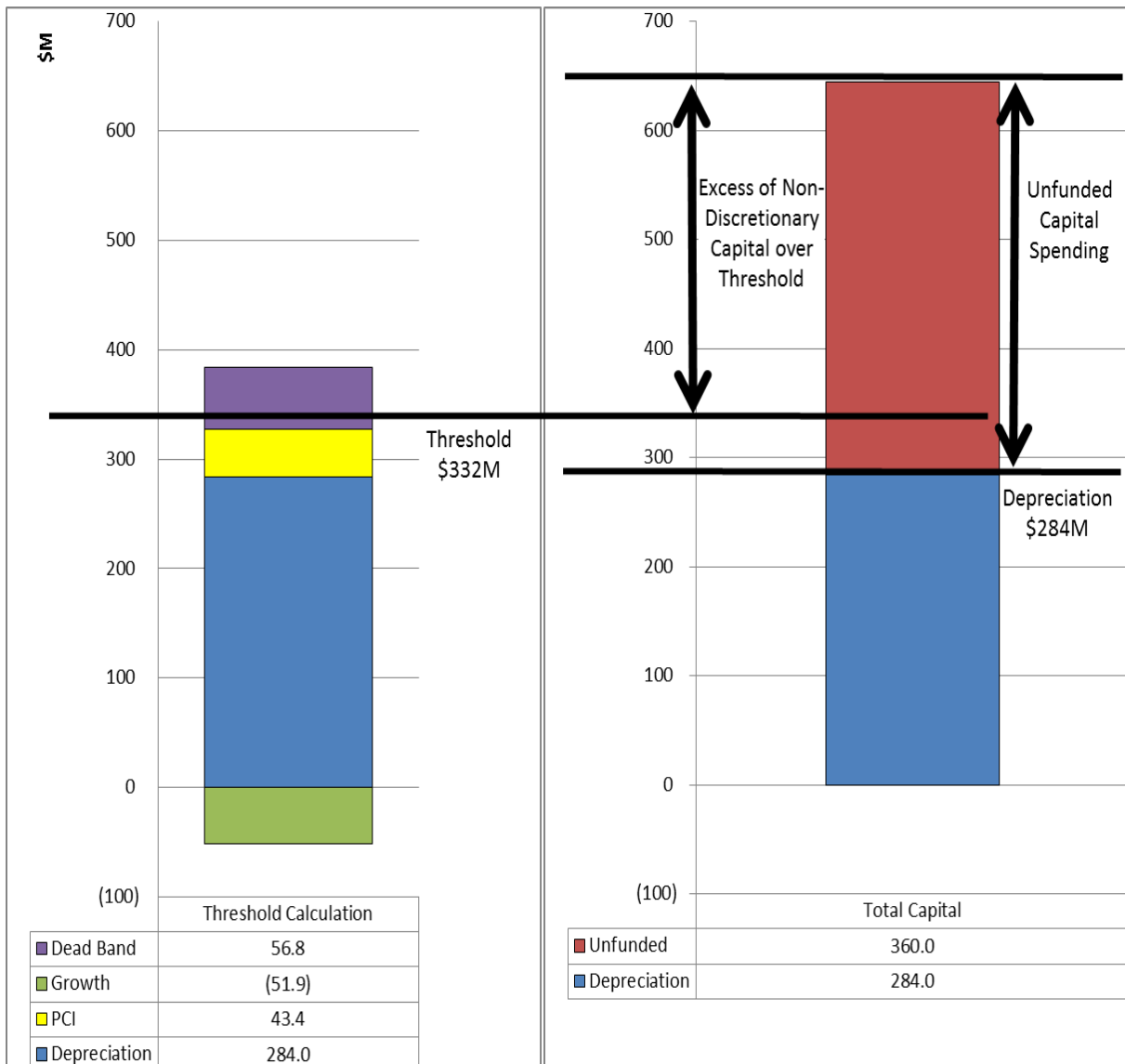
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a) Please illustrate how Hydro One's ICM application meets the OEB's ICM materiality threshold and how the incremental revenue requested will not be recovered through other means using the approach used in EB-2008-0187, Exhibit K1.15. Please provide explanation.

Response

Total non-discretionary capital is \$644M. The threshold value is determined to be \$332M (see below). Non-discretionary capital exceeds the threshold therefore ICM is triggered.

The short fall in Rate Base is \$360M. Hydro One has no other means by which it can fund the proposed, non-discretionary capital spend.



Consumers Council of Canada (CCC) INTERROGATORY #1 List 1

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

Ex. A/T2

Please provide all materials provided to HON's Board of Directors when seeking approval of the current application.

Response

Hydro One is providing a redacted version of the following documents:

- Attachment 1 - the submission to the Board of Directors regarding the 2012 Budget and Corporate Scorecard Measures Update
- Attachment 2 - the submission to the Regulatory and Public Policy Committee of the Board of Directors regarding 2013 and 2014 Distribution IRM Rate Application Update.

Hydro One has filed the attached interrogatory request pursuant to the Board's Practice Direction on Confidential Filing. Hydro One's Disclosure Policy, as well as applicable securities legislation, prohibits the release of non-public, financial information on a selective bases to individuals or groups of individuals.

Hydro One Inc.
Submission to the Board of Directors

Date: April 5, 2012

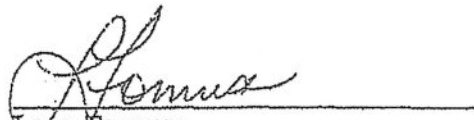
Subject: 2012 Budget and Corporate Scorecard Measures Update

Submitted by:

Approved for Submission to the Board by:



Sandy Struthers
Executive Vice President and
Chief Financial Officer



Laura Formosa
President and Chief Executive Officer

RECOMMENDATION

THAT the Board of Directors of Hydro One Inc. ("Hydro One" or the "Company") approve the updated 2012 Budget, including the associated revised Net Income and Corporate Scorecard measures for the year. The 2012 Budget and 2013-2014 Outlook reflect the Company's regulatory filings for 2012 and proposed Transmission and Distribution regulatory filings for 2013 and 2014.

KEY HIGHLIGHTS

- Hydro One received, on March 23rd, approval of its Cost of Service (COS) Distribution application filed December 1, 2011 on a single item requesting the use of US GAAP for its Distribution business commencing January 1, 2012. The use of US GAAP for accounting and regulatory purposes is consistent with the November 2011 approved Business Plan and mirrors the OEB decision for the Transmission business received November 23, 2011.
- The November 2011 Hydro One Board-approved business plan assumed that the Company would file a COS Distribution rate application for 2012 and 2013 and a Transmission COS rate application for 2013 and 2014. The Company will file a Transmission COS rate Application in April 2012 for rates effective January 1, 2013.
- Subsequent regulatory decisions by the OEB, including the approval of the COS Distribution application to record costs in US GAAP and revised cost of capital inputs (i.e. future income tax rate changes), have resulted in the Distribution rate increase being requested for 2012 being below the required regulatory rate threshold for a COS application. As a result, the

Company is subject to an Incentive Regulatory Mechanism (IRM) for Distribution rate making purposes for rates effective January 2012, 2013 and 2014.

- The Company has chosen, at its option and after consideration of the impact on its customers, not to file an IRM application for 2012 and will continue to have its 2011 approved rate schedules apply for 2012. The Company will file IRM applications for 2013 and 2014, the remaining two years of the IRM period, seeking to recover costs and returns associated with the Advanced Distribution System (smart grid) and in-service capital investments. The Company will be required to file a COS application for its Distribution business in 2014 which will rebase its rates effective January 1, 2015
- As a result of these changes in assumptions, and subsequent changes to future income tax rates, the 2012 budgeted revenues will increase by \$40 million to \$5,658 million and 2012 net income will increase by \$29 million to \$643 million
- Distribution and Transmission work programs for 2012, 2013, and 2014 remain unchanged from the November-approved Business Plan
- The impact of the changes to the Budget and the Outlook are discussed in the attached Schedule A.
- The 2012 Corporate Scorecard target for Transmission Unit and Distribution Unit Costs remains unchanged at 10.1% (Capital and OM&A per Asset) and \$9,900/Km (Capital and OM&A costs per Km of line) respectively. Net Income will increase to \$643 million from \$614 million.

This Board Memorandum was reviewed and approved for submission to the Board of Directors of Hydro One Inc. by the Audit and Finance Committee at a joint meeting with the Regulatory and Public Policy Committee on April 4, 2012.

EXECUTIVE SUMMARY

1. Strategic Significance

The Budget establishes the level of OM&A and capital expenditures for the year, as well as net income and critical financial metrics. The measures in the Corporate Scorecard are designed to ensure that the corporate strategy is achieved over a specified time period. Net income is measured in the Corporate Scorecard.

2. Purpose

In November 2011, Management stated it would revise and resubmit to the Board of Directors for consideration and approval a revised Budget in the event that decisions were made or events occurred following Board approval that would have a material impact. The Budget and Outlook are now revised to reflect the OEB's decisions with respect to Cost of Capital as it relates to Transmission COS rate applications during the Outlook years and the impact of IRM to Distribution rates during the Budget and Outlook period.

3. Cost Estimate and Recovery

The Appendix includes a schedule which identifies the adjustments made in revising the 2012 proposed budget. A summary of the key financial results is as follows:

SM except where noted	Budget Approved				Change November to April
Revenue					
Income before PILs					
Net Income					
EBITDA					
Cash Flow					
Debt Ratio					
FFO Coverage					
Actual Rate Base					
ROE (GAAP)					
Capital Expenditures					
OM&A					
Dividends					
PILs					
Total Long-Term Debt					
Total Equity					

Except as outlined below, the proposed 2012 Budget is consistent with the Budget presented at the November 2011 meeting of the Board of Directors.



4. Regulatory

By not filing an IRM application for 2012 Distribution rates, Hydro One's Distribution business will continue to earn revenues in 2012 based on the 2011 approved rate schedules which were derived from the 2011 COS rate revenue application. The 2011 Distribution COS rates were based on a 9.66% regulated Return on Equity, which has since been updated and reduced.

IRM applications will be made for Distribution rates effective January 1, 2013 and 2014. The requested rate increases will be based on the 2011 approved rate schedule and will include a Smart Grid (Advanced Distribution System) adder and seek recovery through an Incremental Capital Module (ICM) rider for incremental in-service additions.

The OEB-approved 2012 Transmission COS application has a 9.42% regulated Return on Equity. In 2013, the revised regulated Return on Equity, based on the OEB updated Cost of Capital calculations, would be 9.16% as compared to the regulated Return of Equity included in the November Board-approved Outlook of 9.70%. In 2014, the revised regulated Return on Equity will be 9.44% as compared to the November Board-approved Outlook of 10.20%

5. Risk Analysis

There are a number of risks that could impact the accomplishment of this Budget. These are consistent with the operating and business risks identified in the Budget brought forward to the Board of Directors in November 2011.

The financial impact of OEB decisions with respect to rate applications for the Outlook period will be known in advance as rate decisions are rendered prior to the applicable rate year. Any operating and business risks associated with those decisions will be discussed with the Hydro One Board when they are known.

Schedule A

Hydro One Inc.

2012 Budget and 2013/2014 Outlook (Amended April 5, 2012)

1. INTRODUCTION

The 2012 Budget and 2013/2014 Outlook approved by the Hydro One Board of Directors on November 10, 2011 have been updated to reflect current regulatory assumptions consistent with the proposed rate applications for 2012(no rate application in this year), 2013 and 2014. The impacts of the changes are as noted in the table presented below:

SM except where noted	Budget Approved				
Revenue					
Income before PILs					
Net Income					
EBITDA					
Cash Flow					
Debt Ratio					
FFO Coverage					
Actual Rate Base					
ROE (GAAP)					
Capital Expenditures					
OM&A					
Dividends					
PILs					
Total Long-Term Debt					
Total Equity					

This update is consistent with the expectation that if subsequent to the approval of the Budget, information arises or decisions are made that materially impact the original assumptions of the November-approved Business Plan, then the Budget would be revised and resubmitted to the Hydro One Board of Directors for their consideration and approval.

2. CHANGES TO BUSINESS PLAN ASSUMPTIONS

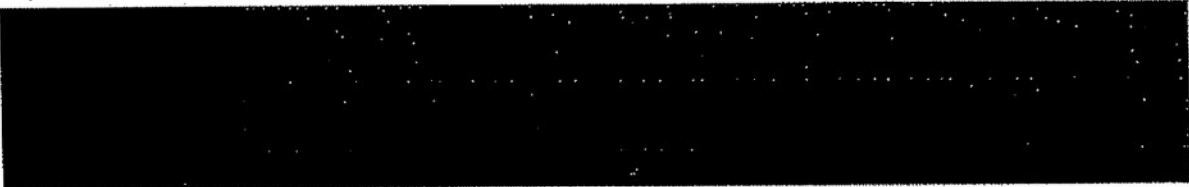
The following significant changes have been made to the Budget and Outlook assumptions as previously presented:

	November 2011	April 2012	Explanation
Cost of Capital Allowed Return on Equity (Transmission and Distribution)	2012: 9.42% 2013: 9.70% 2014: 10.20%	2012: 9.42% 2012: for rates effective after May 1 st : 9.12% 2013: 9.16% 2014: 9.44%	In February 2012, the OEB updated its cost of capital rates to reflect lower long term bond rates. The updated financial results reflect the OEB's updates to cost of capital parameters as well as revisions to interest rates per the February 2012 consensus forecast.
Rate Application methodology for Distribution Rates	Cost of Service Rate application for 2012 and 2013	No rate application in 2012 – existing approved 2011 rate schedules applied in 2012; IRM application for 2013 and 2014	The Company chose not to file a cost of service rate application in 2012. Approved 2011 rate schedules continue to be applied in 2012 with no rate increase to customers. In 2013 and 2014, the Company will be under an IRM regime. Rates will be rebased in 2015 through a COS application
Corporate Tax Rates	Provincial Corporate tax rates would be reduced to 10% in 2013	Corporate tax rates frozen at 11.5%	Corporate taxes are adjusted pursuant to the March 2012 Ontario Budget
Load Impacts	Declines in load impact would have increased transmission rates by 0.8% in 2013	Revised load forecasts indicate load impacts in 2013 will increase and reduce rates by 0.4%	A load review completed in February 2012 indicates that projected load reductions will not occur as originally forecast

The revised assumptions reflect OEB-mandated changes to the Cost of Capital which are set by the OEB at various points during the year for rates applicable January 1st or May 1st. The Cost of

Capital parameters are used to arithmetically calculate allowed rates of return on equity, interest costs and revenue requirements under a COS filing. The revised amounts reflect the decline in long bond rates which occurred in fourth quarter 2011 and have continued in 2012.

Recent OEB regulatory decisions have confirmed how the OEB would apply rules concerning the application of when an IRM rate regime would be applied. Under these rules, Company would be required to file its distribution rate application for 2012, 2013 and 2014. Under an IRM regime, existing 2011 approved rate schedules are adjusted annually according to a formula which recognizes cost inflation and productivity factors.



3. IMPACT TO 2012 BUDGET

The assumptions underlying the 2012 Budget for the Transmission Business have not changed from the results presented and approved in November 2011 and there has been no material change in the financial results of the Transmission Business for 2012.



While the Company was eligible to file for IRM-based rates in 2012, it chose not to and in so doing saved its customers from the impact a 0.9% tariff increase for which the Company would have been eligible under an IRM application.

With respect to the Corporate Scorecard, small changes recorded in Capital Expenditures and OM&A in 2012 reflect minor changes in respect to the implementation of IFRS at Hydro One Brampton. These changes to Capital Expenditures and OM&A do not impact the 2012 Corporate Scorecard.

4. IMPACT TO OUTLOOK YEARS

The financial performance in the Outlook years for the Transmission Business reflects the change in assumptions noted above. Balances forward for 2013 have also been adjusted to reflect actual and projected in service capital amounts. The resulting impact of the changes in the assumptions, the most significant of which are the lower allowed rate of return and debt costs, higher export credit amounts and higher projected load, is that the requested increase in transmission tariffs for 2013 decline from 7.0% in to 0.8% and as a result of the lower cost of capital assumptions in 2014 requested rates of 10.2% decline to 9.0%.

Embedded within the 2013 Transmission rate application is the use of a new depreciation study which extends the life of the assets and reduces the annual recoverable depreciation expense. If the new depreciation study is not approved, the existing depreciation rates would continue and the tariff increase required would be 2.4%.

The financial performance in the Outlook years for the Distribution Business is most impacted by the requirement that the Company fall under an IRM regime for 2012, 2013 and 2014. During this period, the approved rates are based on the approved 2011 rate schedule adjusted for inflation and a productivity factor. On an annual basis the IRM adjustment to rates is calculated as a 0.9% tariff increase.

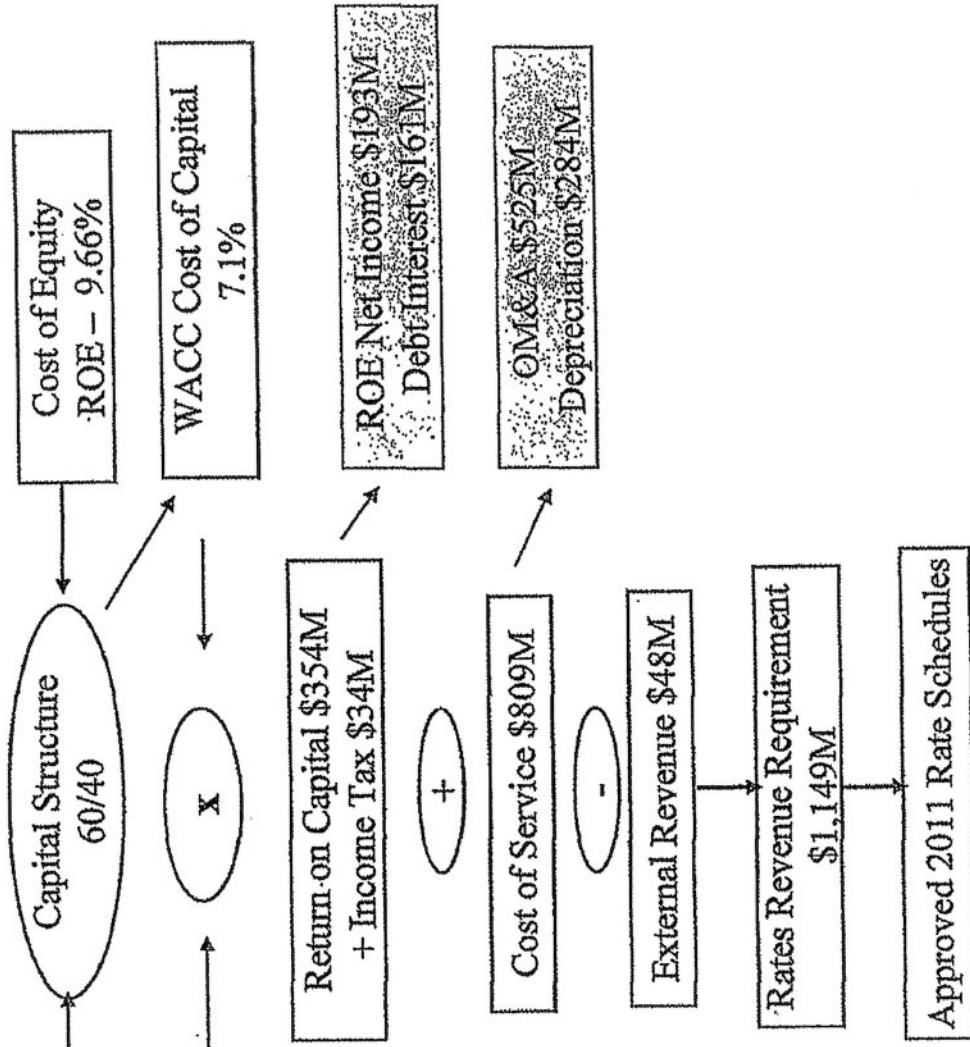
The Company did not file in 2012 but plans to file an IRM with an ICM, requesting the recovery of all in-service capital in excess of book depreciation, for 2013 and 2014. The in-service capital requested will be consistent with previous capital spending levels already approved by the OEB in the 2011 Distribution COS application. The net increase in in-service capital in 2013 of \$361 million and [REDACTED] will be sought as an ICM rider and will increase rates by 2.4% in 2013 and [REDACTED] on top of the IRM adjustment. This is consistent with the position Hydro One is supporting as part of the OEB's Renewed Regulatory Framework initiative.

Hydro One will also request the re-instatement of a smart grid rider to recover the OM&A costs of approximately \$20 million for the smart grid program/Advanced Distribution System and the continuation of the associated variance account in 2013. This will add 1.6% to the IRM and ICM rate request for 2013. [REDACTED]

Distribution Tariffs %	2012	2013			
2013 [REDACTED] with ICM for all In-service Capital above Depreciation & SG Rider	(0.2)	4.9	[REDACTED]		
No IRM filing for 2013 or [REDACTED]	(0.2)	0.0			

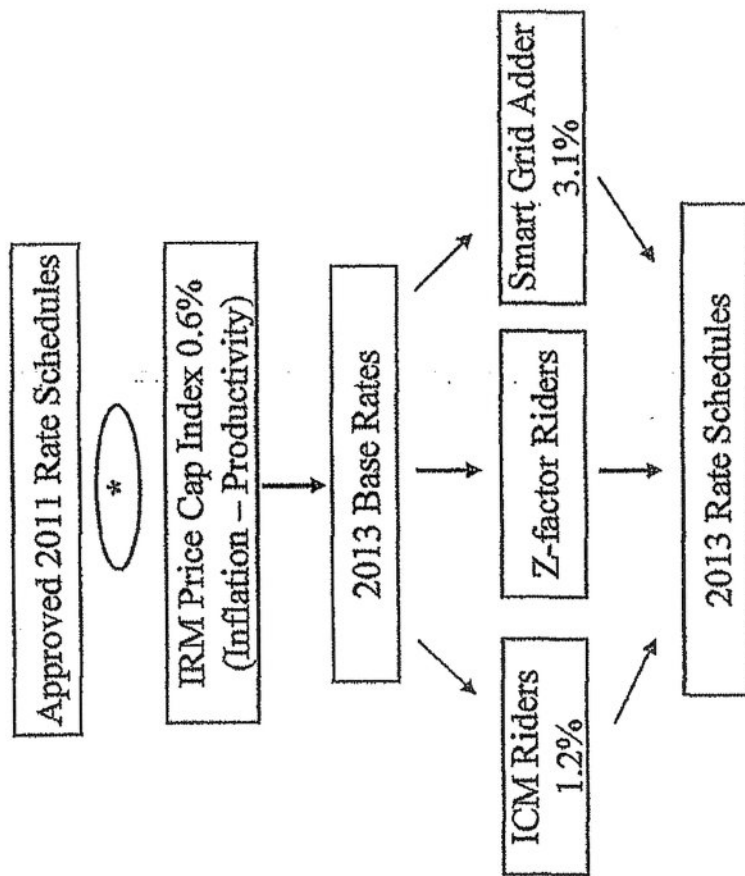
2012-14 Business Plan April Update

Approved 2011 Distribution Revenue - Cost of Service Requirement



OEB approved	
\$ million	
net income	193
PIUs	34
Depreciation	284
Interest	161
OM&A	525
External Revenue	(48)
Revenue	1,149
Rate base	4,987
Equity	1,995
ROE	9.66%

2013 Distribution Rates – IRM/ICM



2013 Rate Increase	
Approved 2011 Rates	Base
PCI Adjustment	0.6%
2013 Base Rates	0.6%
ICM Riders	1.2%
Z-Factor Riders	0
SG Adders	3.1%
2013 Rate Increase	4.9%

Summary of Assumptions

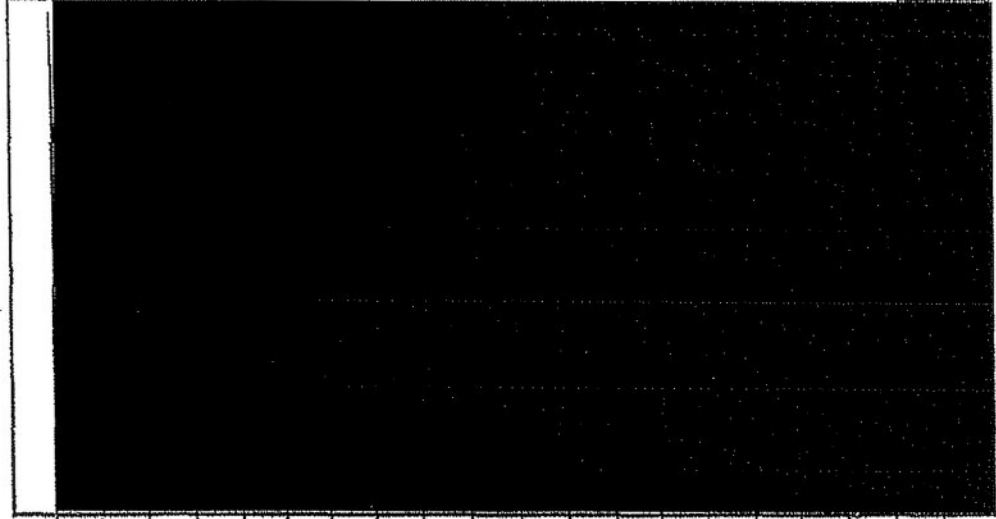
- Transmission cost of service in 2013/14, 2015/16
- No Distribution cost of service in 2012
- Distribution IRM/ICM in 2013/14, cost of service in 2015/16
- Plan updated to reflect 2011 actual results
- Revised ROE per February 2012 consensus forecast
 - 2013: 9.16% (9.70% Nov Board)
 - 2014: 9.44% (10.20% Nov Board)
 - [REDACTED]
- Revised interest rates per February 2012 consensus forecast
- Revised load forecast, LVSG and Export Credit assumptions
- [REDACTED]
- OEB approval of US GAAP request for Dx
- Ontario corporate income tax rate frozen at 11.5%

April Update - Financial Results

	Actual 2010	Actual 2011
\$M. except where noted		
Revenue	5,124	5,471
Income before PILs	661	790
Net Income	591	641
EBITDA	1,572	1,751
Cash Flow	(533)	(304)
Debt Ratio	57%	55%
FFO Coverage	3.9x	4.2x
Actual Rate Base	12,728	13,527
ROE (GAAP)	11%	10.5%
Capital Expenditures	1,570	1,447
OM&A	1,048	1,069
Dividends	28	168
PILs	70	150
Total Long-term Debt	7,783	8,008
Total Equity	5,981	6,454
Headcount	5,717	5,781

Results in US GAAP

Change from Nov Board: Financial Results



\$M: except where noted	Actual 2010	Actual 2011
Revenue	0	4
Income before PILs	0	20
Net Income	0	27
EBITDA	0	28
Cash Flow	0	122
Debt Ratio	0%	0%
FFO Coverage	0.0x	0.2x
Actual Rate Base	0	48
ROE (GAAP)	0.0%	0.4%
Capital Expenditures	0	(63)
OM&A	0	(37)
Dividends	0	0
PILs	0	(8)
Total Long-term Debt	0	(124)
Total Equity	0	27
Headcount	0	(104)

Results in US GAAP

April Update: Long-Term Financial

Results

\$ M except where noted

	2011
Revenue	5,471
Income before PILs	790
Net Income	641
EBITDA	1,751
Cash Flow	(304)
Debt Ratio	55%
FFO Coverage	4.2x
Actual Rate Base	13,527
Tx Rate Increase (%)	7.0%
Dx Rate Increase (%)	8.9%
Allowed Regulatory ROE	9.7%
ROE (GAAP)	10.5%
Capital Expenditures	1,447
OM&A	1,069
Dividends	168
PILs	150
Total Long-term Debt	8,008
Total Equity	6,454

Assumptions

- No Distribution cost of service in 2012.
- Distribution IRM-ICM 2013/14, cost of service in 2015/16.
- Transmission cost of service in 2013/14, 2015/16.

Results in US GAAP

Change from Nov Board: Long-Term Financial Results

\$ M except where noted

	2011
Revenue	4
Income before PILs	20
Net Income	27
EBITDA	28
Cash Flow	122
Debt Ratio	0%
FFO Coverage	0.2x
Actual Rate Base	48
Tx Rate Increase [%]	0.0%
Dx Rate Increase [%]	0.0%
Allowed Regulatory ROE	0.0%
ROE (GAAP)	0.4%
Capital Expenditures	(63)
OM&A	(37)
Dividends	0
PILs	[8]
Total Long-term Debt	(124)
Total Equity	27

Results in US GAAP

Customer Rate Impact

hydroOne

Distribution				Transmission					
	Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill		Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill
No COS	2012	0.0%	-0.2%	-0.1%		2012	7.2%	0.6%	0.6%
IRM/ICM	2013	3.2%	1.6%	1.6%		2013	1.8%	-1.1%	0.1%
						2014	9.2%	0.0%	0.7%

Tariff impacts			
Without riders		with riders	
	Dx	Tx	Total
2012	0.0%	7.2%	7.8%
2013	3.2%	1.8%	0.8%
2014		9.2%	9.2%
average		6.1%	5.9%

Total Bill Impact			
	Dx	Tx	Total
2012	-0.1%	0.6%	0.5%
2013	1.6%	0.1%	1.7%
2014		0.7%	
average		0.4%	

9

Transmission

Tx: Long-Term Financial Results

\$ M except where noted

	2011	2012	2013	2014
	COS	COS	COS	COS
Revenue	1,391	1,429	1,469	1,563
Income before PILs	457	440	439	491
Net Income	379	383	390	433
EBITDA	956	985	1,017	1,104
Cash Flow	(236)	(481)	(576)	(529)
Debt Ratio	56%	57%	59%	60%
Actual Rate Base	7,877	8,649	9,460	10,073
Tx Rate Increase (%)	7.0%	7.8%	0.8%	9.2%
Allowed Regulatory ROE	9.7%	9.4%	9.2%	9.4%
ROE (GAAP)	10.6%	10.1%	9.8%	10.5%
Capital Expenditures	810	962	1,070	1,089
OM&A	434	444	452	460
PILs	77	56	50	58
Total Debt	4,845	5,323	5,895	6,422
Total Equity	3,823	3,984	4,157	4,324

Assumptions

- Transmission cost of service in 2013/14, 2015/16.

Results in US GAAP

Tx Summary of Key Changes

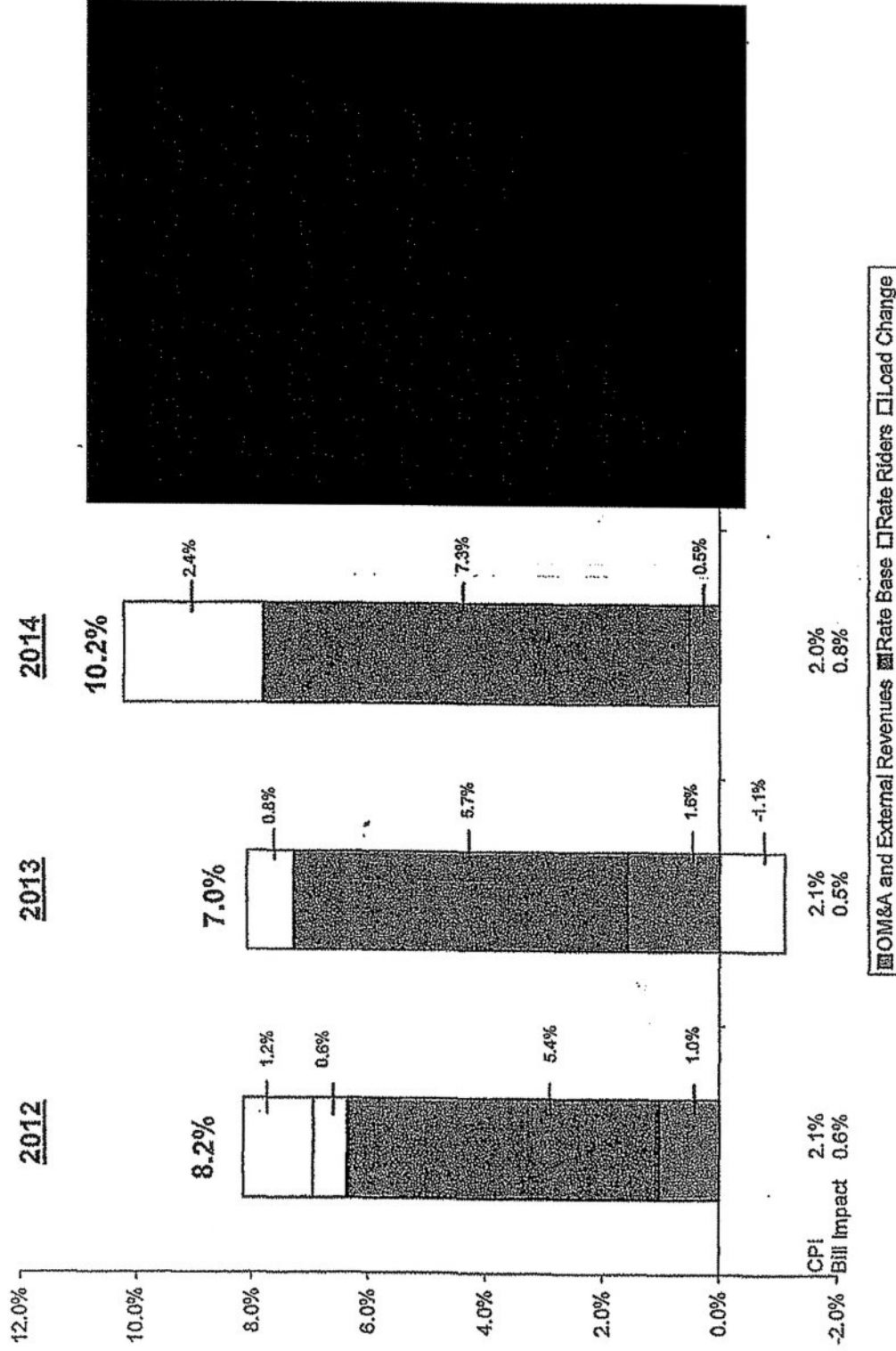
April Update:

- ROE: 9.16% (2013), 9.44% (2014), [REDACTED]
- Load impact on rates in 2013 of (-0.4%)
- Export credit estimate of \$31M
- 2011 Actuals updated
- Ontario budget freezes provincial income tax rates at 11.5%

November Board:

- ROE: 9.70% (2013), [REDACTED] 10.20% (2014), [REDACTED]
- Load impact on rates in 2013 of (+0.8%)
- Export credit estimate of \$16M
- 2011 Forecast
- Ontario provincial income tax rates declining to 10% in 2013

Tx Rate Increase: Nov Board

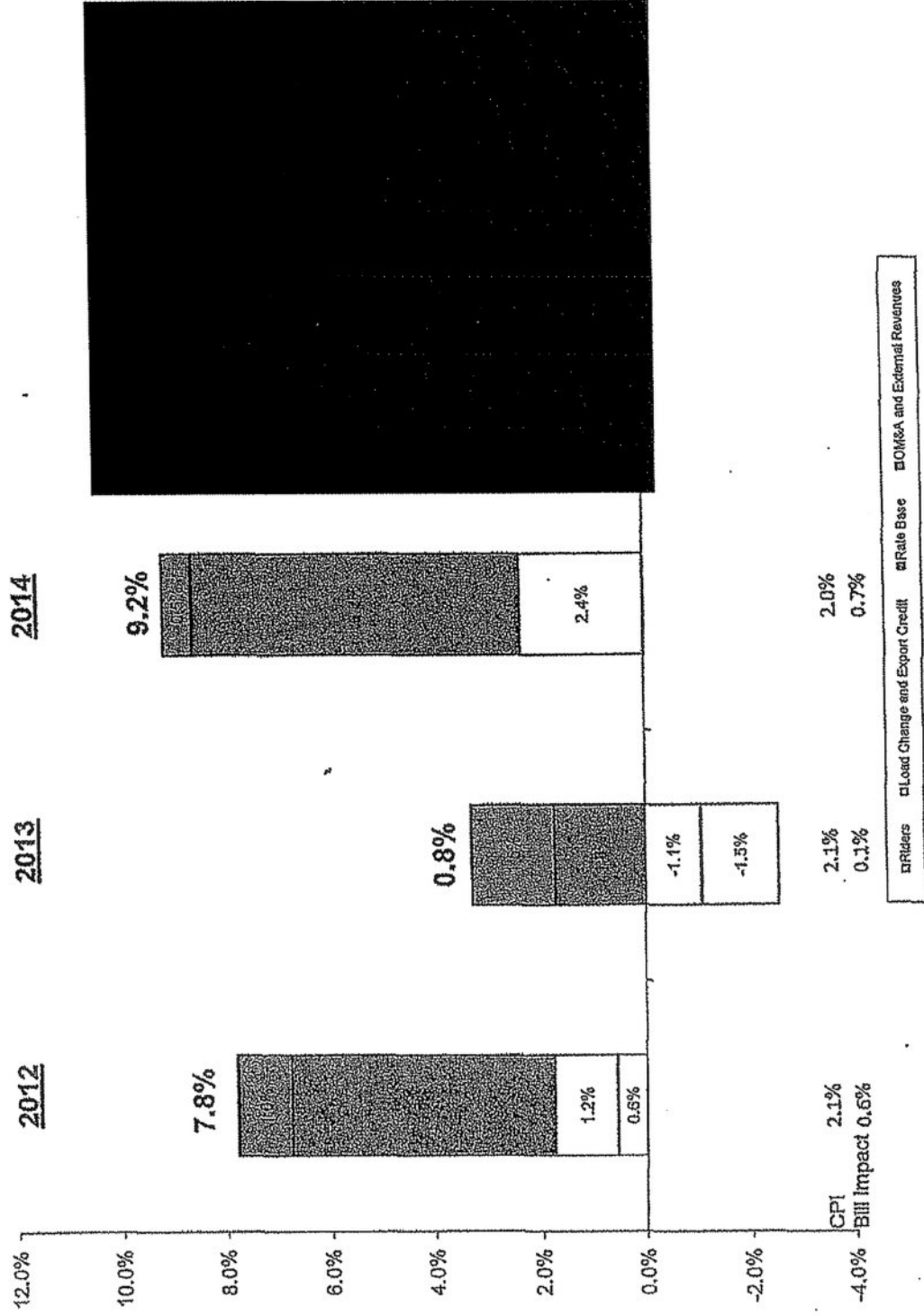


- Rate adders and riders causes changes to rates as collections or refunds begin and end
- Rate base component of rate change increases due mainly to in-servicing of capital projects

Tx Rate Increase: April Update

hydroOne

Updated for Ontario budget change to Provincial Tax Rates



Distribution

Dx: Long-Term Financial Results

\$ M except where noted

	2011	2012	2013
	COS	No-File	IRM
Revenue	3,569	3,726	3,783
Income before PILs	302	300	320
Net Income	236	260	289
EBITDA	729	739	795
Cash Flow	(3)	(503)	(168)
Debt Ratio	56%	59%	58%
Actual Rate Base	5,311	5,643	6,077
Dx Rate Increase (%)	8.9%	-0.2%	4.9%
Allowed Regulatory ROE	9.7%	9.4%	9.2%
ROE (GAAP)	11.8%	12.1%	12.7%
Capital Expenditures	596	731	635
OM&A	554	566	582
PILs	66	40	31
Total Debt	2,748	3,248	3,415
Total Equity	2,168	2,280	2,426

Assumptions

- No Distribution cost of service in 2012.
- Distribution IRM-ICM 2013/14, cost of service in 2015/16.
- ICM uses 2011 OEB Hydro One cost of capital
- 2013 ICM consists of \$150M CIS and \$211M Dx Capital;

Results in US GAAP

Dx Summary of Key Changes

hydroOne

April Update:

- No 2012 cost of service
- CIS embedded in ICM in 2013/14

[REDACTED]

• ROE: 9.16% (2013), [REDACTED]

[REDACTED]

- SM adder stopping in 2015
- SG adder stopping in 2012; [REDACTED]

• 2011 Actuals updated

- Ontario budget freezes provincial income tax rates at 11.5%

November Board:

- 2012 cost of service
- CIS go-live 2012, accounting in-service 2013

- 2012 variance amounts refunded in 2013/14

- ROE: 9.70% (2013), [REDACTED]

- New (lower) depreciation rates effective 2012

- Load impact reflected in rates in 2012 (-2.9%)

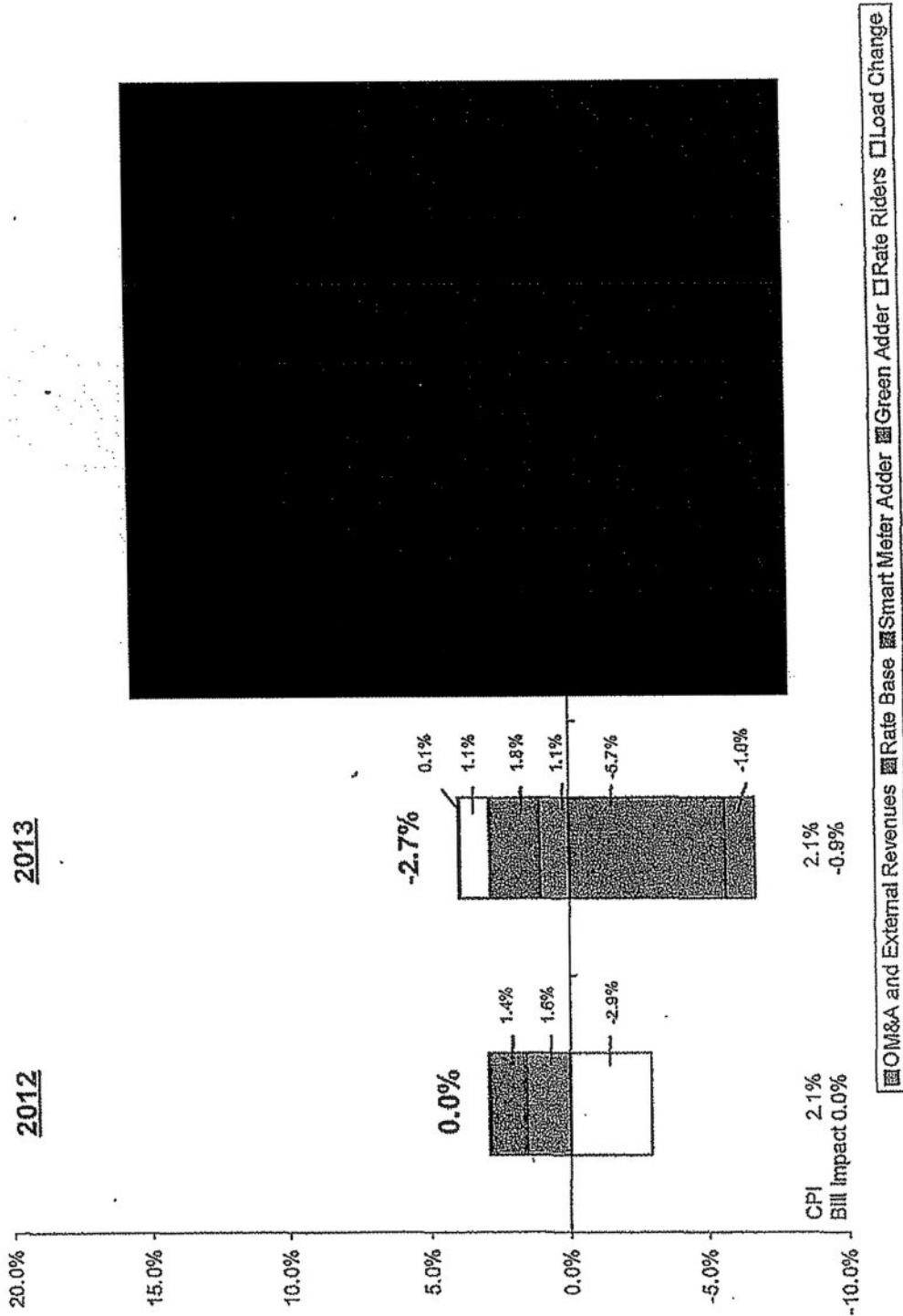
- SM adder stopping in 2013

- 2011 SG adder continued through 2012; [REDACTED]

- 2011 Forecast

- Ontario provincial income tax rates declining to 10% in 2013

Dx Rate Increase: Nov Board

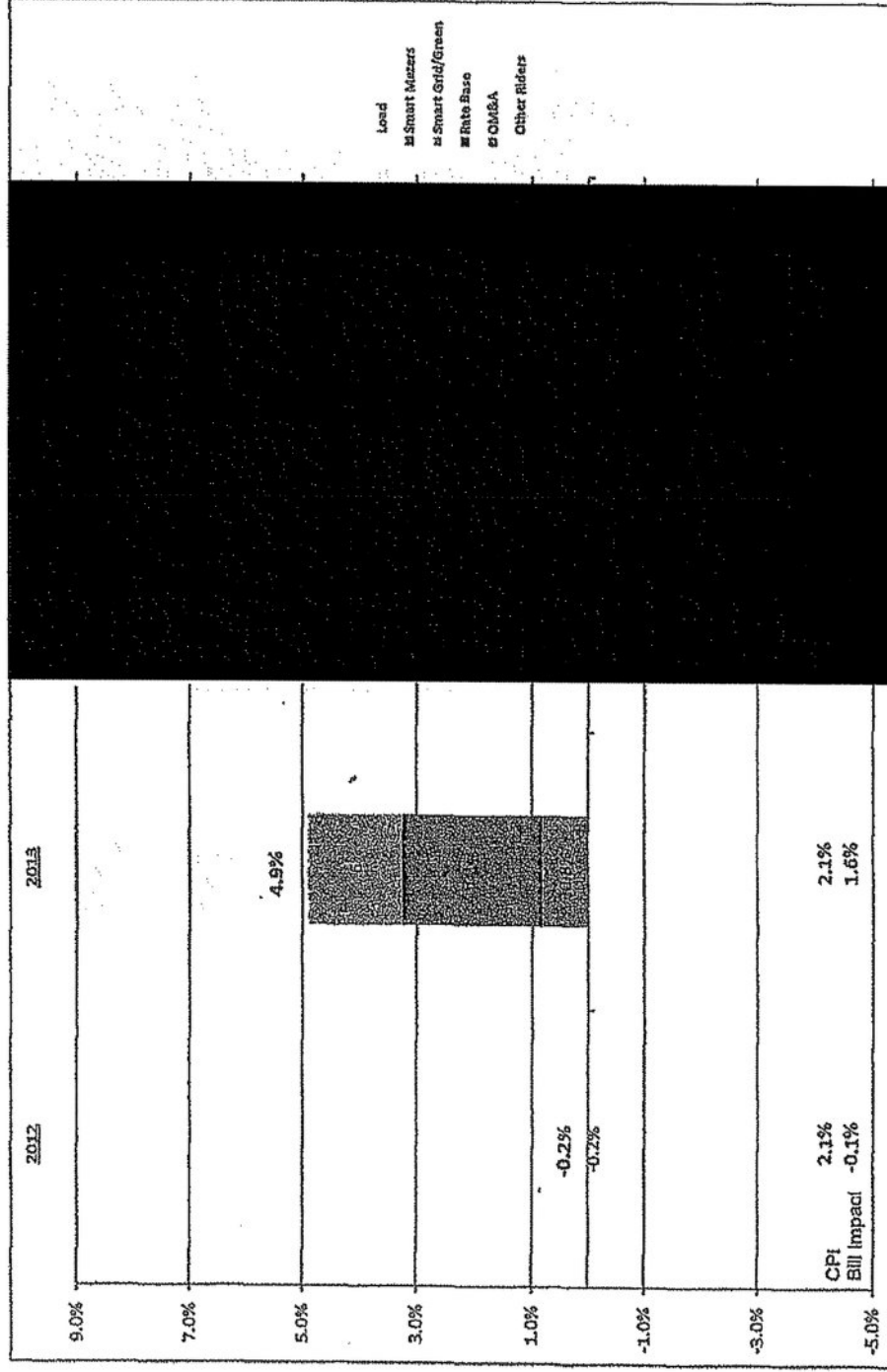


- Rate adders and riders causes changes to rates as collections or refunds begin and end
- Rate base component of rate change increases due mainly to in-servicing of capital projects

Dx Rate Increase: April Update

Forecasted COC & Dep Threshold

hydroOne



- Forecasted cost of capital applied to ICM
- Depreciation materiality threshold

Hydro One Inc.
Submission to the Regulatory and Public Policy
Committee of the Board of Directors



Date: April 4, 2012

Subject: 2013 and 2014 Distribution IRM Rate Application Update

Submitted by:

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Vice President and
Chief Regulatory Officer

REASON FOR REPORT

This Report is submitted to the Regulatory and Public Policy Committee of the Hydro One Board of Directors to inform the Committee about Hydro One's current thinking in respect to its plans to file a 2013 and 2014 Distribution Incentive Regulation Mechanism (IRM) rate application with the Ontario Energy Board (OEB). The new rates would be effective January 1st of each year. The 2013 IRM application would be filed with the OEB in July of 2012 and a similar application for 2014 would be made in July of 2013.

KEY HIGHLIGHTS

- The applications should include a request for an Incremental Capital Module (ICM) for in-service capital expenditures above book depreciation and a rider to recover smart grid or advanced distribution system OM&A costs in 2013. In 2014, the rider would look to recover OM&A and in-service capital costs for the Advanced Distribution System or smart grid project.
- The resulting increase requested will be 4.9% in 2013 [REDACTED]
[REDACTED]

BACKGROUND

At the last RPPC meeting held on February 8, 2012, this Committee reviewed two scenarios Hydro One was considering for filing for its rate application in 2013 and 2014. Management's recommendation for the preferred option was to proceed with a Distribution IRM application. The IRM application would include an ICM and a smart grid rider.

An IRM application for rates effective January 1, 2013 would be filed in July 2012 and for rates effective January 1, 2014 in midyear 2013.

Hydro One has further reviewed potential elements of the application and can now provide this Committee with additional details with respect to the preferred option being considered for the final applications.

IRM Considerations

Formula Adjustment

The OEB uses a "price cap index adjustment factor" to determine a distributor's annual rate increase under IRM. Based upon the OEB's latest parameters for the IRM formula the resulting price cap index adjustment for Hydro One for 2013 would be:

$$\begin{aligned}\text{Price Cap Index} &= \text{Price Escalator} - \text{Productivity Factor} - \text{Stretch Factor} \\ &= 2.0\% - 0.72\% - 0.4\% \\ &= \mathbf{0.88\%}\end{aligned}$$

Hydro One's existing rates would all be adjusted upward by approximately 0.9%. The Board will issue a letter establishing the updated price escalator for IRM applications in the fall of each year. [REDACTED]

[REDACTED]

Incremental Capital Module

The IRM applications will also request funding to recover the costs of the Company's capital program through the ICM. The ICM is currently designed for discrete, material and non-discretionary projects which cannot be funded through normal operation of the IRM formula mechanism.

Hydro One plans to file an IRM with an ICM requesting the recovery of all in-service capital in excess of book depreciation for 2013 and 2014. The in-service capital requested will be consistent with previous capital spending levels already approved by the OEB in the 2011 Distribution Cost of Service application. The increase in 2013 of \$361 million [REDACTED] will increase rates by 2.4% in 2013 [REDACTED]. This is consistent with the position Hydro One is supporting as part of the OEB's Renewed Regulatory Framework initiative.

If Hydro One does not apply for an ICM, the IRM base formula adjustment would only provide for recovery of in-service capital equivalent to approved book depreciation levels of approximately \$284 or 44% of the \$645 million planned 2013 in-service capital forecast. However, even if Hydro One applies for an ICM, the current OEB guidelines for ICM only allow for potential recovery of capital above a threshold level determined by application of a formula which, for Hydro One, would be \$292 million or 45% of the approved 2013 capital forecast. The return on the remaining 11%, or the amount of the threshold calculation above book depreciation, is expected to be recovered by the Company through productivity initiatives in addition to those already addressed through price cap index formula. Hydro One does not believe the current ICM structure is fair to the Company, its shareholders and its ratepayers for the following reasons:

- In the last Cost of Service proceeding, the OEB already determined what it felt was a reasonable capital expenditure level for Hydro One for maintaining its assets and connecting new customers. Those investments are already in excess of annual depreciation charges and many of the investments are being placed into service in the 2012 through 2014 period. Providing the Company does not exceed these approved levels, rates should be allowed to be adjusted automatically to recover this level of

spend. Any spend above these previously-approved levels should be included in an ICM module for consideration by the OEB in an IRM application;

- Reducing expenditures below previously-approved levels would only encourage the harvesting of assets and system investment would be held to an amount only equivalent to depreciation expense; and
- The IRM base formula already adjusts for productivity; to do so again as part of an ICM module is unduly punitive.

Although current OEB guidelines require the use of the OEB cost of capital parameters, approved in an LDC's last Cost of Service proceeding, Hydro One will be proposing the use of the most current OEB approved cost of capital parameters at the time an IRM application is filed to determine the appropriate recovery of costs.

Smart Grid Rider Request

Hydro One will also request the re-instatement of a smart grid rider to recover the OM&A costs of approximately \$20 million for the smart grid program/advanced distribution system and the continuation of the associated variance account in 2013. This will add 1.6% to the rate request for 2013. [REDACTED]

[REDACTED]

Z Factors

Hydro One will not request any Z factors for extraordinary expenditures beyond the Company's control in the applications. Pension cost increases will continue to be tracked in the variance account with recovery sought in the next Cost of Service application.

RATE ANALYSIS

Table 1 summarizes the rate increases associated with the proposed applications. Table 2 compares the impact on net income. [REDACTED]

Table 1
Distribution Rate Impact
%

Option	2012	2013	[REDACTED]	[REDACTED]	[REDACTED]
2013 and 2014 IRM with ICM for all In-service Capital above Depreciation & SG Rider	(0.2)	4.9	[REDACTED]	[REDACTED]	[REDACTED]
No IRM filing for 2013 or 2014	(0.2)	0.0	[REDACTED]	[REDACTED]	[REDACTED]

Table 2
Net Income
\$m

Option	2012	2013	[REDACTED]	[REDACTED]	[REDACTED]
Original Business Plan	236.7	263.6	[REDACTED]	[REDACTED]	[REDACTED]
2013 and 2014 IRM with ICM for all In-service Capital above Depreciation & SG Rider	260.7	289.0	[REDACTED]	[REDACTED]	[REDACTED]
No IRM filing for 2013 or 2014	260.7	260.3	[REDACTED]	[REDACTED]	[REDACTED]

File Density Study

The density study, directed to be undertaken by the OEB in the last distribution rate proceeding, confirmed that as customer density decreases the cost to serve the same number of customers' increases. If the study findings were reflected in final rate design, a reduction of UR (urban) rates by about 14% and a compensating increase in R2 (rural) rates of 2% would result.

Although IRM normally does not contemplate cost allocation or rate design changes, given the wide gap between current rates and the cost-based rates identified in the density study, Hydro One should consider applying for a phased implementation of the study recommendations. For example, if the approved IRM rate was 3%, Hydro One might suggest that the R2 customer rates go up by 3.5% and the UR customer rates remain unchanged. In addition to being more reflective of the Density Study directions, these adjustments would assist with distribution rationalization.

RECOMMENDATION

It is recommended that Hydro One proceed with a distribution IRM application in July of 2012 for 2013 rates including an ICM for all in-service capital above book depreciation levels and a rider for smart grid OM&A costs. A similar application would be filed for 2014. [REDACTED]

[REDACTED]

[REDACTED]

IRM GLOSSARY OF TERMS

IRM Price Cap Index Adjustment

The OEB uses an IRM “price cap index adjustment factor” to determine a distributor’s annual rate increase during each year of the 3-year IRM period. Distribution rates under IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 0.72% and a distributor-specific stretch factor which for Hydro One is 0.4%.

$$\text{Price Cap Index} = \text{Price Escalator} - \text{Productivity Factor} - \text{Stretch Factor}$$

The Board will issue a letter establishing the updated price escalator for IRM applications in the fall of each year.

Incremental Capital Module

ICM is designed to provide rate relief for discrete, material and non-discretionary projects which cannot be funded through normal operation of the IRM mechanism above an OEB formulaic determined threshold level.

Z-factor Claims

Z-factors are intended to provide relief for unforeseen events outside of a distributor’s control and a distributor must submit evidence that the costs incurred meet the three eligibility criteria of causation, materiality and prudence .A distributors must notify the Board, in writing within 6 months a Z-factor event occurring.

OFF-RAMPS

The IRM plan includes a trigger mechanism with an annual ROE dead band of plus or minus 300 basis points. A distributor would be required to report to the OEB no later than 60 days after the company’s receipt of its annual audited financial statements, in the event that earnings fall short of the allowed ROE by 300 basis points.

Consumers Council of Canada (CCC) INTERROGATORY #2 List 1

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

EX. A/T2

Please provide all materials provided to HON's Shareholder in the course of developing the current rate application. Please include all correspondence, presentations, e-mails etc.

Response

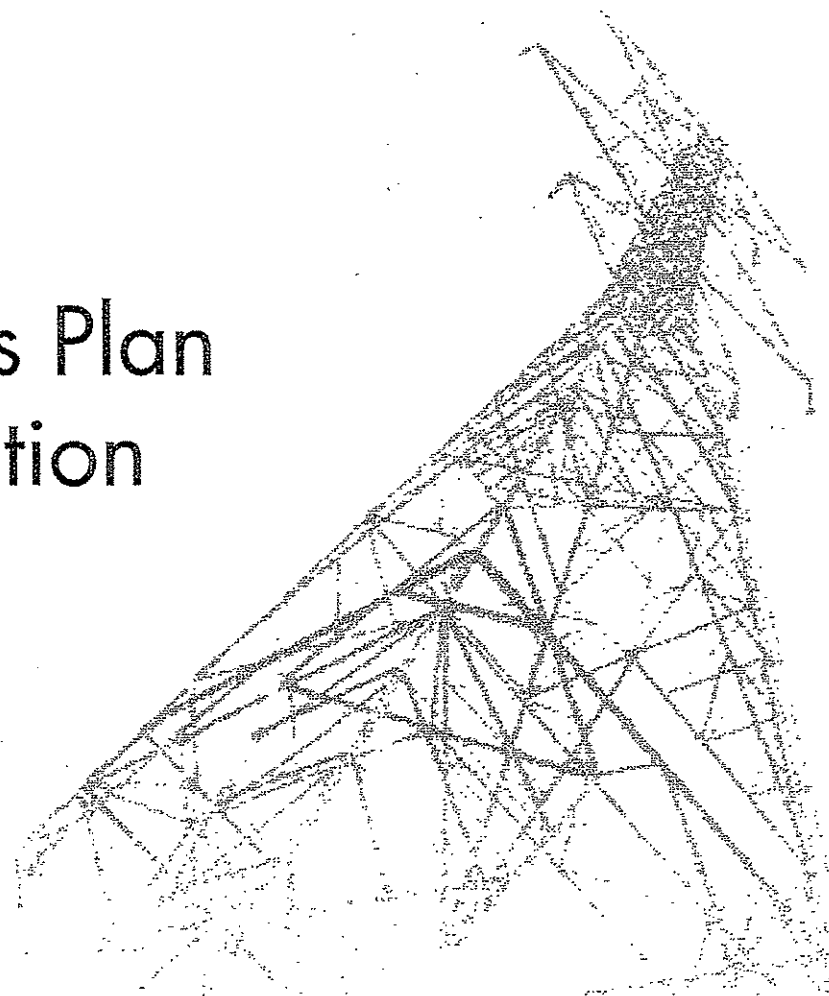
Hydro One is providing a redacted version of:

- Attachment 1 – Hydro One 2012-14 Business Plan and Rate Application April Update

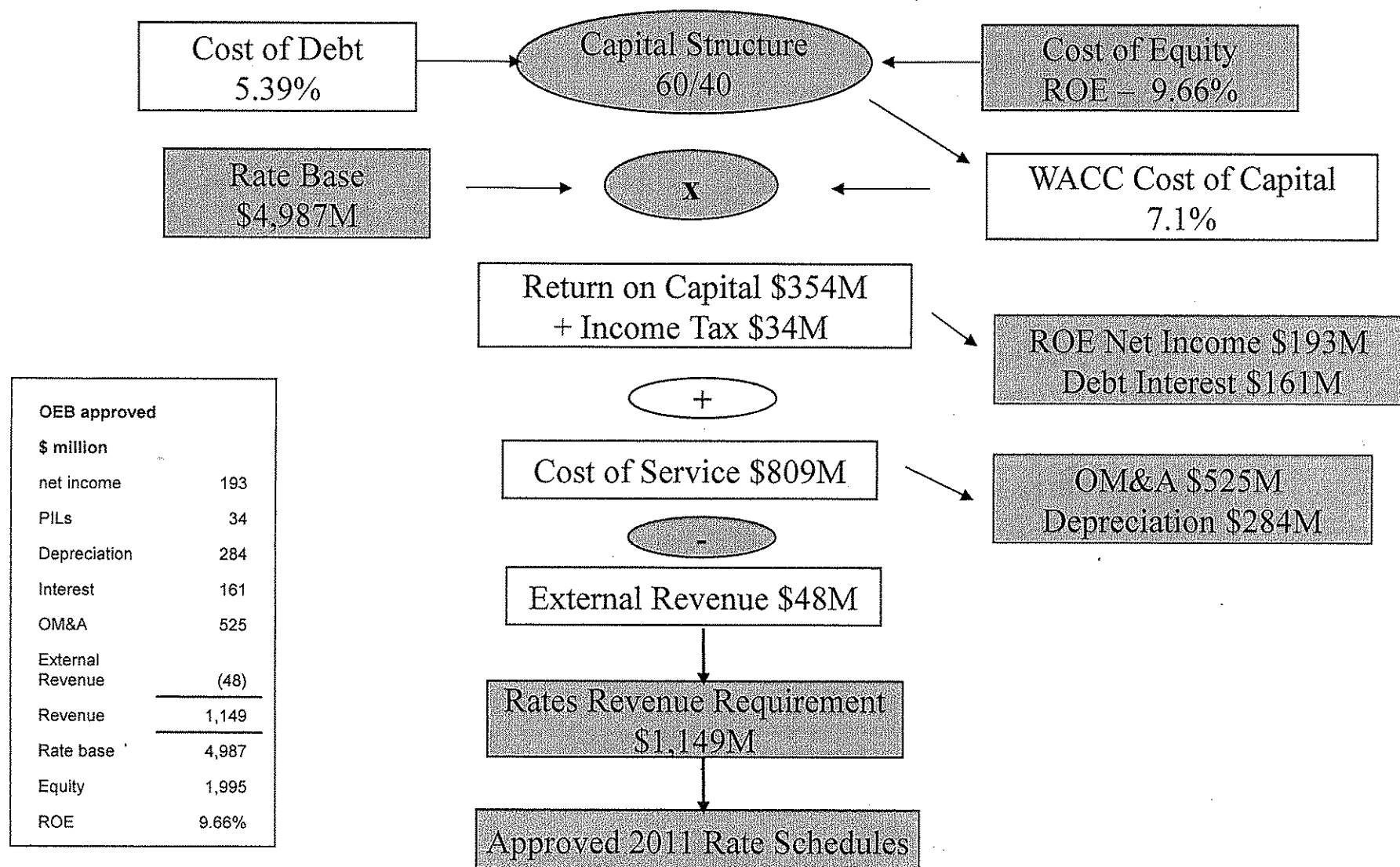
Hydro One has filed the attached interrogatory request pursuant to the Board's Practice Direction on Confidential Filing. Hydro One's Disclosure Policy, as well as applicable securities legislation, prohibits the release of non-public, financial information on a selective bases to individuals or groups of individuals.

Hydro One

2012-14 Business Plan and Rate Application April Update



Approved 2011 Distribution Revenue - Cost of Service Requirement



2013 Distribution Rates – ICM/ICM ^{hydro}One

Approved 2011 Rate Schedules

*

IRM Price Cap Index 0.8%
(Inflation – Productivity)

2013 Base Rates

ICM Riders
2.4%

Group 1 Rider
-1.5%

Smart Grid Adder
1.6%

2013 Rate Schedules

2013 Rate Increase

Approved 2011 Rates	Base
PCI Adjustment	0.8%
2013 Base Rates	0.8%
ICM Riders	2.4%
Group 1 Refund Rider	-1.5%
SG Adders	1.6%
2013 Rate Increase	3.3%

Summary of Assumptions

- Transmission cost of service in 2013/14, 2015/16
- No Distribution cost of service in 2012
- Distribution IRM/ICM in 2013/14, cost of service in 2015/16
- Plan updated to reflect 2011 actual results
- Revised ROE per February 2012 consensus forecast
 - 2013: 9.16% (9.70% Nov Board)
 - 2014: 9.44% (10.20% Nov Board)
 - [REDACTED]
- Revised interest rates per February 2012 consensus forecast
- Revised load forecast, LVSG and Export Credit assumptions
- [REDACTED]
- OEB approval of US GAAP request for Dx
- Ontario corporate income tax rate frozen at 11.5%

April Update - Financial Results

\$M except where noted	Actual 2010	Actual 2011
Revenue	5,124	5,471
Income before PILs	661	790
Net Income	591	641
EBITDA	1,572	1,751
Cash Flow	(533)	(304)
Debt Ratio	57%	55%
FFO Coverage	3.9x	4.2x
Actual Rate Base	12,728	13,527
ROE (GAAP)	11%	10.5%
Capital Expenditures	1,570	1,447
OM&A	1,048	1,069
Dividends	28	168
PILs	70	150
Total Long-term Debt	7,783	8,008
Total Equity	5,981	6,454
Headcount	5,717	5,781

Results in US GAAP

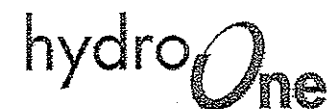
Change from Nov Board: Financial Results

hydroOne

\$M, except where noted	Actual 2010	Actual 2011
Revenue	0	4
Income before PILs	0	20
Net Income	0	27
EBITDA	0	28
Cash Flow	0	122
Debt Ratio	0%	0%
FFO Coverage	0.0x	0.2x
Actual Rate Base	0	48
ROE (GAAP)	0.0%	0.4%
Capital Expenditures	0	(63)
OM&A	0	(37)
Dividends	0	0
PILs	0	(8)
Total Long-term Debt	0	(124)
Total Equity	0	27
Headcount	0	(104)

Results in US GAAP

April Update: Long-Term Financial Results



\$ M except where noted

	2011
Revenue	5,471
Income before PILs	790
Net Income	641
EBITDA	1,751
Cash Flow	(304)
Debt Ratio	55%
FFO Coverage	4.2x
Actual Rate Base	13,527
Tx Rate Increase (%)	7.0%
Dx Rate Increase (%)	-8.9%
Allowed Regulatory ROE	9.7%
ROE (GAAP)	10.5%
Capital Expenditures	1,447
OM&A	1,069
Dividends	168
PILs	150
Total Long-term Debt	8,008
Total Equity	6,454

Assumptions

- No Distribution cost of service in 2012.
- Distribution IRM-ICM 2013/14, cost of service in 2015/16.
- Transmission cost of service in 2013/14, 2015/16.

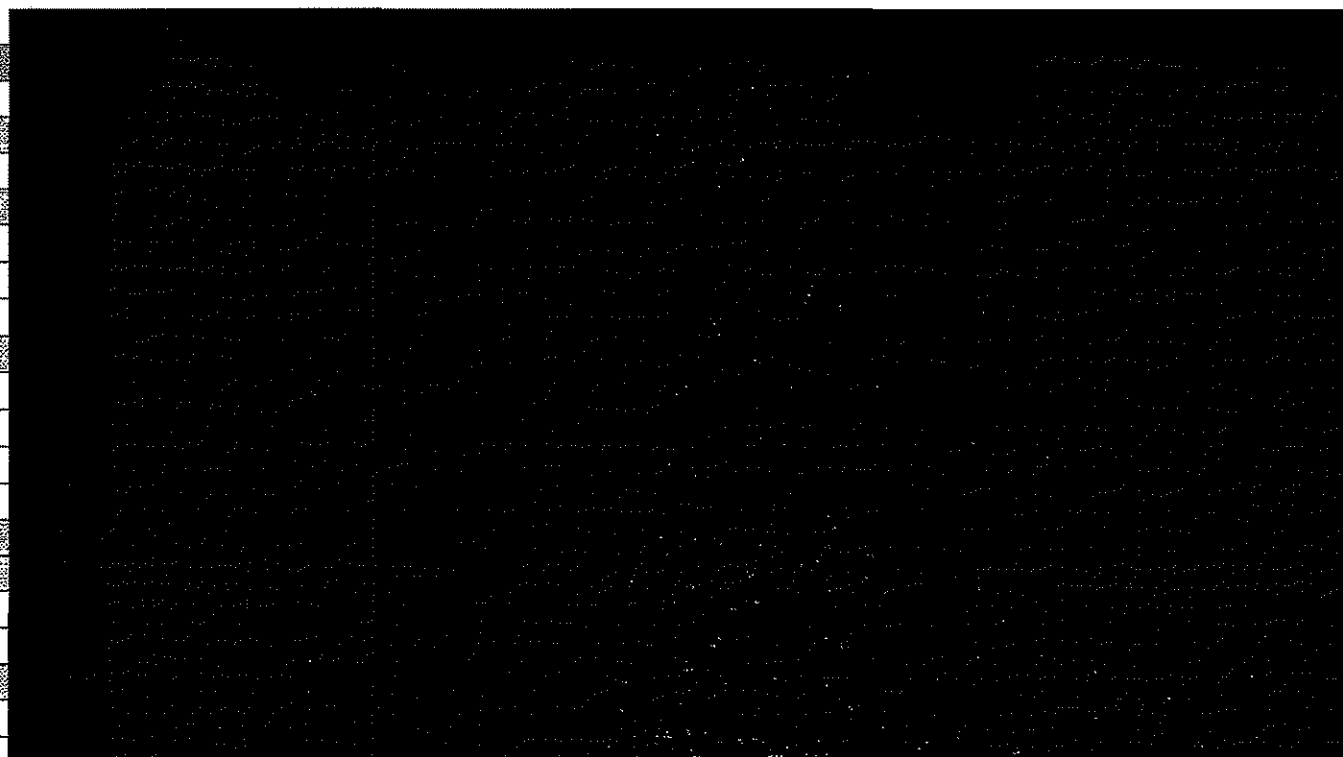
Results in US GAAP

Change from Nov Board: Long-Term Financial Results

hydroOne

\$ M except where noted

	2011
Revenue	4
Income before PILs	20
Net Income	27
EBITDA	28
Cash Flow	122
Debt Ratio	0%
FFO Coverage	0.2x
Actual Rate Base	48
Tx Rate Increase (%)	0.0%
Dx Rate Increase (%)	0.0%
Allowed Regulatory ROE	0.0%
ROE (GAAP)	0.4%
Capital Expenditures	(63)
OM&A	(37)
Dividends	0
PILs	(8)
Total Long-term Debt	(124)
Total Equity	27



Updated Customer Rate Impact



		Distribution			
		Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill
No COS	2012	0.0%	-0.2%	-0.2%	-0.1%
IRM/ICM	2013	3.2%	0.1%	3.3%	1.1%
	2014				
	average				

Tariff impacts

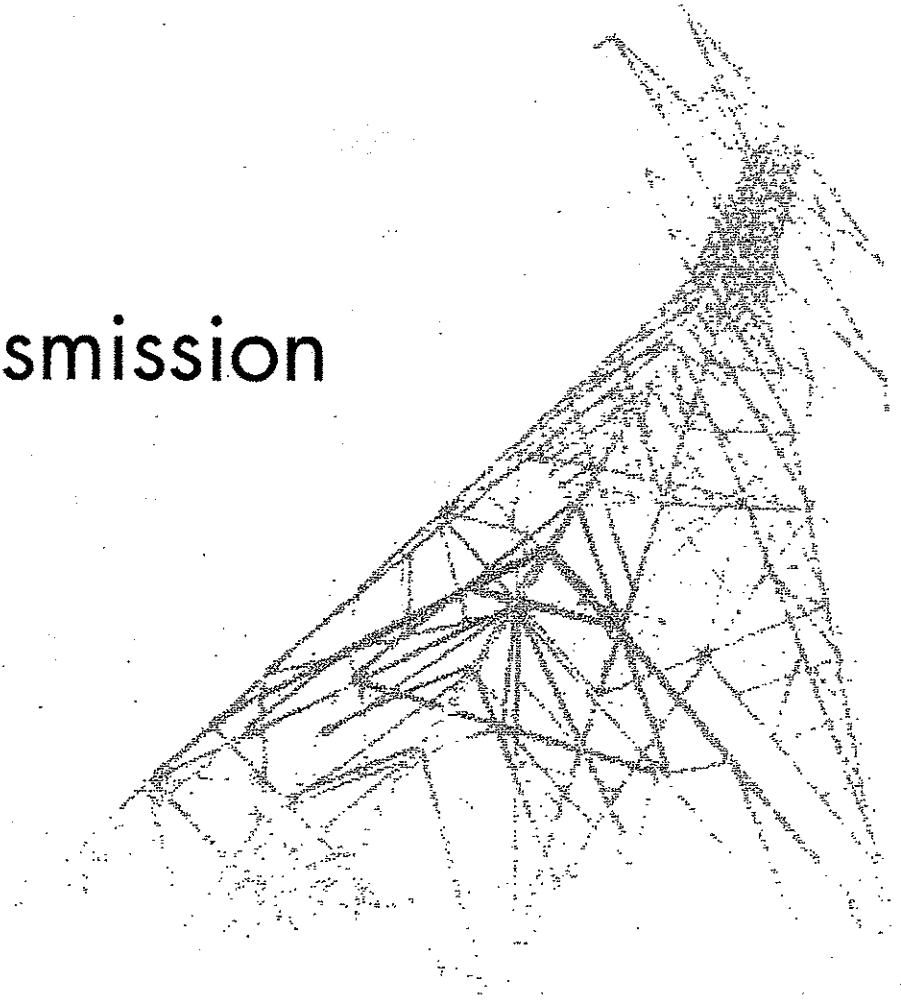
	Without riders		with riders	
	Dx	Tx	Dx	Tx
2012	0.0%	7.2%	-0.2%	7.8%
2013	3.2%	1.8%	3.3%	0.8%
2014		9.2%		9.2%
average		6.1%		5.9%

		Transmission			
		Total Base and Other Tariff Impact	Rate Rider	Total Tariff Impact	Impact on Total Bill
COS	2012	7.2%	0.6%	7.8%	0.6%
COS	2013	1.8%	-1.1%	0.8%	0.1%
	2014	9.2%	0.0%	9.2%	0.7%
	average				

Total Bill Impact

	Dx	Tx	Total
2012	-0.1%	0.6%	0.5%
2013	1.1%	0.1%	1.2%
2014		0.7%	
average		0.4%	

Transmission



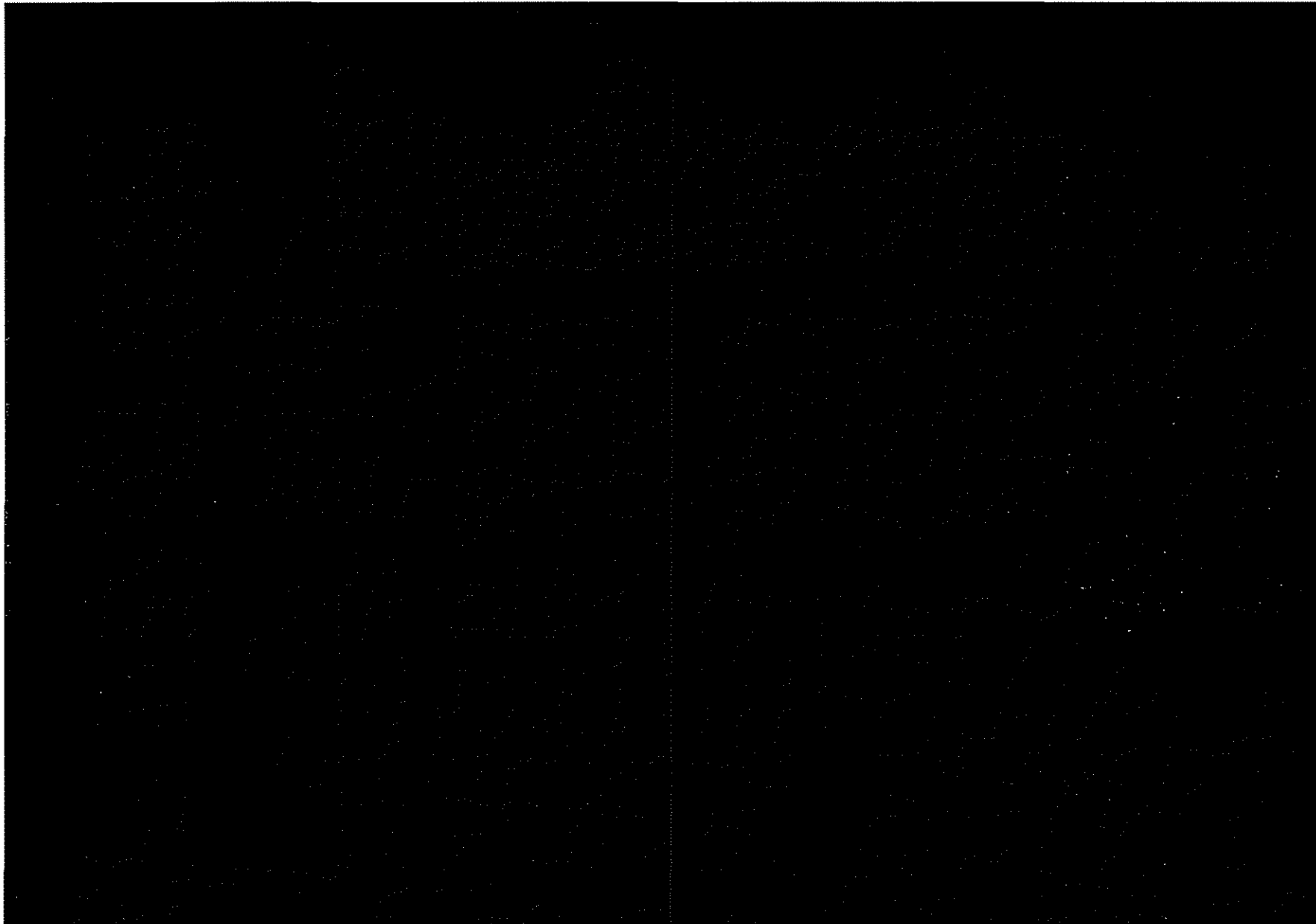
Tx Summary of Key Changes

hydroOne



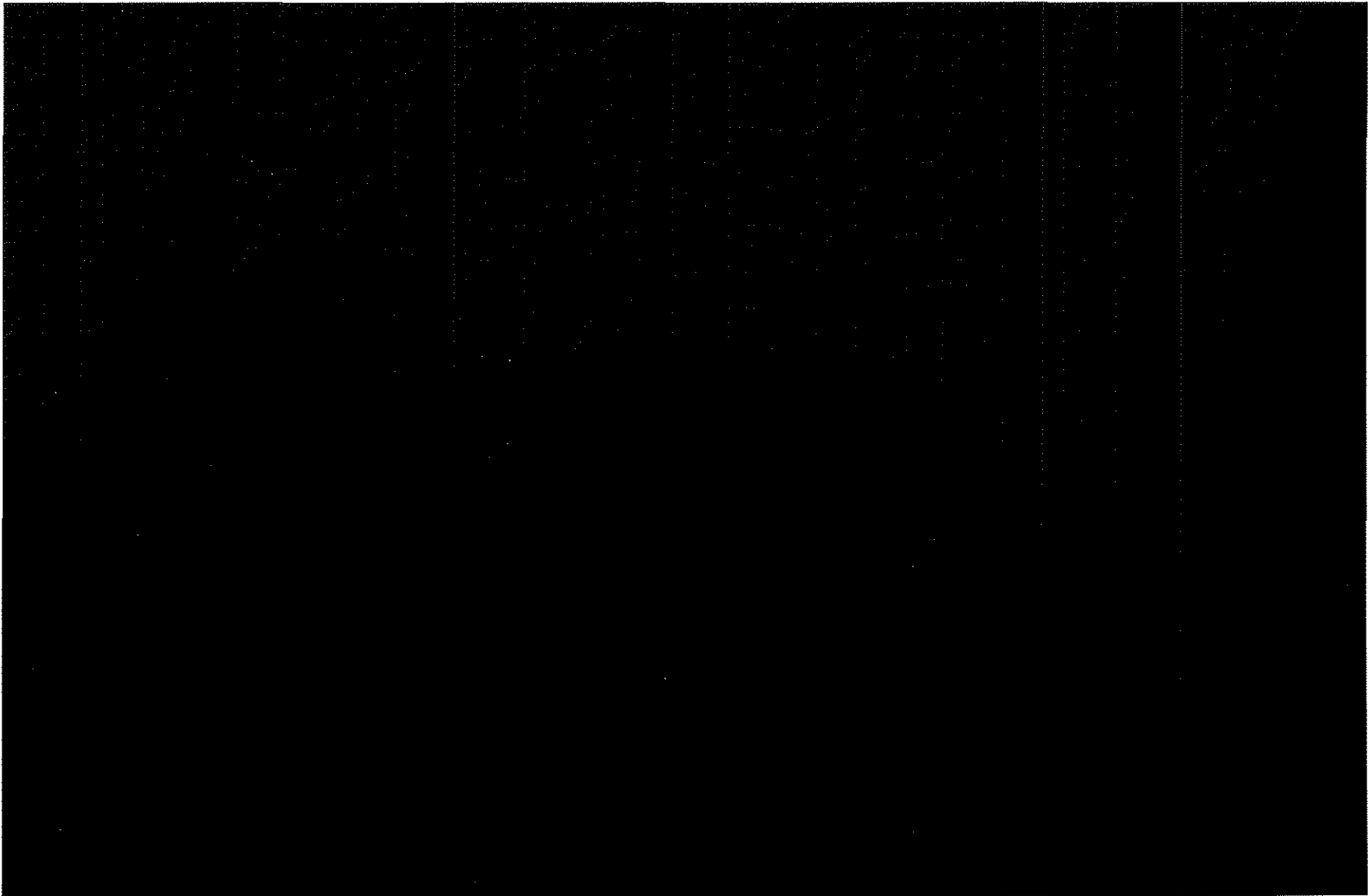
Tx Rate Increase: Nov Board

hydroOne



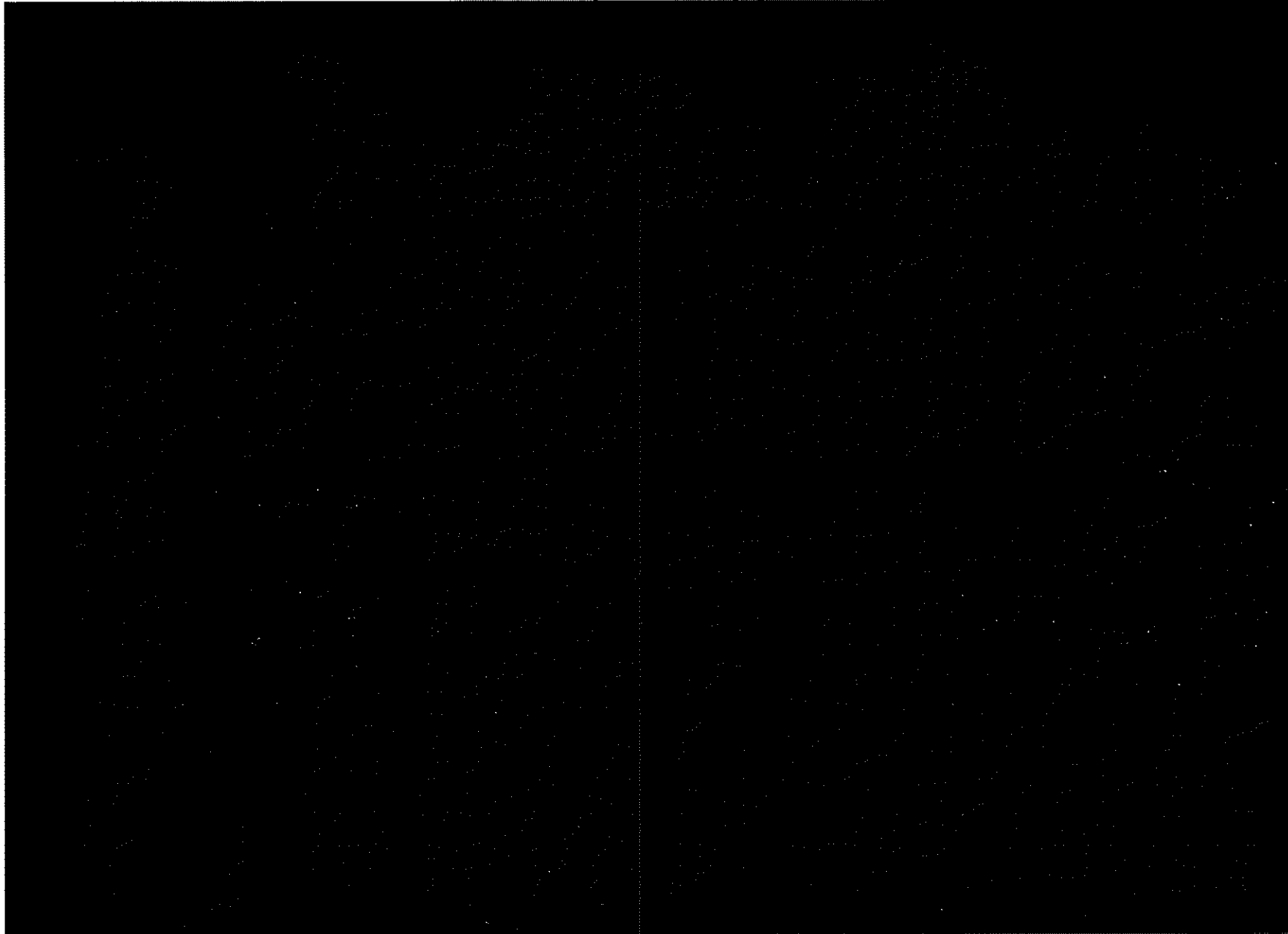
Details of 2013 Tx Rate Change

hydroOne



Tx Rate Increase: April Update

hydroOne



Distribution



Dx Summary of Key Changes

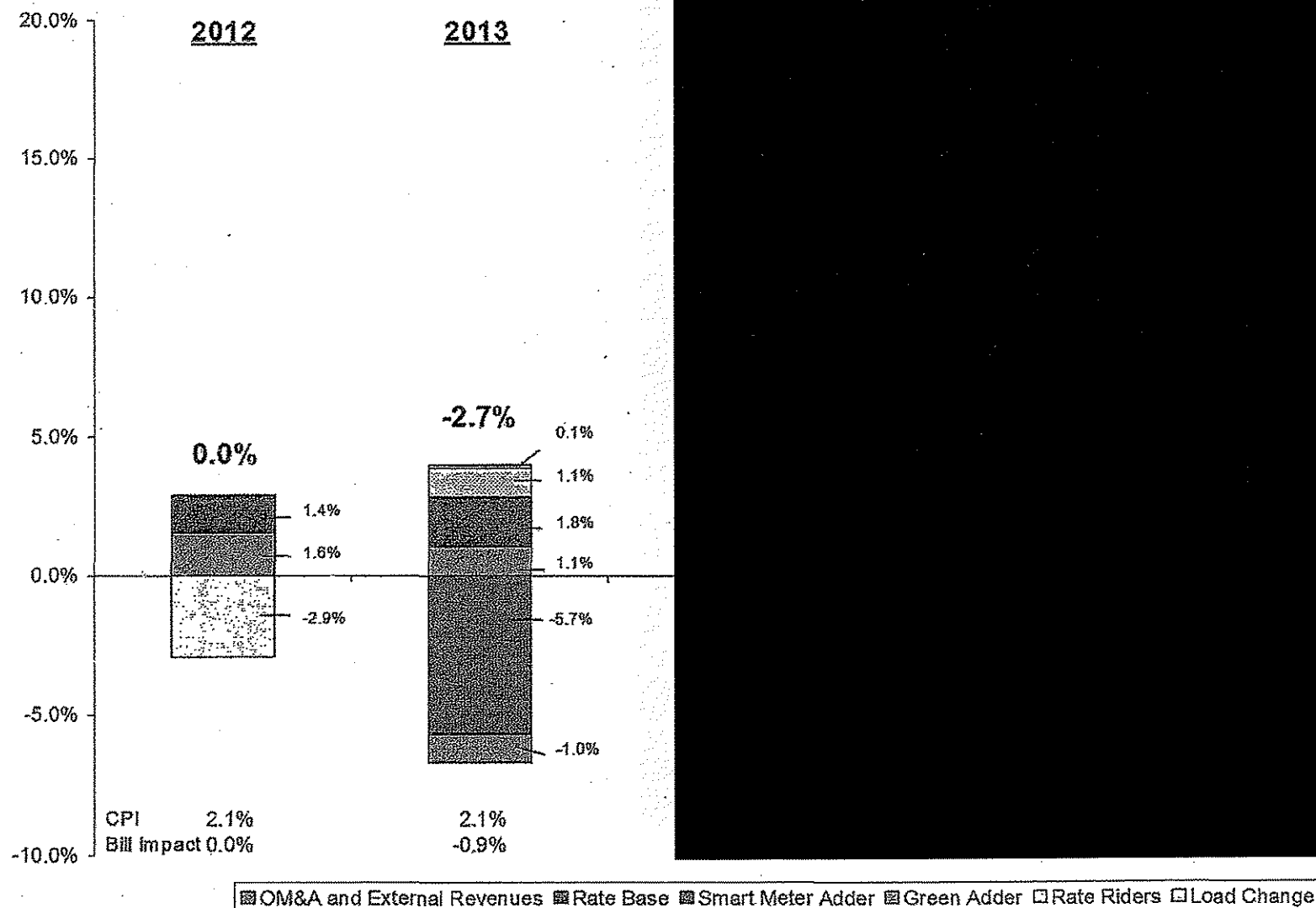
April Update:

- No 2012 cost of service; IRM Based with ICM filed for 2013, 2014
- CIS embedded in ICM in 2013/14
- Variance accounts continue and are refunded in 2015/16
- ROE: 9.16% (2013), [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- Smart Meter adder stopping in 2015
- Smart Grid adder stopping in 2012; partial adder in 2013/2014
- 2011 Actuals updated
- Ontario budget freezes provincial income tax rates at 11.5%

November Board:

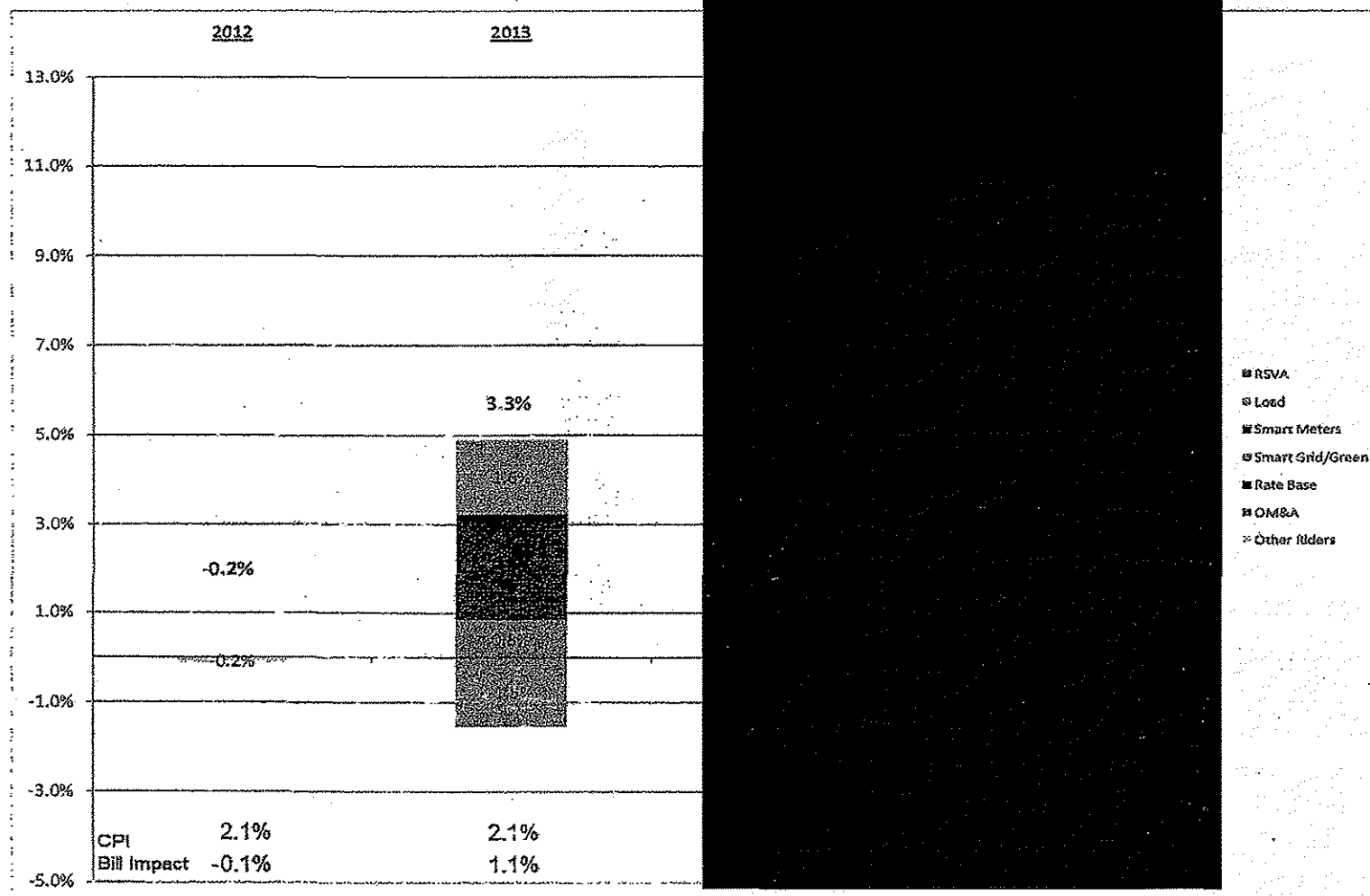
- 2012 cost of service(COS)
- CIS go-live 2012, accounting in-service 2013
- 2012 variance amounts refunded in 2013/14
- ROE: 9.70% (2013), [REDACTED]
- [REDACTED]
- New (lower) depreciation rates effective 2012
- Load impact reflected in rates in 2012 (-2.9%)
- SM adder stopping in 2013
- 2011 Smart Grid adder continued through 2012; updated adder in 2013/2014
- 2011 Forecast
- Ontario provincial income tax rates declining to 10% in 2013

Dx Rate Increase: Nov Board



- Rate adders and riders causes changes to rates as collections or refunds begin and end
- Rate base component of rate change increases due mainly to in-servicing of capital projects

Dx Rate Increase: April Update Forecasted COC and RSVA refund over 2 years



- Refund Retail Settlement Variance account of \$37.3M over 2 years (2013 and 2014) to reflect group 1 balances at Dec 31, 2011
- Forecasted cost of capital applied to ICM
- Depreciation materiality threshold

Consumers Council of Canada (CCC) INTERROGATORY #3 List 1

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

EX. A/T3/S1/P. 2

The evidence states that the Application is "substantially consistent" with the 2006 Electricity Distribution Rate Handbook and the Filing Requirements for Transmission and Distribution Applications. Please indicate where the Application is not consistent, and the reasons for not complying.

Response

Please refer to Exhibit I, Tab 1, Schedule 5.02 VECC 2.

Consumers Council of Canada (CCC) INTERROGATORY #4 List 1

Issue 1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

Interrogatory

EX A/T3/S1

What rate-making approach will HON apply for beyond 2013?

Response

Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2, part d).

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref:

- 1) Filing Requirements for Transmission and Distribution Applications,
June 28, 2012, Chapter 3, Section 2.2.
 - 2) Exhibit B/Tab1/Sch2
 - 3) Exhibit B/Tab1/Sch1
- a) In accordance with the Filing Requirements please provide a detailed description and summary showing, for each capital project or item:
- i. Whether the project is discretionary or not?
 - ii. an explanation of why each discretionary and non-discretionary project is needed.
 - iii. the expected in-service date for each project.
 - iv. Whether any capital project is required to accommodate customer or demand growth.
- b) Please provide:
- i. An explanation of why each project could not have been anticipated as required at the time of the last cost of service application (EB-2009-0096).
 - ii. An explanation of why each project should not be dealt with through a rebasing application at the next opportunity.
 - iii. The action that Hydro One will take if the Board does not approve the project as eligible.
- c) Please complete the incremental capital module spreadsheets including
- i. the summary
(http://www.ontarioenergyboard.ca/OEB/Documents/2013EDR/2013_Incremental_Capital_Project_V1.0_20120727.xlsm) and
 - ii. the workform, which includes threshold and other calculations
(http://www.ontarioenergyboard.ca/OEB/Documents/2013EDR/2013_IRM3_Incremental_Capital_Wrkfrm_V1.0_20120727.xlsm)
- d) Hydro One has indicated in its August 29, 2012 update, that it intends to have updated rates based on a Cost of Service application, on January 1, 2015. Does Hydro One contemplate a new IRM application for the 2014 rate year?

Response

a)
Hydro One is seeking ICM treatment for \$372M of incremental capital projects. The projects in question are:

Name	Capex (\$M)
Typical Capital	142.0
Commerce Way TS Capital Contribution	9.2
Distribution & Regulating Stations	42.6
Wood Pole Replacement	22.9
CIS	155.4

i) None of these projects are discretionary. Hydro One believes that all these projects are necessary and must be completed.

ii) All of them are required in order to maintain the system in line with good utility practice.

For typical capital, the need for this spending was previously established in EB-2009-0096. This investment represents the amount that is required to merely maintain Hydro One operations at their current level of performance and to meet customer needs.

Commerce Way TS is a project for which leave to construct was proposed and approved by the Board in EB-2009-0079. This project is approaching completion in order to meet customer demand in the Woodstock area.

The acceleration of the Distribution & Regulating Stations and Wood Pole Replacement programs is being recommended for approval in order to prevent a degradation of service to customers, prevent increases in safety risks and to minimize OM&A costs on a life-cycle basis.

The capital project to replace Hydro One's Customer Information System ("CIS") is non-discretionary. The current CIS system is no longer supported by the vendor and has reached its end of life and must be replaced. The nature of the application (several million lines of code), the extent of changes that have already been made, and the number of changes which will be required if the system is not replaced, create significant risk for Hydro One and the ability to bill and service its customers.

There are four core drivers that necessitate the replacement of the system:

- The ability to meet ongoing requirements related to our role as a distributor in the Ontario electric system
- The significance of the CIS within Hydro One's customer service delivery strategy
- The value to be delivered from the CIS investment

- 1 - The relationship between the CIS replacement and the Inergi
2 outsourcing contract

3
4 Ability to meet ongoing requirements:

5 Ontario's electricity market continues to evolve at a rapid pace.
6 The requirements associated with the Open Market in the early
7 2000's have been followed by Smart Metering, Time-of-Use
8 pricing, Distributed Generation and the Feed-in-Tariff program,
9 and provincially-mandated conservation programs. Hydro One
10 expects these requirements to continue to evolve over the years
11 ahead. The CIS system is a key enabler of our ability to implement
12 these changes, and the changes themselves are very complex and
13 time consuming. Implementing these changes within the current
14 CIS (Customer Service System or "CSS") requires custom
15 modifications to the core programs that make up the CSS
16 application, and it is expensive and risky to make these types of
17 changes. The risks are associated with Hydro One's ability to
18 generate timely bills for its customers. As many changes are made
19 to the programs that make up the application there is increased risk
20 of introducing unintentional impacts which could ultimately affect
21 timely accurate billing. Significant quality assurance and testing is
22 therefore required with every change to reduce the risk of such
23 impacts. Moving to a modern, off-the-shelf, configurable CIS
24 application, supported by a vendor whose business is to maintain
25 the relevance of their software to their customers, and which is
26 designed around the existence of smart-meters, distributed
27 generation, time of use pricing, and CDM programs, will allow
28 Hydro One to respond to the changing needs of the Ontario electric
29 system in the future.

30
31 Customer Service Delivery Strategy:

32 In parallel with the changes in the electricity market in Ontario,
33 customers' expectations of their utilities have shifted with respect
34 to customer service and billing. Hydro One has responded by
35 creating a Customer Service Delivery vision which points to more
36 customized service, from a streamlined, laterally integrated,
37 empowered delivery organization. This new organization will have
38 an emphasis on simplifying the interactions for customers (first
39 contact resolution) and simplifying the way customer requests are
40 handled and fulfilled within Hydro One, by reducing handoffs
41 between departments, and providing information systems that
42 support staff in responding appropriately, at the first point of
43 contact. The Vision is enabled through the investment in a core set
44 of foundational technologies. The CIS investment will be one of

these key building blocks to developing the Service Delivery Model of the future. It will enable, for example, improved segmentation of the customer base, identification of customer's interaction channel preferences, maintaining a customer record for life (through movement within the service territory) and better presentation of customer history to customer service agents.

Value of the Investment:

As well as the enabling capabilities which better position Hydro One for the future, the CIS replacement will deliver significant value in the areas of:

- Finance (cash flow) – by reducing the time lag between the end of the bill period and the delivery of the bill to the customer. The lag time was introduced to facilitate open market conditions but with today's technology it is no longer relevant and only skews real time consumption in relationship to the actual bill.
- Customer Service – improving first call resolution, reducing the time required to handle specific types of transaction, and reducing the volume of 'exceptions' ie conditions in which an agent is required to review an account, bill or payment before it can continue processing
- IT – by reducing the number of applications required to meet the requirements, we reduce the effort and cost associated with system maintenance, and the cost to support the hardware required to operate the applications – particularly the ability to eliminate the mainframe computers required to operate CSS.

As highlighted in Exhibit B, Tab 3, Schedule 1, the financial benefits are projected to be \$172M over seven years, including \$24.6M of avoided costs. These savings will commence after the system is fully implemented and training complete, beyond 2013.

Alignment with Outsourcing Strategy:

A major driver of the CIS investment is its timing relative to the end of the Inergi outsourcing agreement. Included in the scope of the outsourcing agreement is both the business operation of Hydro One's customer service, billing, collections and payment activities, as well as the IT hosting and maintenance of the enterprise applications including the CIS. As a result, the outsourcer plays a major part in the ongoing use and maintenance of the CIS system. The outsourcing agreement expires in early 2015 and Hydro One is

1 embarking on a competitive process to deliver these capabilities
2 through a new outsourcing agreement. Hydro One anticipates that
3 the market for these services will be more competitive if the CIS
4 application is based on a commercially available platform
5 (SAP/Itron) which is in wide use by utilities around the world,
6 relative to an aging system, last implemented in the 1990s, which
7 has been heavily customized and the user base for which is
8 declining.

9
10 iii) Commerce Way TS is planned to be placed in-service for December 2012
11 but capital contribution payments are slated to being in 2013. CIS is
12 planned to be placed in-service for Q2 2013. The other 3 projects are on-
13 going in nature and therefore will be in-serviced in phases during 2013.

14
15 iv) Commerce Way TS is being reconfigured to address capacity shortfalls in
16 the Woodstock area. The \$9.2M requested in this proceeding is the
17 unfunded share that Hydro One has agreed to contribute in order to fund
18 the transmission revenue shortfall of the project that was detailed and
19 agreed to as part of the leave-to-construct proceedings EB-2009-0079.
20 The other projects are being executed to allow the continued service of the
21 Hydro One customer base and are not proposed to address customer or
22 demand growth.

23
24 b)

25 i) All of the projects outlined above were anticipated.

26
27 Typical Capital was anticipated as required during EB-2009-0096. The
28 objectives and nature of these expenditures were rigorously reviewed and
29 ultimately approved during that proceeding. Rather than detailing a
30 defined set of particular projects, this capital represents an on-going,
31 recurring program of spending that, like OM&A, must be undertaken to
32 maintain the continued, safe operation of the business. For example, a
33 significant item in typical capital is the funding for system capability
34 reinforcement. These reinforcements take place in a planned fashion at a
35 relatively steady level from year to year. Presumably, in approval of the
36 capital portion of EB-2009-0096, the Board directed Hydro One to
37 continue its system reinforcement program in future years; not just 2011.

38 Commerce Way TS was anticipated as required during EB-2009-0079 and
39 leave-to-construct under Section 92 was approved. Inclusion here is
40 seeking to recover the capital contribution of \$9.2M that Hydro One is
41 required to make in support of the \$44.7M total project cost.

42 Hydro One has previously described to the Board the details surrounding
43 the advanced demographics of both wood poles and Distribution stations.
44 Exhibit D1 Tab 2 Schedule 1 of EB-2009-0079 demonstrates that Hydro

One has given these programs a very high priority. It was always understood that these issues would require an increased funding request at a future hearing. As more asset condition information has become available, it is now apparent that the level of deterioration is such that the system can no longer be reasonably sustained at current spending levels and acceleration of these programs is required.

CIS is the fourth phase of our successful Cornerstone program which has been discussed in past proceedings. This phase was originally planned for a 2016 in-service date. It was necessary to accelerate the project as described in Exhibit B Tab 3 Schedule 1.

- ii) The investments described in these projects are required to be made during the ICM year 2013 and thus cannot be deferred to a, as of yet undetermined, future rebasing proceeding.

Typical capital is a recurring program of spending and this funding is required in 2013 as in other years. Using the example of system reinforcements referred to in section i) above, Hydro One must provide for this investment to maintain reliability of the system. Withholding of recovery for these expenditures would be punitive.

Commerce Way is approaching completion. Failure to complete the project as planned would have serious consequences for the Woodstock area customers. Failure to fund the contribution that Hydro One has agreed to pay in 2013 would place an unfair burden on customers in other jurisdictions.

Deferral of the Refurbishment projects would potentially degrade the viability of the system. Systems have reached a critical juncture and temporary funding via the rider contemplated in this hearing is being sought now in order to allow for those critical investments to take place.

Several factors prompted the necessity for reconsideration and ultimately an acceleration of the CIS project from the original 2016 timeline. The decision to proceed with CIS was made in order to address customer needs, as well as the timing regarding the expiry of the Inergi Outsourcing Contract and the evolving industry requirements around distributed generation set against the significant risk associated with continuing to operate such a critical system at a severely advanced age.

- iii) Hydro One has a non-discretionary capital program that it needs to execute upon and believes that the amounts asked for herein are just and prudent. Hydro One successfully defended the costs in its typical capital and ultimately was awarded recovery of those expenses by the Board.

1 Hydro One has continued to spend funds in line with the original award
2 for substantially similar work.

3 Projects and work beyond the Typical Capital yet deemed necessary as
4 part of Hydro One's maintenance of the system is the focus of this
5 proceeding and Hydro One stands ready to defend the validity of those
6 investments. However, conducting another hearing or asking Hydro One
7 to defend yet again the Typical Capital costs which have already been
8 approved, would be inefficient and would only increase costs and
9 uncertainty which is ultimately detrimental to customers.

10 The Board has already agreed to the investments within the Typical
11 Capital program. Moreover, Hydro One believes that the Board will see
12 fit to make appropriate award for the necessary incremental investments
13 (Commerce Way TS, Distribution & Regulating Stations, Wood Pole
14 Replacement and CIS) also described in this proceeding. Therefore,
15 Hydro One has not gone through the significant effort of devising an
16 alternative Business Plan, complete with the necessary Board of Director
17 and shareholder approvals, to provide detailed alternative plans if the
18 proposed spending herein is disallowed.

19
20 c)

21
22 i) 2013 Incremental Capital Project work form is included in this Exhibit as
23 Attachment 1.

24
25 ii) ICM Rate Rider work form is included in this Exhibit as Attachment 2.

26
27 d) When Hydro One filed its update on August 29, 2012, an IRM application was
28 planned for 2014 rates and a cost of service application was planned for 2015
29 rates. The OEB has since provided an update on plans for a Renewed Regulatory
30 Framework for Electricity which provides three options for setting rates. Hydro
31 One is assessing these options to determine its approach for 2014 and 2015 rates.



Incremental Capital Project Summary for 2013 Filers

Version 1.0

Applicant Name
Name:
Title:
Phone Number:
Email Address:

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your IRM application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.



Incremental Capital Project Summary for 2013 Filers

Using the pull-down menu below, please identify what year of the IRM cycle you are in.

2nd year of IRM cycle

Name or General Description of Project

Incremental Capital Projects - 2013 ICM

Details of Project

see pre-filed evidence for complete details

Asset Component	Capital Cost	Depreciation Rate	CCA Class	CCA Rate
1 Typical Capital	142	4%	47	8%
2 Commerce way TS Capital Contribution	9	2%	47	8%
3 Distribution and Regulating Stations	43	2%	47	8%
4 Wood Pole Replacement	23	2%	47	8%
5 CIS	155	11%	12	50%
	2013	2014	2015	2016
Closing Net Fixed Asset	349	327	304	281
Amortization Expense	23	23	23	23
CCA	95	55	34	23



Incremental Capital Project Summary for 2013 Filers

Fixed Asset Amortization and UCC 1

Name or General Description of Project

[Incremental Capital Projects - 2013 ICM](#)

Asset Component

[Typical Capital](#)

Average Net Fixed Assets

Net Fixed Assets

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment	\$ -	\$ 142	\$ 142	\$ 142	\$ 142
Capital Investment	\$ 142	\$ -	\$ -	\$ -	\$ -
Closing Capital Investment	\$ 142	\$ 142	\$ 142	\$ 142	\$ 142
Opening Accumulated Amortization	\$ -	\$ 5	\$ 10	\$ 15	\$ 20
Amortization	4% \$ 5	\$ 5	\$ 5	\$ 5	\$ 5
Closing Accumulated Amortization	\$ 5	\$ 10	\$ 15	\$ 20	\$ 25
Opening Net Fixed Assets	\$ -	\$ 137	\$ 132	\$ 127	\$ 122
Closing Net Fixed Assets	\$ 137	\$ 132	\$ 127	\$ 122	\$ 117
Average Net Fixed Assets	\$ 69	\$ 135	\$ 130	\$ 125	\$ 120

For PILs Calculation

UCC

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC	\$ -	\$ 131	\$ 120	\$ 111	\$ 102
Capital Additions	\$ 142	\$ -	\$ -	\$ -	\$ -
UCC Before Half Year Rule	\$ 142	\$ 131	\$ 120	\$ 111	\$ 102
Half Year Rule (1/2 Additions - Disposals)	\$ -	\$ -	\$ -	\$ -	\$ -
Reduced UCC	\$ 142	\$ 131	\$ 120	\$ 111	\$ 102
CCA Rate Class	47				
CCA Rate	8%				
CCA	\$ 11	\$ 10	\$ 10	\$ 9	\$ 8
Closing UCC	\$ 131	\$ 120	\$ 111	\$ 102	\$ 94



Incremental Capital Project Summary for 2013 Filers

Fixed Asset Amortization and UCC 1

Name or General Description of Project

[Incremental Capital Projects - 2013 ICM](#)

Asset Component

[Commerce way TS Capital Contribution](#)

Average Net Fixed Assets

Net Fixed Assets

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment	\$ -	\$ 9	\$ 9	\$ 9	\$ 9
Capital Investment	\$ 9	\$ -	\$ -	\$ -	\$ -
Closing Capital Investment	\$ 9	\$ 9	\$ 9	\$ 9	\$ 9
Opening Accumulated Amortization	\$ -	\$ 0	\$ 0	\$ 1	\$ 1
Amortization	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Closing Accumulated Amortization	\$ 0	\$ 0	\$ 1	\$ 1	\$ 1
Opening Net Fixed Assets	\$ -	\$ 9	\$ 9	\$ 9	\$ 8
Closing Net Fixed Assets	\$ 9	\$ 9	\$ 9	\$ 8	\$ 8
Average Net Fixed Assets	\$ 5	\$ 9	\$ 9	\$ 9	\$ 8

For PILs Calculation

UCC

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC	\$ -	\$ 8	\$ 8	\$ 7	\$ 7
Capital Additions	\$ 9	\$ -	\$ -	\$ -	\$ -
UCC Before Half Year Rule	\$ 9	\$ 8	\$ 8	\$ 7	\$ 7
Half Year Rule (1/2 Additions - Disposals)	\$ -	\$ -	\$ -	\$ -	\$ -
Reduced UCC	\$ 9	\$ 8	\$ 8	\$ 7	\$ 7
CCA Rate Class	47				
CCA Rate	8%				
CCA	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1
Closing UCC	\$ 8	\$ 8	\$ 7	\$ 7	\$ 6



Incremental Capital Project Summary for 2013 Filers

Fixed Asset Amortization and UCC 1

Name or General Description of Project

[Incremental Capital Projects - 2013 ICM](#)

Asset Component

[Distribution and Regulating Stations](#)

Average Net Fixed Assets

Net Fixed Assets

	2013	2014	2015	2016	2017
	Forecasted	Forecasted	Forecasted	Forecasted	Forecasted
Opening Capital Investment	\$ -	\$ 43	\$ 43	\$ 43	\$ 43
Capital Investment	\$ 43	\$ -	\$ -	\$ -	\$ -
Closing Capital Investment	\$ 43	\$ 43	\$ 43	\$ 43	\$ 43
Opening Accumulated Amortization	\$ -	\$ 1	\$ 2	\$ 3	\$ 3
Amortization	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1
Closing Accumulated Amortization	\$ 1	\$ 2	\$ 3	\$ 3	\$ 4
Opening Net Fixed Assets	\$ -	\$ 42	\$ 41	\$ 40	\$ 39
Closing Net Fixed Assets	\$ 42	\$ 41	\$ 40	\$ 39	\$ 38
Average Net Fixed Assets	\$ 21	\$ 41	\$ 40	\$ 40	\$ 39

For PILs Calculation

UCC

	2013	2014	2015	2016	2017
	Forecasted	Forecasted	Forecasted	Forecasted	Forecasted
Opening UCC	\$ -	\$ 39	\$ 36	\$ 33	\$ 31
Capital Additions	\$ 43	\$ -	\$ -	\$ -	\$ -
UCC Before Half Year Rule	\$ 43	\$ 39	\$ 36	\$ 33	\$ 31
Half Year Rule (1/2 Additions - Disposals)	\$ -	\$ -	\$ -	\$ -	\$ -
Reduced UCC	\$ 43	\$ 39	\$ 36	\$ 33	\$ 31
CCA Rate Class	47				
CCA Rate	8%				
CCA	\$ 3	\$ 3	\$ 3	\$ 3	\$ 2
Closing UCC	\$ 39	\$ 36	\$ 33	\$ 31	\$ 28



Incremental Capital Project Summary for 2013 Filers

Fixed Asset Amortization and UCC 1

Name or General Description of Project

[Incremental Capital Projects - 2013 ICM](#)

Asset Component

[Wood Pole Replacement](#)

Average Net Fixed Assets

Net Fixed Assets

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment	\$ -	\$ 23	\$ 23	\$ 23	\$ 23
Capital Investment	\$ 23	\$ -	\$ -	\$ -	\$ -
Closing Capital Investment	\$ 23	\$ 23	\$ 23	\$ 23	\$ 23
Opening Accumulated Amortization	\$ -	\$ 0	\$ 1	\$ 1	\$ 2
Amortization	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Closing Accumulated Amortization	\$ 0	\$ 1	\$ 1	\$ 2	\$ 2
Opening Net Fixed Assets	\$ -	\$ 22	\$ 22	\$ 22	\$ 21
Closing Net Fixed Assets	\$ 22	\$ 22	\$ 22	\$ 21	\$ 21
Average Net Fixed Assets	\$ 11	\$ 22	\$ 22	\$ 21	\$ 21

For PILs Calculation

UCC

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC	\$ -	\$ 21	\$ 19	\$ 18	\$ 16
Capital Additions	\$ 23	\$ -	\$ -	\$ -	\$ -
UCC Before Half Year Rule	\$ 23	\$ 21	\$ 19	\$ 18	\$ 16
Half Year Rule (1/2 Additions - Disposals)	\$ -	\$ -	\$ -	\$ -	\$ -
Reduced UCC	\$ 23	\$ 21	\$ 19	\$ 18	\$ 16
CCA Rate Class	47				
CCA Rate	8%				
CCA	\$ 2	\$ 2	\$ 2	\$ 1	\$ 1
Closing UCC	\$ 21	\$ 19	\$ 18	\$ 16	\$ 15



Incremental Capital Project Summary for 2013 Filers

Fixed Asset Amortization and UCC 1

Name or General Description of Project

[Incremental Capital Projects - 2013 ICM](#)

Asset Component

[CIS](#)

Average Net Fixed Assets

Net Fixed Assets

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment	\$ -	\$ 155	\$ 155	\$ 155	\$ 155
Capital Investment	\$ 155	\$ -	\$ -	\$ -	\$ -
Closing Capital Investment	\$ 155	\$ 155	\$ 155	\$ 155	\$ 155
Opening Accumulated Amortization	\$ -	\$ 16	\$ 33	\$ 49	\$ 65
Amortization	\$ 16	\$ 16	\$ 16	\$ 16	\$ 16
Closing Accumulated Amortization	\$ 16	\$ 33	\$ 49	\$ 65	\$ 82
Opening Net Fixed Assets	\$ -	\$ 139	\$ 123	\$ 106	\$ 90
Closing Net Fixed Assets	\$ 139	\$ 123	\$ 106	\$ 90	\$ 74
Average Net Fixed Assets	\$ 70	\$ 131	\$ 115	\$ 98	\$ 82

For PILs Calculation

UCC

	2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC	\$ -	\$ 78	\$ 39	\$ 19	\$ 10
Capital Additions	\$ 155	\$ -	\$ -	\$ -	\$ -
UCC Before Half Year Rule	\$ 155	\$ 78	\$ 39	\$ 19	\$ 10
Half Year Rule (1/2 Additions - Disposals)	\$ -	\$ -	\$ -	\$ -	\$ -
Reduced UCC	\$ 155	\$ 78	\$ 39	\$ 19	\$ 10
CCA Rate Class	12				
CCA Rate	50%				
CCA	\$ 78	\$ 39	\$ 19	\$ 10	\$ 5
Closing UCC	\$ 78	\$ 39	\$ 19	\$ 10	\$ 5

Incremental Capital Rate Rider Model

Applicant Name	Hydro One Networks Inc.
Application Type	IRM3
LDC License Number	ED-2003-0043
Applied for Effective Date	January 1, 2013
Strech Factor Group	
Stretch Factor Value	0.40%
Last COS Re-based Year	2011
Last COS OEB Application Number	EB-2009-0096
ICM Billing Determinant for Growth - Numerator	2011 Re-based Forecast
ICM Billing Determinant for Growth - Denominator	2010 Actual

Table of Contents

Sheet Name	Purpose of Sheet
A1.1 LDC Information	Enter LDC Data
A2.1 Table of Contents	Table of Contents
B1.1 Re-Based Bill Det & Rates	Set Up Rate Classes and enter Re-Based Billing Determinants and Tariff Rates
B1.2 Removal of Rate Adders	Removal of Rate Adders
B1.3 Re-Based Rev From Rates	Calculated Re-Based Revenue From Rates
B1.4 Re-Based Rev Req	Detailed Re-Based Revenue From Rates
C1.1 Ld Act-Mst Rcent Yr	Enter Billing Determinants for most recent actual year
D1.1 Current Revenue from Rates	Enter Current Rates to calculate current rate allocation
E1.1 Threshold Parameters	Shows calculation of Price Cap and Growth used for incremental capital threshold calculation
E2.1 Threshold Test	Input sheet to calculate Threshold and Incremental Capital
E3.1 Summary of I C Projects	Summary of Incremental Capital Projects
E4.1 IncrementalCapitalAdjust	Shows Calculation of Incremental Capital Revenue Requirement
F1.2 Incr Cap RRider Opt B Var	Option B - Calculation of Incremental Capital Rate Rider - Variable Allocation

Rate Class and Re-Based Billing Determinants & Rates

Select the appropriate Rate Groups and Rate Classes from the drop-down menus in Columns C and D respectively. Following your selection, all appropriate input cells will be shaded green.

Last COS Re-based Year		2011							
Last COS OEB Application Number		EB-2009-0096							
Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Tariff Service Charge D	Re-based Tariff Distribution Volumetric Rate kWh E	Re-based Tariff Distribution Volumetric Rate kW F
UR	Residential - Urban	Customer	kWh	140,540	1,311,340,739		14.52	0.02918	
R1	Residnetial - Medium Density	Customer	kWh	412,455	4,397,300,810		19.72	0.03317	
R2	Residnetial - Low Density	Customer	kWh	367,107	5,374,784,594		55.69	0.03600	
Seasonal	Seasonal Residential	Customer	kWh	156,901	718,301,357		19.71	0.08205	
Gse	General Service Energy Billed (less than to 50 kW)	Customer	kWh	98,776	2,195,769,825		35.15	0.03938	
GSd	General Service Demand Billed (50 kW and above)	Customer	kW	7,361	3,122,290,618	10,389,644	47.72		10.439
UGe	Urban General Service Energy Billed (less than to 50 kW)	Customer	kWh	10,577	363,517,757		14.08	0.02325	
UGd	Urban General Service Demand Billed (50 kW and above)	Customer	kW	1,130	599,925,889	1,898,173	33.62		8.120
STR	Street Lights	Customer	kWh	5,234	122,364,767		1.05	0.05219	
SEN	Sentinel Lights	Customer	kWh	37,506	21,039,860		1.05	0.06972	
DGen	Distributed Generation	Customer	kW	88	4,181,950	66,329	37.32		5.823
ST	Sub-Transmission	Customer	kW	607	17,937,820,542	33,188,720	717.06		0.810

Removal of Rate Adders

Last COS Re-based Year

2011

Last COS OEB Application Number

EB-2009-0096

Rate Class	Re-based Tariff Service Charge A	Re-based Tariff Distribution Volumetric Rate kWh B	Re-based Tariff Distribution Volumetric Rate kW C	Service Charge Rate Adders D	Distribution Volumetric kWh Rate Adders E	Distribution Volumetric kW Rate Adders F	Re-based Base Service Charge H = A - D	Re-based Base Distribution Volumetric Rate kWh I = B - E	Re-based Base Distribution Volumetric Rate kW J = C - F
Residential - Urban	14.52	0.02918		0.00	0.00000	0.000	14.52	0.02918	0.000
Residential - Medium Density	19.72	0.03317		0.00	0.00000	0.000	19.72	0.03317	0.000
Residential - Low Density	55.69	0.03600		0.00	0.00000	0.000	55.69	0.03600	0.000
Seasonal Residential	19.71	0.08205		0.00	0.00000	0.000	19.71	0.08205	0.000
General Service Energy Billed (less than to 50 kW)	35.15	0.03938		0.00	0.00000	0.000	35.15	0.03938	0.000
General Service Demand Billed (50 kW and above)	47.72		10.439	0.00	0.00000	0.000	47.72	0.00000	10.439
Urban General Service Energy Billed (less than to 50 kW)	14.08	0.02325		0.00	0.00000	0.000	14.08	0.02325	0.000
Urban General Service Demand Billed (50 kW and above)	33.62		8.120	0.00	0.00000	0.000	33.62	0.00000	8.120
Street Lights	1.05	0.05219		0.00	0.00000	0.000	1.05	0.05219	0.000
Sentinel Lights	1.05	0.06972		0.00	0.00000	0.000	1.05	0.06972	0.000
Distributed Generation	37.32		5.823	0.00	0.00000	0.000	37.32	0.00000	5.823
Sub-Transmission	717.06		0.810	0.00	0.00000	0.000	717.06	0.00000	0.810

Calculated Re-Based Revenue From Rates

Last COS Re-based Year	2011
Last COS OEB Application Number	EB-2009-0096

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Base Service Charge D	Re-based Base Distribution Volumetric Rate kWh E	Re-based Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I	Service Charge % Revenue K = G / J	Distribution Volumetric Rate % Revenue kWh L = H / J	Distribution Volumetric Rate % Revenue kW M = I / J	Total % Revenue N = J / R
Residential - Urban	140,540	1,311,340,739		14.52	0.02918		24,493,479	38,259,018	0	62,752,497	39.0%	61.0%	0.0%	5.5%
Residnetial - Medium Density	412,455	4,397,300,810		19.72	0.03317		97,603,619	145,840,462	0	243,444,080	40.1%	59.9%	0.0%	21.2%
Residnetial - Low Density	367,107	5,374,784,594		55.69	0.03600		245,325,200	193,501,563	0	438,826,763	55.9%	44.1%	0.0%	38.2%
Seasonal Residential	156,901	718,301,357		19.71	0.08205		37,109,412	58,933,287	0	96,042,699	38.6%	61.4%	0.0%	8.4%
General Service Energy Billed (less than to 50 kW)	98,776	2,195,769,825		35.15	0.03938		41,667,398	86,463,622	0	128,131,020	32.5%	67.5%	0.0%	11.2%
General Service Demand Billed (50 kW and above)	7,361	3,122,290,618	10,389,644	47.72		10.439	4,215,517	0	108,456,724	112,672,241	3.7%	0.0%	96.3%	9.8%
Urban General Service Energy Billed (less than to 50 kW)	10,577	363,517,757		14.08	0.02325		1,787,587	8,450,647	0	10,238,235	17.5%	82.5%	0.0%	0.9%
Urban General Service Demand Billed (50 kW and above)	1,130	599,925,889	1,898,173	33.62		8.120	455,852	0	15,413,404	15,869,256	2.9%	0.0%	97.1%	1.4%
Street Lights	5,234	122,364,767		1.05	0.05219		65,672	6,385,815	0	6,451,487	1.0%	99.0%	0.0%	0.6%
Sentinel Lights	37,506	21,039,860		1.05	0.06972		470,596	1,466,886	0	1,937,483	24.3%	75.7%	0.0%	0.2%
Distributed Generation	88	4,181,950	66,329	37.32		5.823	39,440	0	386,202	425,642	9.3%	0.0%	90.7%	0.0%
Sub-Transmission	607	17,937,820,542	33,188,720	717.06		0.810	5,222,009	0	26,867,863	32,089,872	16.3%	0.0%	83.7%	2.8%
							458,455,782	539,301,300	151,124,193	1,148,881,275				100.0%
							O	P	Q	R				

Detailed Re-Based Revenue From Rates

Last COS Re-based Year	2011
Last COS OEB Application Number	EB-2009-0096

Applicants Rate Base

Average Net Fixed Assets

			Last Rate Re-based Amount	
Gross Fixed Assets - Re-based Opening	\$	7,491,600,000	A	
Add: CWIP Re-based Opening			B	
Re-based Capital Additions	\$	547,400,000	C	
Re-based Capital Disposals	\$	300,000	D	
Re-based Capital Retirements	-\$	31,100,000	E	
Deduct: CWIP Re-based Closing			F	
Gross Fixed Assets - Re-based Closing	\$	8,008,200,000	G	
Average Gross Fixed Assets			\$	7,749,900,000
Adjustment per EB-2009-0096			-\$	159,100,000
				$H = (A + G) / 2$

Accumulated Depreciation - Re-based Opening	\$	2,775,950,000	I	
Re-based Depreciation Expense	\$	283,700,000	J	
Re-based Disposals	\$	-	K	
Re-based Retirements			L	
Accumulated Depreciation - Re-based Closing	\$	3,059,650,000	M	
Average Accumulated Depreciation			\$	2,917,800,000
				$N = (I + M) / 2$

Average Net Fixed Assets			\$	4,673,000,000	$O = H - N$

Working Capital Allowance

Working Capital Allowance Base	\$	313,600,000	P	
Working Capital Allowance Rate		100.0%	Q	
Working Capital Allowance			\$	313,600,000
				$R = P * Q$

Rate Base			\$	4,986,600,000	$S = O + R$

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	\$	199,464,000	$W = S * T$
Deemed Long Term Debt %	56.00%	U	\$	2,792,496,000	$X = S * U$
Deemed Equity %	40.00%	V	\$	1,994,640,000	$Y = S * V$
Short Term Interest	2.43%	Z	\$	4,846,975	$AC = W * Z$
Long Term Interest	5.60%	AA	\$	156,500,309	$AD = X * AA$
Return on Equity	9.66%	AB	\$	192,682,224	$AE = Y * AB$
Return on Rate Base			\$	354,029,509	$AF = AC + AD + AE$

Distribution Expenses

OM&A Expenses	\$	525,000,000	AG	
Amortization	\$	283,700,000	AH	
Ontario Capital Tax (F1.1 Z-Factor Tax Changes)			AI	
Grossed Up PILS (F1.1 Z-Factor Tax Changes)	\$	34,200,000	AJ	
Low Voltage			AK	
Green Energy Riders	\$	20,600,000	AL	
			AM	
			AN	
			AO	
			\$	863,500,000
				$AP = \text{SUM} (AG : AO)$

Revenue Offsets

External Revenue	-\$	48,050,000	AQ	
Green Energy Riders	-\$	20,600,000	AR	
			AS	
			AT	
			-\$	68,650,000
				$AU = \text{SUM} (AQ : AT)$

Revenue Requirement from Distribution Rates			\$	1,148,879,509	$AV = AF + AP + AU$

Rate Classes Revenue

Rate Classes Revenue - Total (B1.1 Re-based Revenue - Gen)			\$	1,148,881,275	AW
Difference			-\$	1,766	$AZ = AV - AW$
Difference (Percentage - should be less than 1%)				0.000%	$BA = AZ / AW$

Load Actual - Most Recent Year (2010)

Rate Class	Fixed Metric	Vol Metric	Billed		Billed kWh	Billed kW	Base Service Charge	Base	Base	Distribution	Distribution	Total Revenue by Rate Class	
			Customers or Connections	Volumetric Rate kWh				Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Revenue kWh		Revenue kW
			A	B	C	D	E	F	G = A * D * 12	H = B * E	I = C * F	J = G + H + I	
Residential - Urban	Customer	kWh	156,008	1,541,499,421		\$14.52	\$0.02918		\$27,189,179	\$44,974,012	\$0	\$72,163,191	
Residnetial - Medium Density	Customer	kWh	393,658	4,392,848,608		\$19.72	\$0.03317		\$93,155,508	\$145,692,800	\$0	\$238,848,308	
Residnetial - Low Density	Customer	kWh	366,295	5,494,175,979		\$55.69	\$0.03600		\$244,782,431	\$197,799,859	\$0	\$442,582,290	
Seasonal Residential	Customer	kWh	158,247	717,944,476		\$19.71	\$0.08205		\$37,427,785	\$58,904,007	\$0	\$96,331,791	
General Service Energy Billed (less than to 50 kW)	Customer	kWh	98,010	2,292,030,276		\$35.15	\$0.03938		\$41,344,351	\$90,254,105	\$0	\$131,598,456	
General Service Demand Billed (50 kW and above)	Customer	kW	7,028	2,925,055,456	10,288,535	\$47.72		\$10.439	\$4,024,567	\$0	\$107,401,248	\$111,425,814	
Urban General Service Energy Billed (less than to 50 kW)	Customer	kWh	11,641	400,238,954		\$14.08	\$0.02325		\$1,967,510	\$9,304,300	\$0	\$11,271,810	
Urban General Service Demand Billed (50 kW and above)	Customer	kW	1,266	677,000,110	1,981,526	\$33.62		\$8.120	\$510,538	\$0	\$16,090,242	\$16,600,780	
Street Lights	Customer	kWh	4,943	126,331,424		\$1.05	\$0.05219		\$62,021	\$6,592,821	\$0	\$6,654,842	
Sentinel Lights	Customer	kWh	34,508	20,129,823		\$1.05	\$0.06972		\$432,980	\$1,403,439	\$0	\$1,836,419	
Distributed Generation	Customer	kW	88	5,970,096	59,361	\$37.32		\$5.823	\$39,440	\$0	\$345,633	\$385,073	
Sub-Transmission	Customer	kW	595	16,999,727,157	32,069,678	\$717.06		\$0.810	\$5,119,434	\$0	\$25,961,945	\$31,081,379	
									\$456,055,743	\$554,925,344	\$149,799,067	\$1,160,780,154	

Rate Class	Fixed Metric	Vol Metric	Current Base	Current Base	Current Base	Re-based	Re-based	Re-based	Current Base	Current Base	Current Base	Service	Distribution	Distribution	Total %	
			Service Charge A	Distribution Volumetric Rate kWh B	Distribution Volumetric Rate kWh C	Billed Customers or Connections D			Billed kWh E	Billed kWh F	Charge Revenue G = A * D *12					Distribution Volumetric Rate kWh Revenue H = B * E
Residential - Urban	Customer	kWh	14.52	0.02918	0.000	140,540	1,311,340,739	0	24,493,479	38,259,018	0	62,752,497	2.1%	3.3%	0.0%	5.5%
Residential - Medium Density	Customer	kWh	19.72	0.03317	0.000	412,455	4,397,300,810	0	97,603,619	145,840,462	0	243,444,080	8.5%	12.7%	0.0%	21.2%
Residential - Low Density	Customer	kWh	55.69	0.03600	0.000	367,107	5,374,784,594	0	245,325,200	193,501,563	0	438,826,763	21.4%	16.8%	0.0%	38.2%
Seasonal Residential	Customer	kWh	19.71	0.08205	0.000	156,901	718,301,357	0	37,109,412	58,933,287	0	96,042,699	3.2%	5.1%	0.0%	8.4%
General Service Energy Billed (less than to 50 kW)	Customer	kWh	35.15	0.03938	0.000	98,776	2,195,769,825	0	41,667,398	86,463,622	0	128,131,020	3.6%	7.5%	0.0%	11.2%
General Service Demand Billed (50 kW and above)	Customer	kWh	47.72		10.439	7,361	3,122,290,618	10,389,644	0	21,525,517	0	108,456,724	0.4%	0.0%	9.4%	9.8%
Urban General Service Energy Billed (less than to 50 kW)	Customer	kWh	14.08	0.02325	0.000	10,577	363,517,757	0	1,787,587	8,450,647	0	10,238,235	0.2%	0.7%	0.0%	0.9%
Urban General Service Demand Billed (50 kW and above)	Customer	kW	33.62		8.120	1,130	959,925,889	1,898,173	455,852	0	15,413,404	15,869,256	0.0%	0.0%	1.3%	1.4%
Street Lights	Customer	kWh	1.05	0.05219	0.000	5,234	122,364,767	0	65,672	6,385,815	0	6,451,487	0.0%	0.6%	0.0%	0.6%
Sentinel Lights	Customer	kWh	1.05	0.06972	0.000	37,506	21,039,860	0	470,596	1,466,886	0	1,937,483	0.0%	0.1%	0.0%	0.2%
Distributed Generation	Customer	kW	37.32		5.823	88	4,181,950	66,329	39,440	0	386,202	425,642	0.0%	0.0%	0.0%	0.0%
Sub-Transmission	Customer	kW	717.06		0.810	607	17,937,820,542	33,188,720	5,222,009	0	26,867,863	32,089,872	0.5%	0.0%	2.3%	2.8%
									458,455,782	539,301,300	151,124,193	1,148,881,275	39.9%	46.9%	13.2%	100.0%
												K				

Threshold Parameters

Price Cap Index

Price Escalator (GDP-IPI)	2.00%
Less Productivity Factor	-0.72%
Less Stretch Factor	-0.40%

Price Cap Index **0.88%**

Growth

ICM Billing Determinants for Growth - Denominator : 2010 Actual	<u>\$ 1,160,780,154</u>	B
ICM Billing Determinants for Growth - Numerator : 2011 Re-based Forecast	<u>\$ 1,148,881,275</u>	A
Growth	<u><u>-1.03%</u></u>	C = A / B

Threshold Test

Year	2011	
Price Cap Index	0.88%	A
Growth	-1.03%	B
Dead Band	20%	C
Average Net Fixed Assets		
Gross Fixed Assets Opening	\$ 7,491,600,000	
Add: CWIP Opening	\$ -	
Capital Additions	\$ 547,400,000	
Capital Disposals	\$ 300,000	
Capital Retirements	-\$ 31,100,000	
Deduct: CWIP Closing	\$ -	
Gross Fixed Assets - Closing	\$ 8,008,200,000	
Adjustment per EB-2009-0096	-\$ 159,100,000	
Average Gross Fixed Assets	<u>\$ 7,590,800,000</u>	
Accumulated Depreciation - Opening	\$ 2,775,950,000	
Depreciation Expense	\$ 283,700,000	D
Disposals	\$ -	
Retirements	\$ -	
Accumulated Depreciation - Closing	\$ 3,059,650,000	
Average Accumulated Depreciation	<u>\$ 2,917,800,000</u>	
Average Net Fixed Assets	<u>\$ 4,673,000,000</u>	E
Working Capital Allowance		
Working Capital Allowance Base	\$ 313,600,000	
Working Capital Allowance Rate	100.0%	
Working Capital Allowance	<u>\$ 313,600,000</u>	F
Rate Base	<u>\$ 4,986,600,000</u>	G = E + F
Depreciation	D \$ 283,700,000	H
Threshold Test	117.20%	I = 1 + (G / H) * (B + A * (1 + B)) + C
Threshold CAPEX	\$ 332,508,115	J = H *I

Summary of Incremental Capital Projects (ICPs)

Number of ICPs

5

Project ID #	Incremental Capital Non-Discretionary Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Typical Capital	\$ 142,000,000	\$ 4,970,000	\$ 11,130,000
ICP 2	Commerce Way TS Capital Contribution	\$ 9,200,000	\$ 190,000	\$ 730,000
ICP 3	Distribution and Regulating Stations	\$ 42,630,000	\$ 840,000	\$ 3,400,000
ICP 4	Wood Pole Replacement	\$ 22,860,000	\$ 440,000	\$ 1,820,000
ICP 5	CIS	\$ 155,400,000	\$ 16,360,000	\$ 77,700,000
		\$ 372,090,000	\$ 22,800,000	\$ 94,780,000

Incremental Capital Adjustment

Current Revenue Requirement

Current Revenue Requirement - Total	\$	1,148,879,509	A

Return on Rate Base

Incremental Capital CAPEX			\$	372,090,000	B
Average Depreciation Expense			\$	22,800,000	C
Incremental Capital CAPEX to be included in Rate Base			\$	349,290,000	D = B - C
Deemed ShortTerm Debt %	4.0%	E	\$	13,971,600	G = D * E
Deemed Long Term Debt %	56.0%	F	\$	195,602,400	H = D * F
Short Term Interest	2.0%	I	\$	280,829	K = G * I
Long Term Interest	4.9%	J	\$	9,662,759	L = H * J
Return on Rate Base - Interest			\$	9,943,588	M = K + L
Deemed Equity %	40.0%	N	\$	139,716,000	P = D * N
Return on Rate Base -Equity	9.16%	O	\$	12,797,986	Q = P * O
Return on Rate Base - Total			\$	22,741,573	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	\$	22,800,000	S

Grossed up PIL's

Regulatory Taxable Income	O	\$	12,797,986	T
Add Back Amortization Expense	S	\$	22,800,000	U
Deduct CCA		\$	94,780,000	V
Incremental Taxable Income		-\$	59,182,014	W = T + U - V
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26%	X		
PIL's Before Gross Up		-\$	15,091,414	Y = W * X
Incremental Grossed Up PIL's		-\$	20,256,931	Z = Y / (1 - X)

Ontario Capital Tax

Incremental Capital CAPEX	\$	372,090,000	AA
Less : Available Capital Exemption (if any)	\$	-	AB
Incremental Capital CAPEX subject to OCT	\$	372,090,000	AC = AA - AB
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.00%	AD	
Incremental Ontario Capital Tax	\$	-	AE = AC * AD

Incremental Revenue Requirement

Return on Rate Base - Total	Q	\$	22,741,573	AF
Amortization Expense - Total	S	\$	22,800,000	AG
Incremental Grossed Up PIL's	Z	-\$	20,256,931	AH
Incremental Ontario Capital Tax	AE	\$	-	AI
Incremental Revenue Requirement		\$	25,284,642	AJ = AF + AG + AH + AI

Calculation of Incremental Capital Rate Rider - Option B Variable

Rate Class	Fixed Metric	Vol Metric	Total Revenue \$ by Rate Class A	Total Revenue % by Rate Class B = A / \$H	Total Incremental Capital \$ by Rate Class C = \$I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential - Urban	Customer	kWh	\$62,752,497	5.46%	\$1,381,060	1,311,340,739		\$0.0011	
Residnetial - Medium Density	Customer	kWh	\$243,444,080	21.19%	\$5,357,731	4,397,300,810		\$0.0012	
Residnetial - Low Density	Customer	kWh	\$438,826,763	38.20%	\$9,657,724	5,374,784,594		\$0.0018	
Seasonal Residential	Customer	kWh	\$96,042,699	8.36%	\$2,113,713	718,301,357		\$0.0029	
General Service Energy Billed (less than to 50 kW)	Customer	kWh	\$128,131,020	11.15%	\$2,819,915	2,195,769,825		\$0.0013	
General Service Demand Billed (50 kW and above)	Customer	kW	\$112,672,241	9.81%	\$2,479,697	3,122,290,618	10,389,644		\$0.2387
Urban General Service Energy Billed (less than to 50 kW)	Customer	kWh	\$10,238,235	0.89%	\$225,324	363,517,757		\$0.0006	
Urban General Service Demand Billed (50 kW and above)	Customer	kW	\$15,869,256	1.38%	\$349,251	599,925,889	1,898,173		\$0.1840
Street Lights	Customer	kWh	\$6,451,487	0.56%	\$141,985	122,364,767		\$0.0012	
Sentinel Lights	Customer	kWh	\$1,937,483	0.17%	\$42,640	21,039,860		\$0.0020	
Distributed Generation	Customer	kW	\$425,642	0.04%	\$9,368	4,181,950	66,329		\$0.1412
Sub-Transmission	Customer	kW	\$32,089,872	2.79%	\$706,236	17,937,820,542	35,499,081		\$0.0199
			\$1,148,881,275	100.00%	\$25,284,642				
			H		I				

Enter the above rate riders onto "Sheet 11. Proposed Rates" in the 2013 OEB IRM3 Rate Generator as a "Rate Rider for Incremental Capital"

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab1/Sch1/page3

At lines 18-20 on page 3, Hydro One indicates that, “The current ICM provides a mechanism for recovering Escalated Issue and Non-Typical capital spending during an IRM period. There is also a requirement to recover Typical capital spending, in excess of approved depreciation, during the period of an IRM.”

Please provide further explanation and rationale for the statement that there is a requirement to also recover Typical capital spending in excess of approved depreciation during the period of an IRM.

Response

Exhibit B, Tab 1, Schedule 1, Table 1 provides the calculation of the amount of rate base that would not be covered if Hydro One spent at the approved level of non-discretionary Typical Capital in 2013. This represents a shortfall of \$142M of unrecovered rate base and a revenue shortfall of \$14M.

Typical Capital spending levels have been successfully defended in very detailed cost of service proceedings and have been approved by the OEB as the amount of capital required to sustain and develop Hydro One’s system. This issue is further discussed in Exhibit I, Tab 2, Schedule 1.01 Staff 2.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab1/Sch1/page6

At lines 16-17, Hydro One indicates that one outcome of not investing in rate base is lower reliability. Has Hydro One quantified or estimated the potential lower reliability that it is referring to?

Response

Hydro One has not quantified the lower reliability. As described in Exhibit B, Tab 2, Schedule 2 and Exhibit B, Tab 2, Schedule 3, Distribution System performance as pertaining to such factors as reliability, safety and customer satisfaction is directionally determined by the state of the assets over time including asset age and asset condition. The older the asset (in particular the closer the asset is to end of life) and the worse the condition of the asset, the higher the risk that performance will deteriorate and factors such as reliability will be negatively impacted.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab1/Sch1/page6/lines 22-24

Please explain fully or clarify how ‘harvesting of assets’ will result in ‘increased contract and employee labour costs as Hydro One would be unable to levelize work based on the most efficient use of resources.’

Response

The harvesting of assets – that is, deferring or forgoing of required sustainment work in the short term - generally results in comparatively more sustainment work to be done over the longer term and often uses more expensive resources to undertake this work.

Harvesting results in increasing risk over time: i) the risk of accelerating deterioration of asset condition and performance; and ii) the risk of asset failure. Accelerating asset deterioration requires overall more sustainment work to be performed by employees and contract staff over time than would otherwise be the case if assets are properly sustained.

Individual asset failures result in unplanned repair or replacement work which can occur at any time of the day or night, weekdays or weekends. Unplanned work is far less efficient than planned sustainment work which is carried out on groups of similar or related assets – resulting in economies of scale. Unplanned work can also interfere with planned work because of the need to divert resources resulting in demobilization and remobilization costs. Unplanned work outside regular work hours is necessarily more expensive due to overtime premiums as well as premium contract fees.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab1/Sch2/page1/lines 6-7

Hydro One indicates that the methodology applied in the application is ‘generally consistent’ with Board requirements as outlined in Chapter 3 of the Filing Requirements. Please provide further detail on where the application may not be consistent with the guidelines.

Response

Hydro One did not populate and submit 2 incremental capital module (ICM) spreadsheets (as posted on the OEB site) and the RTSR Adjustment workform. However, all relevant information was provided as part of the pre-filed evidence. In Exhibit I, Tab 2, Schedule 1.01 Staff 2, part c), Hydro One has provided the ICM spreadsheets. Exhibit I, Tab 11, Schedule 1.01 Staff 33 address the RTSR Adjustment workform.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref:

- 1) Exhibit B/Tab1/Sch1
 - 2) Filing Requirements for Transmission and Distribution Applications, June 28, 2012, Chapter 3, section 2.2.1 page 7
 - 3) Exhibit B/Tab1/Sch 2
- a) Please clarify if, at Reference 1, page 1 on line 28, the reference to 2010 revenue means 2010 actual revenue?
 - b) Also regarding Exhibit B/Tab 1/Schedule1, page 1, on line 28, please clarify the meaning of "... 2010 revenue at 2011 rates of \$1,161 million."
 - i) Why was the adjustment made?
 - ii) Provide a detailed explanation of the adjustment that was made.
 - c) In calculating the Threshold Value, Hydro One appears to have used 2011 as the base year and 2010 for revenues in the threshold value determination. On what basis has Hydro One used 2010 revenues rather than "the most current year" as called for in reference 2? Why has Hydro One not chosen to use 2011 actual revenues instead of 2010?
 - d) Was the final 2011 actual revenue not available at the time of application? If it was available why was it not used in the calculation as a more appropriate comparator for 2011 rates? If it was available, or has since become available, please repeat the calculation of the threshold value, based on the 2011 actual revenue and the 2011 approved revenue requirement.

Response

- a) Yes. This reference refers to actual revenue.
- b)
 - i) The adjustment was made to align with the calculation of growth under the Board's ICM approach which defines growth as "distribution revenue change from load growth (%)" (ref. page V, Appendix B of the Supplemental Report of the Board issued under proceeding EB-2007-0673). In order to isolate for the revenue change from load growth the 2010 revenue needs to be adjusted for current (2011) rates.

- 1 ii) The adjustment consisted of increasing the Jan.1 to Apr. 30 2010 revenues that
2 were collected at 2009 rates to reflect the increase in rates in 2010 and 2011, and
3 increasing the May 1 to Dec. 31 2010 revenues that were collected at 2010 rates
4 to reflect the increase in rates in 2011. The details of this calculation are provided
5 below.
6
7 c) Hydro One followed the example provided by the Board on page V, Appendix B of
8 the Supplemental Report of the Board issued under proceeding EB-2007-0673, which
9 indicates that for an LDC that rebased in 2011, the board approved values should be
10 compared to 2010 actuals.
11
12 d) The 2011 actual revenue was available, but as noted in part c, Hydro One believed
13 that use of the 2010 actual for comparison to 2011 was appropriate. Using the 2011
14 actual distribution rates revenue of \$1,165.8 results in a growth rate of 1.5% (2011
15 actual revenue/2011 Board approved Revenue = \$1,165.8/\$1148.9) and a threshold
16 value of \$458.2M.
17
18

1
2
3

Calculation of ICM Growth

$\text{growth} = \frac{\text{2011 Re-based Revenue Requirement}}{\text{2010 Actual Revenue at 2011 Rates}} - 1$

2011 Re-based Revenue Requirement (\$M)	1148.9	A

Approved Rate Changes

	\$M	% increase	
2008 Board Approved Rates Revenue Requirement	985.8		
2009 Board Approved Rates Revenue Requirement	997.4	1.18%	
2010 Board Approved Rates Revenue Requirement	1084.9	8.77%	B
2011 Board Approved Rates Revenue Requirement	1148.9	5.90%	C

2010 Actual Revenue (\$M)

	Total	Jan. 1 - Apr. 30 (2009 rates)	May 1 - Dec. 31 (2010 rates)
Fixed	428.1	145.1	283.0
Variable	607.1	187.2	419.9
ST	31.1	9.2	21.9
Total	1066.3	341.5	724.8
	D	E	F

Adjustment of 2010 Actual Revenue for 2011 Rates

Jan-Apr 2010 Revenue at 2011 rates (\$M)	393.4	= E x (1+B) x (1+C)
May-Dec 2010 Revenue at 2011 rates (\$M)	767.5	= F x (1+C)
Total	1160.9	G

$\text{Growth} = \frac{\text{A}}{\text{G}} - 1$	$= \frac{1148.9}{1160.9} - 1$

4
5

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref:

- 1) Exhibit B/Tab1/Sch1
- 2) Exhibit B/Tab1/Sch2
- 3) EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008

Hydro One provides information that its Typical spending for 2013 will be \$451.9 million (Exhibit B/Tab1/Sch1/page 8/Table 2); that in-service additions in 2013 will be \$414 million (Exhibit B/Tab1/Sch1/page 4/Table 1/line 2), and that depreciation used to discount the in-service amount in 2013 will be \$283 million (Exhibit B/Tab1/Sch1/page 4/Table 1/line 3).

For its "Typical Capital" it appears that Hydro One is requesting additional revenue beyond the revenue that would be achieved from current rates resulting from the EB-2009-0096 Cost of Service Decision. Hydro One explains that it should be allowed incremental revenue in order to recover the differences between capital expenditures in the year and the depreciation in that year.

- a) Hydro One indicates that capital spending was reviewed in detail by the Board in EB-2009-0096 as noted at Exhibit B/Tab1/Sch1/page 2/lines 18 - 26, and that this Typical capital spending does not require detailed further review. The Board's ICM filing guidelines (section 2.2.5) indicate that amounts claimed are to be clearly non-discretionary and outside the base upon which current rates were derived. Why has Hydro One not filed evidence showing that Typical capital claimed in this ICM is outside of the base upon which current rates were derived?
- b) Please provide additional evidence on the \$451.9 million Typical capital amount to show that this capital is incremental to capital amounts already included current rates as approved in EB-2009-0096.
- c) In EB-2009-0096 the Board approved the capital spending for 2011. Is the capital spending of \$451.9 million in 2013 consistent with the Cost of Service authorization of EB-2009-0096? Please provide additional detail to show what specific projects make up the \$451.9 million.
- d) Hydro One refers (Exhibit B/Tab1/Sch1/page 3/line 20) to its submission on the 3rd generation incentive rate mechanism, that "... there is a requirement to recover Typical capital spending in excess of approved depreciation, during the period of an

1 IRM". In its Supplemental Report of September 17, 2008 (Reference 3), the Board
2 notes at page 30 that "The distributors ... perceive the module would enable them to
3 adjust rates on an on-going as-needed basis to accommodate increase in rate base." It
4 appears to Board staff, that the Board did not accept Hydro One's view and clarified,
5 in the middle of page 31, that "... adjustment in rates will be linked solely to the costs
6 of the incremental capital." The Board also concluded that "The intent is not to have
7 an IR regime under which distributors would habitually have their CAPEX reviewed
8 to determine whether their rates are adequate to support the required funding." How
9 does Hydro One reconcile the application with the findings in the Supplemental
10 Report?

- 11
12 e) Please explain why Hydro One considers that there is or should be a relationship
13 between Capital Expenditure in a particular year (2013) and the depreciation
14 allowance which is approved in a previous test year (2011).
15
16 f) Please provide an explanation as to why the depreciation is insufficient to recover the
17 planned capital expenditures.

18
19 [Response](#)
20

21 a) b) c)

22 The amount and nature of the proposed Typical Capital described in this proceeding
23 is consistent with the spending upon which current rates are derived. This is at the
24 heart of Hydro One's assertion that these expenses have been reviewed, defended,
25 and approved therefore further justification is not appropriate.
26

27 What is not included in current rates is sufficient funding to offset the increase in
28 Rate Base due to these non-discretionary expenditures. Depreciation of \$283M was
29 included in the original award but ICM 2013 calls for in-servicing of \$414M.
30 Therefore, upon completion of the planned spending, Rate Base will grow in 2013 by
31 \$131M. If recovery of this increase to Rate Base is not allowed then the annual
32 revenue shortfall endured by Hydro One is estimated to be \$13M.
33

- 34 d) Hydro One agrees that previously approved capital programs should not be habitually
35 reviewed so long as spending is at the same levels as the approved amount. The only
36 exception ought to be when there is a significant shortfall in revenue due to increased
37 capital spending causing an unfunded increase in Rate Base. The trigger for
38 determining whether that review should take place is the Threshold calculation. Once
39 the threshold is surpassed the unfunded increase in Rate Base due to the non-
40 discretionary spending that is consistent with the amount previously approved by the
41 Board should be accepted in its entirety.
42

43 The result of adhering to this methodology is a steady state wherein rate adjustments
44 follow a smoothed pattern over time. The typical work that was approved by the

1 Board and is expected by customers to be completed on an annual basis can continue
2 uninterrupted.

3
4 e) Under the current IRM scheme, the 2011 depreciation (\$283M) is included in rates
5 for 2011 and for all subsequent years until re-baselining takes place. When capital
6 spending exceeds the depreciation allowed for in rates, the inevitable result is that rate
7 base goes up and this rate base increase is unfunded. To complete its non-
8 discretionary typical capital program that is appropriately in-line with 2011 Board
9 approved amount, Hydro One will in-service \$414M in capital and thus grow its rate
10 base by a net amount of \$131M. Furthermore, Hydro One is proposing escalated and
11 non-typical spending of \$230M which would also increase rate base without funding.

12
13 f) Hydro One is replacing assets that were put in service many decades ago. The cost to
14 replace these assets is much higher than the previous cost to install them. The
15 depreciation amount currently allowed in rates is a factor of the original cost of the
16 asset many years ago. Given the increase in cost to install the asset, the previously
17 approved funding is not sufficient to provide recovery of the depreciation expense
18 that Hydro One will incur after the asset is installed.

19
20 For example, let's assume that an asset was put into service for \$400 in 1972. Also,
21 let's assume that the asset is depreciated straight line over 40 years at \$10 per year.
22 Assuming that inflation has been 2% per year since 1972, the same asset (like-for-like
23 replacement) will cost approximately \$880 to replace in 2012 at the end of the asset's
24 useful life. The resulting depreciation expense on the new replacement asset is \$22
25 (\$880/40 years = \$22). However, in an IRM environment, only the previously
26 approved amount of \$10 of depreciation is included in the calculation of rates.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref:

- 1) EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors
 - a. June 14, 2008
 - b. September 17, 2008.
- 2) Chapter 3 of the Filing Requirements for Transmission and Distribution Applications, June 28, 2012
- 3) Exhibit B/Tab1/Sch1
- 4) Hydro One Draft Rate Order for 2010 and 2011 Rates EB-2009-0096 Exhibit 1.2, December 17, 2010.

The Board's ICM module Threshold Formula calls for a summing of all the test year (incremental) capital requirements and compare them against the threshold determined on the basis of the total Rate Base and total Depreciation for the company as listed in the Draft Rate Order for (in Hydro One's case) the year 2011.

Reference 2, at page 8 advises that "A distributor applying for recovery of incremental capital should calculate the eligible incremental capital amount by taking the difference between the 2013 total non-discretionary capital expenditure and the materiality threshold."

Hydro One, in determining the threshold value for incremental capital, appears to have used the total amount for all capital projects (\$644 million at Exhibit B/Tab1/Sch1/page 9/Table 3) to determine the threshold value. Please indicate why Hydro One feels that the calculations should be based on the total annual amounts rather than on the incremental amounts related to each of the projects for which the incremental capital is sought?

Response

Hydro One has determined the materiality threshold to be \$332M using the Board approved formula specified in Section 2.2.1 of Chapter 3 of the filing requirements. Details of the calculation are available in Exhibit B, Tab 1, Schedule 1. The calculation of the materiality threshold is independent of the incremental capital requirements.

The ICM threshold formula includes a dead-band of 20% above and beyond the growth and inflation adjustments. Hydro One agrees that a 20% dead band is an appropriate band within which a utility could reasonably be expected to maintain the necessary

Filed: October 11, 2012

EB-2012-0136

Exhibit I

Tab 2

Schedule 1.08 Staff 9

Page 2 of 2

- 1 capital spending. Once exceeded the utility should be eligible to apply for recovery of all
- 2 non-discretionary capital above depreciation.
- 3
- 4 With a threshold amount of \$332M, and total non-discretionary spending of \$644M, the
- 5 ICM is triggered and Hydro One is eligible to file for recovery.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref:

- 1) Exhibit B/Tab2/Sch3/page 1
- 2) EB-2009-0096, Decision and Order, page 27, last paragraph
- 3) Application EB-2009-0096, Exhibit B/Tab2/Sch1/page 17/line 20

Hydro One indicates in the pre-filed evidence, that there is a need to increase the rate of replacement of wood poles which are coming to their end of life. At line 22 of reference 1, Hydro One indicates that it is changing its approach from one based on asset condition information to one largely based on replacing aging and deteriorating wood pole populations.

In the EB-2009-0096 proceeding, Hydro One indicated that the proposed work plan was based on asset condition information (Reference 2).

- a) Evidence shows that the problem of defective poles was known during the EB-2009-0096 application. Why should this activity be considered as a new and unanticipated incremental capital expenditure amount? How have the additional wood pole replacement costs in this application been adjusted for the wood pole replacement costs already included in 'Typical' Capital?
- b) Would the new approach eliminate condition assessment for all age categories of poles? Would the new approach replace poles without verifying an EOL condition?
- c) Would the revised approach result in replacing poles which do not need to be replaced (due age and due to condition) and on the other side, result in not replacing some which should be replaced (due to poor condition)?
- d) Please provide any studies, discussion and policy papers related to the changed approach and evidence of approval by Hydro One management reflecting the change in policy from an Asset Assessment based program to one based largely on age-based replacement.
- e) Have there been any modifications to purchase procedures to identify defects at the time of acquisition of the wood poles, so as to avoid future problems similar to this purchase of defectively treated red pine poles?
- f) Has Hydro One undertaken any legal action to recover the additional costs of the defective poles purchased?

- 1
2 g) How does Hydro One propose to complete this additional work in 2013? Please
3 provide data on effects on OM&A including additional staffing and other means to
4 complete the work, and indicate if any other programs will be affected and how they
5 will be affected.
6
7 h) Please indicate the replacement rate of wood poles that has occurred in the “wood
8 pole replacement program” over each of the last 10 years.
9
10 i) Please indicate what failure rate has occurred in poles over each of the last 10 years.
11
12 j) Given that the proactive replacement of EOL poles reduces the outage time and
13 reduces the time for replacement from 9 hours for an unplanned replacement to 2
14 hours in what budget are the savings expected to be seen? Will the OM&A budget be
15 reduced? Has this been taken into account in any way?
16
17 k) Why is it necessary to significantly increase the rate of pole replacements now,
18 instead of for the next cost of service application? What is it that makes this change
19 so urgent at this time? The matter of defective poles was raised in the Hydro One
20 application of 2009 as indicated in Reference 3. Did Hydro One anticipate at that time
21 that it would seek additional funding at the next Cost of Service hearing? Please
22 explain.
23

24 **Response**

- 25
26 a) Please refer to Exhibit I, Tab 2, Schedule 1.09 Staff 2, part b).
27
28 b) Hydro One is not eliminating asset condition assessment for wood poles of any age.
29 The decision to replace wood poles is based on both asset condition assessments and
30 historical failure rates which are correlated to age.
31
32 c) No. Hydro One will continue to schedule replacements for all poles that have reached
33 EOL; which takes into consideration both condition and age demographics as well as
34 as other factors like the likelihood and consequence of failure and the risks associated
35 with system reliability, safety, and future costs.
36
37 d) The proposed approach is an enhancement to the existing approach due to the recent
38 availability of asset inventory. It is not a significant departure from current wood
39 pole replacement practices at Hydro One. Refer to parts b) and c)
40
41 e) Yes. Hydro One has made changes to its purchasing specifications. The manufacturer
42 is required to retain a Hydro One approved 3rd party to perform tests on every pole as
43 opposed to one per batch. Hydro One now includes a sterilization requirement from
44 the ANSI O15.1 standard and is more prescriptive regarding compliance with CSA.

- f) Hydro One did not pursue legal action as it was determined that there was very low probability it would result in cost recovery.
- g) The increase in wood pole replacement work will be resourced mostly with the existing staff complement as the smart meter network installation work is ramping down significantly which will free up resources to be reallocated from one program to the other.
- h) The number of poles replaced annually under the replacement program is outlined in the table below:

Year	Replacement volume (units)
2003	3000
2004	3082
2005	2699
2006	5193
2007	6852
2008	6736
2009	7481
2010	7518
2011	7284
2012	7400
Forecast	

- i) The number of poles replaced annually due to a failure is outlined in the table below:

Year	Poles Replaced Due to a Failure (units)
2003	883
2004	890
2005	1,428
2006	1,393
2007	1,321
2008	827
2009	987
2010	806
2011	1,380
2012	510
YTD	

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Exhibit I

Tab 2

Schedule 1.09 Staff 10

Page 4 of 4

- 1 j) Wood pole replacements proactive or reactive impact the capital budget. The
- 2 proposed plan seeks to mitigate the deterioration of the system not improve it, hence
- 3 no cost savings are expected in the near term.
- 4
- 5 k) Please refer to Exhibit I, Tab 2, Schedule 1.01Staff 2, part b).

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref:

- 1) Exhibit B/Tab2/Sch3/page2/lines 5 to 14
- 2) EB-2009-0096, Exhibit D1/Tab2/Sch1
- 3) Exhibit B/Tab2/Sch3/page 2/line 9 & Exhibit B/Tab 2/Sch3/page 9/lines 11-14

Reference 1 refers to the report dated December 2010 by EDM International Inc. on the examination of a specific manufacturer's wood poles (filed on a confidential basis) and identifies that 55,000 red pine poles are defective and will need to be replaced over a decade.

Reference 2, from Hydro One's previous Cost of Service application EB-2009-0096, also identified that there are 55,000 defective poles, and identifies (page 17, line 16) that "50% of the red pine poles ... will require replacement over the next 5 years".

Reference 3 seems to indicate that the pole replacement rate includes the replacement of poles which are at end of life through old age and poles which are at end of life due to defects (including the defective red-pine poles).

- a) Please confirm that the proposal for an increase in the rate of pole replacements, from 7,200 poles/year to 11,000 poles/year, represents an increase from 0.42% to 0.65% of the total population per year.
- b) Reference 3 appears to show that the proposed replacement rate includes the defective red-pine poles which need to be replaced. Is this correct? Some of the following questions are based on this appearance.
- c) In the present application, Hydro One (Reference 1) identifies that there are 55,000 defective red pine poles (which are the subject of the EDM report) and that they should be replaced over a decade. Please:
 - i. confirm that this constitutes 3% of the pole population and requires an average 0.3% of the total population of poles to be replaced in each year of the next decade, or
 - ii. alternatively, identify the intended replacement pattern for these defective poles.
- d) Reference 3, from Hydro One's application of July 13, 2009 at page 17 first identified the problem of defective red pine poles installed between 1997 and 2004, and that 55,000 poles were affected, and that 50% of these poles should be replaced within 5

years. How many of these defective poles have been replaced in the years 2009 through 2012?

- e) Please confirm that the proposed increased replacement rate for poles, from 0.42% per year to 0.65% per year (see a) above), represents an increase of 0.23%.
- f) Please confirm that the increased replacement rate is less than what is required to replace the defective poles (0.3% per year), and that the replacement rate for the “non-defective” balance of the poles will actually be lower than the current replacement rate (0.65%-0.3%=0.35%).
- g) Is Hydro One satisfied that the replacement of the defective red pine poles is being effected on a sufficiently rapid basis? How does this relate to Reference 2, where it is stated that 50% of the defective poles should be replaced in 5 years?

Response

- a) Yes
- b) Yes
- c) Yes, based on the EDM Report recommendation, in order to replace the “defective” poles over a decade, an average of 0.3% of the total population of poles would require replacement each year.
- d) The number of “defective” poles replaced in the years 2009 through to 2012, is outlined in the table below:

2009	2010	2011	2012 YTD	Total
121	201	374	1122	1822

- e) Yes
- f) Assuming a constant rate over ten years, the increased replacement rate is less than what is required to replace the “defective” poles. However, Hydro One plans to increase replacement rates in the years beyond 2013 as indicated in the evidence in Exhibit B, Tab 2, Schedule 3, page 13.
- g) While it is likely that 50% of the pine poles will not be replaced in the next 5 years, Hydro One is carefully targeting poles for replacement to maintain an acceptable level of risk on the system and plans to increase replacement rates in years beyond 2013 to deal with the issue.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab2/Sch2

Hydro One states that it has learned from the Asset Management approach but is moving to increase replacements based on service life. Hydro One suggests that there has been a greater dependency on maintenance of distribution assets.

Section 2 starting at page 4 is entitled “Station Refurbishments Program”, but at numerous points within the section the term “replacement” is used, e.g. on page 6 at line 16 the application refers to “the proposed replacement of 32 stations per year ...” Furthermore, page 15 describes the concept of a prefabricated integrated modular distribution station.

Hydro One indicates at Exhibit B/Tab 2/Sch2/page 1, line 25 that it has “continuously learned from available condition assessment information”, and that this is “not viewed to be sustainable or prudent from a long-term perspective”.

- a) What would Hydro One do in regard to this program if the Board did not grant the amount sought for the Station Refurbishments program? What would Hydro One do, and what would the consequences be, if the Board granted only half of the requested increment in the rate of replacement i.e. replacement of 18 substations (additional 14 over current rate) instead of 32 proposed in 2013?
- b) What would Hydro One do in regard to this program if the Board did not grant the amount sought for the Transformer Spares and Replacement program? What would Hydro One do, and what would the consequences be, in regard to this program if the Board granted only half the amount sought for the Transformer spares and Replacement program?
- c) How have the additional Station Refurbishment costs in this application been adjusted for the Station Refurbishment costs already included in ‘Typical’ Capital?
- d) Please provide additional information on the new Asset Analytic tools Hydro One has developed and applied, as indicated at Exhibit B/Tab2/Sch2/page 2/line 4. Has this approach been applied elsewhere? If so, please provide information.
- e) What are the criteria for replacement of substations as opposed to refurbishment?

- 1 f) What assumptions have been made as to the proportion of refurbishments vs.
2 replacements?
3
4 g) What is the basis of the forecast in Exhibit B/Tab2/Sch2/page 3/Table 1, of \$29
5 million for station refurbishment?
6
7 h) Given that the age distribution and condition assessment have been available for some
8 time, why is this requirement something that should not have been foreseen?
9
10 i) Please complete the table below, indicating, for the refurbishments of distribution and
11 regulating stations in the last 10 stations, whether there was replacement with new
12 components (“new”) or rehabilitation of the whole station (“rehab”). Please indicate
13 why the increase in Transformer Spares replacement cannot be accommodated
14 through a Cost of Service application.
15

Station/year	Main Transformer	HV busbars	LV busbars	HV circuit breakers	LV circuit breakers	Relay panels	Battery Charger

- 16
17 j) Given that the referenced statements refer to the “long-term perspective” (page 1 line
18 28) and the “longer term view of investment needs” why should the modified
19 program be considered as urgent?
20
21 k) Regarding Operating Spare Purchases, Exhibit B/Tab2/Sch2, page18: Please provide
22 evidence of the difference in lifespan of a fully refurbished used transformer
23 compared with a new station. What would Hydro One do, and what would the
24 consequences be, if the Board declined to allow incremental capital for this item?
25
26 l) At Exhibit B/Tab2/Sch2/page 8 on line 17, Hydro One mentions that “Customers will
27 be impacted with unplanned outages occurring more often than normal”. Can Hydro
28 be more specific and quantify how more often outages will occur?

Response

- a) Please see Exhibit I, Tab 2, Schedule 1.01 Staff 2 part b).
- b) Please see Exhibit I, Tab 2, Schedule 1.01 Staff 2 part b).
- c) The proposed expenditure in 2013 of \$29.0 million for Station Refurbishments, as outlined in this application, consists of: the typical capital spending of \$3.2 million, plus the proposed incremental Escalated Issue capital spending of \$25.8 million.
- d) As part of Phase 3 of the Cornerstone project, Hydro One is developing new Asset Analytics tools which will consolidate information from multiple sources allowing improved asset investment decisions while optimizing cost and risk. The Asset Analytic tools are being developed in a prioritized manner for Transmission & Distribution assets. For further details, please refer to EB-2012-0031 Exhibit D1, Tab 4, Schedule 3 page 11.
- e) Within the referenced exhibit, station refurbishment and station replacement are used interchangeably in the context of capital expenditure. Generally an entire station will be replaced or refurbished when the several major components are in need of replacement, and it is a more prudent and cost effective solution to complete as a single project.
- f) See response to part e).
- g) The proposed 2013 capital expenditure of \$29.0 million is the amount required to complete a total of 32 stations refurbishments in 2013. A detailed summary of the 32 station refurbishments and associated planned costs are outlined below.

Station	Estimate (\$)	Station	Estimate (\$)
Meaford DS # 2	1.0M	Campbellford Industrial DS	0.7M
Nestor Falls DS	1.4M	Havelock Industrial DS	0.7M
Crow River DS	2.0M	Trenton Frankford DS	0.7M
Oxley DS	0.7M	Mountain Chute DS	1.7M
Currie DS	0.7M	Lindsay Eglinton DS	1.7M
Carleton Place Edmund DS	0.8M	Little Current DS	1.1M
Barwick DS	0.8M	Maxville George DS	1.1M
Wilsonville DS	1.0M	Brockville Water DS	0.9M
Longlac West DS	0.8M	Emsdale DS	1.1M
Bobcaygeon Duke DS	0.3M	Kirkland Lake Goodfish	1.1M
Bobcaygeon Boyd DS	0.3M	Haliburton DS	1.1M
Chesley Hawkins DS	0.3M	Geraldton South DS	1.4M
Elginfield RS	0.3M	Elora Union	0.8M
Cache Bay DS	0.7M	Athens DS	0.5M

Station	Estimate (\$)	Station	Estimate (\$)
Post Creek DS	0.6M	Tara DS	1.0M
Brockville Parkdale DS	0.7M	Kirkland Lake Woods	1.0M
TOTAL:			29.0M

The rationale for this work is outlined in pages 4 – 16 of the referenced exhibit.

- h) Since Hydro One's last cost of service application EB-2009-0096, Hydro One has been taking a longer-term view of its asset fleets with the objective of managing to the lowest total sustainment cost over time through a combination of capital and OM&A solutions. Hydro One has also been obtaining and making increasing use of more asset condition information and more advanced analysis tools to determine that these assets require the investments set out in this application.
- i) The table below has been completed for the last 10 Station Refurbishments. Each of these stations involved replacement of multiple components within the existing station, as opposed to a complete replacement of the station itself.

Station/year	Main Transformer	HV bus/ busbars	LV bus/ busbars	LV circuit breakers	LV reclosers	Relay panels	Battery Charger
Calabogie DS (2012)	Replaced with refurbished	Not replaced	Not replaced	N/A	Replaced with new	N/A	N/A
Lindsay Durham West DS (2012)	Refurbished existing transformers	Replaced with new	Replaced with new	Removed & replaced with LV reclosers	Installed new	Removed, no longer required	Removed, no longer required
Sioux Narrows DS (2012)	Replaced with refurbished	Not replaced	Replaced with new	N/A	Partial replacement	N/A	N/A
Red Lake DS (2012)	Refurbished existing transformers	Replaced with new	Replaced with new	N/A	Replaced with new	N/A	N/A
Iroquois Dam DS (2012)	Replaced with new	Replaced with new	Replaced with new	Replaced with new	N/A	Removed, no longer required	Removed, no longer required
Madawaska DS (2012)	Replaced with refurbished	Not replaced	Not replaced	N/A	Replaced with new	N/A	N/A
Matachewan DS (2012)	Replaced with new	Replaced with new	Replaced with new	N/A	Replaced with new	N/A	N/A
Abitibi Canyon DS (2012)	Replaced with refurbished	Replaced with new	Replaced with new	Removed & replaced with LV reclosers	Installed new	N/A	N/A
Huntsville RS (2012)	Replaced with new	Replaced with new	Replaced with new	Removed & replaced with LV reclosers	Installed new	Removed, no longer required	Removed, no longer required
Larder Lake DS (2012)	Replaced with refurbished	Not replaced	Not replaced	N/A	Replaced with new	N/A	N/A

Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2 part b) regarding why the transformer spares purchases should be approved as incremental capital.

1 j) Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2.

2
3 k) The scope of the refurbishments has not been to replace the aged internal components
4 (i.e. windings and insulation systems) which ultimately determine the transformer's
5 end-of-life; therefore refurbishment of a transformer does not extend the ESL of the
6 transformer.

7
8 Hydro One is now experiencing failures of transformers that have previously been
9 refurbished. For example, the T1 transformer at South Gower DS was built in 1968.
10 This transformer was refurbished in 2009. In 2012, 3 years after refurbishment, the
11 transformer failed and now will be replaced with a new transformer.

12
13 If the \$13.3 million for the purchase of operating spares was denied in its entirety,
14 then refurbishment of 23 used transformers would be required to address the gaps in
15 the spare complement. The approximated increase in 2013 OM&A to refurbish 23
16 used transformers to acceptable condition for deployment as a spare would be \$3.5
17 million.

18
19 l) Please refer to Exhibit I, Tab 2, Schedule 1.03 Staff 4.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab2/Sch2/page12

Hydro One states that there has been an average of one metal clad breaker failure per year but that the failure rate is increasing as there were 5 failures in 2011. Does Hydro One regard this as an increasing trend for failures? Please provide a record of failures from 2005 to 2011 and provide a year-to-date failure number for 2012.

Response

The increased number of Circuit Breaker failures at distribution stations, when combined with the demographic trends, deteriorating condition, and technical obsolescence is of concern to Hydro One. Failures are unplanned events that result in power interruptions to customers (typically urban areas affecting many customers) and potentially impact the safety of Hydro One personnel. Also, replacements under failure conditions are more costly than planned replacements. It is prudent for Hydro One to keep circuit breaker failure events to a minimum. The following table outlines the number of circuit breaker failures since 2008. Details are not readily available prior to 2008.

Year	2008	2009	2010	2011	2012 YTD (June 30, 2012)
Number of Failures	1	2	1	5	2

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab2/Sch2/page14

Hydro One indicates that OM&A expenditures will be contained as additional capital expenditures are made. Can Hydro One estimate how OM&A budget areas are affected when capital expenditures are increased?

Response

The proposed 32 station refurbishments will address roughly 3% of the installed fleet of Distribution Stations. OM&A expenditures for these newly refurbished stations will be significantly less than the alternative of having to continue to operate the aged station in a degraded state. The remaining 97% of the installed fleet however, is still subjected to increasing pressure on Sustaining OM&A expenditures due to such issues as aging demographics and increased regulations (such as PCBs, noise assessments, etc.).

Because a relatively small amount of the installed fleet is addressed each year, it is unlikely to see any significant reductions in OM&A expenditures within the short term. Over several years however, continued Sustaining Capital reinvestment at the proposed level will allow Hydro One to stabilize the required future OM&A expenditures for Distribution Stations that would otherwise have to increase as the station infrastructure ages.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B/Tab2/Sch2/page27

Hydro One indicates that the Distribution operating spare complement is currently below the defined requirement. Please provide further explanation of this statement. On what evidence is this statement based? Was this also the case when Hydro One made its EB-2009-0096 application?

Response

Hydro One's methodology for determining the required operating spare inventory takes into account several factors of the installed fleet such as: capacity and voltage ratings, tapchanger requirements, demographics, condition, and failure trends. This assessment results in a current short-fall of dependable operating spares, consisting of transformers and regulators of a variety of ratings.

The following table outlines the categories of spares, the required operating spare complement, the existing number of spares, and the planned expenditures in 2013.

Capacity (MVA)	# In- Service	# of Spares Required	# of Spares On-Hand	2013 Purchase	
				#	\$
3 and less	345	6	0	2	\$1.6
5 - 7.5	679	42	30	15	\$8.0
10	75	15	12	3	\$1.2
12.5	7	6	2	2	\$1.9
15 - 25	102	7	6	1	\$0.6
40	4	2	2	0	\$0.0
TOTAL	1212	78	52	23	\$13.3

The incremental purchase of 23 new transformers is inline with the updated strategy of addressing inventory gaps through the purchase of new transformers as opposed to the alternative of refurbishing aged transformers for reasons outlined in the evidence.

The purchase of operating spares from the EB-2009-0096 proceeding, was to close inventory gaps that existed at that time, and are distinct from the proposed operating spares purchase required for 2013.

Energy Probe (EP) INTERROGATORY #2 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 1

- a) Please describe the differences between Distribution Stations and Regulating Stations.
- b) How many of each does Hydro One have in its system?
- c) Is the age profile of Regulating Stations different from Distribution Stations?
- d) Are the replacement criteria different for Distribution Stations compared to Regulating Stations?
- e) Are the refurbishment and replacement costs different for Distribution Stations compared to Regulating Stations? Please provide typical costs of replacement for each of the two types of stations.

Response

a) A Distribution Station's main function is to step down voltage from a primary voltage (typically 44, 28, 12kV) to a secondary voltage (typically 12, 8, 4kV) to allow for the delivery of power to downstream customers supplied by feeders emanating from the distribution station. These stations consist of a combination of step-down transformers, reclosers/breakers, switches, bus work and structures.

A Regulating Station's main function is to regulate or adjust the voltage over a narrow range in the range of roughly +/- 10% to provide a level of voltage on the feeders consistent with the system requirements. These stations consist of regulators, switches, bus work and structures.

b) Hydro One has 926 Distribution Stations and 76 Regulating Stations.

c) The age profile of the Distribution Stations is significantly worse than Regulating Stations. The average age for Regulating Stations is 30 years compared to 42 years for Distribution Stations.

d) No, replacement criteria are generally the same.

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Exhibit I

Tab 2

Schedule 2.01 EP 2

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- 1 e) The cost of refurbishing a Distribution Station is typically in the range of \$0.3 Million
- 2 to \$2.0 million, and average approximately \$0.9 million. These costs vary from one
- 3 station to the next and are a function of scope of the work and complexity of the
- 4 station (i.e. number of transformers, transformers voltage and capacity ratings,
- 5 number of feeders, etc.)
- 6
- 7 The cost of refurbishing a Regulating Station is typically 10% less than that of a
- 8 Distribution Station.

Energy Probe (EP) INTERROGATORY #3 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 6

Line 4 states that Hydro One has “1002 Distribution Stations” whereas Line 6 on Page 1 states that it has “1002 Distribution and Regulating Stations”.

a) Are these terms used interchangeably?

b) If there are significant differences in the two types of stations please explain why they are treated the same in the evidence.

Response

a) Throughout the evidence the terms “Distribution Stations” and “Distribution & Regulating Stations” are used interchangeably.

b) There are no significant differences between Distribution and Regulating Stations for purposes of investment planning, aside from the typical slightly lower cost of refurbishment of Regulating Stations as referenced in Exhibit I, Tab 2, Schedule 2.01 EP2.

Energy Probe (EP) INTERROGATORY #4 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 10

Figures 4 and 5 show structural components requiring repair. Please describe the remediation necessary in these two examples.

Response

Figure 4 depicts an old tube and clamp structure which is at end of life and requires replacement with a structure built to today's standards to manage reliability and safety risks.

Figure 5 is a transformer pad which is beyond repair and requires replacement with new to manage reliability, safety and environmental risks.

Energy Probe (EP) INTERROGATORY #5 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 10

Figure 6 shows a cracked concrete foundation. The cracking appears to be limited to the surface layer of the concrete. Please comment on the structural integrity of this foundation and the danger of failure.

Response

Figure 6 shows the outer layer of the foundation cracked and separating, exposing the inner concrete to the elements. Water ingress into the exposed layer of concrete allows the inner layer to degrade compromising the structural integrity of the foundation.

In some cases degraded foundations are repaired under OM&A. However, foundation conditions similar to those shown in Figure 6 are typically recommended for replacement following assessment by structural engineers. This is due to a combination of the limited effectiveness of a repair to prevent further deterioration as well as the safety and reliability consequences should the condition degrade to the point of structural failure.

Energy Probe (EP) INTERROGATORY #6 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 18

Line 7 states that the operating spare complement is below the defined requirement.
Please describe how the defined requirement is arrived at, what the complement currently is and what it should be at.

Response

Please refer to Exhibit I, Tab 2, Schedule 1.14 Staff 15.

Energy Probe (EP) INTERROGATORY #7 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 18

a) Has Hydro One always had refurbished transformers in its operating spares inventory? If not, please explain when it started keeping refurbished transformers as operating spares.

b) Has it always used refurbished transformers to replace failed transformers? If not, please explain when it started using them and for what reason.

c) How many operating spares are deployed to a station in an average year? How many are refurbished units?

d) How many refurbished operating spares deployed to a station in the last 10 years, have required replacement within the 5-10 years noted in line 18.

e) What are the average costs for design, labour and equipment to replace a failed transformer? Are the costs the same whether the replacement unit is a new one or a refurbished one?

Response

a) Yes

b) Hydro One has used refurbished transformers as well as new transformers to replace failed transformers. Hydro One plans to deploy primarily new transformers during failure scenarios as the operating spare inventory is renewed with new units.

c) In an average year, 9 operating spares are deployed from inventory, and two-thirds of the operating spares that are deployed have been refurbished units.

d) In the last ten years, approximately seven refurbished operating spares have required replacement within 5-10 years of being deployed.

e) The average capital expenditure for design, construction, commissioning and equipment to replace a failed transformer with a new transformer is between \$0.5 million and \$1.15 million. This is dependant on several factors such as the voltage

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Exhibit I

Tab 2

Schedule 2.06 EP 7

Page 2 of 2

1 and capacity ratings of the transformer and whether the transformer has a tap-
2 changer.

3

4 The cost and revenue requirements are different if a refurbished transformer is
5 utilized as opposed to a new transformer. Typical costs for design, refurbishment of
6 the transformer, construction, and commissioning are in the range of \$0.3 million to
7 \$0.7 million. This includes typical OM&A refurbishment expenditures of \$15,000 to
8 \$400,000 with a typical cost of \$150,000.

Energy Probe (EP) INTERROGATORY #8 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 18

- a) Please provide a listing of operating spare transformers with age and condition for each.
- b) What is the average cost of refurbishing a used distribution station transformer?
- c) What is the average cost of purchasing a new transformer?
- d) What has occurred to make operating spares an escalated issue requiring immediate attention rather than just a typical issue?
- e) What will Hydro One do if the Board does not approve its proposal for replacing refurbished operating spares with new operating spares?

Response

- a) The below table groups the operating spares that are in acceptable condition and ready for deployment by transformer capacity along with their average age. In addition to these deployable spares, Hydro One also has 67 additional transformers with an average age of 42 years that are not in an acceptable condition for deployment, requiring significant OM&A prior to being deployed. As indicated throughout this application, continued deployment of aged transformers is not viewed as an effective long-term solution to managing the aging distribution station infrastructure.

Transformer MVA	# of Spares	Average Age of Spares
3 and less	0	0
5 – 7.5	30	7
10	12	10
12.5	2	2
15 - 25	6	15
40	2	8
TOTALS:	52	8

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Exhibit I

Tab 2

Schedule 2.07 EP 8

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- 1 b) Refer to Exhibit I, Tab, 2, Schedule 2.06 EP 7.
- 2
- 3 c) The purchase cost a transformer can range from \$0.3M to \$0.8M depending on the
- 4 transformer specifications such as: voltage, capacity, etc.
- 5
- 6 d) Refer to Exhibit I, Tab 1, Schedule 1.01 Staff 2, part a).
- 7
- 8 e) Refer to Exhibit I, Tab 1, Schedule 1.11 Staff 12, part k).

Energy Probe (EP) INTERROGATORY #9 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 25

Figure 16 on page 25 shows Major Distribution Station Transformer Failures over the past ten years.

- a) What is the significance of the word “Major” in this figure? Are there also minor failures not shown in the figure? Please explain.
- b) Did Hydro One analyze the spike in failures in 2009 to determine the causes of failure? If yes, please describe the findings.
- c) If the data for 2009 is removed, the balance of the chart does not reveal any particular trend toward increasing failures. In fact, the last two years exhibit less failures than the average of the last ten years. Please comment.

Response

a) Hydro One classifies Distribution Station transformer failures as follows:

Class 1 Failures: Transformer automatically removed from service. Major failures which require replacement of the transformer. Typically the failure will involve the core, windings, and/or tank. Damage is beyond repair.

Class 2 Failures: Transformer automatically removed from service. Less significant failures where damage can typically be repaired on site. Typical failures include tapchanger contacts, bushings, minor oil leaks, etc.

Class 3 Failures: Transformer manually forced from service by maintenance personnel. Defects that would likely proceed to Class 1 (or occasionally Class 2) failures without reactive measures to remove the transformer from service to execute repairs. Typical examples include severe internal electrical discharge or overheating, major oil leaks, etc. as detected by on-going maintenance programs.

In an attempt to simplify the presentation of evidence, the referenced Figure 16 includes only the “Major” or Class 1 failures. Class 2 and 3 failures are not shown in the figure.

b) Yes, all failures are analyzed to determine the causes of failure.

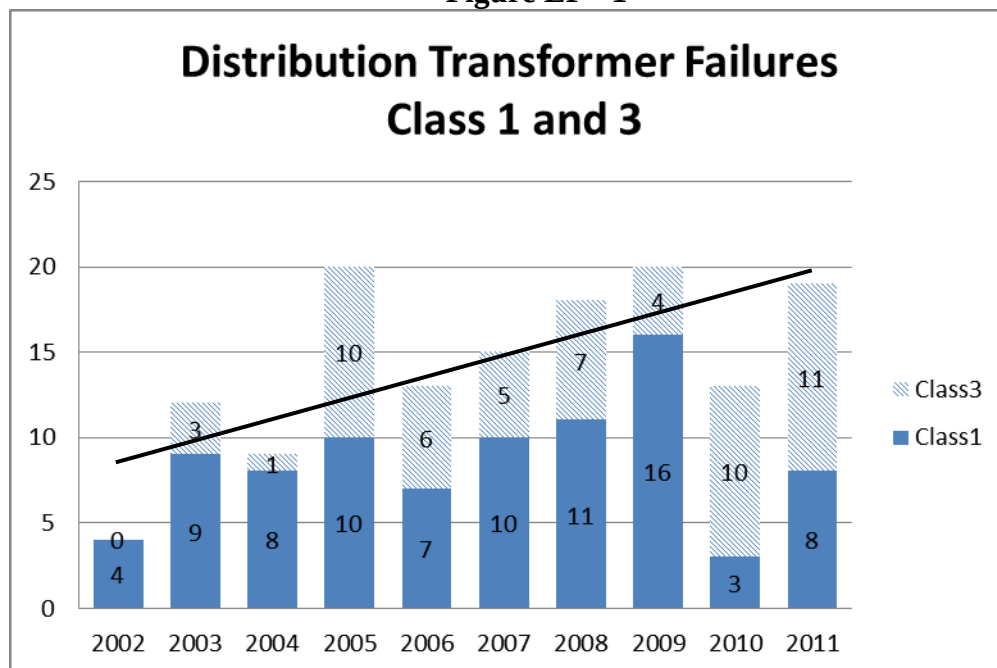
The root causes for the Class 1 failures of 2009 are generally consistent with findings from previous years:

- 12 were failures of aged and degraded internal insulation systems
- 2 failed during electrical storms
- 2 were a result of tap-changer component failures

c) Consideration must be given to both short term data such as the number of annual failures and longer term trends. Some year over year variation of equipment failures is expected; however the long-term trend of Class 1 failures is increasing gradually.

As indicated in part a), the referenced Figure 16 included only Class 1 failures. A more definitive and concerning long-term trend can be observed by combining Class 1 failures and Class 3 failures together as shown in Figure EP9-1. This long-term trend of increasing failures, is a clear indicator that additional capital expenditure is required to manage the aging fleet in an efficient manner.

Figure EP - 1



Energy Probe (EP) INTERROGATORY #10 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Pages 25 - 26

What is the average cost to regasket a leaking transformer? Please show the costs of installing a temporary MUS and removing it separately from the cost to regasket.

Response

Many refurbishment activities are conducted when Hydro One refurbishes a distribution transformer, one of which is regasketing. The cost associated with the refurbishment of the transformer can range from \$15,000 - \$400,000 with a typical cost of \$150,000. Regasketing accounts for about 10-20% of the cost of refurbishment.

In addition to these costs, the cost of installing and removing a temporary 115kV MUS is \$15,000 and a 44kV or 28kV MUS is \$10,000.

Energy Probe (EP) INTERROGATORY #11 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Pages 25 - 26

What is the average cost to install noise barriers in a station?

Response

The typical cost to install a noise barrier in a station can be up to \$300,000 depending on the noise level and proximity of nearby receptors.

Energy Probe (EP) INTERROGATORY #12 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Pages 25 - 26

- a) How long has Hydro One been working on eliminating PCBs from its station equipment?
- b) How many transformers older than 1985 are there in service?
- c) Does Hydro One have a program to sample oil in transformer bushings? If yes, please describe it along with the results so far on how many bushings have PCBs.
- d) Is it necessary to replace the entire transformer if PCB is identified in the bushings or can just the bushings be replaced?

Response

- a) Hydro One has been working on eliminating PCB's from the large oil volumes (i.e. transformer and regulator main tanks) within its station equipment since the 1980s. This work is effectively complete and all large volumes are within regulated limits. New regulations enacted in 2008 require further work to test all oil volumes (including transformer bushings) and eliminate any oil found greater than 50ppm PCB by 2025.
- b) There are 893 distribution power transformers older than 1985 in service.
- c) Yes, an on-going program exists to test distribution station transformer bushing PCB concentration. Testing requires the transformer out of service, and is coordinated with other planned work at the station. The program has tested 461 out of 3,612 bushings (13%), and found that 70 (15% of those tested) are greater than or equal to 50ppm PCB.
- d) It is not necessary to replace the entire transformer if PCB in excess of the regulated limits is identified in the bushings. However a case-by-case assessment is made to determine if bushing replacement or transformer replacement is the appropriate solution based on transformer condition.

Energy Probe (EP) INTERROGATORY #13 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 3, Page 8

- a) Has Hydro One or its predecessor company Ontario Hydro experienced similar issues in the past with poles showing faster deterioration than expected? Please describe the past problems and how they were dealt with.
- b) Does HONI have a quality assurance program in place to ensure that new poles purchased meet specifications? If yes, please describe the program and explain how it failed to identify the problem with treatment penetration. If not, please explain how HONI determines it is getting what it pays for.
- c) Is the supplier of the defective poles providing any financial support for replacing them? If yes, please describe the contribution. If not, please explain why not.
- d) Have other distributors experienced similar problems with CCA treated red pine poles? If yes, what are they doing about the problem? If not, please explain why not.

Response

- a) No. However, Ontario Hydro did experience issues with Bell-owned joint use poles. These Bell-owned "TDL" southern yellow pine poles of 1984-1987 vintage deteriorated prematurely due to improper sterilization. These poles were identified and Ontario Hydro issued a climbing ban.
- b) Please refer to Exhibit I, Tab 2, Schedule 1.09 Staff 10, part e).
- c) Please refer to Exhibit I, Tab 2, Schedule 1.09 Staff 10, part f).
- d) Hydro One is not aware of any distributors experiencing similar issues.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, page 1

Preamble: HON states that its approach to ICM is consistent with Hydro One's submission in the Renewed Regulatory Framework proceeding.

- a) Please indicate where HON's ICM approach is consistent and where it is inconsistent with the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors dated July 14, 2008 and the related Supplementary Reports and Addendums.

Response

- a) Please refer to Exhibit I, Tab 1, Schedule 5.02 VECC 2, b) and c).

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, page 1

- a) Please provide a schedule setting out the derivation of the \$1,161 M for 2010 revenue at 2011 rates.
- b) What was HON's actual 2011 distribution revenue (comparable to the approved value of \$1,149 M)?
- c) Please provide a schedule that compares HON's actual 2011 billing quantities by rate class with the approved values.
- d) If practical, please also include in the foregoing schedule the weather normalized billing quantities as well as actual quantities by rate class for 2011.

Response

- a) A schedule explaining the derivation of the \$1,161M of revenue is provided in Exhibit I, Tab 2, Schedule 1.06 Staff 7, part b).
- b) The actual 2011 distribution revenue was \$1,165.8M.
- c) Please see the response to part (d) below.

- 1 d) The table below provides the approved, actual, and weather normalized actual billing
2 quantities, by rate class for 2011.

Rate Class	Approved Billing Quantities for 2011			Actual Billing Quantities for 2011			Weather Normalized Billing Quantities for 2011	
	Number of customers	Sales (GWh)	Peak demand (kW)	Number of customers	Sales (GWh)	Peak demand (kW)	Sales (GWh)	Peak demand (kW)
UR	140,540	1,311		159,086	1,541		1,568	
R1	412,455	4,397		402,173	4,402		4,481	
R2	367,107	5,375		368,479	5,491		5,590	
Seasonal	156,901	718		157,017	701		714	
GSe	98,776	2,196		98,095	2,329		2,360	
GSd	7,361	3,122	10,389,644	7,183	3,100	10,331,311	3,142	10,030,850
UGe	10,577	364		11,650	397		403	
UGd	1,130	600	1,898,173	1,272	686	1,964,583	695	1,907,448
St Lgt	5,234	122		4,830	125		125	
Sen Lgt	37,506	21		33,228	19		19	
DGen	88	4	66,329	106	8	68,282	8	66,297
ST	607	17,938	33,188,720	794	16,787	35,730,299	16,901	34,691,170

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, page 2, lines 9-11

- a) Does exceeding the Threshold Test in itself provide “access” to the ICM or are there additional requirements that must be met under the Board’s ICM module guidelines?

Response

- a) Based upon Section 2.5 of the Board’s July 14, 2008 Report Hydro One believes that exceeding the Threshold test does allow a distributor to apply for recovery under the ICM. Additional requirements for success include a demonstration of need as well as prudence.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, page 2, (lines 25-26)

- a) Please explain more fully why “typical capital spending” based on historically approved levels of spending does not require “further detailed review during the period of IRM”.
- b) In principle, couldn’t historically approved levels of spending for sustainment, development and shared services & other spending include projects that were specific to the approval period and for which funding is not required during the IRM period?

Response

- a) Please refer to Exhibit I, Tab 2, Schedule 1.07 Staff 8, a)
- b) Please refer to Exhibit I, Tab 2, Schedule 1.07 Staff 8, b) and c)

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, pages 4 & 8

- a) Please explain how the \$414 M value for in-service capital additions was established.
- b) Please confirm that Table 2 sets out the approved capital spending for each year net of that associated with renewable generation and smart grid investments.
- c) If the response to (b) is yes, please provide a schedule that sets out how each year's value was established and provide references/sources for the data used in the calculations.
- d) Also, if the response to part (b) is yes, please clarify if the capital spending includes that associated with the implementation/installation of smart meters. If it does, please re-do Table #2 so as to exclude such spending.
- e) If the response to part (b) is no, please provide a table that sets out these values and indicate how each year's value was established, providing references/sources for the data used in the calculations. In doing the calculations please exclude spending on smart grid, renewable generation and smart meters.
- f) What were the (same year) capital additions associated with the approved capital spending for each year 2008-2011?

Response

- a) Resulting from Hydro One's business planning processes, the amount of typical capital spending required to maintain the system in line with what was approved in EB-2009-0096 was determined to be \$451.9M for ICM year 2013. The forecast in-service amount of \$414M is forecast based upon that capital spending.
- b) Yes. The capital spending in Table 2 does not include renewable generation and smart grid.

c)

Typical Capital Spending and Capital Additions (\$M)						
	Actual				Forecast	
	2008	2009	2010	2011	2012	2013
Total Capex	541.5	606.2	589.7	595.7	720.2	654.0
Less:						
CIS	-	-	-	51.6	85.7	18.1
"Escalated" Capital	-	-	-	-	-	74.7
Distributed Generation	-	1.9	12.4	13.5	37.0	34.7
Smart Grid	-	1.0	18.0	29.9	73.4	60.2
Smart Metering	106.2	147.8	128.8	68.9	80.2	14.5
Typical Capital Spending	435.3	455.5	430.5	431.9	443.9	451.9

d) No. The capital spending in table 2 does not include new smart meter installations. Refer to part c) above for spending levels.

e) N/A

f)

Typical Capital Spending and In-Service Additions (\$M)						
	Actual				Forecast	
	2008	2009	2010	2011	2012	2013
Capital Spending	435.3	455.5	430.5	431.9	443.9	451.9
In-Service Additions	407.7	404.8	433.4	450.8	481.4	414.3

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, page 8

- a) Please provide a schedule that breaks down the typical spending approved for each year (2008-2011) as between Sustainment, Development, Operating, and Shared Services & Other. In the case of Sustainment please provide a further breakdown between stations, lines and meters. Similarly, for Development spending please provide the breakdown between the various categories used in EB-2009-0096, D1/T3/S1, Table 1 and for Shared Service capital please provide a breakdown between the various categories used in EB-2009-0096, D1/T3/S5, Table 1.
- b) Does the 2011 capital spending shown in Table 2 (\$437.6 M) include the spending in same year for the CIS as shown in Table 2 of Exhibit B, Tab 3, Schedule 1, page 5. If yes, why is this appropriate?

Response

- a) Please find table below that breaks down the typical spending from past years as requested.

\$M	2008 ¹	2009 ¹	2010 ¹	2011 ²
Sustainment	170.7	180.3	185.5	207.3
Development	153.2	170.3	150.6	169.1
Operations	0.9	1.7	1.2	1.4
Shared Services	110.5	103.2	93.2	59.8
TOTAL CAP EX	435.3	455.5	430.5	437.6

Note 1 – Actual Capital Expenditures

Note 2- Board Approved Expenditures

- b) No. Table 2 referenced above does not include CIS spending.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, pages 4 - 5

- a) Does HON agree that one of the objectives of ICM is to provide electricity distributors with increased incentives to improve efficiency in the use of resources? If not, why not?
- b) Please confirm that, under a price-capped based ICM approach (as adopted by the OEB), distribution rates for the test year are not based on the test year's costs as is the case under a cost of service approach. If not confirmed, why not?
- c) Please confirm that any additional resources (e.g. funds) freed up through increased efficiencies (over and above those reflected in PCI) would be available to help fund new investments. If not, why not?
- d) If ICM rates are not cost-based, please explain the basis for HON's contention that in 2013 \$11 M in rate base is not funded due to a decrease in revenues.

Response

- a) Our understanding is that, among others, one of the objectives of ICM is to provide Distributors with incentives to achieve efficiency in their operations.
- b) Under an ICM, the rates in the Test year are not based on the test year's cost. The rates within an ICM period are based upon the decision emanating from the original base year cost review. If an ICM proceeding is pursued, then the projects considered for incremental treatment do undergo an examination of prudence. If the costs are deemed appropriate then a temporary rate rider is added to the original base rates.
- c) In the event that a distributor is successful in achieving efficiencies which provide additional resources, the utility would then need to evaluate the uses for those additional resources, one such use being new investments in infrastructure and technology.
- d) The \$11M represents the rate base no longer funded due to a decrease in consumption as described on Page 5 of Exhibit B, Tab 1, Schedule 1.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, pages 4 - 5

- a) Is the recovery of “typical capital spending no longer funded” provided for under the Board’s current ICM guidelines?
- b) If HON’s response is yes, please reconcile this view with each of the following:
- Board’s Supplemental Report EB-2007-0673, September 2008, pages 30-31 – particularly the Board’s stated view that the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor
 - Board Decision, EB-2008-0205 (Part II), pages 10-11
 - Board Decision, EB-2008-0187, pages 7-8.

Response

- a) To be effective, Hydro One believes the ICM module must provide for non-discretionary typical capital spending in support of the system. The reference in evidence to “no longer funded” {to address part a) above} refers to the existing rate base that is not funded due to a decrease in consumption.
- b) The 3GIRM and ICM processes were devised to meet the objectives of ensuring that utilities are adequately funded to continue operations while simultaneously seeking to inject more efficiency and rate stability into the process. Hydro One strongly supports this endeavor.

Increasingly, we find that the Board is rendering decisions that signal an acknowledgement that the ICM process continues to evolve.

In the decision from EB-2008-0205 (same proceeding as referenced above) the Board found that the Concrete Pole replacement project is incremental and non-discretionary and allowed this amount to be recovered. Installation of concrete poles is a typical activity performed by a distributor.

1 In EB-2011-0173, the Board found that:

2
3 *“Hydro Hawkesbury provided sufficient evidence documenting*
4 *potential asset failure, the cost consequences of deferring action and*
5 *risking asset failure, condition deterioration and safety issues to*
6 *establish materiality, need and prudence of each project...”*

7
8 The work that Hydro One proposes to complete is also in support of the reliability
9 and safety of the system.

10
11 In EB-2011-0178 Kingston Hydro was awarded funding for several items including
12 an Underground Rebuild, 2 Transformer Vaults and a Circuit Breaker retrofit. All of
13 these activities too are typical activities of a distributor.

14
15 In this proceeding, Hydro One has applied for recovery of the non-discretionary
16 typical capital that it must investment to maintain the system in a safe and sustainable
17 fashion to meet customer needs. Failure to make these capital investments in 2013
18 will degrade system reliability and/or defer critical investments and in so doing in any
19 case will have the consequence of reducing the ability to perform this necessary work
20 in a planned fashion – the ultimate result being less stable rates, reduced reliability
21 and a more expensive system for customers.

22
23 If Hydro One proceeds with these investments without appropriate funding this would
24 cause a significant revenue shortfall compared to its costs. The effect of this shortfall
25 has not gone un-noticed by the financial community. In the September 14, 2012
26 edition of Scotiabank – GlobalViews, Stephen Dafoe opined that:

27
28 *“Any lag in assets entering rate base can become a credit concern*
29 *for utilities whose Capex programs are much larger than*
30 *depreciation, since it pressures free cash flow and other credit*
31 *ratios. We think that this adverse cash impact of a rising capital*
32 *program is magnified under IRM.”*

33
34 Clearly, degradation of credit ratios due to a short-term underfunding via rates would
35 cause long-term capital costs to increase.

36
37 Finally, in the same 2008 Supplemental Report of the Board referenced in this
38 interrogatory, the Board states that:

39
40 *“the capital module is intended to be reserved for unusual*
41 *circumstances ... where the distributor has no other options for*
42 *meeting its capital requirements within the context of its financial*
43 *capacities underpinned by existing rates.”*
44

1 If Hydro One funds the necessary investments described in this proceeding, Rate
2 Base would increase without commensurate funding in rates. Hydro One has “*no*
3 *other options for meeting its capital requirements*” and thus requires that the Board
4 allow for provision of funding these expenditures through the proposed temporary
5 rate rider.
6

7 Hydro One strongly believes that the result of providing for the award sought herein
8 will be:
9

- 10 • a more reliable system because necessary investments are made when required
11 rather than face the potential of deferral,
12 • more stable rates since the timing of expenditures better matches the timing of the
13 costs incurred and,
14 • ultimately lower long-term costs for customers as Hydro One, with continued,
15 low long-term capital costs, is able to more prudently plan the necessary work
16 rather than deal with it in a more expensive, emergency fashion.
17

18 These outcomes are certainly in keeping with the intention and desired evolution of
19 the 3GIRM and ICM processes.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1, pages 6 - 8

- a) Is the recovery of type of capital spending that HON characterizes as “Escalated Issue” spending provided for under the Board’s current ICM guidelines?
- b) If HON’s response is yes, please reconcile this view with each of the following:
- Board’s Supplemental Report EB-2007-0673, September 2008, pages 30-31, particularly the Board’s stated view that the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor
 - Board Decision, EB-2008-0205 (Part II), pages 10-11
 - Board Decision, EB-2008-0187, pages 7-8.

Response

- a) Hydro One believes the ICM module provides for funding of Escalated Issue capital.
- b) For discussion on the enclosed references please refer to Exhibit I, Tab 2, Schedule 5.08 VECC 11.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

**Reference: Exhibit B, Tab 1, Schedule 1, pages 2, 4 & 9
 Exhibit B, Tab 1, Schedule 2, page 5**

- a) Please confirm that under the Board's ICM module only capital spending in excess of the Threshold Test is subject to recovery through the ICM rate rider. If HON disagrees please provide references to Board Reports/Decisions that support this (alternate) view of how the ICM module works.
- b) Please confirm that HON has not applied the Threshold (calculated by HON to be \$332) in determining the amount of capital spending to be recovered through the ICM.
- c) Please re-do Table 3 (B/1/1) and Table 1 (B/1/2) so as calculate the ICM revenue associated with capital expenditures in excess of the Threshold Test.

Response

- a) Please refer to Exhibit I, Tab 2, Schedule 1.08 Staff 9
- b) Please refer to Exhibit I, Tab 2, Schedule 1.08 Staff 9
- c) Please refer to Exhibit I, Tab 2, Schedule 1.08 Staff 9

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, page 1 (lines 14 – 23) and Figure 2

- a) Please provide the demographics for HON's distribution and regulating stations at the time of HON's Application for 2010/2011 rates (EB-2009-0096). If available, please provide references as to where in that Application the demographics of these assets were described.

Response

- a) The following table outlines the demographics for Distribution and Regulating Stations in 2009 compared with the referenced information from this application.

	2009	2012
Older than 50 years	23 %	25 %
40 – 50 years	23 %	26%
Younger than 40 years	54 %	49 %
Total Number of Stations	1,005	1,002

The age demographics of Distribution and Regulating Stations was not presented in detail in the EB-2009-0096.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, page 1 (lines 26-28) & 3 (lines 11-13)

- a) Does the existing refurbishment rate of 4 stations per year include any transformer replacements? If yes, how many on average and is this number included or excluded from the 6 existing transformer replacements that occur each year?
- b) What is the current (e.g. 2011) maintenance expense associated with the 32 stations that HON plans on refurbishing in 2013 and what will be the annual maintenance expense associated with these stations afterwards?
- c) What is the current (e.g. 2011) maintenance expense associated with the 36 transformers that HON plans on replacing in 2013 and what will be the annual maintenance expense associated with these transformers afterwards?
- d) Did the 2010/2011 Rate Application indicate the number of Station Refurbishments planned for each of the test years? If yes, what are numbers and what are the relevant references?
- e) Did the 2010/2011 Rate Application indicate the number of planned transformer replacements for each of the test years? If yes, what are the numbers and what are the relevant references?

Response

- a) Yes, approximately one-third of the Station Refurbishments have included the replacement of transformers. These historic replacements have predominantly used refurbished transformers as opposed to new. These replacements have been included in the existing 6 transformer replacements per year.
- b) The 2011 maintenance expenses associated with the 32 specific stations that are planned within the 2013 Station Refurbishment program are \$11,000 on a per station average basis. Note that very little maintenance was executed on these stations in 2011, knowing that plans for Station Refurbishment were upcoming.

To obtain an understanding of how future OM&A expenditures relate to increased capital expenditure, a more representative comparison is to compare typical stations

1 that are operating beyond or approaching the their expected service life and do not
2 have significant capital expenditures planned, to those stations that are either new or
3 have undergone station Refurbishment.

4
5 This comparison results in the average annual maintenance expenditure for a station
6 greater than 40 years of \$19,000. Comparatively the average annual maintenance
7 expenditure for a station less than 10 years old is significantly less at \$10,000.

- 8
9 c) The 2011 maintenance expenses associated with the specific transformers planned for
10 replacement in 2011 are \$8,300 on an average per transformer basis.

11
12 To obtain a broader understanding of how future OM&A expenditures relate to
13 increased capital expenditure, a more representative comparison is to compare typical
14 transformers that are operating beyond or approaching their expected service life and
15 are not planned for replacement, to new transformers.

16
17 This comparison results in the average annual maintenance expenditure for a
18 transformer greater than 40 years of \$9,500. Comparatively the average annual
19 maintenance expenditure for a transformer less than 10 years old is significantly less
20 at \$4,000.

- 21
22 d) Yes. Four stations were identified to be completed over the 2010 and 2011 test years
23 within Exhibit D2, Tab 2, Schedule 3 ISD# S4 from the EB-2009-0096 application.

- 24
25 e) No, the EB-2009-0096 application did not specifically identify how many
26 transformers were planned for replacement under Sustaining Capital.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, page 3

- a) Please provide the actual 2011 capital spending for each of the four categories of station capital shown in Table 1.
- b) Please provide the approved level of 2010 capital spending for each of the four categories of station capital shown in Table 1.

Response

- a) The below table provides the actual 2011 capital spending for each of the four categories of station capital.

Description	2011 Actual (\$ Millions)
Station Refurbishments	2.3
Transformer Spares and Replacements	8.7
MUS Reinvestment	3.4
Other Station Component Replacements and demand Programs	6.7
Total	21.1

- b) The below table provides the approved level of 2010 capital spending for each of the four categories of station capital.

Description	2010 Approved (\$ Millions)
Station Refurbishments	3.2
Transformer Spares and Replacements	3.6
MUS Reinvestment	2.5
Other Station Component Replacements and demand Programs	4.7
Total	14.0

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, pages 12 - 13

- a) Please provide a schedule that compares the percentage of each of the following categories of assets that had “poor” or “very poor” condition ratings in the Asset Condition assessments underpinning the 2010/2011 Distribution Rate Application with the recent Asset Condition assessment results (per page 13, lines 10-12):
- Transformers
 - Metal Clad Breakers
 - Batteries and Chargers.
- b) Please provide schedules or graphs that indicate the annual failures associated with metal-clad breakers over the 2008-2011 period (e.g. similar to Figure 10 for Battery and Charger failures and Figure 16 for Transformer failures).
- c) Please provide a schedule that sets out HON’s values for SAIDI, SAIFI and CAIDI for each of the years 2008 – 2011. In each case please indicate the contribution that failures of either the stations or transformers have made to the overall annual values.

Response

- a) Please see Table VECC 17 -1 below, which provides a comparison of very poor and poor condition ratings underpinning the EB-2010-0096 application, to the most recent condition assessment results for each of the three asset categories.

**Table VECC 17 – 1
Very Poor & Poor Condition Rating Percentages**

Asset Category	EB-2009-0096	EB-2012-0136
	2009	2012
Transformers	15%	15%
Metalclad Breakers	n/a	10%
Batteries and Chargers	n/a	12%

Note: An Asset Condition Assessment for distribution station breakers and station batteries and chargers were not performed at the time of the EB-2010-0096 application.

- b) For historical breaker failures, refer to Exhibit I, Tab 2, Schedule 1.12 Staff 13.
- c) Please see Table VECC17-2 for a summary of the overall distribution system reliability for the years 2008-2011. The following Table VECC17-3, is the contribution that station transformer failures made to this overall distribution system reliability. The CAIDI values in Table VECC 17-3 illustrate that the average duration of outages caused by station transformer failures are longer than average outages caused by overall equipment failures on the distribution system.

Table VECC 17 – 2
Overall System Dx Reliability

Overall Distribution System Reliability			
Year	SAIFI Frequency of Interruptions	SAIDI Duration of Interruptions	CAIDI Average Interruption Time
2008	3.5	8.6	2.4
2009	3	7.4	2.5
2010	2.9	7.5	2.5
2011	3.1	7.4	2.4

** Note: These values exclude Force Majeure Interruptions*

Table VECC 17-3
Contribution of Dx Station Transformer Failure to Overall System Dx Reliability

Interruptions caused by Station Transformer Failure			
Year	SAIFI Frequency of Interruptions	SAIDI Duration of Interruptions	CAIDI Average Interruption Time
2008	0.001	0.001	1.6
2009	0.004	0.014	3.7
2010	0.002	0.010	6.2
2011	0.002	0.009	6.0

** Note: These values exclude Force Majeure Interruptions*

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, page 14 (lines 10-16)

- a) Please provide a listing of 70 Distribution Stations with the highest risk of failure based on poor asset health and provide the asset health index/rating for each.
- b) Please indicate which Stations are currently undergoing refurbishment in 2012. Please reconcile the choice of these stations with the health indexes/ratings reported in response to part (a) - i.e. are these the most critical health stations and, if not, why not?
- c) Please provide a schedule setting out the stations slated for refurbishment in 2013. Again, reconcile the choice of these stations with the health indexes/ratings reported in response to part (a).

Response

- a) Hydro One is refurbishing 12 stations in 2012 and 32 stations in 2013. Hydro One has deemed that these 44 stations have the highest risk of failure based on asset health as well as other factors. The factors in determining stations requiring refurbishment are listed in Exhibit B, Tab 2, Schedule 2, page 14. The remaining stations will be identified in a future application.
- b) Hydro One is refurbishing the following 12 stations in 2012, selected based on the rationale described in Exhibit B, Tab 2, Schedule 2, page 14.
 - Calabogie DS
 - Lindsay Durham DS
 - Sioux Narrows DS
 - Dundalk Victoria DS
 - Red Lake DS
 - Espanola DS
 - Huntsville RS
 - Iroquois Dam DS
 - Larder Lake DS
 - Madawaska DS
 - Matachewan DS
 - Abitibi Canyon DS

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Exhibit I
Tab 2
Schedule 5.15 VECC 18
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- 1 c) For a list of the 32 stations Hydro One is planning to refurbish in 2013, please see
- 2 Exhibit I, Tab 2, Schedule 1.11 Staff 12, part g). Hydro one has chosen these stations
- 3 to refurbish based on the rationale described in Exhibit B, Tab 2, Schedule 2, page 14.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, pages 7 (Figure 3), 13 (lines 12-15) and 16 (lines 15-20)

- a) The Application claims that without the proposed \$29.0 M in 2013 for station refurbishment various risks will increase. Please explain why a short-term increase in such risks (through either a delay of 1-2 years in the start of this refurbishment activity or a phasing-in of the spending required) is unacceptable such that the proposed level of spending is “non-discretionary” as required by the Board’s ICM criteria.

Response

- a) Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2 part a).

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, page 18

- a) Please confirm that the 35 transformers to be purchased under the Transformer Spares and Replacement program include 6 for planned replacements and 6 for demand replacements. Please further confirm that (per page 3) 6 planned replacements are consistent with existing practice.
- b) Please explain why the 6 planned replacements and the 6 demand replacements are not considered to be included as part of the Typical Sustainment spending.
- c) Are the 23 transformers to be purchased in 2013 as “Operating Spares” effectively an increase in the inventory of spare/replacement transformers? If not, please explain why.

Response

- a) Yes, both elements are confirmed.
- b) The historical replacement rate of 6 transformers per year is a combination of utilizing an average of two new transformers and four refurbished transformers. Costs for the two new transformers of \$1.2 million are included in the Typical sustaining capital. The Typical sustaining capital also includes the purchase of 5 operating spares at a cost of \$2.9 million, for a total Typical sustaining Capital of \$4.1 million.

To best manage the life-cycle costs and minimize rate impacts, Hydro One is increasing the number of new transformers used for replacements and decreasing the reliance on refurbished transformers.
- c) Yes, there will be an additional 23 new transformers purchased as operating spares to address the current shortfalls in the operating spare inventory.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, pages 17, 18 and 20

- a) The text on page 17 indicates that the Transformer Spares and Replacement program does not include transformers purchases under the Station Refurbishment program. Page 20 indicates that the Spares and Replacement program will increase the replacement to 36 transformers per year. However, Table 2 (page 18) shows that the planned replacement of transformers is 36 in total (including those replaced under the Refurbishment program) and that only 12 (not 36) will be replaced outside the Refurbishment program. Furthermore, these twelve seem to reflect the typical level of past replacement. Please reconcile.

Response

Reference: Exhibit B, Tab 2, Schedule 2

- a) Referring to Table 2 on page 18, a total of 36 transformers are planned to be replaced in 2013. This includes 24 transformer replacements within the Station Refurbishment program and 12 transformer replacements in the Transformer Spares and Replacement program.

Figure 12 illustrates a “10-year scenario based on the proposed 2013 replacement rate of 36 transformers each year” (page 20, lines 10-11), and includes replacements from both Station Refurbishment and Transformer Spares and Replacement programs.

The typical level of past replacement is 6 transformers.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, pages 18-21

- a) The discussion on pages 18-19 suggests that the purpose of the increase in transformers purchased under the Spares and Replacement program is to increase the number of new (as opposed to refurbished) transformers in the spare pool. However, the discussion on page 20-21 suggests that the purpose of the increase in transformer purchases under this program is to increase the number of transformers actually replaced each year. Please reconcile and clarify the purpose of the increase in transformer purchases under this program.

Response

Table 2 on page 18 within the referenced exhibit provides a breakdown of the \$20.3 million within the category of Transformer Spares and Replacement. As per Exhibit I, Tab 2, Schedule 8.25 SEC 25; \$16.2 million of this expenditure is incremental above the typical level. The primary purpose of the incremental expenditures is to address the gap within the operating spare inventory (\$10.4 million), but also address the requirement to increase the number of planned and demand transformer replacements (\$5.8 million).

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, page 18

a) What was the approved OM&A budget in 2010 and 2011 for transformer refurbishments and how many transformers was this meant to address in each of these years?

b) How many were actually refurbished in each of 2010 and 2011 and at what overall cost for each year?

c) Does increasing the number of “new” spare transformers in 2013 by 23 mean that there will be reduction of 23 in the number of used transformers that need to be refurbished in 2013? If not, please explain why and indicate what the reduction in numbers will be.

Response

a) and b)

The approved versus actual expenditures and accomplishments for 2010 and 2011 transformer OM&A refurbishments are as follows:

Transformer OM&A Refurbishments		2010	2011
Approved	Expenditure (\$ millions)	3.4	4.0
	Accomplishment (# of units)	41	50
Actual	Expenditure (\$ millions)	4.3	3.7
	Accomplishment (# of units)	48	56

c) Hydro One is purchasing 23 new spare transformers to address the shortfall in the operating spare complement, rather than the alternative which would require the refurbishment of 23 used transformers in poor condition to address the gap in the spare inventory.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, page 19

- a) Please provide the analysis showing that the use of new as opposed to refurbished transformers is more cost effective.
- b) Please confirm that such analysis would only demonstrate that the use of new transformers is prudent and does not demonstrate that the use of new as opposed to refurbished transformers is “non-discretionary”. If this cannot be confirmed, please explain why.

Response

- a) Reliance upon aged refurbished transformers as part of the operating spare inventory is not a sustainable and cost effective strategy to address the transformer fleet demographic pressures.

The typical cost for the refurbishment of a used operating spare transformer prior to deployment is approximately \$0.15 million. This expenditure is expensed as OM&A. Note: refurbishments do not extend the expected service life (ESL) of 50 years for a transformer, as outlined in Exhibit I, Tab 2, Schedule 1.11 Staff 12, part k), therefore even with this refurbishment investment another replacement will be required within a few years.

The typical cost to purchase a new transformer into the operating spare pool is approximately \$0.6 million, with an ESL of 50 years. This expenditure is capitalized and has a lower revenue requirement compared with the alternative of OM&A refurbishment.

- b) The requirement to address the short-fall in the operating spares complement is non-discretionary. The purchase of new transformers has been determined to be the most cost-effective option to address the short-fall.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2, pages 21-22 and 25

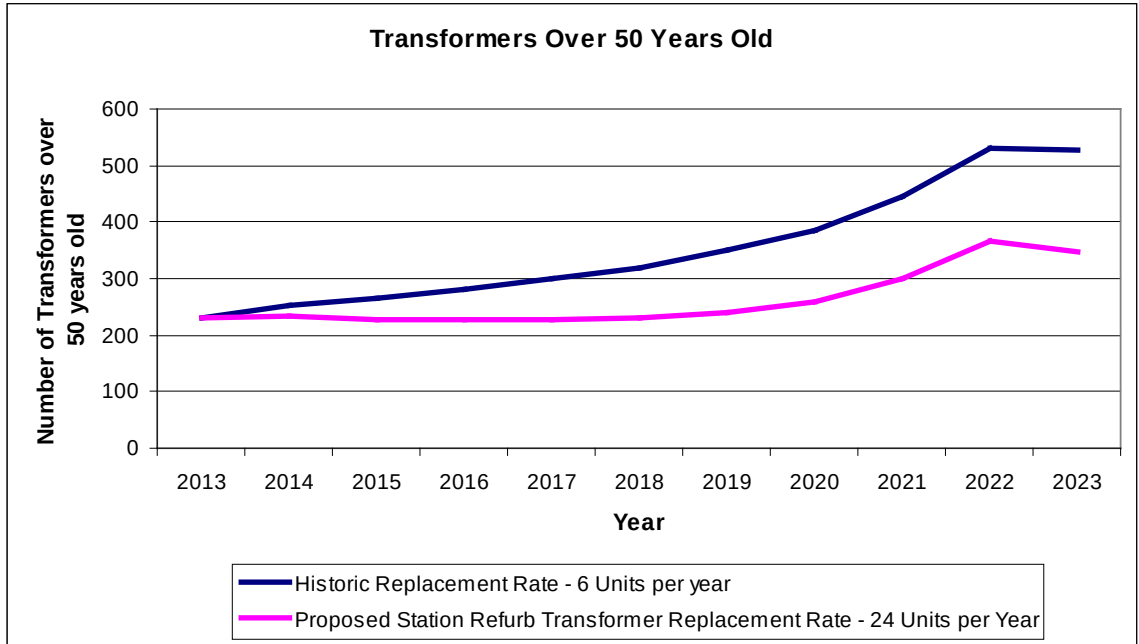
- a) As opposed to discussing the impact of maintaining the Status Quo (page 25), please explain why the concerns about transformer reliability are not being adequately addressed through the increased transformer replacements that are funded as part of the Station Refurbishment program.
- b) Please re-do Figure 12 including in the “Proposed Replacement” line only those transformers that would be replaced under the Station Refurbishment program.

Response

- a) Addressing only the 24 transformer replacements across the 32 stations within the Station Refurbishment program would forego the replacement of six transformers in very poor condition on a planned basis that are required to manage risks specifically associated with end-of-life transformers installed in stations which do not require significant station refurbishment at this time, and would exclude the replacement of the forecasted six major transformer failures which are required to address customer outages.

At a fleet-wide replacement rate of 24 transformers per year, the 10-year projection of transformers operating beyond their expected service life (ESL) increases significantly to approximately 375 transformers versus today’s 232 transformers. Having this large a portion of the inventory beyond ESL would result in significant deterioration of station reliability, in addition to requiring increased OM&A over the next 10 years to adequately manage risks.

- b) The following figure shows a 10-year projection of transformers operating beyond their expected service life (ESL) of 50 years assuming a replacement rate of 24 transformers per year. This illustration assumes that the oldest transformers are replaced first.



1
2
3
4

Note: with this modeling assumption, the 10-year projection of transformers operating beyond their ESL increases significantly to approximately 375 transformers versus today's 232 transformers.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 3, page 1

- a) Please demonstrate that if the replacement rate increase for wood poles was delayed until 2014 then “the backlog of end of life (“EOL”) poles in the system will become unmanageable”.

Response

- a) As stated in Exhibit B, Tab 2, Schedule 3, page 1, the backlog of EOL poles will become unmanageable if the current replacement rate is not increased in 2013 and continued at an increased rate the years following.

“Scenario 1” as discussed in Exhibit B, Tab 2, Schedule 3, pages 10-12, provides a demonstration of how a constant replacement rate of 7,500 poles per year is not aggressive enough to replace the number of EOL poles added to the system each year. As a result, a growing backlog of poles develops and grows over time.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 3, pages 1 (line 9) and 2 (line 7)

- a) The Application states (page 1) that over the next 10 years 340,000 poles are expected to require replacement. Please confirm that this includes the poles that were not treated to CSA standards as discussed on page 2.

Response

- a) No, the replacement of the poles that were not treated to CSA standards is in addition to the 340,000 poles that are expected to require replacement over the next 10 years. Reference Exhibit B, Tab 2, Schedule 3, page 2 line 3.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 3, page 9

- a) What was the approved level of spending for Wood Pole Replacement in 2010 and how many poles was this expected to address?
- b) How many wood poles were actually replaced in 2010?
- c) What was the actual spending on the Wood Pole Replacement Program in 2011 and how many poles were replaced?

Response

- a) The 2010 approved level of spending was \$46.4M for 7500 poles.
- b) The 2010 actual units replaced was 7518 wood poles.
- c) The 2011 actual spending was \$54.8M and 7284 poles were replaced.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 3, page 13

- a) For 2013, how much of increase in pole replacement (11,000 versus 7,200) is to specifically address the poles that were not treated to CSA standards?
- b) If the poles were not treated to standard, what recourse does HON have to obtain compensation from the manufacturer? If none, please explain why.
- c) If recourse to compensation is an option, please explain what actions HON has taken to date, the current status and the anticipated outcome.

Response

- a) In 2013 Hydro One plans to replace a minimum of 2000 poles which were not treated to CSA standards.
- b) Please refer to Exhibit I, Tab 2, Schedule 1.09 Staff 10 part f).
- c) Please refer to Exhibit I, Tab 2, Schedule 1.09 Staff 10 part f).

Power Workers Union (PWU) INTERROGATORY #2 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 1/Schedule 2/Page 1/Lines 6-9 (Calculation of Incremental Capital Module Revenue Requirement).

In calculating the revenue requirement for the proposed ICM introduced in Exhibit B, Tab 1, Schedule 1, the methodology applied is generally consistent with Board requirements as outline in Chapter 3 of “the Filing Requirements for Transmission and Distribution Applications”, dated June 28, 2012.

Ref (2): Ontario Energy Board Filing Requirements For Electricity Transmission and Distribution Applications. Last Revised on June 28, 2012.2 Chapter 3, Pages 9-10.

2.2.5 ICM Filing Guidelines

The Board requires that a distributor requesting relief for incremental capital during the IRM3 plan term must include comprehensive evidence to support the claimed need, which should include the following:

...

A description of the actions the distributor will take in the event that the Board does not approve the application.

...

Ref (3): Exhibit B/Tab 1/Schedule 1/Page 6/Lines 6-24 (Proposed Incremental Capital Module)

It is critical that Hydro One recover Typical, Escalated Issue and Non-typical capital spending during the period of an IRM. Hydro One is not in a position, due to credit rating issues, to invest in rate base for which there is no cost recovery. Any negative impact to Hydro One’s credit rating would result in borrowing challenges and increased borrowing costs for our customers. In order to avoid any negative credit rating impacts, Hydro One must maintain its earnings metrics including rate of return. Adding to this pressure, Hydro One was recently downgraded by Moody’s by one notch. Also, Standard and Poors has revised Hydro One’s outlook from stable to negative. ...

An unintended outcome of not being in a position to invest in rate base for which there is no return is lower reliability as Hydro One would have less ability to replace or refurbish assets prior to breakdown. A common industry term for this is the “harvesting” of assets. Another unintended outcome is not replacing or refurbishing assets when it is economically beneficial to do so. Planning for replacement and refurbishment and executing the plan is less costly than simply replacing or refurbishing assets when they break. ...The harvesting of assets would certainly result in increased contract and employee labour costs as Hydro One would be unable to levelize work based on the most efficient use of resources.

Ref (4): Exhibit B/Tab 1/Schedule 1/ Page 2/Lines 14-24 (Proposed Incremental Capital Module)

Hydro One has defined three categories of capital investment that make up the \$644 million in required in-service additions: “Typical” capital spending; “Escalated Issue” capital spending; and “Non-typical” capital spending.

The first category is Typical capital spending which includes historically approved levels of sustainment, development and shared services and other spending. Sustainment spending includes categories such as wood pole replacements, transformer replacements, investments in distributing and regulating stations, repairing storm damage and the replacement of meters. Development spending includes categories such as new load connections, and upgrades and system capability reinforcement. Shared services and other spending includes information technology, fleet, and work and office equipment. ...

Ref (5): Exhibit B/Tab 3/Schedule 1/Page 5/Lines 7-10 (Non-Typical Capital – Customer Information System)

Table 2

CIS Capital 2011– 2013 (\$ Millions)

	2011	2012	2013	Total In-service 2013
Minor Fixed Assets	10.1	0		10.1
Development Project	41.5	85.7	18.1	145.3
Total Capital Cost	51.6	85.7	18.1	155.4

1
2 a) Please provide a detailed description of the consequences of the actions that Hydro
3 One will take if the proposed ICM is not approved.

4
5 b) Please provide a detailed description of the consequences of the actions that Hydro
6 One will take if the Board allows Hydro One to recover all incremental capital costs
7 except for:

8 i. The planned 2013 Development and Shared Services work under the typical
9 category; or,

10 ii. The proposed CIS capital investment under the Non-Typical work category.
11

12 **Response**

13
14 a) and b)

15 For discussion on these items please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2,
16 b) iii) and Exhibit I, Tab 2, Schedule 5.08 VECC 11.
17

Power Workers Union (PWU) INTERROGATORY #3 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 4/Lines 18-20 (Escalated Issue Capital Distribution and Regulating Stations)

The Station Refurbishment Program addresses assets that are beyond their expected service life and exhibit conditions or design deficiencies that result in safety and customer supply reliability risks. ...

Ref (2): Exhibit B/Tab 2/Schedule 3/Page 10/Lines 6-8 (Escalated Issue Capital – Wood Pole Replacement Program)

Distribution wood poles have an expected useful life of 62 years. While the actual age of failure may be younger or older for individual poles, for analysis purposes, any poles in the distribution system that have reached this age are considered to require replacement.

Ref (3): Exhibit B/Tab 2/Schedule 2/Page 1/Lines 14-15 (Escalated Issue Capital – Distribution and Regulating Stations)

Although asset age is not the only indicator, it does provide a useful measure for determining capital and OM&A investment needs.

Ref (4): EB-2010-0002/Exhibit D1/Tab 2/Schedule 1/Page 9/Lines 16-24 (Sustainment Planning and Asset Investment Criteria)

Assets are declared EOL in the context of Hydro One's Capital Sustainment programs when the risk of allowing an asset to remain in service in its present condition/situation exceeds acceptable risks associated with Hydro One's business values. EOL is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Identifying the appropriate indicators to project an asset's EOL is an important factor in Sustainment planning. Some assets have very specific and agreed to EOL markers, perhaps based on regulations or industry-accepted standards. Others require a number of inputs to identify the risks that prompt an EOL determination.

Ref (5): EB-2010-0002/Exhibit D1/Tab 2/Schedule 1/Page 11/Lines 1-7 (Sustainment Planning and Asset Investment Criteria)

Age can be used as a probabilistic EOL indicator for assets with large installed bases where statistically significant conclusions can be drawn for expected age prior to failure. For assets with smaller installed bases, typically station power equipment, asset age provides a relative indication of expected remaining life that can be used to complement other factors in determining EOL. While Hydro One does not program replacements based on age, there are generally accepted expectations for the useful service life of many components of the power system. ...

Ref (6): Exhibit B/Tab 2/Schedule 3/Page 12 Lines 6-7 (Escalated Issue Capital – Wood Pole Replacement Program)

At the end of 10 years the volume of EOL poles will increase to 300,000.

- a) What is Hydro One's definition of "expected service life"?
- b) Is the definition Hydro One provided in Reference 4 for EOL the definition that Hydro One applies to EOL today?
- c) Is "expected service life" the same as EOL? If not, what is Hydro One's definition of EOL?
- d) Please confirm that EOL poles are poles that are beyond the expected service life for poles of 62 years [see Reference 6].
- e) Please describe how Hydro One determines the expected service life and/or EOL for its various types of distribution assets.
- f) Can Hydro One confirm that EOL along with other factors is a good analytical indicator for the need to replace assets?
- g) Does Hydro One have targets and/or maximum limits for % EOL of its various assets? If not, please explain why not. If yes, please provide:
 - i. Explanation on how the EOL limits/targets are derived;
 - ii. The limits and/or targets for distribution stations, transformers, Mobile Unit Substations ("MUS"), and wood poles; and,
 - iii. If the %EOL for each of these categories of assets are not currently at the EOL limit/target, when the limits/targets are expected to be attained with the proposed replacement rates.
- h) Does Reference 5 apply equally to distribution assets as it does to transmission assets?

Response

- a) Hydro One defines "expected service life" as meaning the average time in years that an asset can be expected to operate under normal system conditions.
- b) Yes, the same definition still applies.

- 1 c) No, expected service life is the typical age at which EOL is expected. Note that
2 multi-dimensional risk assessments drive specific end of life investment decisions.
3
- 4 d) EOL poles are as per the definition in b). The Scenarios used in the evidence were
5 based on an expected service life of 62 years for illustrative purposes only.
6
- 7 e) Expected service life and EOL is determined through a combination of Hydro One's
8 experience and experience of other utilities and manufacturers.
9
- 10 f) The expected service life along with other analytical factors is a good analytical
11 indicator for the need to replace assets.
12
- 13 g) Hydro One does not have a hard target for the percentage of individual assets that can
14 be beyond EOL. To do this would ignore the difference in risks between our asset
15 classes and their effect on overall company business values.
16
- 17 h) Yes

Power Workers Union (PWU) INTERROGATORY #4 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 6/Lines 15-18; Page 7/Lines 1-2 (Escalated Issue Capital – Distribution and Regulating Stations)

Figure 3 shows a 10 year planning outlook based on the existing replacement rate (4 stations per year, 0.4% of the fleet) and the proposed replacement rate of 32 stations per year respectively. At the current replacement rate, by 2023, more than half of Hydro One's distribution stations will be beyond their expected service life; double the number today. At the proposed investment level, the number of stations beyond their expected service life will remain generally constant over the next 10 years.

- a) Assuming an EOL target of 0%, and assuming a 10 year horizon to get there, what would be the additional cost if another 20 stations (i.e. 10% of the backlog) are replaced per year (i.e. 52 stations per year)?
- b) What would be the additional annual revenue requirements associated with (a)?
- c) What would be the additional incremental capital cost associated with (a) for 2013?

Response

- a) The additional cost to refurbish an additional 20 stations per year would be in the range of \$18 million.
- b) The additional annual revenue requirement associated with \$18 million additional capital expenditure is approximately \$1.4 million.
- c) The additional incremental capital cost for 2013 would be approximately \$18 million

Power Workers Union (PWU) INTERROGATORY #5 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 20/Lines 9-15 (Escalated Issue Capital – Distribution and Regulating Stations)

Figure 12 illustrates a 10-year scenario of transformer fleet demographics based on historic replacement rates of 6 transformers per year and a 10-year scenario based on the proposed 2013 replacement rate of 36 transformers each year. At the historic replacement rate, almost half of the distribution transformers will be beyond their expected service life in 10 years; more than double the amount of transformers today. As illustrated in Figure 12, moving to the proposed 2013 replacement rate for 10 years will essentially maintain the proportion of transformers beyond 50 years of age.

- a) Assuming an EOL target of 0%, and assuming a 10 year horizon to get there, what would be the additional cost if another 20 transformers (i.e. 10% of the backlog) are replaced per year (i.e. 56 transformers per year)?
- b) What would be the additional annual revenue requirements associated with (a)?
- c) What would be the additional incremental capital cost associated with (a) for 2013?

Response

- a) The cost to replace an additional 20 transformers per year would be in the range of \$10-23 million based on typical installed cost per unit of \$0.5 - \$1.15 million.
- b) The additional revenue requirement would be approximately \$0.8 - \$1.8 million.
- c) The additional incremental cost for 2013 would be approximately \$10-23 million.

Power Workers Union (PWU) INTERROGATORY #6 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 3/Page 12/Line 27; Page13/Line 10 (Escalated Issue Capital – Wood Pole Replacement Program)

From the scenarios illustrated above, it is evident that if replacement rates are not increased in the near future, annual volumes of EOL poles will accumulate to an unmanageable amount. However, if an appropriate replacement plan is implemented the volume of these poles existing in the system can at least be maintained at a generally constant level.

For 2013, Hydro One is proposing a transitional increase in its spending to \$81.8M to increase the replacement rate from 7,200 per year to about 11,000 as per the first year of Scenario 2. Hydro One is not pursuing a larger increase in 2013 as the current resources could not manage a larger change in one year. Instead, transitional steps will be taken to begin to address the increasing accumulation of poles reaching their EOL. Hydro One will seek approval for increased pole replacement levels in future applications.

- a) Please describe the current resourcing circumstances that do not allow Hydro One to manage a larger change in pole replacement in one year (i.e. 2013).
- b) Please describe the transitional steps that Hydro One will be taking to begin to address the increasing accumulation of poles reaching their EOL.
- c) Please describe how Hydro One will provide resourcing to accommodate the transitional steps.

Response

- a) Hydro One will be utilizing staff resources as explained in part c) below. Hydro One is also balancing dollar resources with a need to increase the work offset by the need to minimize ratepayer impacts in any one year.
- b) The concept of transitional steps, and the reason it is required is discussed in the evidence but the actual dollar amounts and rate of increase will be approved in stages through future rate applications.
- c) Please see Exhibit I, Tab 2, Schedule 1.09 Staff 10, part g).

Power Workers Union (PWU) INTERROGATORY #7 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 1/Schedule 1/Page 6/Lines 16-24 (Proposed Incremental Capital Module)

An unintended outcome of not being in a position to invest in rate base for which there is no return is lower reliability as Hydro One would have less ability to replace or refurbish assets prior to breakdown. A common industry term for this is the “harvesting” of assets. Another unintended outcome is not replacing or refurbishing assets when it is economically beneficial to do so. Planning for replacement and refurbishment and executing the plan is less costly than simply replacing or refurbishing assets when they break. The harvesting of assets would certainly result in increased contract and employee labour costs as Hydro One would be unable to levelize work based on the most efficient use of resources.

- a) Please describe how HO determines when it is economically beneficial to replace or refurbish an asset.
- b) Does Hydro One see any net benefit opportunities to adjusting maintenance work such that more distribution asset categories might be run to fail?

Response

- a) Economic assesment of the alternative of refurbishment versus replacement is based on several factors including:
- remaining expected life of the two alternatives,
 - present value cost of the two alternatives,
 - associated revenue requirement of the two alternatives.
- b) Neither Wood Poles nor Distribution & Regulating Station Assets are “run to fail”.

Power Workers Union (PWU) INTERROGATORY #8 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 1/Lines 14-23 and Lines 25-28; Page 2/Lines 1-2

Although asset age is not the only indicator, it does provide a useful measure for determining capital and OM&A investment needs. Of Hydro One's 1,002 distribution and regulating stations, 25% are beyond their expected service life of 50 years, with an additional 25% between 40 and 50 years old. This aged plant requires significantly increased capital re-investment on an ongoing basis to ensure that the existing risk profile does not deteriorate. If the current capital reinvestment for distribution stations is not significantly increased, the volume of station assets that are beyond their expected service life will become unmanageable over a period of time. The result will be a degrading level of performance to customers, increasing safety risks to the public and employees, and escalating OM&A costs.

...

Hydro One has continuously learned from available condition assessment information. Over the past several years, success in maintaining the reliability of the station fleet has been achieved through a greater dependency on maintenance of distribution station assets. This is not viewed to be sustainable or prudent from a long-term perspective, as an increasing number of assets are beyond a point which makes them technically or economically maintainable compared with the alternative of replacement.

- a) What would have been the percentage of distribution stations beyond their expected service life if the assets had been replaced when maximum economic benefit is indicated based on Asset Life Cycle cost?
- b) What will be the impact of the proposed replacement rate on reliability performance, environment, and public and worker safety? Will the risk remain at the current levels, increase or decline?

Response

- a) Hydro One cannot provide the percentage of distribution stations that would be beyond their expected service life if the assets had been replaced when maximum

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EB-2012-0136

Exhibit I

Tab 2

Schedule 6.07 PWU 8

Page 2 of 2

- 1 economic benefit is indicated. Replacements are driven by reliability, safety,
2 environment and other factors and not just economic benefit.
3
- 4 b) Based on the proposed replacement rate the risk will remain relatively constant in the
5 short term due to the aging demographics of distribution stations. If sustained over
6 time, the proposed rate should result in lower risk in the longer term.

Power Workers Union (PWU) INTERROGATORY #9 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 3/Page 4/Lines 5-11(Escalated Issue Capital – Wood Pole Replacement Program)

Replacing poles on a planned basis is recognized as a good utility practice and is less costly than "emergency" or reactive type replacements. In addition to the increased labour costs (i.e. overtime premiums), reactive replacements result in longer outage durations to customers and increased safety risks.

On average, a planned outage that replaces a pole is only 2 hours while an unplanned outage that involves replacing poles lasts 9 hours.

- a) Is the impact of reactive replacements of poles compared to planned replacement of poles equally applicable to the replacements of station and transformers? Please provide explanation in your response.

Response

- a) Yes, work in Distribution & Regulating Stations is typically less costly to complete under planned conditions than reactive conditions. Under planned conditions, work can be completed in a more efficient manner, and premiums associated with overtime, material expediting, etc. are minimized. Conducting work on a demand or reactive basis also has the negative consequence of deferring other planned work.

Power Workers Union (PWU) INTERROGATORY #10 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 16/Lines 11-13 (Escalated Issue Capital – Distribution and Regulating Stations)

Hydro One’s proposed step change will set in motion a volume of work that is required to prevent the existing risk levels from deteriorating over the next 10 year period.

- a) Is the “next 10 year period” referred to in the reference the period 2013 – 2022?
- b) How does Hydro One’s step change prevent deterioration of risk levels for stations beyond the next 10 years (i.e. 2023-2032)?

Response

- a) Yes
- b) Hydro One’s proposed 2013 incremental capital expenditures will more effectively manage the risks associated the aging and degrading infrastructure. To simplify the discussion, if only age is used as a proxy for overall risk, then maintaining the 2013 accomplishment rate through 2032 would result in a reduction of the number of stations operating beyond their expected service life (as outlined in Exhibit I, Tab 2, Schedule 6.13 PWU 14), and hence a reduction from the existing risk level.

Forward looking information beyond 2013 is for illustrative purposes only and is not intended to represent future proposed work programs; future replacement rates will be determined through future applications.

Power Workers Union (PWU) INTERROGATORY #11 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 20/Lines 9-15 (Escalated Issue Capital – Distribution and Regulating Stations)

Figure 12 illustrates a 10-year scenario of transformer fleet demographics based on historic replacement rates of 6 transformers per year and a 10-year scenario based on the proposed 2013 replacement rate of 36 transformers each year. At the historic replacement rate, almost half of the distribution transformers will be beyond their expected service life in 10 years; more than double the amount of transformers today. As illustrated in Figure 12, moving to the proposed 2013 replacement rate for 10 years will essentially maintain the proportion of transformers beyond 50 years of age.

- a) Is the “10 years” referred to in the reference the period 2013 – 2022?
- b) What is the impact of the proposed 2013 replacement rate on the proportion of transformers beyond 50 years of age over the next 10 year period (i.e. 2023-2032)?

Response

- a) Yes
- b) Hydro One’s proposed 2013 incremental capital expenditures will more effectively manage the risks associated the aging and degrading infrastructure. To simplify the discussion, if only age is used as a proxy for overall risk, then maintaining the 2013 accomplishment rate through 2032 would result in a reduction of the number of transformers operating beyond their expected service life (as outlined in Exhibit I, Tab 2, Schedule 6.13 PWU 14), and hence a reduction from the existing risk level.

Forward looking information beyond 2013 is for illustrative purposes only and is not intended to represent future proposed work programs; future replacement rates will be determined through future applications.

Power Workers Union (PWU) INTERROGATORY #12 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 3/Page 12/Lines 4-13 (Escalated Issue Capital – Wood Pole Replacement Program)

Scenario 2 shows what will happen assuming a volume of 11,000 poles in 2013 plus an incremental increase of 2,000 poles replaced annually through the Wood Pole Replacement program up to 20,000 poles annually by 2018. At the end of 10 years the volume of EOL poles will increase to 300,000. After 20 years that volume will remain the same. By 2042, about 20% (~320,000) of all poles remaining in the system will have exceeded their expected useful life. Scenario 2 is similar to Scenario 1 during the first eight years. However, due to its ramp-up in replacement values it is able to maintain a relatively stable level of EOL poles existing on the system beginning in 2021. However, throughout this period the number of EOL poles on the system would be over 300,000 poles, more than double the current amount.

- a) Is the “10 years” referred to in the reference the years 2013 – 2022?
- b) How does Hydro One’s proposed wood pole replacement rate prevent deterioration of risk levels for wood poles beyond the next 10 years (i.e. 2023-2032)?

Response

- a) Yes.
- b) Under Scenario 2, the risk level would be held relatively constant beyond the next 10 years as the volume of EOL poles existing on the system would be held at a relatively stable level.

This example was for illustration purposes only; future replacement rates will be determined through future applications.

Power Workers Union (PWU) INTERROGATORY #13 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 22/Lines 4-10 (Escalated Issue Capital – Distribution and Regulating Stations)

Figure 13 shows an updated fleet-wide condition assessment of the in-service distribution transformers. According to the currently available information, 397 in-service transformers, or one third for the population of 1,212 transformers, are in a deteriorated condition that identifies them for replacement.

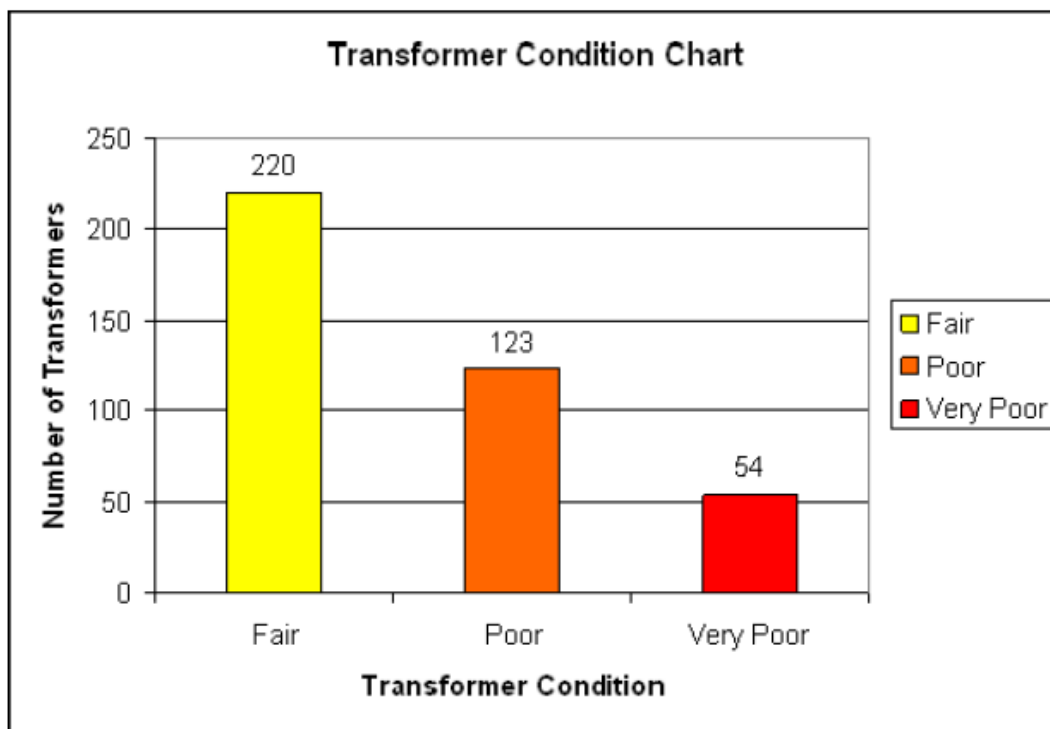


Figure 13 - Transformer Fleet Condition Assessment

- a) What will be the impact of the proposed transformer replacement rate of 36 replacements per year on the statistics illustrated in Figure 13 (i.e. number of transformers in Fair, Poor and Very Poor condition in each year from 2013 through 2023)? Please provide the statistics in number of transformers as well as % of total transformer numbers.

- b) Please provide the information illustrated in Figure 13, or similar information if the same information is not available, for Stations and for Wood Poles.
- c) Please provide the information requested in (a) or similar information if the same information is not available, for Stations and for Wood Poles assuming the proposed replacement rates for Stations and Wood Poles.

Response

- a) It is difficult to predict the number of Fair, Poor & Very Poor assets in each year over the next decade, as many assumptions would be required to perform such analysis. Directionally however, it is expected the impact of 36 annual transformer replacements over the next 10 years, will generally maintain the relative portion of the transformer fleet in good/poor/fair condition as current day. Increased replacement rates are required to offset the fleet condition degradation and the demographic pressures as outlined in the application.

b)

Table PWU 13-1 Distribution Station Overall Condition 2012

DS Station Condition	Number of Stations
Very Poor	42
Poor	158
Fair	139

Table PWU 13-2 Distribution Line Wood Pole Condition 2012

Wood Pole Condition	Number of Wood Poles
Very Poor	500
Poor	51,000
Fair	195,000

- c) As discussed in part a), the number of fair, poor and very poor assets for every year is difficult to predict, as many assumptions would be required to perform such analysis. Directionally however, it is expected the impact of the proposed replacements over the next 10 years, will generally maintain the relative portion of the fleet in good/poor/fair condition as current day. Increased replacement rates are required to offset the fleet condition degradation and the demographic pressures as outlined in the application.

Power Workers Union (PWU) INTERROGATORY #14 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 3/Lines 15-21; Page 4/Lines 1-2 (Escalated Issue Capital – Distribution and Regulating Stations)

The expenditures are required for increased asset replacement to manage demographic pressures and the asset condition of the aged station infrastructure as Hydro One approaches the “bow wave” of required re-investment work that can be seen in the age profiles. Increased capital reinvestment starting in 2013 will maintain the current risk levels, and allow the stabilization of OM&A expenditures over a 10-year time period that would otherwise have to increase as the station infrastructure ages.

Ref (2): Exhibit B/Tab 2/Schedule 3/Page 1/Lines 21-28 (Escalated Issue Capital – Wood Pole Replacement Program)

Hydro One has been mitigating the risk of failure by selectively targeting replacement of EOL poles based on improved asset condition information. However, the demographics of the pole population require a change in approach. Delaying the required increase in replacement volumes would push the population of wood poles into an unmanageable state of deterioration. By investing in the aging and deteriorating wood pole population today, risks associated with system reliability, safety, future costs and future work resourcing can be mitigated to ensure the integrity of the distribution system and the reliability of supply.

a) Please fill out the following table. Please provide references for data sources or provide explanation on derivation of information.

1

	Asset Class	Stations	Transformers	Poles
(1)	Number of Units 2012			
(2)	Current Replace Rate			
(3)	Proposed Replace Rate			
(4)	% EOL 2012			
(5)	# EOL 2012			
(6)	Ave # per year Reaching EOL 2013-2021			
(7)	% EOL 2021 using (2)			
(8)	# EOL 2021 using (3)			
(9)	Ave # per year Reaching EOL 2022-2031			
(10)	Backlog # EOL Reduced over 2022-2031 using (2)			
(11)	Backlog # EOL Reduced over 2022-2031 using (3)			
(12)	% EOL 2031 using (2)			
(13)	# EOL 2031 using (2)			
(14)	% EOL 2031 using (3)			
(15)	# EOL 2031 using (3)			

3

Response

Please see below completed table for the requested analysis with respect to number of units exceeding the expected service life.

	Asset Class	Stations	Transformers	Poles
(1)	Number of Units 2012	1002	1212	1,700,000
(2)	Current Replace Rate	4	6	7,200
(3)	Proposed Replace Rate	32	36	11,000
(4)	% ESL 2012	24%	19%	10%
(5)	# ESL 2012	242	226	170,000
(6)	Ave # per year Reaching ESL 2013-2021	24	30	30,500
(7)	% ESL 2021 using (2)	42%	36%	22%
	# ESL 2021 using (2)	421	439	380,000
	% ESL 2021 using (3)	17%	14%	20%
(8)	# ESL 2021 using (3)	169	169	346,000
(9)	Ave # per year Reaching ESL 2022-2031	25	34	22,400
(10)	Backlog # ESL Reduced over 2022-2031 using (2)	Increase of 178	Increase of 193	Increase of 152,000
(11)	Backlog # ESL Reduced over 2022-2031 using (3)	Reduction of 74	Reduction of 77	Increase of 114,000
(12)	% ESL 2031 using (2)	63%	59%	31%
(13)	# ESL 2031 using (2)	628	716	532,000
(14)	% ESL 2031 using (3)	10%	12%	27%
(15)	# ESL 2031 using (3)	96	146	460,000

Notes:

- (1) A constant replacement rate was assumed to complete the above table. However, this information is for illustrative purposes only and is not intended to represent future proposed levels; future replacement rates will be determined through future applications.
- (2) To simplify the analysis in the table above, it was assumed the oldest station, transformer, or pole would be replaced first. However this is for illustrative purposes only, actual replacement candidates are selected based on a combination of age, condition, etc.
- (3) The analysis in the above table utilized Expected Service Life (ESL) for the assets. For distribution stations and transformers the ESL assumed was 50 years, and an ESL of 62 years for distribution poles. This analysis for distribution poles replacements does not include poles that were not treated to CSA standard.

Power Workers Union (PWU) INTERROGATORY #15 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ref (1): Exhibit B/Tab 2/Schedule 2/Page 1/Lines 11-18; Page 1/Lines 15-21 (Escalated Issue Capital – Distribution and Regulating Stations)

... Of Hydro One's 1,002 distribution and regulating stations, 25% are beyond their expected service life of 50 years, with an additional 25% between 40 and 50 years old. This aged plant requires significantly increased capital re-investment on an ongoing basis to ensure that the existing risk profile does not deteriorate. If the current capital reinvestment for distribution stations is not significantly increased, the volume of station assets that are beyond their expected service life will become unmanageable over a period of time. ...

Ref (2): Exhibit B/Tab 2/Schedule 3/Page 1/Lines 23-28 (Escalated Issue Capital – Wood Pole Replacement Program)

... Delaying the required increase in replacement volumes would push the population of wood poles into an unmanageable state of deterioration. By investing in the aging and deteriorating wood pole population today, risks associated with system reliability, safety, future costs and future work resourcing can be mitigated to ensure the integrity of the distribution system and the reliability of supply.

- a) Are there currently distribution assets other than the stations, transformers and wood poles that have EOL backlogs that need to be addressed through increased replacement rates? If yes, please describe the circumstances of those assets.
- b) If the response to (a) is yes, is Hydro One putting on hold any of the required increases in replacement rates for those assets until the next cost of service application? Please provide explanation in the response.
- c) If the response to (b) is yes, please describe the impact on service reliability performance, environment, and safety of the public and workers of doing so.

Response

- a) No, currently these are the only areas. However, due to aging infrastructure, there are other areas that may need to be addressed in future years; funding will be obtained through future applications.
- b) Not applicable

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- 1 c) Not applicable

Consumers Council of Canada (CCC) INTERROGATORY #5 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

EX. B1/T1/S1

Please provide HON's forecast and actual capital expenditures for the years 2006-2012

Response

Typical Capital Expenditures (\$ Million)							
	2006	2007	2008	2009	2010	2011	2012
Capital Expenditures	378.1	399.9	435.3	455.5	430.5	431.9	443.9

2006 – 2011: Actual spending

2012: Forecast spending

Please note that the capital expenditures associated with smart meters and green projects (smart grid and renewable generation related) and non-typical projects (CIS) have been removed.

Consumers Council of Canada (CCC) INTERROGATORY #6 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

EX. B/T1/S1/P. 4

Please provide a detailed breakdown of the \$414 in typical capital spending for 2013.
How was that budget derived?

Response

Please refer to Exhibit I, Tab 2, Schedule 5.05 VECC 8, part a).

Consumers Council of Canada (CCC) INTERROGATORY #7 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

EX. B/T1/S1/P. 8

What is HON's forecast of "typical" capital spending in 2012? Please provide a detailed budget. Please include actual spending to date.

Response

Forecast 2012 Typical Capital Spending (\$M)

Sustainment	192.6
Development	157.3
Operations	4.4
Shared Services	89.6
Total Capital	443.9

Consumers Council of Canada (CCC) INTERROGATORY #8 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

EX. B/T2/S2/P. 3

Please add 2012 forecast and 2011 actual numbers to Table 1 - Stations Capital. When did HON identify the need for increased levels of spending on Station Refurbishment and Transformer Spares and Replacements? How could the need to refurbish stations go from 4 stations per year to 32? How could the need to replace transformers go from 6 per year to 36 per year in such a short time period?

Response

Please refer to Exhibit I, Tab 2, Schedule 9.03 AMPCO 3, part e) for the breakdown of the 2011 and 2012 capital expenditures.

Since the last cost of service application, Hydro One has identified the need for increased levels of spending, please refer to Exhibit I, Tab 2, Schedule 8.16 SEC 16.

Consumers Council of Canada (CCC) INTERROGATORY #9 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

EX. B/T2/S3/P. 1

Please explain why HON is of the view that it "must immediately begin to implement a more aggressive pole replacement strategy ". When was this immediate need identified?

Response

Please see Exhibit I, Tab 2, Schedule 1.01 Staff 2.

Consumers Council of Canada (CCC) INTERROGATORY #10 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Ex. B/T2/S3/p. 9

Please provide the 2011 Actual Net costs for the Wood Pole Replacement Program.
Please provide the expected 2012 expenditures.

Response

The Actual Net cost for the wood pole replacement program in 2011 was \$54.8 million.
The 2012 year-end forecast (as of June 30, 2012) is \$52.8 million.

School Energy Coalition (SEC) INTERROGATORY #1 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.9] Please provide the Applicant's current forecasts for "distribution revenue change from load growth" from 2011 to 2012 and from 2012 to 2013.

Response

The "distribution revenue change from load growth" from 2011 to 2012 is forecast to be +0.90% and from 2012 to 2013 it is forecast to be -0.11%.

School Energy Coalition (SEC) INTERROGATORY #2 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.3] Please provide the source reference for the claim “*The Board’s examination under the Renewed Regulatory Framework recognizes that one of the major challenges facing the sector today, and the most significant driver of costs, is the scale of capital spending expected over the next number of years to modernize the system and to provide for new demand*”.

Response

The reference can be found on Page 7 of “Moving Forward”, Remarks for the Ontario Energy Network, November 21, 2011 – available on the OEB website at http://www.ontarioenergyboard.ca/OEB/Documents/Speeches/speech_Leclair_OEN_20111121.pdf.pdf.

School Energy Coalition (SEC) INTERROGATORY #3 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p4] Please confirm that by the calculation in Table 1 Applicant seeks ICM treatment of the capital spending equivalent of the reduction in revenue due to reduced load, and the amount by which capital spending exceeds depreciation.

Response

Yes. Hydro One is seeking a rate rider to allow for recovery of the rate base no longer funded due to decreased consumption as well as the amount by which capital spending exceeds depreciation.

For further discussion please refer to Exhibit I, Tab 2, Schedule 1.07 Staff 8, parts a), c) and f), as well as Exhibit I, Tab 2, Schedule 5.07 VECC 10, part d).

School Energy Coalition (SEC) INTERROGATORY #4 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 1] Please confirm that the sole reason for the outlook downgrade by S&P was the rating downgrade of the Applicant's shareholder, the Province of Ontario.

Response

Credit rating agencies initiate rating actions and provide investors with an independent (third party) measure of the credit quality for a debt issuer. They provide their reasons and rationale for these actions. S&P's rationale for the outlook downgrade is provided in Exhibit A, Tab 6, Schedule 1, Attachment 1, page 2, "Rating Action".

School Energy Coalition (SEC) INTERROGATORY #5 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 2/p.1] Please confirm that the sole reason for the rating downgrade by Moody's was the rating downgrade of the Applicant's shareholder, the Province of Ontario.

Response

Credit rating agencies initiate rating actions and provide investors with an independent (third party) measure of the credit quality for a debt issuer. They provide their reasons and rationale for these actions. Moody's' rationale for the rating downgrade is provided in Exhibit A, Tab 6, Schedule 1, Attachment 2, page 1.

School Energy Coalition (SEC) INTERROGATORY #6 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 2/p.1] Please provide an explanation of the term “high default dependence”, and how it relates to Hydro One and the Province of Ontario.

Response

The term “high default dependence” is used by Moody’s Investors Service when they employ their methodology in rating government related issuers. The definition of the term “high default dependence” can be found on page 3 of Attachment 1 which is the Government-Related Issuers: Methodology Update by Moody’s Investors Service dated July 22, 2010.

RATING METHODOLOGY

Government-Related Issuers: Methodology Update

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This methodology update provides additional transparency about our approach to rating government-related issuers (GRIs) and reflects lessons learned from the financial crisis regarding the willingness and ability of governments to support GRIs. It does not constitute a change in Moody's fundamental rating approach to GRIs. Accordingly, this methodology update by itself will not cause any rating changes. This document updates and replaces the previous GRI methodology entitled "Application of Joint Default Analysis to Government-Related Issuers", published in April 2005.

Since Moody's first began to apply Joint Default Analysis (JDA) to its analysis of GRIs five years ago, this approach has provided a roadmap for deciphering the credit links between GRIs and their supporting governments. Further to the recent financial turmoil and heightened market concern over GRI credit risks, this methodology update is intended as a refresher about JDA and outlines improvements to how we apply this approach to GRIs. Specifically, this update aims to:

- » Offer a detailed discussion of the factors framing our opinions on (a) the probability of extraordinary support from a supporting government to a GRI on the verge of default; and (b) the degree of default dependence linking the credit profile of the two entities.
- » Present a scorecard that is based on these factors, which acts as a tool to help estimate extraordinary support and default dependence and apply JDA to GRIs. While this tool provides valuable insights, it has - like any scorecard - limitations. Therefore, it is not meant to be a substitute for rating committee judgments.
- » Outline refinements to how we will disclose levels of extraordinary support and default dependence going forward.

In line with rating actions taken since the introduction of JDA in 2005, we will continue to monitor rating drivers for GRIs globally and take individual actions in response to (a) changes in the standalone creditworthiness of GRIs and (b) shifts in the extraordinary support dynamics.

Rated Universe of GRIs

We define a GRI as an entity with full or partial government ownership or control, a special charter, or a public policy mandate from the national or local government. We generally use 20% as the minimum government ownership level before we consider an issuer to be a GRI. In some rare cases, an issuer that is fully or partially owned (or controlled) by another GRI may also be treated as a GRI. There are currently published Moody's ratings on over 400 GRIs in more than 60 countries. By their nature, GRIs are generally strategically important entities and prominent issuers within their respective markets.

JDA Framework¹

The global financial crisis has demonstrated the need for a robust approach to rating GRIs, based on assessments of GRI-specific credit risks and an understanding of why governments decide to bail out certain entities while leaving others to default. On the one hand, the crisis has highlighted governments' willingness to support strategic assets even when they are not contractually obliged to do so. On the other hand, the crisis has also revealed the adoption of more targeted, or selective, support strategies by some countries, indicating limits in the public sector's capacity to socialize credit risks.²

Conceptually, Joint Default Analysis (JDA) captures these realities by first assessing the standalone credit profile of a GRI, then layering on top both a clear estimate of the likelihood of extraordinary support and an assessment of the likely solvency of the supporting government in such a scenario.

As set out in the 2005 methodology, JDA explicitly accounts for:

- » the GRI's standalone risk or Baseline Credit Assessment (BCA)
- » the supporting government's rating
- » an estimate of the default correlation between the two entities (dependence)
- » an estimate of the likelihood of extraordinary government support (support)

The BCA is defined on a numeric scale (1-21) that maps to Moody's alphanumeric rating scale (Aaa to Ca) and represents the intrinsic credit strength of a GRI, accounting for all ongoing transfers, subsidies or long-term contracts from the supporting government, but absent any concept of extraordinary support. Essentially, the BCA can be viewed as being equivalent to a rating category, for which the likelihood that the GRI would require extraordinary support is comparable to the probability of default of non-GRIs (expressed in the corresponding rating category). Guidance on the assignment of BCAs is outlined in industry-specific rating methodologies and is not addressed in this update.

Default dependence reflects the tendency of a GRI and its supporting government to be jointly susceptible to adverse circumstances that simultaneously move them closer to default. Since the capacity of the supporting government to provide extraordinary support is conditional on its solvency, the higher the level of correlation between the two obligors' default risks, the lower the benefits achieved from joint support. This methodology update provides detailed guidance on the factors we assess to determine the degree of default dependence for a GRI and its supporting government.

¹ A full, technical, discussion of JDA is available in Appendix I: Technical Overview of JDA.

² A broader discussion of these issues is available in Appendix II: Lessons Learned From the Global Financial Crisis.

Extraordinary support is assessed by determining the likelihood that the supporting government would act in a timely manner to prevent an imminent default of a GRI. Support may take different forms, ranging from formal guarantees to cash injections or actions that enhance the GRI's access to interim financing. This update provides greater clarity on the factors that we assess to determine the likelihood of extraordinary support.

Issues related to the technical foundation of JDA and how Moody's applies JDA to GRIs in special circumstances are dealt with in the appendices. Appendix I provides a technical overview of JDA. Appendix II reviews lessons learned from the crisis and how it influences our views on support. Appendix III covers cases of credit substitution. Appendix IV discusses the issue of rating a GRI at par with the government rating when the BCA is significantly lower. Appendix V covers the anchor rating for non-bank financial GRIs. Appendix VI discusses how we deal with cases of multiple government supporters.

Default Dependence

Default Dependence Defined

In the application of JDA to GRIs, default dependence (dependence) reflects the tendency of a GRI and its supporting government to be jointly susceptible to adverse circumstances that simultaneously move them closer to default. Since the capacity of the supporting government to provide extraordinary support – and prevent a default by a GRI – is conditional on its solvency, the higher the level of correlation between the two obligors' default risks, the lower the benefits derived from joint support.

Accordingly, default dependence is employed to reflect the likelihood that the credit profiles of two obligors may be imperfectly correlated. This has important diversifying effects influencing the joint-default outcome. Intuitively, if the default probabilities of a GRI and its supporting government are uncorrelated, implying that their respective credit profiles are independent of one another, the likelihood that the two entities would simultaneously default is less than the probability of either one defaulting on its own. In contrast, if their default probabilities are correlated, implying that the credit profiles are not independent of one another, the probability that the two entities may simultaneously default is heightened.

Levels of Dependence

Within the JDA framework for GRIs, we have refined our approach to disclosing dependence in our published research on GRIs. Moody's had previously explained dependence by using three ranges: low (0%-30%), medium (31%-70%) and high (71%-100%). Going forward, we will set default dependence at one of four levels: low (30%), moderate (50%), high (70%) and very high (90%). The four levels represent a more consolidated approach, compared to the broader ranges previously provided, and seek to enhance ratings transparency. Moreover, this change recognizes the need to assess dependence at a conceptual level and to avoid complex attempts to differentiate default correlation across a more open-ended spectrum. In most cases, GRIs demonstrate moderate to very high degrees of default dependence with their supporting governments, which reflects the existence of institutional linkages and shared exposure to economic conditions that draw credit profiles together.

Determining Dependence

When determining the level of dependence for a given GRI and its supporting government, we focus on three broad factors: (1) the extent to which the GRI and government are operationally and financially linked; (2) the extent to which the GRI and government rely on the same revenue base; and (3) the extent to which the GRI and government are exposed to common credit risks.

Operational and Financial Linkages

The first step in assessing default dependence consists of analyzing the operational status of the GRI. A GRI operating as a commercial venture, with no visible ties to the supporting government, may possess a distinct credit profile. However, a GRI with clear operational or administrative linkages to the government, including an explicit and well recognized mandate to carry out a government responsibility, would tend to have a credit profile that overlaps with that of the government, suggesting a very high level of default dependence.

In conjunction with operational status, financial linkages between the two entities may also connect the two credit profiles. For instance, a structural reliance on government transfers or subsidies may provide a channel through which financial stress is communicated between the government and the GRI. Likewise, in cases where the GRI sends dividends to the government, or where the GRI relies on the government for a significant share of its annual sales, financial pressure may also be transferred between the two entities under a stress scenario.

KEY METRICS

- » Direct and Indirect Government Transfers as a % of GRI Revenue
- » Government Purchases as a % of GRI Revenue
- » GRI Payments (Dividends) to Government as a % of Government Revenue

Reliance on Overlapping Revenue Base

The second step in determining default dependence consists of assessing the extent to which the GRI and the government derive their income from the same revenue base or economic space. For instance, a GRI with an export-oriented business model may not be exposed to the same revenue shocks as the central government, whose revenues are influenced predominantly by fluctuations in domestic economic performance.

Accordingly, in determining the degree of overlap in revenue bases, our analysis focuses on the extent to which the income of both the GRI and the supporting government is derived from within a common economic space.

KEY METRICS

- » GRI: Exports as a % Revenue
- » Sovereign Supporting Government: Externally Derived Revenues as a % of Revenue
- » Sub-Sovereign Supporting Government: Intergovernmental Transfers³ as a % of Revenue

³ Transfers from the central government and income derived from an economic space larger than that of the sub-sovereign territory.

Exposure to Common Credit Risks

The third step in assessing default dependence consists of analyzing the extent to which the GRI and the supporting government are exposed to common credit risks. For instance, depending on the structure of their debt obligations, exchange rate volatility may pose a common credit risk for the GRI and the government, causing their default probabilities to move in tandem. Likewise, in the context of developing economies, unstable political environments may lead to political event risk (e.g. a coup, revolution, civil strife or paralysis of the political system) with adverse consequences for both the GRI and the government. The assessment of exposure to common risks may overlap with previously discussed factors, as in the case where both the GRI and the government rely upon a similar industry or product (e.g. single commodity export), or it may take other forms.

KEY CONSIDERATIONS

- » Foreign Exchange Risk in Debt Structure
- » Shared Industry Exposure
- » Political Event Risks

Extraordinary Support

Extraordinary Support Defined

Extraordinary support (support) represents the probability that a government owner of a GRI would provide financial support, or other contractual protections, to a GRI to avoid a default on its debt obligations. Support may be supplied either directly by a government or provided directly through third parties under the influence of the government – for example, the provision of emergency finance by banks under the direction of a government. In general, support encompasses any assistance provided outside of the ordinary course of business that avoids a default by the GRI.

Levels of Support

Within the JDA framework for GRIs, we have refined our approach to disclosing dependence in our published research on GRIs. Similar to its assessment of dependence, Moody's had previously classified support into three ranges: low (0%-30%), medium (31%-70%) and high (71%-100%). Going forward, we will categorize support into one of five ranges: low (0% - 30%), moderate (31% - 50%), strong (51% - 70%), high (71% - 90%) and very high (91% - 100%). These five ranges represent a more granular breakdown than those provided in the past and aim to increase transparency. The use of ranges, rather than specific percentage points, recognizes the inherent uncertainty surrounding assessments of potential support before they occur. By definition, support is provided in a stressed environment, thus making it difficult to pinpoint the circumstances impacting an eventual support decision.

FIGURE 1

GRI Support Factors

STRUCTURAL FACTORS

1. Guarantees
2. Ownership
3. Barriers to Support

WILLINGNESS FACTORS

4. Government Intervention
5. Political Linkages
6. Economic Importance

Determining Support

In determining the level of support for a GRI, we focus on three structural factors and three factors explaining the level of the government's willingness to provide support. Structural factors address the legal and quasi-legal aspects of the government's relationship with the GRI and include: (1) guarantees, (2) ownership issuers and (3) barriers to support. The factors underlying willingness consider the softer connections between the two entities and include (4) the level of government intervention, (5) political linkages and (6) economic importance.

Guarantees

An analysis of the existence or non-existence of guarantees is essential to determining potential support. While guarantees come in a variety of different strengths and forms, suggesting differing levels of support for GRIs, they demonstrate a contractual, or, at a minimum, a moral obligation to assist a GRI on the verge of default. The three main types considered are (a) explicit guarantees, (b) verbal guarantees and comfort letters, and (c) special legal status.

- » **Explicit guarantees.** An explicit, legally binding guarantee, covering all of the GRI's debt obligations in a timely manner, usually suggests a very high likelihood of support and lifts the GRI's rating to the level of the supporting government. However, if only a portion of debt is guaranteed, the rating for the remaining non-guaranteed amounts may reflect a differentiation in the government's intention to support various classes of debt.
- » **Verbal guarantees and/or comfort letters.** While these are judged on their individual merits – with their value dependent upon the person or entity giving the guarantee, the language used, the length of time since the guarantee was given and whether it was given publicly or only to Moody's – they illustrate a proactive position and support a higher likelihood of support.
- » **Special legal status.** In cases where guarantees are not present, Moody's also analyzes whether or not the GRI possesses a special legal status that may prevent it from entering normal bankruptcy proceedings and/or confers some state responsibility for the GRI's debts – e.g. as in the case of certain public entities in France that hold the status of an *établissement public à caractère industriel et commercial* (EPIC), or of an *Ente Público* in Spain. Such legal status suggests a higher level of support, as the government may take measures to avoid the uncertain chain of events stemming from a default.

Ownership

Moody's considers a high level of government ownership as being indicative of potential support. While the ownership level indicates the importance of the GRI to the state, control through other legal means is also considered in Moody's analysis.

- » **The government's ownership stake.** The level of government ownership is one empirical measurement of the GRI's importance to the government. All else being equal, higher levels of ownership indicate that the GRI is more likely to be supported. Moody's may also incorporate ownership stakes held by closely controlled entities. In cases where the GRI is not fully owned by the government, support may be conditional upon the acceptance of other shareholders and/or their willingness to provide additional capital.
- » **Privatization plans.** Plans for privatization, including the motives and any degree of uncertainty surrounding the outcome, may also influence the decision to provide support. Moody's tends to discount the support level of a GRI that has been slated for privatization as such plans suggest that the GRI is of lesser importance to the government. Indeed, GRIs for which there are firm and near-term privatization plans will have their support levels reduced significantly in advance of the actual privatization. Even if privatization plans are uncertain, support may be adjusted downwards to incorporate the reduced likelihood of a bailout over the rating horizon.

Barriers to Support

Legal or policy barriers to support may reduce the likelihood that support will be provided. The focus is usually on European Union (EU) rules prohibiting preferential support to commercial entities, although, in limited cases, non-EU governments or other trading blocs may also be subject to domestic laws or competition commissions that restrict support. In practice, EU members do provide extraordinary financial support to GRIs despite EU rules, which is why we also consider the likelihood that the government would obey barriers, should they exist.

Government Intervention

The tendency of a government to intervene in the economy, whether for ideological, political or socio-economic reasons, may suggest an inclination to support GRIs. This base inclination may then be strengthened or weakened by the nature of connections between the government and GRI. We assess these factors by looking at past behaviour, the attitude of the current government and the connections between the government and the GRI.

- » **History of state bail-outs.** Past behavior is often a good predictor of future actions. Moody's assumes that governments that have provided extraordinary support to GRIs or private sector companies in the past are more likely to do so again in future, while those that have allowed GRIs to default have demonstrated indifference. This assessment is generally standardized across all GRIs with the same government owner.
- » **Ideological and political inclinations.** Moody's assesses whether the current government is politically or ideologically predisposed towards or against state intervention in the economy. Generally, governments that expound a significant role for the state in the economy are viewed as more likely to support GRIs.
- » **Government direction of the GRI.** Government influence over the GRI's financial condition, through regulation or other similar means, may provide an incentive for support. Indirect control over the GRI's revenues and profits (e.g. through the setting of tariffs) may also create a sense – within government or externally – that the government is responsible for the GRI's welfare.

- » **Business planning.** Government participation in business or funding plans, and/or the appointment of board members may indicate a greater propensity to provide support. The government may be held accountable for the GRI's financial condition if it approved or sponsored the GRI's strategic plans. The appointment of board members may also be perceived as oversight of a GRI. Both suggest a higher level of potential support.

Political Linkages

Governments may calculate that the political costs of a defaulted GRI are greater than the financial costs of a bailout. As such, even free-market-oriented governments are sometimes incited to support GRIs due to reputation risks. In assessing this dynamic, Moody's analyzes both the extent to which a default by the GRI would (a) lead to higher borrowing costs for the government and/or related entities and (b) generate political embarrassment given the GRI's proximity to the government and the GRI's status either nationally or internationally.

Economic Importance

Moody's sees a direct relationship between the economic stature of a GRI and the likelihood of support. A high level of economic importance, including trade and financial linkages or a large, politically mobilized workforce may provide an incentive to the government. When assessing this association, however, Moody's is cognizant of the fact that governments can rescue GRIs without preventing a default and that it is often possible for a GRI to continue to operate through a restructuring or bankruptcy process. An important consideration is whether the legal system is likely to give rights to creditors to gain access to assets. While this is likely to improve recovery prospects, it also represents a strong incentive for the government to avoid a default that could imply a loss of ownership of strategic assets.

As part of the analysis of the economic importance of the GRI, Moody's assessments also take into consideration the nature of the service or product provided by the GRI. For instance, a GRI that supplies military equipment may provide a strong incentive for a bailout, especially if the government is worried about the potential outcome of a bankruptcy. Likewise, a GRI without viable competitors, or one that provides an essential public service, may incite the government to provide support if a default would lead a disruption in services.

GRI Scorecard

Scorecard Overview

The GRI scorecard is a tool used by analysts to apply JDA to government-related issuers. In addition to generating estimates of support and dependence levels based on the factors outlined in the previous two sections, the scorecard also provides guidance on how we layer these estimations on top of the GRI's baseline credit assessment (BCA) and the supporting government's rating in order to come up with a final rating outcome.

Accordingly, the scorecard generates three key reference points: (1) the estimated level of default dependence, (2) the estimated range of extraordinary support and (3) a range of potential rating outcomes taking into account these estimations, alongside the GRI's baseline credit assessment and the supporting government's rating.

Scorecard Estimates of Dependence

As a tool used by analysts to assess the degree of default correlation between a GRI and its supporting government, the scorecard (presented below) estimates dependence levels based on three previously discussed factors: (1) the extent to which the GRI and government are operationally and financially linked; (2) the extent to which the GRI and government rely on the same revenue base; and (3) the extent to which the GRI and government are exposed to common credit risks.

Within the scorecard, each of the three factors is assigned a level related to the implied correlation of credit risks (low (30%), moderate (50%), high (70%) and very high (90%)). The scorecard then estimates dependence based on the highest level generated by any one of the three factors (given the importance of any one of the three factors in influencing a shared exposure to credit risks). The dependence level generated by the scorecard acts as a reference point for rating committees decisions in applying JDA to GRIs.

While factors one and two are measured and scored using quantitative metrics (see table below), factor three entails a qualitative assessment of criteria discussed previously. Factor one includes three metrics, covering transfer levels, government purchases and GRI dividends to the governments, which are scored according to dependence levels as indicated in the above table. For instance, fiscal transfers that represent more than 20% of the GRI's revenues are scored at a 'very high' level. Factor two includes one principal metric, covering the extent to which both the supporting government and the GRI rely on the same economic base to generate revenues. For instance, if both the government and the GRI derive more than 95% of their respective revenues from sources within the government's territory, this scores a very high level of dependence.

FIGURE 2

Operational and Financial Linkages

	LOW	MODERATE	HIGH	VERY HIGH
Direct and Indirect Government Transfers as a % of GRI Revenue	0-5%	6-10%	11-20%	>20%
Government Purchases as a % of GRI Revenue	0-5%	6-10%	11-20%	>20%
GRI Payments (Dividends) to Government as a % of Government Revenue	0-5%	6-10%	11-20%	>20%
Reliance on Overlapping Revenue Base				
	LOW	MODERATE	HIGH	VERY HIGH
Percentage of income derived from within the government's territory	Both GRI and government derive less than 50%	Government and/or GRI derive more than 50%	Both GRI and government derive more than 75%	Both GRI and government derive more than 95%

Scorecard Estimates of Support

As a tool used by analysts to assess the probability of extraordinary support, the scorecard (presented below) generates an estimated support range based on three structural factors – (1) guarantees, (2) ownership issues and (3) barriers to support – and three willingness factors: (4) level of government intervention, (5) political linkages and (6) economic importance.

Within the scorecard, each of the six factors is assigned a range of support: low (0% - 30%), moderate (31% - 50%), strong (51% - 70%), high (71% - 90%) and very high (91% - 100%). The scorecard

then estimates support based on an average of the scores for the six factors, which represents a balanced interpretation of various factors that influence a government's decision to provide or not to provide a bailout.⁴ The support range generated by the scorecard acts as a reference point for rating committee decisions in applying JDA to GRIs.

With the exception of factor two, which uses data on ownership levels to determine scoring levels (e.g. a government ownership level of 80% scores a high level of support), all of the other five remaining factors are largely qualitative. For these factors, analysts select scores for individual factors that reflect the rationales discussed in previous sections in order to position the support relative to national and international peers.

FIGURE 3

Ownership

	LOW	MODERATE	STRONG	HIGH	VERY HIGH
Ownership Level	0-30%	31-50%	51-70%	71-90%	91-100%

Scorecard + Autocall Rating Range

Once dependence and support have been estimated, the scorecard uses additional JDA inputs, specifically the GRI's assigned baseline credit assessment (BCA) and the supporting government's rating, to generate a range of potential rating outcomes that are discussed by Moody's rating committees.

The scorecard's output of a rating range, rather than a specific rating, ensures that analyst judgments regarding elements outside the scorecard, including evolving market dynamics and shifts in credit culture, are captured. Moreover, even though the scorecard acts a tool to ensure that a consistent list of analytical factors are considered for every GRI, and provides flexibility to ensure that the principal elements that may impact support are fully accounted for, rating committees are ultimately responsible for assigning ratings.

For instance, as part of deliberations on the rating range generated by the scorecard, rating committees may also choose to limit the uplift provided by support when:

- a. Government ability to provide support is constrained by a combination of large off-balance-sheet liabilities and macroeconomic stress. While the sovereign rating captures a large part of these limitations, there are cases where the risk of a systemic crisis, impacting a large number of entities looking for extraordinary support, may reduce government capacity, even though willingness remains strong.
- b. Policy transparency or predictability in a country is low and, as a result, limits our ability to assess the likelihood of support.⁵

In order to enhance rating transparency, an example of how the scorecard is applied, based on the case of a hypothetical GRI, is provided below. This example demonstrates how analysts employ the scorecard and provides explanations for the scoring of all the factors behind the assessment of dependence and support, and an interpretation of the rating range output.

⁴ In cases where there are no legal barriers to support, factor three (barriers to support) is excluded and the average is calculated based on the remaining five factors.

⁵ A broader discussion of these issues is available in Appendix II: Lessons Learned From the Global Financial Crisis.

Scorecard Limitations

The scorecard offers valuable insights into the key factors that drive rating committee decisions. Nevertheless, the scorecard has limitations since it cannot capture exhaustively all the elements that go into rating decisions. Accordingly, the scorecard is not meant to be a substitute for rating committee judgments, nor is it meant to be a matrix for automatically assigning or changing these assessments.

Scorecard Example: Case of a State-Owned Water Company

This hypothetical example applies JDA – using the aforementioned scorecard as a tool – to a national water company owned by the central government of a small developing country.

Dependence

Operational and Financial Linkages

The operational and financial linkages between the water company and the national government are moderate. Although the company does not pay dividends, government transfers represent 10% of the company's total income and government purchases also represent another 10%.

Reliance on Overlapping Revenue Base

The company and the government rely heavily on the same economic base, implying a very high level of default dependence. Both of them derive nearly 100% of their revenues from within the government's territory.

Exposure to Common Credit Risks

For both the company and the government, exposure to common credit risks is moderate and related to foreign exchange risk. Both rely heavily on cross-border debt issuance and maintain significant unhedged currency exposure.

Overall, these results generate guidance on default dependence at the very high level (90%).

DEPENDENCE	LOW	MODERATE	HIGH	VERY HIGH
Operational and Financial Linkages				
Direct and Indirect Government Transfers as a % of GRI Revenue		✓		
Government Purchases as a % of GRI Revenue				
GRI Payments (Dividends) as a % of Government Revenue				
Reliance on Overlapping Revenue Base				
Percentage of income derived from within the government's territory				✓
Exposure to Common Credit Risks				
Foreign Exchange Risk in Debt Structure		✓		
Shared Industry Exposure				
Political Event Risks				
Guidance Dependence Level				✓

Support Guarantees

The central government has told Moody's analysts that it would back the debt of the water company if a default were imminent. Similar comments have also been made by government officials during recent press conferences. Given that the level of public policy transparency and predictability in this country is relatively strong, we view this verbal guarantee as suggesting a high probability of extraordinary support.

Ownership

The central government owns 100% of the water company and does not have any privatization plans, implying a very high probability of extraordinary support.

Barriers to support

There are no legal or policy barriers to support.

Government intervention

In conjunction with a history of state intervention (recent cases when the government provided extraordinary support to national GRIs facing liquidity crises), the government appoints 9 out of 12 board members and is actively involved in establishing and approving GRI business plans. Collectively, these considerations suggest a very high probability of extraordinary support.

Political linkages

The reputation risk of allowing the water company to fail, in conjunction with the increase in public sector borrowing costs that would follow a default by the water company, provides a strong incentive to the central government and implies a very high probability of extraordinary support.

Economic importance

In addition to providing what is considered an essential service in the country (100% of households and 95% of industries rely on the water company for water and sewer services), the GRI employs a fairly large and politically mobilized workforce (4th largest public sector union in the country). These factors support a high probability of extraordinary support.

Overall, these results generate guidance on extraordinary support at the very high range (91% to 100%).

SUPPORT	LOW	MODERATE	STRONG	HIGH	VERY HIGH
Guarantees					
Explicit Guarantees				✓	
Verbal Guarantees and/or Comfort Letters					
Special Legal Status					
Ownership					
Ownership Level					✓
Privatization Plans					
Barriers to Support					✓
Government Intervention					
History of State Bailouts					
Ideological and Political Inclinations					✓
Government Direction of GRI					
Business Planning					
Political Linkages					✓
Economic Importance				✓	
Guidance Support Range					✓

Rating Range

Based on this guidance for dependence and support, alongside the water company's underlying BCA of 11 (equivalent to Ba1) and the central government's credit rating of Baa1, the scorecard provides a range of rating outcomes, which is between Baa2 and Baa1.

Rating Range

GRI BCA: 11 (EQUIVALENT TO Ba1) GOVERNMENT SUPPORTER RATING: Baa1 (RATINGS NEED TO BE IN LOWER CASE)

Support	Low	Moderate	Strong	High	Very High
Dependence	Low	Moderate	High	Very High	
Aaa					
Aa1					
Aa2					
Aa3					
A1					
A2					
A3					
Baa1					Baa1
Baa2					Baa2
Baa3					
Ba1					
Ba2					
Ba3					
B1					
B2					
B3					
Caa1					
Caa2					
Caa3					
Ca					
C					

Appendix I: Technical Overview of JDA

Conditional Default Probabilities

The probability that two parties will jointly default depends on (a) the probability that one of them defaults, and (b) the probability that the second will default, given that the first has already defaulted. Expressed algebraically, one can write:⁶

$$P(A \text{ and } B) = P(A | B) \times P(B) \quad (1)$$

Or equivalently,

$$P(A \text{ and } B) = P(B | A) \times P(A) \quad (2)$$

We define A as the event “obligor A defaults on its obligations” and B as the event “obligor B defaults on its obligations”. Likewise, “A and B” is the joint-default event “obligors A and B both default on their obligations”.⁷ The operator $P(\bullet)$ represents the probability that event “ $\bullet$ ” will occur and $P(\bullet | *)$ is defined as the conditional probability of event “ $\bullet$ ” occurring, given that event “ $*$ ” has occurred.

Moody's ratings can be used to infer directly the probability that a particular issuer will default ($P(A)$ and $P(B)$).⁸ But in order to estimate the conditional default probabilities $P(A | B)$ and $P(B | A)$, one must take into account the relationship between the drivers of default for both obligors. Each of these four probabilities – $P(A)$, $P(B)$, $P(A | B)$ and $P(B | A)$ – are intended to represent unsupported risk measures. That is, they represent the likelihood of an obligor default in the absence of any joint support or interference.

Although this problem can, in theory, be tackled directly by estimating either one of the conditional default probabilities described in equations (1) and (2), it may be more intuitive to focus on the product of the conditional probability of default for the lower-rated, or supported, firm and the unconditional probability of default for the higher-rated, or supporting, firm. Using L to denote the event “lower-rated obligor L defaults on its obligations” and H to denote “higher-rated obligor H defaults on its obligations,” we can rewrite equation (1) as:

$$P(L \text{ and } H) = P(L | H) \times P(H) \quad (3)$$

It is not difficult to imagine situations where the conditional probability $P(L | H)$ might be at its theoretical maximum (i.e. 1) or at its minimum (i.e. $P(L)$).⁹ Let us consider these extreme outcomes in turn by way of example.

$P(L | H) = 1$. Suppose that the financial health of an issuer is crucially linked to the operations of another, higher-rated entity. For example, the default risk of a distributor in a competitive distribution

⁶ Statisticians will recognize these equations as axioms of probability theory that underlie Bayes' Theorem.

⁷ The implication here is that the default events occur simultaneously, but we require only that the timing be such that a holder of the supported obligation suffers credit loss within a specified horizon.

⁸ Moody's ratings are defined as ordinal (or relative) measures of default risk and not in terms of cardinal (or absolute) default rates. However, as long as ratings can provide a constant measure of relative default risk, with actual default probabilities rising and falling proportionately by rating category over a credit cycle, the methods proposed here will produce logically consistent measures of jointly supported ratings.

⁹ Technically, the conditional default probability $P(L | H)$ could be as low as zero, a situation which would occur if the default correlation between the two obligors was at its theoretically maximum negative value. However, throughout this discussion, we follow the standard practice of ignoring the highly unlikely possibility that the default experience of the two obligors will be negatively correlated.

market dominated by a single supplier may be highly dependent on the financial health of that supplier. In other words, the conditional probability of the distributor's default given a default by the higher-rated supplier, $P(L | H)$, is equal to one. In this case, events L and H are maximally correlated.¹⁰ Under such a scenario, the joint default probability $P(L \text{ and } H)$ in equation (3) above is simply $P(H)$. That is, the rating applied to such jointly supported obligations would equal the supplier's rating, without any ratings uplift, regardless of issuer L's standalone rating.

$P(L | H) = P(L)$. Suppose a highly rated European bank provides a letter of credit to a lower-rated agribusiness in the US. While there may be circumstances in which the agribusiness might face financial difficulties on its own, its intrinsic operational health is generally unrelated to the circumstances that might lead the European bank to default on its obligations. Under this scenario, the conditional probability of a default by the agribusiness, given a default by the bank – i.e., $P(L | H)$ – is simply the standalone default risk $P(L)$ of the agribusiness. That is, events L and H are uncorrelated and independent of one another. In this case, their joint-default probability is the product of their standalone default probabilities, $P(L) \cdot P(H)$. The jointly supported obligation rating implied by such a relationship is generally higher than the rating of the supporting entity H.

In practice, the conditional default risk of the lower-rated entity, given a default by the stronger entity, will vary somewhere between these two extremes, maximum correlation (i.e. where $P(L | H) = 1$) and independence, (i.e. where $P(L | H) = P(L)$).

Intermediate levels of Correlation

We propose here a simple tool for modelling intermediate cases of default risk linkage. Let us denote the variable W as a correlation weighting factor, where $W = 1$ corresponds to a maximum theoretical correlation between the default of the lower-rated entity and that of the higher-rated entity; and $W = 0$ corresponds to a complete independence (i.e. zero correlation) between default events. Fractional values of W indicate intermediate levels of correlation between the two default events.

Using the correlation weighting concept, we can express the joint-default probability between obligors L and H as:

$$P(L \text{ and } H) = W \cdot P(L \text{ and } H | W=1) + (1-W) \cdot P(L \text{ and } H | W=0) \quad (4)$$

Or more compactly,

$$P(L \text{ and } H) = W \cdot P(H) + (1 - W) \cdot P(L) \cdot P(H) \quad (5)$$

In other words, once we have determined standalone ratings for the two obligors, the task of assigning a rating to a jointly supported obligation may be reduced to the assignment of a correlation weight.¹¹

¹⁰ This use of the term "correlation" applies to default events that follow a binomial distribution and should not be confused with potential correlation in rating transitions (or default intensities). When the default profiles of two obligors are maximally correlated, $P(L | H) = 1$ and $P(H | L) = P(H)/P(L)$. That is, the weaker entity always defaults when the stronger entity defaults, and the stronger entity will only default if the weaker entity also defaults. This leads to the result $P(H | L) = P(H)/P(L)$. Note that maximum correlation will be less than 1 in cases where obligors have different ratings.

¹¹ While this derivation focused on $P(L | H)$, it could also be approached through a focus on $P(H | L)$. An alternative methodology is described in a paper published by Douglas Lucas, "Default Correlation and Credit Analysis," The Journal of Fixed Income, Vol. 4, No. 4, March 1995.

Partial Support

In many cases, an obligation benefits from external support, but that support falls short of an iron-clad guarantee. Examples include bonds issued by a weak subsidiary of a relatively strong parent firm, or bonds issued by an issuer with partial government ownership. In the latter case, the government's incentive to bail the issuer out, should it run into difficulties, may be a function of the share of government ownership or of the importance of that issuer to the national economy.

It is helpful to think of the two extreme situations in which an investor faces losses. The first is where the issuer of the obligation defaults and there is no external support. The probability of this event occurring is simply $P(L)$, the probability that issuer L will default on its own. The second is where there is full support, but both the issuer and the support provider default on their obligations. As above, this is given by $P(L \text{ and } H)$. The degree of support can also be thought of as a probability and can therefore vary between 0 and 1. We model the risk to the investor as a shifting probability between the two risk outcomes $P(L)$ and $P(L \text{ and } H)$:

$$P(L \text{ and } H | S) = (1-S)*P(L) + S*P(L \text{ and } H) \quad (6)$$

Here, the weighting parameter S represents the likelihood of support. Full support (i.e., $S = 1$) leads to the joint default outcome and no support (i.e., $S = 0$) yields the standalone default risk of the obligor, $P(L)$.

Appendix II: Lessons Learned From the Global Financial Crisis

Shifting government behavior during the global financial crisis highlights the inherent difficulty in assessing support in a context of heightened market and economic turmoil.

Three principal lessons emerged from the crisis, which has led to some rating adjustments over the last year and which will continue to influence our views on an ongoing basis. First, support assumptions need to recognize that governments facing large contingent liabilities may resort to credit ring-fencing, providing support to a selective group of GRIs, whilst allowing others—deemed less important—to fail. Second, support assumptions should be assigned conservatively in countries characterized by low policy transparency and predictability, where it can be difficult to decipher government intentions. Third, given shifts in government behavior during the recent period of stress, we need to be vigilant in assessing cases where support assumptions lift the rating of GRIs with weak baseline credit assessments to the level of the supporting government (i.e. rating at par) in the absence of critical features that offer near certainty surrounding the likelihood of support.

Credit Ring-Fencing

Following shifts in government behavior during the crisis, Moody's acknowledges the need to clearly identify and assess the impact of credit ring-fencing. Support assumptions need to incorporate the risk that governments facing large contingent liabilities may resort to credit ring-fencing in stress scenarios, providing support for a only selective group of GRIs, whilst allowing others to fail. For instance, in April of 2010, the outlook on the Government of Kazakhstan's Baa2 rating was revised to stable, from negative, to reflect, amongst other considerations, the government's policy of containing its exposure to contingent liabilities (banks, private companies and GRIs) via a high degree of credit ring-fencing. While this ring-fencing helped to sustain long-term sovereign credit fundamentals, it simultaneously led Moody's to revise downwards our support assumptions for some GRIs in the country.

Weak Policy Transparency and Predictability

Events during the crisis also highlighted how difficult it can be to decipher government intentions in opaque environments. Accordingly, support assumptions need to be assigned conservatively in countries characterized by low policy transparency and predictability. For instance, although Moody's had viewed corporate GRIs in Dubai as benefiting from significant implicit support prior to the crisis – based on a high level of government ownership, extensive government intervention in the economy and incentives to maintain investor confidence – government actions on Dubai World in November of 2009 generated uncertainty surrounding whether or not timely support would be forthcoming. As a result of these events, Moody's revised downward, in December of 2009, support assumptions for Dubai GRIs that are not directly part of, or formally guaranteed by, the government.

Rating at Par

As a reflection of potential shifts in government positions, which are illustrated by the above two examples, we also need to evaluate closely cases where support assumptions lift the ratings of GRIs with weak baseline credit assessments to the level of the supporting government (i.e. rating at par). In the absence of critical features that offer near certainty surrounding the likelihood of support, we may chose to offer some modest differentiation between the GRI rating and the rating of the government.¹²

¹² A full discussion of these issues is available in Appendix IV: When to Rate at Par with the Government if the BCA is Materially Lower.

Continued Monitoring

In line with recent rating actions taken during the global financial crisis, we will continue to monitor rating drivers for GRIs globally and take individual actions when warranted by: a) changes in the standalone credit worthiness of GRIs and b) shifts in the extraordinary support dynamics.

Appendix III: Cases of Credit Substitution

Within our rated universe of GRIs, material differences exist in the level of financial and operational proximity to their governments. In a limited number of cases, the level of integration between the GRI and its government is so strong that our ability to conduct a “stand-alone” analysis, and then layer on top an assessment of support and dependence, is significantly impaired. In such instances, we may use a credit substitution (CS) approach and assign to the GRI a rating at, or very near, the government’s rating, instead of applying the more granular JDA framework to assign such rating.

In general, GRIs most suitable for CS are characterized by a very limited degree of autonomy, playing what is considered within the country to be a key policy role or government function, with a heavy government “footprint” over their business plans, budgets, revenue sources and funding. From an analytical standpoint, a distinguishing feature is that the GRI’s management has no or very limited control over the financial health of the entity, as all key decisions are ultimately made by the government. As a result, while a separate entity from a legal standpoint, the GRI essentially functions as a government department or delivery mechanism of government policy. In such cases, instead of assigning a BCA and assumptions on both support and dependence, Moody’s may apply credit substitution and simply assign a rating at, or very near, the government’s rating.

Appendix IV: When to Rate a GRI at Par with the Government if BCA is Materially Lower

Within our rated universe of GRIs, we have many instances where the BCA is materially lower (more than three notches) than the rating of its government sponsor. One question often asked in these cases by market participants is under what conditions Moody's considers assigning a GRI rating at par with the rating of its government, when the GRI does not benefit from a "blanket" guarantee from its government. During the crisis, the governments of a few countries have given priority to protecting their balance sheets sometimes at the expense of GRIs, and this led us to be somewhat more cautious in this area.

Although there may be exceptions, GRIs most suited for a par rating in these cases would typically benefit from a special status, conferring the strategic importance of their role and offering elements of protection such as a carve-out from normal bankruptcy procedures, a pledge of financial resources commensurate with their role, or other pledges in the form of capital replenishment, backstopping of operating losses or legal provisions transferring GRI debt obligations to the government upon dissolution. Explicit government guarantees on some of the debt issued by a GRI are also taken into account when considering the option of assigning the government rating at the issuer level and to non-guaranteed debt, once the decision of the government to guarantee some debt obligations but not others is well understood and does not suggest that government has decided to differentiate its support for the various classes of debt. The presence of cross-default provisions in the guaranteed debt is also considered as it may increase the government's incentive to support the unguaranteed debt instruments.

Given the transition risks in such cases, Moody's is particularly attentive to any changes in status stemming from shifts in government policies and priorities or international treaties that may impact a government's willingness and/or ability to intervene. Similarly, increasingly large international activities at a GRI, in contrast to a core domestic policy role, could affect a government's propensity to support or encourage a more selective approach.

Appendix V: The Anchor Rating for Non-Bank Financial GRIs

Moody's rates a large number of government-related financial institutions.

Many of these are deposit-taking institutions, for which we apply our banking methodology and the JDA construct that was specifically designed for banks.¹³

For "non-bank" financial GRIs (non-deposit-taking institutions), Moody's applies the standard JDA framework discussed in this report, including the use of the government rating as the "anchor" for support. However, in a number of limited cases, we may choose the anchor rating used for banks, which is typically one to two notches higher than the government rating in non-Aaa-rated countries. The anchor rating for banks is referred to as the country's systemic support indicator or SSI. The higher SSI rating is based on the view that the national government's ability to support a bank can be greater than its ability to service its own debt, in part because of the array of tools available to governments and their central banks, even when governments are facing difficulties in servicing their own debt.¹⁴

For non-bank financial GRIs, we may select the SSI as the anchor rating – instead of the government rating – if the institution plays a central role in the economic life of the country and if its default has the potential to erode the stability of the country's banking system. In such cases, if ever in need of assistance, national governments and central banks are likely to treat them like banks and consider the full array of support tools at their disposal. However, such profiles are rare, and the government rating is used as the anchor for non-bank financial GRIs in all cases but a few exceptions.

¹³ "Bank Financial Strength Ratings: Global Methodology", published in February 2007; "Incorporation of Joint Default Analysis into Moody's Bank Ratings: A Refined Methodology", published in March 2007.

¹⁴ "Financial Crisis More Closely Aligns Bank Credit Risk and Government Ratings in Non-Aaa Countries", published in May 2009.

Appendix VI: Multiple Government Owners

When a GRI is owned by more than one government, our general approach is to measure support on the assumption that the owner with the largest share will have the most to gain from supporting the GRI. If the government owner with the largest share does not or cannot provide support, then there is significantly less incentive and therefore propensity for other government owners to do so. However, where two or more governments have significant and similar shareholdings, then the support burden may be shared and how we apply JDA is adjusted.

Multi-government ownership cases would generally be dealt with in the following way:

1. If there is one majority government owner of the GRI, or one government has a significantly higher shareholding than any other government, that significant owner is considered the sole supporter for the purposes of the GRI Rating Methodology.
2. Governments that own less than 20% are not included in our support analysis.
3. In cases where two or more governments have shareholdings of between 50% and 20% (but there is no dominant shareholder), an "average" supporter assumption is made. More specifically, (i) the GRI's ownership % is deemed to be the arithmetic mean of the % shareholdings of all the relevant shareholders, and (ii) the supporter's rating is deemed to be the weighted average rating of the relevant shareholders.
4. Where ownership is widely shared across a larger number of governmental parties (e.g. municipalities), we might still consider using their aggregated % shareholding if there is clear history or evidence to suggest they would act in concert together on a timely and effective basis, perhaps because they themselves are bound by joint-and-several liability.

... continues from page 1

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School Energy Coalition (SEC) INTERROGATORY #7 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 3] Please confirm that the distribution and transmission businesses of Hydro One are not rated separately.

Response

The distribution and transmission businesses are not rated separately.

School Energy Coalition (SEC) INTERROGATORY #8 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p. 5 and A/6/1, Attach 3] Please provide capital spending as a percentage of depreciation for each of transmission and distribution for each of 2007 through 2013, the latter two years being at forecast spending levels.

Response

Transmission expenditures are not a matter for this proceeding.

Distribution Capital Expenditures and Depreciation							
	2007A	2008A	2009A	2010A	2011A	2012F	2013F
Capital Expenditures	399.9	435.3	455.5	430.5	431.9	443.9	451.9
Depreciation	253.8	266.3	253.7	259.6	264.4	264.4	283.0
Depreciation %	63%	61%	56%	60%	61%	60%	63%

School Energy Coalition (SEC) INTERROGATORY #9 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 4/p.3] Please provide the full distribution capital budget – broken down into its normal categories - for each of 2011 (actual), 2012 (most recent actuals plus forecast), 2013 (plan), and 2014 (outlook). To the extent that the capital spending for any of those years is materially different from the \$720 million forecast by S&P in this report (40% of \$1.8 billion), please explain the major drivers of that difference.

Response

Expenditures in 2014 are not a matter for this proceeding.

Details on other years are included in Exhibit I, Tab 2, Schedule 9.01 AMPCO 1, part g).

The \$1.8B of capital expenditures referred to in the S&P report in pre-filed evidence refers to an analyst's estimate for the total forecast spending of Hydro One Inc. and all its subsidiaries. Using the S&P's 40% rough estimate for Distribution, they arrived at \$720M capital expenditures.

Hydro One has indicated that the planned in-service capital additions will be \$644M in 2013 (see Table 3 in Exhibit B, Tab 1, Schedule 1, page 9). The difference is primarily related to smart grid, smart meter and renewable generation capital which are recorded in variance accounts.

School Energy Coalition (SEC) INTERROGATORY #10 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 5/p.1] Please provide copies of all materials or other information provided to DBRS prior to August 22, 2012 that could have caused them to conclude the Hydro One's capex will be lower by \$165 million in 2012 due in part to "lower distribution development". If this information was communicated to DBRS verbally, please provide details of who communicated this information, when, and in what circumstances.

Response

Hydro One's Second Quarter Financial Results and MD&A were released to the public and filed with the Ontario Securities Commission on August 9, 2012. As normal course business, after the release of the financial results Hydro One e-mailed a copy of the document to investors and other stakeholders, including DBRS. Attachment 1 is the Q2 Report - MD&A available on the Hydro One website. Hydro One's capex is discussed on page 8 under "Future Capital Expenditures."

RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three and six months ended June 30, 2012 to the three and six months ended June 30, 2011, respectively. On January 1, 2012, Hydro One Inc. (Hydro One) adopted United States (US) Generally Accepted Accounting Principles (GAAP) as its approved basis for accounting and financial reporting. Comparative 2011 information is presented under US GAAP, unless otherwise noted.

Revenues

	Three months ended June 30				Six months ended June 30			
	2012	2011	\$ Change	% Change	2012	2011	\$ Change	% Change
<i>(Canadian dollars in millions)</i>								
Transmission	370	337	33	10	731	688	43	6
Distribution	974	915	59	6	2,065	2,008	57	3
Other	15	16	(1)	(6)	31	32	(1)	(3)
	1,359	1,268	91	7	2,827	2,728	99	4
Average Ontario 60-minute peak demand (MW) ¹	21,029	20,519	510	2	20,870	21,138	(268)	(1)
Distribution - units distributed to customers (TWh) ¹	6.7	6.5	0.2	3	14.5	14.8	(0.3)	(2)

¹ System-related statistics are preliminary

Electricity demand generally follows normal weather-related variations, and consequently, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, as demonstrated by our first quartile reliability results. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets and ancillary revenues which are mostly attributable to maintenance services provided primarily to generators and secondary use of our land rights.

Our transmission revenues were higher by \$33 million, or 10%, in the second quarter of 2012, and by \$43 million, or 6%, in the first six months of 2012, compared to the same periods in 2011. On December 23, 2010, the Ontario Energy Board (OEB) rendered its Decision With Reasons on our 2011 and 2012 transmission rate applications. This decision followed extensive oral and written reviews of our evidence submitted for the necessary funding in support of system requirements. On November 23, 2011, the OEB issued its Decision With Reasons which approved the use of US GAAP as the basis for setting rates for our Transmission Business. In that decision, the OEB made adjustments to our previously approved 2012 transmission revenue requirement, capital expenditure levels and rate base, consistent with those proposed in our evidence. On December 20, 2011, effective January 1, 2012, the OEB approved new transmission tariff rates for 2012 that reflect the inclusion of new capital investments in our transmission rate base effective January 1, 2012. These new assets will support our aging critical infrastructure and the Province of Ontario's (Province) supply mix objectives for generation, including off-coal initiatives and investments in support of the Green Energy Act (GEA). These decisions resulted in higher transmission revenues of \$26 million and \$52 million for the three and six months ended June 30, 2012, respectively, compared to the same periods in 2011.

Our 2012 transmission revenues also increased due to a higher average monthly peak demand experienced during the second quarter of 2012. The average Ontario 60-minute peak demand was 510 MW higher in the second quarter of 2012 than in the same period in 2011, resulting in higher revenues of \$13 million. This increase in demand was attributable to warmer weather experienced in the second quarter of 2012, compared to 2011. This increase in our transmission revenues was partially offset by a \$2 million decrease associated with OEB-approved regulatory accounts, a \$2 million decrease following the completion of recovery of a regulatory account effective December 31, 2011, as well as a \$2 million decrease in transmission-related external revenues.

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

The increase in our 2012 transmission revenues related to OEB rate decisions for the six months ended June 30, 2012 was partially offset by a \$5 million decrease following the completion of recovery of a transmission regulatory account effective December 31, 2011, a \$2 million reduction associated with OEB-approved regulatory accounts, and a \$2 million decrease in transmission-related external revenues and lower average monthly peak demand experienced during the period.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our Distribution Business. Our consolidated Distribution Business consists of the separate distribution businesses of our subsidiaries Hydro One Networks Inc. (Hydro One Networks), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), and Hydro One Remote Communities Inc. (Hydro One Remote Communities). Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution services revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries as well as miscellaneous charges, such as those charged for late payments.

Our distribution revenues increased by \$59 million, or 6%, in the second quarter of 2012, and by \$57 million, or 3%, in the first six months of 2012, compared to 2011. These increases were primarily due to the recovery of higher purchased power costs of \$53 million and \$63 million for the three and six months ended June 30, 2012, respectively, as described below under "Purchased Power". Our distribution revenues were also higher due to \$4 million and \$9 million revenue increases for the three and six months ended June 30, 2012, respectively, related to our placement of new smart grid and smart meter investments in-service. These investments are currently recovered through separate rate mechanisms.

Our second quarter revenues also increased by \$2 million as we experienced slightly higher energy consumption from warmer weather experienced in the second quarter of 2012 compared to 2011. The increase in our distribution revenues for the six months ended June 30, 2012 was partially offset by a \$15 million decrease due to lower energy consumption in the six months ended June 30, 2012, resulting primarily from the milder winter experienced in 2012 compared to 2011.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use (TOU) billing, both of which are adjusted twice annually. We began transitioning our RPP customers to TOU billing in May 2010, and a large majority of our RPP customers are now on TOU billing. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP for the reporting and comparative periods is provided below.

Summary of RPP				
Effective Date	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
	Residential	Non-Residential	First Tier	Second Tier
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9
November 1, 2011	1,000	750	7.1	8.3
May 1, 2012	600	750	7.5	8.8

RPP TOU			
Effective Date	Rates (cents/kWh)		
	On Peak	Mid Peak	Off Peak
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2
May 1, 2012	11.7	10.0	6.5

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Purchased power costs increased by \$53 million, or 9%, in the second quarter of 2012, and by \$63 million, or 5%, in the first six months of 2012, compared to the same periods in 2011.

The increase in our second quarter purchased power costs was primarily due to an increase of \$27 million from changes in the OEB's RPP rates for residential and other eligible customers, a \$20 million increase resulting from higher electricity demand, and a \$8 million increase due to higher transmission charges resulting from the OEB transmission rate decision effective January 1, 2012. The increase in our 2012 second quarter purchased power costs was partially offset by a \$2 million reduction in wholesale market service charges levied by the IESO, compared to 2011.

The increase in our purchased power costs for the six months ended June 30, 2012 was primarily due to an increase of \$63 million resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a \$17 million increase resulting from the OEB transmission rate decision effective January 1, 2012, and an \$11 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP. The increase for the six months ended June 30, 2012 was partially offset by a \$21 million decrease related to lower electricity demand, and a \$7 million reduction in wholesale market service charges levied by the IESO, compared to 2011.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof related to certain of our transmission and distribution facilities.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended June 30				Six months ended June 30			
	2012	2011	\$ Change	% Change	2012	2011	\$ Change	% Change
<i>(Canadian dollars in millions)</i>								
Transmission	102	104	(2)	(2)	214	210	4	2
Distribution	156	155	1	1	296	297	(1)	-
Other	20	16	4	25	30	30	-	-
	278	275	3	1	540	537	3	1

Our Company continues to focus on managing costs, which resulted in a slight increase in total operation, maintenance and administration expenditures in the second quarter and the first six months of 2012, as compared to the same periods in 2011.

Transmission

Transmission operation, maintenance and administration costs incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by \$2 million, or 2%, to \$102 million in the second quarter of 2012, and increased by \$4 million, or 2%, to \$214 million in the first six months of 2012, compared to the same periods in 2011. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program costs decreased by \$4 million in the second quarter of 2012 and by \$2 million in the first six months of 2012, compared to 2011, mainly due to lower demand for station-related corrective maintenance, particularly for power equipment, partially offset by increased expenditures related to the Ontario Power Authority's (OPA) recommendation to increase short circuit and/or transformer capacity at 10 of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see "Future Capital Expenditures"). Expenditures in support of our transmission system increased by \$2 million in the second quarter of 2012 and by \$6 million in the first six months of 2012, compared to 2011, mainly due to higher information technology expenditures relating to service contracts, which were partially offset by management cost reduction initiatives.

Distribution

Distribution operation, maintenance and administration costs required to maintain our low-voltage distribution system increased by \$1 million in the second quarter of 2012, and decreased by \$1 million in the first six months of 2012, compared to 2011. Our work program expenditures were unchanged in the second quarter of 2012, and increased by \$1 million in the

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

first six months of 2012, compared to 2011, mainly due to increased forestry program expenditures, resulting from more favourable weather conditions in 2012. The increase in forestry program expenditures in the second quarter of 2012 was offset by decreased power restoration expenditures resulting from lower storm activity in 2012, compared to 2011. Our expenditures in support of our distribution system increased by \$1 million in the second quarter of 2012, and decreased by \$2 million in the first six months of 2012, compared to 2011, mainly due to higher information technology expenses and investments supporting the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project, which were more than offset by a redirection of resources in support of our Transmission Business and cost reduction initiatives in the first six months of 2012.

Depreciation and Amortization

Depreciation and amortization expense increased by \$7 million, or 5%, in the second quarter of 2012, and by \$15 million, or 5%, in the first six months of 2012, compared to 2011. These increases were attributable to higher depreciation expense of \$8 million and \$17 million in the second quarter and the first six months of 2012, respectively, compared to 2011, related to our placement of new assets in service consistent with our ongoing capital work program. These increases were partially offset by lower asset removal costs during the three and six months ended June 30, 2012, compared to 2011.

Financing Charges

Financing charges increased by \$4 million, or 5%, in the second quarter of 2012, and by \$3 million, or 2%, in the first six months of 2012, compared to 2011. These increases were primarily due to higher interest expense, related to our long-term debt, of \$4 million and \$6 million in the second quarter and the first six months of 2012, respectively. This increase was associated with a higher average level of debt, partially offset by a lower average effective interest rate. Higher financing charges in the first six months of 2012 were partially offset by a \$3 million increase in interest capitalized, reflecting higher interest capitalization rates used on construction in progress.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by \$3 million, or 11%, in the second quarter of 2012, and by \$10 million, or 15%, in the first six months of 2012, compared to 2011. These decreases resulted from a reduction in the statutory tax rate from 28.25% to 26.50%, as well as changes in net temporary differences, partially offset by higher levels of pre-tax income, compared to the same periods in 2011.

Net Income

Net income of \$169 million for the second quarter of 2012 and \$379 million for the first six months of 2012 was higher than our comparable 2011 net income by \$27 million, or 19%, and by \$25 million, or 7%, respectively.

These increases were primarily due to higher revenues resulting from new OEB-approved Uniform Transmission Rates that were effective January 1, 2012 and which reflect capital investments to address our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and investments in support of the GEA. Second quarter transmission revenues were further impacted by a higher average Ontario 60-minute peak demand. Increased revenues for the first six months of 2012 were partially offset by lower distribution energy consumption resulting from the mild winter in 2012.

Our net income was also positively impacted by lower payments in lieu of corporate income taxes resulting from a lower statutory income tax rate that became effective January 1, 2012, as well as changes in net temporary differences. In addition, our 2012 net income reflects higher depreciation and amortization costs resulting from our placement of new assets in service consistent with our increased capital work program.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from September 30, 2010 through June 30, 2012. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements which include all adjustments, consisting only of normal recurring

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

<i>(Canadian dollars in millions)</i>	2012		2011				2010	
<i>Quarter ended</i>	Jun.30	Mar.31	Dec.31	Sep.30	Jun.30	Mar.31	Dec.31²	Sep.30²
Total revenue ¹	1,359	1,468	1,359	1,384	1,268	1,460	1,280	1,360
Net income ¹	169	210	120	167	142	212	99	218
Net income to common shareholder ¹	164	206	115	163	137	208	94	214

¹ The electricity demand generally follows normal weather-related variations, and consequently, our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

² Based on Canadian GAAP. US GAAP results would not differ significantly.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from our operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include our capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements and dividends.

Summary of Sources and Uses of Cash

<i>(Canadian dollars in millions)</i>	Three months ended June 30		Six months ended June 30	
	2012	2011	2012	2011
Operating activities	217	334	454	574
Financing activities				
Long-term debt issued	425	-	725	300
Long-term debt retired	-	-	-	(250)
Dividends paid	(30)	(42)	(311)	(84)
Investing activities				
Capital expenditures	(350)	(345)	(667)	(640)
Other financing and investing activities	2	17	(4)	46
Net change in cash and cash equivalents	264	(36)	197	(54)

Operating Activities

Net cash from operating activities decreased by \$117 million to \$217 million in the second quarter of 2012, and by \$120 to \$454 million in the first six months of 2012, compared to 2011. These decreases were primarily due to pension plan contributions paid during the second quarter of 2012 that resulted in a prepaid pension contributions asset, partly offset by higher net income compared to the prior year. During the second quarter of 2012, we experienced growth in accounts receivable balances resulting from higher revenues, which were more than offset by improved accounts receivable collection cycles during the first six months of 2012. In addition, for the six months ended June 30, 2012, we experienced a reduction in taxes payable, resulting from a payment made in the first quarter of 2012 related to the 2011 taxation year.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program, under which we are authorized to issue up to \$1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holding of Province of Ontario Floating-Rate Notes.

Our Commercial Paper Program is supported by a total of \$1,500 million in liquidity facilities comprised of our \$1,250 million committed revolving credit facility with a syndicate of banks, which matures in June 2017, and our holding of \$250 million of Province of Ontario Floating-Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

As at June 30, 2012, we had \$8,726 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2012 and 2051. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is \$3,000 million. As at June 30, 2012, \$1,875 million remained available until September 2013.

Rating Agency	Rating	
	Short-term Debt	Long-term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc. ¹	Prime-1	A1
S&P ²	A-1	A+

¹ On April 27, 2012, Moody's Investors Service Inc. downgraded our senior unsecured rating to A1 from Aa3.

² On April 25, 2012, S&P revised their outlook on our company to negative from stable.

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations as at June 30, 2012.

In the second quarter and the first six months of 2012, we successfully issued \$425 million and \$725 million, respectively, in cost-effective long-term debt under our MTN Program, and no long-term debt matured in 2012. In the first six months of 2011, we issued \$300 million in long-term debt under our MTN Program and repaid \$250 million in maturing long-term debt, all in the first quarter. In the first six months of 2012 and 2011, we did not issue any short-term notes and had no short-term notes outstanding as at either June 30, 2012 or June 30, 2011.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to our quarterly financial results are generally declared and paid in the immediately following quarter.

In the second quarter of 2012, we paid dividends to the Province in the amount of \$30 million, consisting of \$25 million in common dividends and \$5 million in preferred dividends. In the second quarter of 2011, we paid common dividends of \$37 million and preferred dividends of \$5 million.

In the first six months of 2012, we paid dividends to the Province in the amount of \$311 million, consisting of \$302 million in common dividends and \$9 million in preferred dividends. In the first six months of 2011, we paid common dividends of \$75 million and preferred dividends of \$9 million.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our shareholder. In order to ensure ongoing effective access to capital, we target an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

	Three months ended June 30				Six months ended June 30			
			\$	%			\$	%
<i>(Canadian dollars in millions)</i>	2012	2011	Change	Change	2012	2011	Change	Change
Transmission	189	189	-	-	376	361	15	4
Distribution	161	155	6	4	288	278	10	4
Other	-	1	(1)	(100)	3	1	2	200
	350	345	5	1	667	640	27	4

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Transmission

Transmission capital expenditures were unchanged at \$189 million in the second quarter of 2012, and increased by \$15 million, or 4%, to \$376 million in the first six months of 2012, compared to the same periods in 2011.

Investments to expand and reinforce our transmission system were \$73 million in the second quarter and \$166 million for the first six months of 2012, representing respective reductions of \$20 million and \$17 million, compared to 2011. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation, although we continue to make significant investments on load customer connection and local area supply projects to address growing loads. The 2012 decrease in our expenditures results from the completion of several large projects in 2011. Major inter-area network projects completed and put into service in 2011 included the installation of complex static var compensators (SVCs) at our Nanticoke, Detweiler, Porcupine and Kirkland Lake transformer stations. Also contributing to the variance were lower expenditures in 2012 related to our Bruce to Milton Transmission Reinforcement Project connecting refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. This project was successfully declared in-service ahead of schedule on May 14, 2012 and contributed approximately half of our total 2012 investments to expand and reinforce our transmission system. The impact of the reductions in expenditures in both periods was partially offset by increases in our expenditures resulting from local area supply projects progressing into their build phases, investments in our transformer stations related to the Advanced Distribution System (ADS) Project, which supports clean Distributed Generation (DG) connected to our transmission system consistent with the GEA, as well as increased investments related to our transmission projects and upgrades to safely and reliably accommodate additional renewable energy.

Our local area supply project expenditures include investments in our Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure and increase the load supply capacity to ensure reliability of supply to customers in the area. Together with Toronto Hydro-Electric System Limited, we continue to invest in our Midtown Electricity Infrastructure Renewal Project to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work is progressing at our Hearn Switching Station to rebuild an existing switchyard that has reached its end-of-life. This project will also increase short circuit capability to accommodate future connection of renewable generation in central and downtown Toronto. In 2012, we also incurred expenditures related to our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area. This project was put into service in March 2012.

Expenditures to sustain our existing transmission system were \$104 million in the second quarter and \$186 million in the first six months of 2012, representing increases of \$16 million and \$25 million, respectively, compared to 2011. These increases were primarily related to the refurbishment and replacement of end-of-life equipment at our transformer stations in order to improve reliability.

Our other transmission capital expenditures were \$12 million in the second quarter and \$24 million in the first six months of 2012, representing increases of \$4 million and \$7 million, respectively, compared to 2011. The majority of these expenditures were related to fleet acquisitions and to information technology investments.

Distribution

Our distribution capital expenditures increased by \$6 million, or 4%, in the second quarter, and by \$10 million, or 4%, in the first six months of 2012, compared to 2011.

Capital investments to expand and reinforce our distribution network were \$78 million in the second quarter and \$133 million in the first six months of 2012, representing increases of \$10 million and \$2 million, respectively, compared to 2011. We experienced increases in 2012 related to our continued investments in our ADS Project, a multi-year initiative to identify, deploy, analyze and assess equipment and applications to modernize our distribution system. The ADS Project is anticipated to improve outage restoration, reduce construction and ongoing maintenance costs, and reduce line losses. Increased capital expenditures in 2012 were also due to investments related to our other distribution projects and upgrades to safely and reliably accommodate additional renewable energy, and higher volumes of new customer connections and upgrades, partially offset by reduced expenditures within our Smart Meter Project as it nears completion.

Expenditures to sustain our distribution system were \$63 million in the second quarter and \$108 million in the first six months of 2012, representing decreases of \$3 million and \$5 million, respectively, compared to 2011. Our sustainment

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

program reduction in 2012 was related to lower storm restoration work given two major storms in Ontario in 2011. This impact was partially offset by increased work within our wood pole replacement and lines programs, as resources were utilized in 2012 to advance these programs given favourable weather conditions.

Other distribution capital expenditures were \$20 million in the second quarter and \$47 million for the first six months of 2012, representing a decrease of \$1 million and an increase of \$13 million, respectively, compared to 2011. The year-to-date variance is primarily attributable to expenditures for the CIS phase of our entity-wide information system replacement and improvement project. In addition to replacing end-of-life systems, this implementation will result in process improvements that are expected to provide many benefits, including enhancements to customer satisfaction through reduced call times and first call resolution of issues given faster availability of information.

Future Capital Expenditures

Our capital expenditures for 2012 are budgeted at approximately \$1,800 million. Our 2012 capital budgets for our transmission and distribution businesses are about \$1,000 million and \$800 million, respectively. Consolidated capital expenditures are also expected to be approximately \$1,800 million in each of 2013 and 2014. These expenditure levels reflect meeting the sustainment requirements of our aging infrastructure. Our sustainment program is budgeted at approximately \$700 million in 2012, \$950 million in 2013 and \$1,000 million in 2014. Our development projects include the ADS, inter-area network upgrades that reflect supply mix policies, local area supply requirements, and requirements to enable DG. Our development expenditures are budgeted at approximately \$750 million in 2012, \$600 million in 2013 and \$550 million in 2014. These development investments also reflect customer demand work. Other capital expenditures are budgeted at approximately \$350 million in 2012 and \$250 million in each of 2013 and 2014. These expenditures include investments to replace our end-of-life customer billing system and to realize increased productivity from our enterprise-wide SAP platform. Our capital expenditures for 2012 are anticipated to be lower than budget by approximately \$165 million, primarily due to changes in the cost and timing of certain large transmission projects, for example the Midtown Electricity Infrastructure Renewal Project, as well as lower distribution development including DG capital expenditures reflecting a lower volume of activity due to proponent delays and lower than anticipated proponent applications received by our Company.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. The estimated capital expenditures associated with these projects and upgrades to the system are anticipated to be up to approximately \$700 million over a period to the in-service dates of these projects and the applicable expenditures are reflected in our budgets. On February 28, 2011, the OEB amended our subsidiary Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy. This licence amendment requires Hydro One Networks to develop and seek approvals for these projects in accordance with recommendations from the OPA. In a letter dated April 7, 2011, to accommodate small-scale renewable generation, the OPA provided the scope and timing requirements to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence. Six of these upgrades have been completed and we are currently anticipating that one additional station upgrade will be placed in-service later in 2012. For the remaining three upgrades, alternative solutions have been identified. The overall capital cost for the stations is estimated to be up to \$40 million. On June 30, 2011, we received a letter from the OPA recommending the scope and timing to reconductor two circuits between Sarnia and London. This West of London Transmission Upgrade Project will enable the connection of additional renewable generation in the west of London area. On March 28, 2012, we filed a Section 92 leave-to-construct application with the OEB for our West of London Transmission Upgrade Project. This project has a required in-service date of December 2014. On October 3, 2011, we received a letter from the OPA recommending the scope and timing of a Southwestern Ontario Reactive Compensation Priority Project, formerly known as the Southwestern Ontario Series Compensation Project. After consideration of the options, the OPA recommended that we install an SVC at our Milton Switching Station to increase the transmission capability of the Bruce transmission system. A new transmission line west of the City of London was also included in the Hydro One Transmission Licence Amendment. We have not yet received a recommendation from the OPA regarding the construction of this line.

In accordance with the memorandum of agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and our company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of our company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from micro Feed-in Tariff (FIT) and small-scale (capacity allocation exempt) FIT generation projects or

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

proponents thereof for costs related to investments and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendment made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within our company, including the timing of any such decisions. In the first six months of 2011 and the full year 2011, we spent approximately \$2 million and \$21 million, respectively, on these projects, and in the first six months of 2012, we spent approximately \$12 million. Of the amounts spent, \$2 million and \$19 million was charged to results of operations in the first six months of 2011 and the full year 2011, respectively, and in the first six months of 2012, \$11 million was charged to results of operations.

In August 2010, the OEB introduced a framework for competitive designation for the development of eligible transmission projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework. We do not plan to undertake large capital expenditures without a reasonable expectation of recovering them in our rates, with the exception of the transformer station upgrades noted above.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments.

<i>June 30, 2012 (Canadian dollars in millions)</i>	Total	2012¹	2013/2014	2015/2016	After 2016
Contractual Obligations (due by year)					
Long-term debt – principal repayments	8,700	600	1,350	1,000	5,750
Long-term debt – interest payments	6,964	216	765	663	5,320
Inergi LP (Inergi) outsourcing agreement ²	352	69	262	21	-
Operating lease commitments	55	5	19	11	20
Environmental and asset retirement obligations ³	322	23	61	48	190
Total Contractual Obligations	16,393	913	2,457	1,743	11,280
Other Commercial Commitments (by year of expiry)					
Bank line ⁴	1,250	-	-	-	1,250
Letters of credit ⁵	135	124	11	-	-
Guarantees ⁵	326	326	-	-	-
Pension ⁶	327	-	313	14	-
Total Other Commercial Commitments	2,038	450	324	14	1,250

¹ The amounts disclosed represent the amounts due over the period July 1, 2012 to December 31, 2012.

² On May 1, 2010, we extended our Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would otherwise have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

³ We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement obligations for the removal of asbestos-contaminated materials from our facilities and the decommissioning and removal of certain switching stations. The expenditure pattern reflects our planned work programs for the periods.

⁴ In support of our liquidity requirements, we have a \$1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2017.

⁵ We currently have outstanding bank letters of credit of \$124 million relating to retirement compensation arrangements. On April 27, 2012, our highest credit rating declined from the "Aa" category to the "A" category. Based on this credit rating category, we provided letters of credit to the IESO in the amount of \$10 million to meet our current prudential requirement. The other \$1 million included in letters of credit pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of \$325 million, and on behalf of two distributors using guarantees of up to a maximum of \$660 thousand.

⁶ Contributions to the Hydro One pension fund are generally made one month in arrears. The 2012, 2013 and 2014 minimum contributions are based on an actuarial valuation filed in May 2012 and effective December 31, 2011. Based on expected levels of 2012 pensionable earnings, our total 2012 annual pension contributions of approximately \$163 million were paid during the six months ended June 30, 2012. Future minimum contributions beyond 2014

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2014 are not estimable at this time.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with this debt is recorded under financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to the IESO, which is a related party by virtue of its status as an agency of the Province. The year-over-year changes related to these amounts are described more fully in the discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our payments in lieu of corporate income taxes and property taxes, which are paid or payable to the Ontario Electricity Financial Corporation (OEFEC). In January 2010, we purchased \$250 million of Province of Ontario Floating-Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first six months of 2012, we contributed \$163 million to our pension plan and incurred \$104 million in net periodic pension benefit cost. An actuarial valuation filed in May 2012 and effective December 31, 2011 did not result in significant changes to our 2012 required contributions or our 2012 net periodic benefit cost. Actuarial valuations are minimally required to be filed every three years. We currently estimate our total annual pension contributions to be approximately \$163 million, \$162 million, and \$165 million for 2012, 2013, and 2014, respectively, based on the projected level of pensionable earnings and the same actuarial valuation effective December 31, 2011. Future minimum contributions beyond 2014 will be based on the actuarial valuation effective no later than December 31, 2014. Our pension plan experienced positive returns of about 3.6% in the first six months of 2012.

TRANSITION TO US GAAP

Accounting Framework for External Reporting

In 2011, the Ontario Securities Commission (OSC) and our Board of Directors approved our application to adopt US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, without becoming a Securities and Exchange Commission (SEC) registrant, for our 2012, 2013 and 2014 fiscal years. As a result, our unaudited interim Consolidated Financial Statements and accompanying notes as at, and for the three and six months ended June 30, 2012 have been prepared in accordance with US GAAP. Our first US GAAP unaudited interim Consolidated Financial Statements were as at, and for the three months ended March 31, 2012. Our first US GAAP annual Consolidated Financial Statements will be dated December 31, 2012.

Our company's Consolidated Financial Statements were prepared in accordance with Canadian GAAP until December 31, 2011. Canadian GAAP differs in some areas from US GAAP as disclosed in the reconciliation to US GAAP included in Note 17 to the unaudited interim Consolidated Financial Statements as at and for the three and six months ended June 30, 2012. Descriptions of the effect of the transition from Canadian GAAP to US GAAP on our financial position, financial performance and cash flows as at and for the year ended December 31, 2011 are also provided in Note 17 to our unaudited interim Consolidated Financial Statements for the period ended June 30, 2012. The accounting policies set out in the unaudited interim Consolidated Financial Statements for the period ended June 30, 2012 have been consistently applied to all

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

the periods presented. The comparative figures in respect of 2011 were retrospectively restated effective January 1, 2011 to reflect our adoption of US GAAP.

Accounting Framework for Rate-Setting

Consistent with the OSC's decision to approve our adoption of US GAAP, two of our subsidiaries, Hydro One Networks and Hydro One Remote Communities requested that the OEB approve the adoption of US GAAP as the basis for future rate-setting and regulatory accounting and reporting in place of its standard modified International Financial Reporting Standards (IFRS) basis. The OEB approved Hydro One Networks' request to adopt US GAAP for its regulated distribution and transmission businesses, and approved Hydro One Remote Communities' request to adopt US GAAP as its approved basis for rate-setting, all effective January 1, 2012. We did not make a request to adopt US GAAP for rate-setting purposes on behalf of our subsidiary, Hydro One Brampton Networks. Hydro One Brampton Networks has implemented IFRS for its 2012 fiscal year. As a result, Hydro One Brampton Networks will have its rates set based on modified IFRS once its current incentive rate-setting period is complete.

Debt Covenants

None of our financial covenants were impacted by our conversion to US GAAP.

Internal Controls over Financial Reporting and Disclosure Controls and Procedures

Our transition to US GAAP did not result in any significant revisions to our internal controls over financial reporting and disclosure controls and procedures.

Financial Reporting Expertise

Given the similarities between US GAAP and Canadian GAAP for our company, there has also been no significant impact from the transition to US GAAP with respect to financial reporting expertise. Our US GAAP training efforts have been focused on specific areas of difference between the two accounting frameworks and these efforts have been targeted to specific finance staff, senior executive management and the Audit and Finance Committee of our Board of Directors. We continue to provide additional training to our other finance and operational staff, concentrating on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs. During the remainder of 2012, we will focus our US GAAP training on new accounting and reporting developments and on emerging issues.

Information Systems

Given the similarities between US GAAP and Canadian GAAP, we did not experience any significant impacts from the transition to US GAAP with respect to our information systems.

IFRS

Prior to our adoption of US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, we had planned to adopt IFRS effective January 1, 2012, with comparative restatement of our 2011 results. Accordingly, by mid-2011, we had substantively completed our four-phase IFRS conversion project, which included separate diagnostic, design and planning, solution development, and implementation phases. Our IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on our financial statements, a review and upgrade of our information systems to meet IFRS requirements, an assessment of our internal controls over financial reporting and disclosure controls and processes, as well as training of our key finance and operational staff.

As a result of our 2011 decision to adopt US GAAP, our IFRS conversion project efforts were effectively halted. However, our IFRS conversion work has been, and will continue to be, managed in such a way that it can effectively be restarted if a future transition to IFRS is required. We continue to monitor major accounting developments arising from initiatives of the international standard setter, particularly as several major projects are joint efforts with the US Financial Accounting Standards Board.

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Training of our key finance and operational staff commenced in 2007, and continues on a reduced but on-going basis, as we have certain subsidiaries that are required to prepare their unconsolidated financial statements in accordance with IFRS. IFRS training was also previously provided to our Audit and Finance Committee and senior executive management. In 2012, we will continue to provide IFRS training to specific staff with a focus on new IFRS accounting and reporting developments and emerging issues.

Our company has the customary financial covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Depending on the outcome of various international standard setting initiatives, including the Rate Regulated Accounting Project, a potential future adoption of IFRS could result in changes to our financial position and increased volatility in our results of operations that could impact our debt covenants. We continue to monitor the potential impact that an IFRS conversion could have under various scenarios.

As part of a company-wide information systems improvement project, many of our major financial systems were replaced in 2008 and 2009. Our new financial systems were designed with maximum flexibility given the uncertainty of the outcome of certain impactful International Accounting Standards Board projects. Our financial systems have the ability and capacity to handle current accounting and reporting processes in accordance with IFRS, should that be required in the future.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

To optimize our customer service operations, we have started the final phase of our SAP enterprise-wide information system by initiating our CIS Project. This new system will increase productivity by replacing two legacy applications currently providing service to our distribution customers and key constituents for billing, customer contacts, field services, settlements and customer choice administration. With the design phase complete, the CIS Project is currently in the build and test phases. During these phases, internal controls will be tested for adequacy and effectiveness with any remediation effort to be completed prior to the go-live date. In addition to the benefits associated with CIS, we continue to leverage our other SAP enterprise systems to gain other productivity improvements.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the unaudited interim Consolidated Financial Statements for the period ended June 30, 2012, together with other financial information included in our quarterly securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the unaudited interim Consolidated Financial Statements.

RECENT DEVELOPMENTS

Debt Issuances

On July 31, 2012, we issued \$75 million notes under our MTN Program with a maturity date of July 31, 2062 and a coupon rate of 3.79%.

On May 22, 2012, we issued \$300 million and \$125 million notes under our MTM Program with maturity dates of January 13, 2022 and December 22, 2051, and coupon rates of 3.20% and 4.00%, respectively. These notes were additional offerings of notes originally issued on January 13, 2012 for \$300 million and December 22, 2011 for \$100 million. These additional issuances bring the total amounts outstanding for these debt issues to \$600 million and \$225 million, respectively.

Ontario's FIT Program

On July 12, 2012, the OPA re-launched the microFIT Program, following an April 5, 2012 letter received from the Ministry of Energy directing it to implement recommendations from the Ontario Government's FIT Program Review. Highlights of

HYDRO ONE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

changes implemented include encouraging greater community and aboriginal participation and the protection of agricultural lands. The FIT Program will be re-launched to reflect recommendations from the review at a later date.

Provincial Budget

On June 20, 2012, Bill 55, *Strong Action for Ontario Act (Budget Measures)* received royal assent. Bill 55 is aimed at eliminating Ontario's deficit by 2017-2018, and includes several items aimed at reducing costs within the greater public sector, within the energy sector specifically, and on energy bills. In support of these initiatives, the Ontario government will engage an independent consultant to identify opportunities for efficiencies and benchmark Hydro One against comparable entities.

Bruce to Milton Transmission Reinforcement Project

In May 2012, our Bruce to Milton Transmission Reinforcement Project was declared in-service, ahead of the December 2012 target. The new line will connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area.

Agreement with Saugeen Ojibway Nation

On June 18, 2012, our subsidiary Hydro One Networks, and the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively known as the Saugeen Ojibway Nation (SON), entered into an agreement which contemplates a new Limited Partnership (LP) to hold only the lines and related land rights of our recently completed Bruce to Milton Transmission Reinforcement Project. The carrying value of these assets is expected to be approximately \$600 million when they are transferred to the LP. Under the terms of this agreement, the SON will be eligible to purchase a non-controlling equity interest in the LP at fair value. The LP will be a rate regulated entity under the jurisdiction of the OEB. Transfer of the assets to the LP and subsequent sale of an equity interest to the SON are both subject to the receipt of future regulatory approvals from the OEB.

Retirement of our Chief Executive Officer (CEO)

On June 13, 2012, Laura Formusa, our President and CEO, informed the Board of Directors that she will retire, effective December 31, 2012. Our Board of Directors has made it its priority to ensure we have a robust succession plan in place. Ms. Formusa's retirement at the end of 2012 allows the Board of Directors to execute the succession plan in a manner that provides for an orderly succession process. The Board of Directors has initiated this process to identify our new President and CEO.

East-West Tie LP (EWT LP)

On May 31, 2012, EWT LP, an equal partnership of three entities including Hydro One, received approval from the OEB for its transmission licence, which is required to participate in the East-West Tie Line bid process. On July 12, 2012, the OEB announced that applications for designation of the East-West Tie Line must be filed no later than January 4, 2013.

OEB Rate Applications

On May 28, 2012, our subsidiary Hydro One Networks filed a revenue requirement and cost-of-service rate application for 2013 and 2014 transmission rates. The application seeks approval for revenue requirements of approximately \$1,464 million and \$1,557 million for 2013 and 2014, respectively. This represents an estimated increase in rates of less than 1% in 2013 and 9% in 2014. These increases are estimated to result in no impact on an average customer's total monthly bill in 2013 and a less than 1% increase in 2014.

On May 28, 2012, Hydro One Networks also filed an Incentive Regulation Mechanism rate application for 2013 distribution rates, to be effective January 1, 2013. If approved as filed, distribution rates for a residential customer would rise by approximately 2.9%. Including previously OEB approved Retail Transmission Service Rate (RTSR) adjustments for 2011 and 2012, the total bill impact for 2013 would be approximately 2.1%. A distribution rate application for 2012 was not filed, and therefore, 2012 tariff rates were held at the 2011 levels.

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

SouthPoint Wind Legal Claim

SouthPoint Wind has discontinued its claims against the Ontario government ministries and Environment Canada because the claims were not properly served, leaving Hydro One Networks and the OPA as defendants to the claim received on April 4, 2012. The reason for the discontinuance is that the plaintiff failed to give the above mentioned defendants proper notice, as required by law for proceedings against government entities, before issuing the claim. As the statement of claim serves as sufficient notice, SouthPoint Wind can issue a new claim against the government defendants. Our company is not aware whether SouthPoint Wind has issued a new claim against the government defendants at this time.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		Six months ended June 30	
<i>(Canadian dollars in millions, except earnings per common share and ratios)</i>	2012	2011	2012	2011
Net income	169	142	379	354
Net cash from operating activities	217	334	454	574
Capital expenditures	350	345	667	640
Earnings per common share	1,651	1,375	3,705	3,451
Earnings coverage ratio ¹			2.70	2.65
Net asset coverage on long-term debt ratio ²			1.75	1.81
Total debt to capitalization ratio ³			59%	55%

¹ The earnings coverage ratio has been presented for the twelve months ended June 30, 2012 and June 30, 2011, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

² The net asset coverage on long-term debt ratio has been presented as at June 30, 2012 and December 31, 2011 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

³ Total debt to capitalization ratio has been presented as at June 30, 2012 and December 31, 2011 and has been calculated as total debt divided by total debt plus total shareholder's equity and preferred shares.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy related revenues and profit and their trend; statements related to the use of our approved rates; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility and our long-term credit rating target; expectations regarding our financing activities; expectations about our maturing debt and interest payments; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates; expectations regarding the recoverability of large capital expenditures; statements regarding expected future capital and development expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; expectations related to OEB rate applications, including impacts of such decisions on an average residential customer's bill; statements regarding the retirement of our CEO; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi; statements relating to US GAAP and our adoption of US GAAP; statements regarding accounting related international standard setting initiatives, including the potential future adoption of IFRS and its associated impacts; statements about our agreement with SON; statements related to the FIT program; statements regarding the Ontario government; and expectations regarding future payments made under our operating leases. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission businesses; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our 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 statements include, among other things:

- the impact of the GEA and the Province's Long-Term Energy Plan, including unexpected expenditures arising therefrom;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- unanticipated changes in electricity demand or in our costs;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risks associated with changes in interest rates;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergy is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section Risk Management and Risk Factors in the 2011 Management's Discussion and Analysis (MD&A). You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at August 9, 2012. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

School Energy Coalition (SEC) INTERROGATORY #11 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 5/p.7] Please provide a calculation of the cost of debt included in 2012 rates, and a further calculation that adjusts that amount to include all changes to the cost of debt expected prior to the end of 2013, including but not limited to the refinancing of the \$600 million of 5.77% notes at a lower interest rate.

Response

Please refer to the Hydro One 2011 Distribution Draft Rate Order (EB-2009-0096, Draft Rate Order, dated December 17, 2010) for the calculation of the cost of debt included in 2012 rates.

Please refer to Exhibit I, Tab 7, Schedule 5.01 VECC 36, attachment 1 for an updated forecast of Hydro One Distribution's cost of long-term debt for 2013. Note that the maturity of the 5.77% notes in November of 2012 is factored into the calculation (see Line 7).

School Energy Coalition (SEC) INTERROGATORY #12 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.5 and A/6/1, Attach. 6/p.2] Please provide a history of all changes to Hydro One's "baseline credit assessment" (BCA) from Moody's, currently 8, since 2002.

Response

In their July 2006 rating methodology update for government-related issuers, Moody's published initial baseline credit assessments (BCA) for government-related issuers including Hydro One.

The following is a history of Moody's BCA levels for Hydro One:

- July 6, 2006 – 7
- April 13, 2010 – 8
- Current BCA - 8

School Energy Coalition (SEC) INTERROGATORY #13 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p. 9] Please explain why, if Typical Capital spending is lower than the capital spending included in the last cost of service, there is a \$14 million ICM revenue amount. Please confirm that Hydro One is seeking ICM treatment for all normal capital spending in excess of depreciation.

Response

Hydro One is seeking recovery on all non-discretionary capital in excess of depreciation. Please refer to Exhibit I, Tab 2, Schedule 1.08 Staff 9.

School Energy Coalition (SEC) INTERROGATORY #14 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/1/p.9] Please provide full details of all increases in FTEs expected as a result of the ICM proposals in this Application. Please provide a report in the Board's form 2-K, with 2013 as the final year on the table.

Response

Hydro One does not plan to hire additional full time staff to resource the incremental work. For the increase in station replacements/refurbishments the construction work is done by Hydro One's casual trades and is readily resourced. Hydro One forecasts the need for approximately 30 FTE's of this category in 2013. In addition, new engineering design standards allow for an increased volume of work to be done. As discussed in the evidence, Hydro One will be using integrated Modular Distribution Stations (iMDS). Instead of designing and constructing the stations in a piecemeal fashion, the iMDS units are prefabricated in a factory setting and arrive on site and are quickly assembled in a "plug & play" fashion. There are many advantages to using this approach including low life cycle costs and minimal resource requirements to build.

The transformer spares and replacement costs shown in evidence are largely commodity related. Minimal resources are required in this category to make the purchases.

For resourcing the increase in wood pole replacement work please see Exhibit I, Tab 2, Schedule 1.09 Staff 10, part g).

For CIS, please refer to Exhibit I, Tab 4, 9.01 AMPCO 4 and Exhibit I, Tab 4, Schedule 8.08 SEC 35.

School Energy Coalition (SEC) INTERROGATORY #15 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/1/2/p.2] Please confirm that, if the Board accepts the proposal to take only half of the CCA for the CIS project in 2013, Hydro One will not make any ICM funding application for any projects (including CIS) as part of its application for 2014 rates. If Hydro One currently expects to file a 2014 ICM application, please provide whatever details are currently forecast with respect to that application.

Response

If Hydro One finds it necessary to file an application for ICM treatment in 2014, the application would not include an amount for CIS.

Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2, part d) for discussion on the potential for future filings.

School Energy Coalition (SEC) INTERROGATORY #16 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/ p. 2] Please provide details on the new information available to Hydro One since its last cost of service decision that has resulted in an increase in the budgets for Station Refurbishments and Transformer Spares and Replacements.

Response

Since the last cost of service application, Hydro One has been focused on development and application of new analytical tools with the intention of providing a longer-term view of investment planning. Extrapolating the investment plan into the future using the historic rates of capital renewal with the foreseeable increase in required OM&A expenditures due to the aging infrastructure highlighted that the current strategy is not sustainable.

In addition to the evolving longer-term outlook for distribution stations, additional information has been gathered through the 2010 and 2011 survey of all distribution and regulating stations. The survey was intended to provide some information not previously available (such as the condition of the existing structures within stations), and also to validate the existing asset condition information. It was generally found that station assets were in poorer condition than previously understood.

School Energy Coalition (SEC) INTERROGATORY #17 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p.3] Please advise the basis on which the current refurbishment rate of 4 stations per year, and the current replacement rate of 6 transformers per year, were originally established, and subsequently maintained. Please provide the most recent report, analysis, business case, presentation or similar document that continued to assert either of those rates was appropriate.

Response

The above accomplishment rates form the basis of the Typical Capital as approved by the Board during the EB-2009-0096 proceeding. No more recent documents exist asserting these accomplishment levels were appropriate beyond the 2010 and 2011 test years.

Since the last cost of service application, Hydro One has identified the need for increased levels of spending, please refer to Exhibit I, Tab 2, Schedule 8.16 SEC 16.

School Energy Coalition (SEC) INTERROGATORY #18 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p. 4 and 15] Please confirm that the unit cost for station refurbishments is expected to drop with the implementation of iMDS. Please quantify that reduction. Please provide any cost/benefit analysis or business case prepared with respect to the development of iMDS.

Response

Hydro One is expecting the unit cost for station refurbishments to decrease with the implementation of the iMDS solution. Four pilot iMDS installations are being completed to validate the conceptual solution and anticipated costs. Although detailed pricing is not yet known for the iMDS, total life-cycle costs are expected to decrease in the order of 10-20%.

School Energy Coalition (SEC) INTERROGATORY #19 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p. 12] Please provide the number of transformer failures, the number of transformer component failures, and the number of metalclad breaker failures, for each year from 2006 through 2011.

Response

The number of transformer failures, and transformer component failures are provided in the table below. Class 1 transformer failures represent major failures rendering the transformer un-repairable, and Class 2 / 3 failures represent transformer component failures. Definitions for Class 1, Class 2 and Class 3 transformer failures are provided in Exhibit I, Tab 2, Schedule 2.08 EP 9.

Year	Transformer Failures (Class 1)	Transformer Component Failures (Class 2 + 3)
2006	7	24
2007	10	18
2008	11	17
2009	16	13
2010	3	25
2011	8	25

Please refer to Exhibit I, Tab 2, Schedule 1.12 Staff 13 for the metalclad breaker failure history.

School Energy Coalition (SEC) INTERROGATORY #20 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p. 16] Please explain why corrective maintenance will not be reduced with the increased spending on capital.

Response

Increased capital expenditures will have the effect of decreasing corrective maintenance at the specific stations which undergo Station Refurbishment. Refer to Exhibit I, Tab 2, Schedule 5.12 VECC 15, part, b) for the average annual OM&A expenditures for maintaining an aged station versus a new station.

However, in the short term, over the entire population of distribution stations, OM&A is not expected to be reduced as outlined in Exhibit I, Tab 2, Schedule 1.13 Staff 14.

School Energy Coalition (SEC) INTERROGATORY #21 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p.16] Please provide details of the capital spending on station refurbishment in 2012. To the extent that it is less than \$29.0 million, please explain why.

Response

Please refer to Exhibit I, Tab 2, Schedule 9.03 AMPCO 3, part e) for the capital spending on station refurbishments in 2012. A listing of the 12 specific stations to be refurbished in 2012 can be found in Exhibit I, Tab 2, Schedule 5.15 VECC 18.

The incremental increase to \$29.0 million in 2013 from the typical level in 2011 is required for reasons outlined in Exhibit B, Tab 2, Schedule 2, pages 4 – 16.

School Energy Coalition (SEC) INTERROGATORY #22 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p. 18] Please confirm that Table 2 shows the purchase of 59 transformers in total.

Response

Confirmed total of 59 transformer purchases. A total of 36 of the 59 transformers are planned to be installed at stations, and the other 23 transformers will be purchased as operating spares and stored at Central Maintenance Services in Pickering.

School Energy Coalition (SEC) INTERROGATORY #23 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p. 26] Please explain why the “operating spare complement is currently not at the appropriate level”. For each year from 2008 through 2012, please advise the “appropriate level”, the actual level, the rationale supporting the calculation of the “appropriate level”, and the reasons for any material difference between appropriate and actual.

Response

For an explanation as to why the current operating spare compliment is currently not at the appropriate level please see Exhibit I, Tab 2, Schedule 1.14 Staff 15.

In past years, Hydro One identified the appropriate levels of spares based on inventory gaps with a reliance on refurbishing old transformers as a method of maintaining the spare complement; not through a planned “appropriate level” and actual level of spares analysis for each year. Hydro One has adopted a different strategy within this application with a focus on renewing the operating spare pool with new transformers starting in 2013 in order to move toward an appropriate level of spares.

School Energy Coalition (SEC) INTERROGATORY #24 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p. 27] Please provide a forecast, for each of 2013 through 2017, of the reduced OM&A expenditures relating to transformer maintenance that are expected as a result of “increased capital funding starting in 2013”.

Response

As capital program expenditures increase for Distribution & Regulating Stations beginning in 2013, it is anticipated there will be gradual reduction of OM&A expenditures associated with transformers. This reduction will be based primarily on the reduced dependence on refurbishment of transformers to supply the operating spare pool, as the inventory is renewed through the purchase of new transformers.

As outlined in Exhibit I, Tab 2, Schedule 5.12 VECC 15 part c), new transformers do typically have lower OM&A costs compared with aged units. However given the fact that even at the increased 2013 accomplishment level, only 3% of the transformer inventory is getting replaced on an annual basis, significant changes in the OM&A associated with in-service transformers are not likely to be realized within the five year period in question.

Over several years however, continued Sustaining Capital reinvestment at the proposed level will allow Hydro One to stabilize the required future OM&A expenditures that would otherwise have to increase as the transformer inventory ages.

School Energy Coalition (SEC) INTERROGATORY #25 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/2/p. 27] Please explain how planned and demand transformer replacements are “incremental” capital if they are less than the base year.

Response

Proposed 2013 expenditures associated with planned and demand transformer replacements within the Transformer Spares and Replacements category are in fact incremental to the typical capital expenditure. There appears to be a typographical error in the wording of the evidence, to clarify the incremental increase is outlined in the table below:

	Typical Capital 2011 (\$M)	IRM 2013 (\$M)	Incremental Increase (\$M)
Transformer Spares and Replacements	4.1	20.3	+16.2
Operating Spare Purchases	2.9	13.3	+10.4
Planned Replacements	1.2	3.5	+2.3
Demand Replacements	0	3.5	+3.5

School Energy Coalition (SEC) INTERROGATORY #26 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/3/p. 3] Please confirm that the Applicant seeks to increase total pole replacements in the test year from the current level of 20,200 to a new level of 24,000.

Response

Hydro One seeks to increase the number of units under the wood poles replacement program from 7,200 poles to 11,000 poles per year. In addition to this, approximately 13,000 poles are replaced or newly installed each year from other demand driven programs such as storm repairs, new connections, joint use and relocations and generation connections.

School Energy Coalition (SEC) INTERROGATORY #27 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/3/p. 9] Please advise the level of pole replacement proposed by the Applicant in its last cost of service Application, the previous level of pole replacement that was being adjusted, and the level allowed by the Board in its decision, in each case by reference to either number of poles or budget.

Response

A summary of the proposed and board approved capital expenditure for pole replacements for 2010 and 2011; as well as the 2009 forecast capital expenditure for pole replacements from the EB-2009-0096 application have been provided in the table below:

Year		\$M
2009	<i>Forecast</i>	42.2
2010	<i>Proposed Level</i>	46.4
2010	<i>Board Approved</i>	46.4
2011	<i>Proposed Level</i>	59.0
2011	<i>Board Approved</i>	59.0

School Energy Coalition (SEC) INTERROGATORY #28 List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

[B/2/3/p. 13] Please provide a forecast of the number of poles to be replaced, and the cost of the pole replacement program, for each year from of 2014 to 2022 under Scenario 2.

Response

The Scenario 2 example was used to illustrate the impacts of replacing 11,000 poles in 2013 plus an incremental increase of 2,000 poles per year, until a total volume of 20,000 poles replaced annually is reached by 2018. It can be assumed that under such Scenario that the cost would typically increase at the same proportion as the incremental increase of poles. This example was for illustration purposes only; future replacement rates and associated costs will be determined through future Applications.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1

a) HONI provides explanations for Typical capital spending, Escalated Issues capital spending and Non-typical capital spending.

Please confirm the origin of these definitions and how HONI determined the level of review required during an IRM period.

b) Page 4 - Please expand Table 1 on Page 4 to include 2011 actual and 2012 Bridge.

c) Please provide a breakdown of the Typical Capital Projects spending plan for 2013 segregated between discretionary and non-discretionary.

d) Please provide a description of the non-discretionary Typical Capital Projects and the expected in-service dates.

e) Page 6 - HONI indicates that lower reliability is an unintended outcome of not being in a position to invest in rate base. Please provide the analysis the supports this statement.

f) Page 6 – Please explain further the harvesting of assets would certainly result in increased contract and employee labour costs.

g) Page 8 Table 2 – Please reproduce Table 2 to show the breakdown of spending categories under Typical Capital. Please add 2011 actual and 2012 bridge to the table.

Response

a) The definitions and level of review were provided by Hydro One during the Board's Renewed Regulatory Framework consultation (see Attachment 1).

b) See below for the expanded Table 1 from Exhibit B, Tab 1, Schedule 1 to include the 2011 actual and 2012 forecast.

c)

Line #		COS 2011 Actual	COS 2012 Forecast	IRM 2013
1	Typical capital spending	\$432	\$444	\$452
2	Rate base impact of in-service capital	\$455	\$481	\$414
3	Less rate base funded by depreciation	-\$260	-\$264	-\$283
4	Add rate base no longer funded resulting from decrease in revenue	n/a	n/a	\$11
5	Growth in rate base for Typical capital (line 2 + line 3 + line 4)	n/a	n/a	\$142
6	Revenue required due to growth in rate base for Typical capital	n/a	n/a	\$14

d) All spending proposed within the Typical Capital is non-discretionary.

e) The projects and programs with the Typical Capital spending are substantially the same as those approved under EB2009-0096. For further discussion on Typical Capital please refer to Exhibit I, Tab 2, Section 1.01 Staff 2.

f) Please refer to Exhibit I, Tab 2, Schedule 1.03 Staff 4

g) Please refer to Exhibit I, Tab 2, Schedule 1.04 Staff 5

h)

	Actual				Forecast	ICM
	2008	2009	2010	2011	2012	2013
Sustainment	170.7	180.3	185.5	205.5	192.6	207.3
Development	153.2	170.3	150.6	143.6	157.3	159.9
Operations	0.9	1.7	1.2	1.3	4.4	4.9
Shared						
Services	<u>110.5</u>	<u>103.2</u>	<u>93.2</u>	<u>81.4</u>	<u>89.6</u>	<u>79.8</u>
Total	435.3	455.5	430.5	431.9	443.9	451.9

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Susan Frank

Vice President and Chief Regulatory Officer
Regulatory Affairs

Filed: October 11, 2012
EB-2012-0136
Exhibit I-2-9.01 AMPCO 1
Attachment 1
Page 1 of 13



BY COURIER

April 20, 2012

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

Dear Ms. Walli:

EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004 - Renewed Regulatory Framework - Hydro One Networks Comments

Hydro One Networks Inc. ("Hydro One") appreciates the opportunity to provide comments on the Ontario Energy Board's ("OEB") Renewed Regulatory Framework initiative. Hydro One believes that a long-term regulatory regime should provide a clear, efficient and realistic environment for distributors and other stakeholders to operate within. There should be expectations for smooth rate increases that allow recovery of required investments and predictable rates for customers.

Hydro One has organized its comments under the following topics:

- Investment Recovery
- Planning
- Performance and Incentives

Key points are provided in bullets immediately following headings for easy reference.

Hydro One believes that issues related to investment recovery and regional planning can be dealt with in the near term while issues related to performance and incentives will require more consideration and a longer term approach to renewal.

Investment Recovery

Hydro One will differentiate between 3 types of capital investments and provide a numerical illustration of why "typical" ongoing investments aren't necessarily covered during Incentive Regulation Mechanism ("IRM") periods between Cost of Service ("COS") rebasings. Hydro One will also provide options for how investments could be treated within a renewed regulatory framework.

Types of Investment:

- Hydro One offers that there are 3 basic types of capital investment for purposes of the investment recovery discussion: “typical” capital spending; “escalated issue” capital spending; and “non-typical” capital spending.
- Each type of investment drives a different level of required scrutiny.

Typical capital spending includes historically approved levels of sustainment and development spending. Sustainment spending includes categories such as wood pole replacements, transformer replacements, investments in distributing and regulating stations, repairing storm damage and the replacement of meters, information technology, fleet, and work and office equipment. Development spending includes categories such as new load connections, and upgrades and system capability reinforcement. Typical capital spending is reviewed in detail at COS rebasings and should not require detailed review during the period of the IRM. Typical includes the capital spending approved in the most recent COS application (i.e. net of any OEB directed reductions) less all capital spending associated with renewable generation and smart grid investments.

A second category covers capital spending on typical categories but at a substantial increase over historically approved levels. The higher level of capital spending would be required to address an escalated issue. For ease of reference, this will be called escalated issue capital in the remainder of this document. For example, a distributor may require a substantial increase over historically approved levels to address a quality issue related to certain poles. This quality issue may relate to asset age or a manufacturer issue. Escalated issue capital spending, would require a more detailed review if introduced during the period of an IRM.

A third category covers “non-typical” spending. This category covers items such as substantial green energy investments including distributed generation connections. Non-typical capital spending would also require a more detailed review if introduced during the period of an IRM.

References to these categories will be made in subsequent sections.

Issues with Current Investment Recovery Model:

- Typical capital spending is not fully recovered by distributors whose typical capital spending is significantly greater than depreciation during the period of an IRM.
- Escalated issue capital, and non-typical spending also need to be recovered during IRM periods.
- The current model results in “step” increases at COS rebasings which are not customer friendly.
- A new model is required to address the cost recovery shortfall during IRM periods and the resulting step increases upon COS rebasing.

Many distributors and stakeholders have indicated that the current Incremental Capital Module (“ICM”) does not allow for sufficient recovery of capital investments during an IRM period. This was a common theme in presentations from the Electricity Distributors Association, the Ontario Energy Association, the Distribution Regulation Review Task Force, Waterloo North Hydro and Hydro One. The current ICM seriously constrains the capital additions that may be considered during an IRM. The OEB has not developed or applied a consistent approach in defining the criteria for investment to be included under

the ICM (language such as extraordinary, unanticipated, materiality and non-discretionary have been included in OEB decisions).

There was extensive discussion during the Renewed Regulatory Framework for Electricity Stakeholder Conference on March 30, 2012 around IRM and the ability of a distributor to recover typical capital expenditures during an IRM period. On page 57 line 21, Mr. Sommerville provided an observation in this regard:

“...The idea is that that capital budget is a typical, a typical, capital budget. It is not the capital budget for the test year. It is a capital budget that is typical for that utility going forward, and supports its typical capital expenditure requirements for that IRM period.

In response, Ms. Frank volunteered to provide a numeric illustration to support the notion that the current IRM does not cover typical capital expenditures where typical capital expenditures far exceed depreciation expense. Please refer to Appendix A for this illustration. This illustration uses Hydro One’s typical capital expenditures, revenue requirement, OM&A and depreciation approved in its 2011 cost of service application. (EB-2009-0096) The illustration assumes that the IRM period lasts for 2012, 2013 and 2014. The conclusion of this illustration is that Hydro One would incur \$41 million in lost revenue over a three year IRM period under the assumption that Hydro One only invests in typical capital during that time and that typical capital spending increases by inflation in each year of the IRM. If one assumes that the typical capital spending does not increase by inflation in each year of the IRM, Hydro One would incur \$36 million in lost revenue over a three year IRM period. A full description of assumptions used in the illustration is included in Appendix A.

The current mechanism promotes the harvesting of assets during an IRM period. Distributors are reluctant to spend dollars on rate base for which there is no cost recovery. There are a number of unintended customer outcomes associated with this type of behaviour including: lower reliability as assets are not replaced or refurbished prior to breakdown; not replacing or refurbishing assets when it is economically beneficial to do so; and increased labour costs as a utility is unable to levelize work based on the most efficient use of labour resources. Using the illustration in Appendix A, for 2014 only \$278 million¹ would be funded compared to the OEB approved amount in 2011 of \$438 million. This is unsustainable.

The under-recovery problem is compounded when there is a need to recover escalated capital spending and non-typical capital spending during IRM periods. Many distributors are experiencing requirements for escalated capital spending due to aged infrastructure and non-typical green energy investments to connect distributed generation customers. Non-recovery of typical, escalated and non-typical investments results in step increases in rates at COS rebasings.

Options for addressing these issues are presented in the next subsection.

¹ The \$278 million of funded capital additions is made up of the 2014 rate base impact of the “Typical” approved CapEx with inflation (\$456 million per line 38 of Appendix A) less 2014 cumulative annual unfunded growth in rate base (\$178 million per line 42 of Appendix A)

Options for Dealing with Current Investment Recovery Issues:

- There are two main options to deal with the current investment recovery issues: an annual examination of changes to rate base and rates as part of an IRM filing; and a multi-year approach for achieving necessary rate base and rate adjustments.
- The annual examination option would likely work better for distributors who are less comfortable in forecasting and delivering on multi-year plans. These distributors may transition to the multi-year approach in the longer term.
- Distributors that are filing 2012 IRM applications for 2013 rates should be allowed to file under one of the near term approaches

The renewed regulatory framework should allow for annual adjustments to a distributor's capital additions, which will impact on revenue requirement and rate base. The need for adjustments to the current treatment of capital additions is driven by: limitations of the current incremental capital module; the capital intensive nature of the distributor environment; and the desire for rate smoothing for customers.

A near term option to achieve the necessary capital additions is an annual examination of changes to rate base and rates as part of an IRM filing. Two main approaches could be applied to accomplish this change.

The first approach under the near term option would be to establish an annual rate rider based on a detailed review of forecast changes to rate base in each year of the IRM. A "need" and "prudence" review of capital investments driving rate base changes would occur as part of the annual IRM process. This would apply to the full capital program. The determination of the approved rate rider would take into account actual year-end rate base in prior years. The extent of the required review could be determined based on the materiality of the resulting rate change and the nature of the investments. Typical capital spending and escalated issue capital spending may be handled with a written proceeding while non-typical capital spending may require a more detailed oral proceeding.

Another approach under the near term option would be to set an annual rate adder over the IRM period and conduct a detailed review of rate base changes at the next COS rebasing proceeding. The adder could be set annually as part of the IRM process and would include an adjustment for actual year-end rate base in prior years. Under this approach, there would be no detailed review of capital plans during the IRM period. A "need" and "prudence" review of capital spending, including a true-up of the variance account would take place at the next COS proceeding. This approach is more risky for distributors and investors (in the extreme impacting credit rating) but may work quite well for those that do not have a need for large escalated issue and non-typical capital spending over the IRM period.

The second, longer term, option for achieving necessary rate base adjustments is the introduction of multi-year forecasts of rate base as part of a COS filing. Capital plans and in-service additions would be approved in a COS proceeding and the resulting rate base impacts on revenue requirement would be fixed over the IRM period. Under the multi-year approach, the COS review would identify annual changes to rate base to be recovered in rates and no true up would occur. This approach may be more efficient for consideration of capital requirement when examination takes place during a COS filing. It

may also provide better context for the asset condition and system demand assessments when integrated with the 5 year plan. This approach would work well for distributors who have experience and are comfortable with multi-year forecasts. During times of uncertainty and increased demands on distributors (e.g. Green Energy related investments) this would be less effective.

Distributors that are filing 2012 IRM applications for 2013 rates should be allowed to file under one of the near term approaches identified above. This would allow for recovery of prudent capital spending and help to avoid the step increases for customers at COS rebasings. Filings using one of the near term approaches would also allow the OEB to become familiar with and test some of the concepts prior to making final changes to filing requirements and the IRM model.

Planning

Hydro One will address coordination, cost responsibility and planning horizon under the planning topic.

Coordination:

- The Ontario Power Authority's ("OPA's") regional planning process is robust and transparent and produces balanced and optimal plans.
- The final review and approval of OPA plans should take place during section 92 and distributor cost of service or IRM proceedings.

On the coordination issue, Hydro One contends that there currently exists a comprehensive planning process that serves customers well. The Ontario Power Authority ("OPA") is the regional planning authority in Ontario and it has carried out regional planning since its inception in 2005. The OPA is directly responsible for broad impact and complex planning activities that involve transmitters and distributors when regional solutions exist and when a number of potential options exist.

Hydro One, in its transmitter capacity, continues to work with distributors directly to conduct ongoing connection activities where adequate upstream capability is known to exist. Hydro One informs the OPA of these activities and provides the OPA with data to ensure that these activities are aligned with the OPA's planning activities.

The OPA follows a comprehensive process in developing regional plans. They form teams with representatives from the OPA, distributors, transmitters, the IESO and others as appropriate. They establish terms of reference for their studies that include: roles and responsibilities of the study team members; objectives, scope and key assumptions; and a schedule for completing the study. They provide a balanced viewpoint which allows for the consideration of conservation, local generation, transmission and distribution solutions that are in the best interests of customers. They integrate government policy, regional studies and broader province-wide planning activities into the plans and solutions. When complete, the OPA plans should be considered optimal.

OPA plans should undergo final stakeholdering and approval during section 92 and distributor cost of service or IRM proceedings. This final review and approval will provide an opportunity for all interested

stakeholders to ask questions and comment on the plans to ensure that they are in the best interests of customers.

Cost Responsibility:

- The current process for determining cost responsibility is long, repetitive and often results in the recommended solutions not being implemented.
- Section 6 of the Transmission System Code (“TSC”) should be revised to allow distributor line connections to be pool funded on a province wide basis.
- A small working team with representatives from the OPA, transmitters and distributors should be established to recommend the required changes to section 6.3 of the TSC. These changes should be implemented in 2012.

One of the challenges in implementing the OPA-led regional plans is the current cost responsibility rules contained in section 6.3 of the Transmission System Code (“TSC”) as they apply to distributors. The current cost responsibility model discourages distributors to come forward with connection requests because the distributor that triggers the investment is typically required to pay a capital contribution. This is problematic for most distributors. Economic evaluations often result in high capital contributions. Most distributors’ customers cannot afford to pay the capital contribution to fund the necessary expansion investments. This often drives a very long iterative process that does not reach a solution or results in a sub-optimal short term distribution “fix” to avoid a more economic permanent transmission solution.

Section 6.3.6 states that:

“A transmitter shall develop and maintain plans to meet load growth and maintain the reliability and integrity of its transmission system. The transmitter shall not require a customer to make a capital contribution for a connection facility that was otherwise planned by the transmitter, except for advancement costs.”

Section 6.3.6 does NOT alleviate the current cost responsibility issue. The “otherwise planned by the transmitter” criteria for not requiring a capital contribution is very difficult to satisfy.

In its September 6, 2007 EB-2006-0189 (an application by Hydro One Networks Inc. and Great Lakes Power Limited for the review and approval of transmission connection procedures) Decision and Order, the OEB explained the differences between plans driven by Customers (i.e. capital contribution required) and plans driven by System Needs (i.e. capital contribution not required). Specifically, on page 22 of the Decision and Order (underline added):

Distinguishing Between Plans – Customer Driven versus System Needs

“The Board agrees with the submissions by Hydro One and the CLD that there can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other. In the one case, the Code would not require capital contributions, in the other it would.

That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required.

In the Board's view this means that, to qualify for the exception to the general rule, a project must be encompassed in a plan that has been developed by the transmitter substantially independent of customer request. This does not preclude an appropriate level of discourse between the Transmitter and affected customers in order to ensure the accuracy of the plan.

Each of the other transmitters that made submissions in relation to this issue recognized that an integral part of their undertaking involves the establishment by the transmitter of plans that address load growth identified by the transmitter in its ongoing planning process, together with system reliability and safety requirements. Integrating load growth projections, reliability and safety needs is at the heart of the transmitter's planning process. It is the product of that activity that can give rise to the exception contained in section 6.3.6 of the Code.

Whether the plan meets the criteria giving rise to the exception in any given case is a matter of evidence to be considered by the Board on a case-by-case basis."

In practice, it is very difficult to prepare a comprehensive plan that can address system reliability, safety requirements and load growth projections without significant up front distributor participation. The line between customer driven and transmitter driven is very hard to establish. It is much more efficient to spend time determining and implementing the optimal solution and not waste time on whether it was part of a transmitter's original plan or requested by a distributor.

To address this issue Hydro One recommends that all "basic" line connection costs for distributors be pool funded on a province wide basis. It is not recommended that pool funding be done on a regional basis. Pool funding on a regional basis would be too complex and would likely require changes to the distribution bill. The delivery line on the bill would have to include distribution charges, transmission charges and regional charges. Based on how the transmission system has been developed over time, some regions of the province have excess capacity while other regions have insufficient capacity. This is more an accident of geography for distributors that are in regions that have insufficient capacity. From a long term perspective, provincial pooling of distribution line connection costs is the fairest approach for customers.

The "basic" service would be consistent with the OPA's plan. This treatment aligns well with a distributors obligation to serve and eliminates the temptation for distributors to invest in incremental distribution solutions that are duplicative and less economic in the long run. This treatment also aligns with the pooling foundation upon which transmission rates are set. To ensure that only required assets are pooled, Hydro One recommends that any incremental costs associated with premium services be paid for by the distributor that requests the premium service. Examples of premium service would

include underground lines where a feasible overhead option exists and steel pole towers where lattice structures are feasible. Network connections would continue to be pool funded. Please refer to Appendix B for a graphic representation of this recommendation.

Planning Horizon:

- The planning horizon should be a minimum of 20 years to ensure the transmission corridors are established in the most efficient and cost effective manner.
- Costs to establish the corridors should be treated as current period costs despite the future-use nature of these assets.

As part of planning efficiency, planning needs to look out a minimum of 20 years in order to ensure that transmission right-of-ways are established ahead of, or coincident to, urban development. This is accomplished through effective coordination between gas utilities, electric utilities, municipalities, the Ministry of Transportation and the OPA. This will help ensure that the establishment of corridors is done in a more thoughtful manner and be less crisis driven. Coordinating with all stakeholders, far in advance of need, will ensure the selection of the least obtrusive route for transmission corridors. Associated costs to establish these right-of-ways should be treated as current period costs despite the future-use nature of these assets. Examples of the types of costs that would be included in current period costs are: EA study costs including landowner consultation; First Nation consultation costs including capacity funding; preliminary engineering and design costs including soil and other geotechnical studies; and costs of acquiring property rights. Including these as current period costs will help ensure that right-of-ways are established at the proper time and at a lower overall cost and may also reduce the need to expropriate.

The changes required to implement Hydro One's planning recommendations should be straightforward and implemented in the near term. A working team comprised of individuals from the OPA, 2 or 3 distributors who have recently participated in the OPA's regional planning process and Hydro One could put forward specific changes to the TSC that could be implemented in 2012.

Performance and Incentives

- Changes to performance and incentives will require further thought and consultation. Implemented metrics should drive appropriate behaviour.

It is important for the Renewed Regulatory Framework initiative to take sufficient time to consider options for performance and incentives. Any performance metrics and resulting incentives should drive the appropriate behaviour. A key input to this effort is an understanding of what customers want. If it is unclear what customers want, it is premature to establish a system that would reward distributors for exceeding the current customer service standards.

In the interim, Hydro One supports the approach to performance used by Waterloo North. Mr. Gatien alluded to the use of balanced scorecards during the Renewed Regulatory Framework for Electricity Stakeholder Conference on March 29, 2012 at page 206 of the transcript. When considering performance and incentives, the Renewed Regulatory Framework work should be informed by the fact

that a number of distributors already have balanced scorecards in place that help to drive year over year improvements.

There was also considerable discussion about total bill increases and the need for the OEB to mitigate these increases. Distributors should not be asked to offset bill increases that are not under their control.

Hydro One would also like to make the following points that are specific to Hydro One Remote Communities:

- Capital expansions are quite different for Hydro One Remote Communities because expansions are funded by government.
- Any community expansion has different requirements and different timeframes and therefore multiyear planning is more difficult for Hydro One Remote Communities.
- There are different performance metric considerations for Hydro One Remote Communities. For example, reliability requirements must take into account the fact that remote communities are not grid connected.
- When the OEB changes processes for distributors they should exempt Hydro One Remotes where appropriate.

Hydro One appreciates the opportunity to provide comments on the Renewed Regulatory Framework and looks forward to ongoing participation in this important initiative.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Appendix A – “Typical” Capital Funding under IRM

IRM & ICM Capital Module Parameters for Hydro One

		2012	2013	2014
	Inflation (GDP-IPI)	1.7%	2.0%	2.0%
	Productivity Factor	0.72%	0.72%	0.72%
	Stretch Factor	0.40%	0.40%	0.40%
PCI	Allowed IRM Increase	0.58%	0.88%	0.88%
g	Load Growth (per ICM Formula)	0.9%	0.9%	0.9%
IRM=g+PCI*(1+g)	Combined PCI and Load Growth (per ICM formula)	1.49%	1.79%	1.79%

IRM Approved Revenue Increase Approach

This approach determines the growth in Revenue (net of increased OM&A costs) approved under the IRM model and calculates the amount of Rate Base that this additional revenue funds, which is then compared to the “typical” annual CapEx requirements as approved by the Board in the last cost-of-service application to establish the unfunded Rate Base under IRM.

		COS 2011	IRM Period		2014
		2012	2013		
A	"Typical" CapEx approved in 2011 and assumed during IRM period	438	445	452	461
B	Approved Revenue Requirement	1149			
C	Approved OM&A	525			
D	Approved Depreciation	284			
E=B*(1+IRM)	Implicit Revenue generated by IRM = prior year Revenue increased to reflect combined PCI and load growth increases		1166	1187	1208
F=C*(1+IRM)	Implicit OM&A generated by IRM = prior year OM&A increased to reflect combined PCI and load growth increases		533	542	552
G=E-B	Growth in Revenue		17	21	21
H=F-C	Growth in OM&A		8	10	10
I=G-H	Growth in Revenue available to fund increase in rate base		9.3	11.3	11.5
J = solve so I=K	Growth in Rate Base funded by available growth in Revenue		89	109	110.5
	Depreciation (rate base @ 3.10%)		2.8	3.4	3.4
	Cost of Debt (60% of rate base @ 5.02%)		2.7	3.3	3.3
	Cost of Equity (40% of rate base @ 9.12%)		3.2	4.0	4.0
	Income Tax (ROE @ 17.7%)		0.6	0.7	0.7
K =	Total Revenue Requirement associated with growth in Rate Base		9.3	11.3	11.5
	Rate Base Impacts:				
L	Rate Base impact of approved "typical" CapEx ¹		441	448	456
M	Less decrease in Rate Base due to Depreciation		-284	-286	-290
N=J	Less growth in Rate Base funded by growth in Revenue		-89	-109	-111
O=L+M+J	Unfunded growth in Rate Base driven by "typical" CapEx		69	53	56
	Cumulative annual unfunded growth in rate base		69	122	178
	Unfunded growth in rate base over IRM period				368
P	Lost Revenue associated with unfunded growth in Rate Base²		8	6	6
	Cumulative annual lost revenue		8	14	20
	Lost Revenue over IRM period				41

Note 1: Rate Base impact equals 1/2 of CapEx in prior year plus 1/2 of CapEx in the current year. All CapEx assumed to go in-service in the year which it occurs.

Note 2: Lost revenue is calculated in the same manner as "Total Revenue Requirement associated with growth in Rate Base" above.

Appendix A – “Typical” Capital Funding under IRM

This approach determines the growth in approved Revenue available under the IRM model and calculates the amount of Rate Base that this additional revenue funds. The total Rate Base funded under the IRM model is then compared to the "typical" annual CapEx requirements as approved by the Board in the last cost-of-service application to establish the unfunded increase in Rate Base under IRM.

This approach uses a number of inputs established by the Board’s 3rd Generation IRM model. These include the following:

- PCI = Inflation – Productivity – Stretch Factor. For Hydro One the PCI values are 0.58% for 2012 and 0.88% for 2013.
- Load Growth (g) determined per the ICM module as the % revenue change from load growth. For Hydro One, this was calculated to be 0.9% in 2012 based on comparing the 2010 actual revenues adjusted for 2011 approved rates and the 2011 Board-approved revenue requirement.
- The combined PCI and Load Growth determined per the ICM formula as “ $g + PCI \cdot (1+g)$ ” (referred to as “IRM” growth below). For Hydro One this equals 1.49% in 2012 and 1.79% in 2013

The starting point for the analysis is the Revenue Requirement components approved in the most recent cost-of-service application. This includes the 2011 Board approved values (as per the Rate Order under EB-2009-0096) for the following:

- Revenue Requirement
- OM&A
- Depreciation
- Approved “typical” CapEx. For Hydro One, this is the proposed CapEx amount of \$577M less the Board directed reduction to CapEx of \$43M less all CapEx associated with Renewable Generation of \$34M and less Smart Grid investments of \$62M.

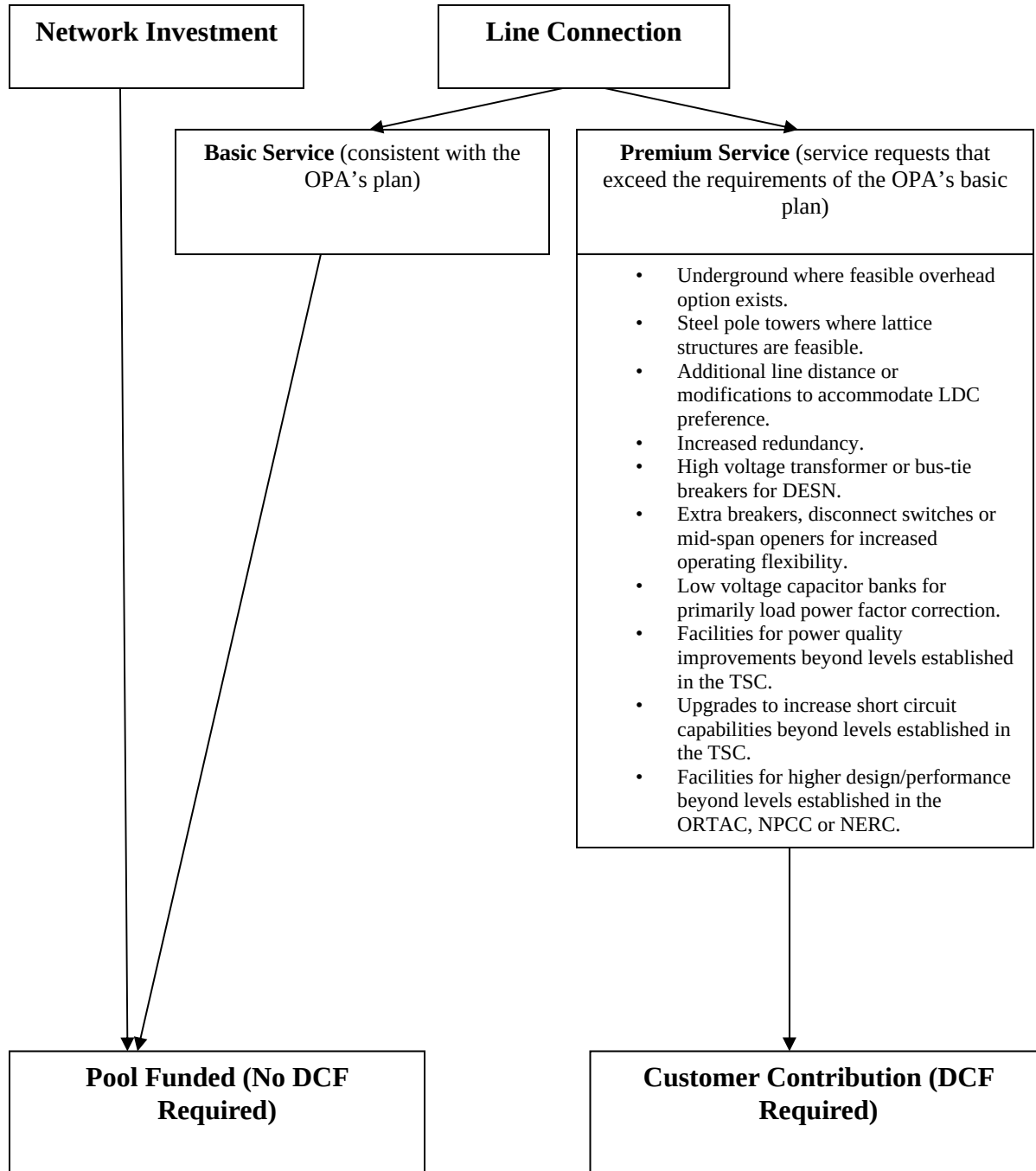
The methodology consists of the following steps:

1. Calculate the increased revenue generated under IRM.
 - $\text{Rev Req} \cdot (1 + \text{IRM Growth})$
2. Calculate the increased OM&A funded under IRM.
 - $\text{OM\&A} \cdot (1 + \text{IRM Growth})$
3. Calculate the difference between growth in Revenue and growth in OM&A. This additional revenue is assumed to be available for funding growth in Rate Base.
4. Calculate the growth in Rate Base funded by the increased revenue generated by the IRM model. This is done using an iterative approach that calculates the following revenue requirement components associated with a change in rate base:
 - Depreciation (average 2012 depreciation rate for all Hydro One Distribution assets)

Appendix A – “Typical” Capital Funding under IRM

- Cost of Debt (Hydro One’s 2012 long term debt rate and the Board’s 2012 short term debt rate)
 - Cost of Equity (Board’s 2012 specified ROE)
 - Income tax (used income tax as proportion of cost of equity calculated from 2011 Distribution Rate Order)
5. Determine the Rate Base impacts of the typical CapEx level approved by the Board in the last COS application.
 - Currently approved typical CapEx amount is escalated by the combined PCI and Load Growth used in the ICM module
 - Rate Base impact in the current year equals $\frac{1}{2}$ of prior’s CapEx + $\frac{1}{2}$ of the current year CapEx.
 6. Calculate the unfunded growth in rate base as:
 - Growth in Rate Base due to approved typical CapEx levels **less** growth funded by depreciation **less** growth funded by increased revenues generated under IRM.
 7. Calculate the lost revenues associated with the unfunded growth in Rate Base (calculated in the same manner as in Step 4 above).

Appendix B – Pool Funding for Basic Service



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

List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 2

a) Page 5 Table 1 Calculation of 2013 ICM Revenue Requirement - Please provide the calculations for the in-service addition amounts shown on the Table.

Response

The calculation to support the in-service amount for Typical capital is provided on Page 4 of Exhibit B, Tab 1, Schedule 1.

Determination of the in-service amounts for the Escalated and non-Typical capital amounts are described throughout Exhibit B, Tab 2.

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

List 1

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 2

- a) Page 1 - Please map the failure rates for HONI's distributing and regulating station facilities from 2008 to 2012.
- b) Page 1 – HONI indicates if the current capital reinvestment for distribution stations is not significantly increased, the volume of station assets that are beyond their expected service life will become unmanageable over a period of time. What is the impact if this work is delayed to HONI's next COS application?
- c) Page 2 - Please provide the scope of the updated asset information project.
- d) Page 2 – Please describe the new Asset Analytic tools referred to by HONI and the application of this information in this 2013 IRM application.
- e) Page 3 Table 1 – Please add columns to the Table for 2008 Board Approved, 2008 Actual, 2011 actual, 2012 Bridge and 2012 Year to Date (YTD).
- f) Page 4 – Please explain how the iMDS will have increased capabilities to deliver the growing Sustaining capital program in 2013 and beyond.
- g) Page 4 - Please provide the expected reduced maintenance costs resulting from the station refurbishment program in 2013.
- h) Page 6 – Please discuss how HONI's resources would manage an increase in the existing replacement rate of 4 stations per year to 32 stations per year.
- i) Page 8 - Please provide information on the demographics of the 110 station structures (11%) that are in a condition that puts them at risk of failure.
- j) Page 13 – Please provide HONI's definition of "fair", "poor" and "very poor" condition categories and the timeframe for replacement for each category. Please provide a condition chart similar to Figure 13 on Page 22 for station structures.
- k) Please provide HONI's reliability statistics for the past three historical years.

- l) Please provide a breakdown of the key causes of outages for the past three historical years.
- m) Page 12 – Please provide the failure trend for transformer stations and transformer component failures from 2008 to 2011.
- n) Page 15 – Please provide the cost of commissioning the iMDS by an external vendor.
- o) Page 26 - Please provide a detailed breakdown of the projects and associated costs that make up the proposed \$29 million in spending. Please confirm the proposed in-service dates by project and segregate the projects between discretionary and non-discretionary.
- p) Page 27 – Please provide the calculation of the expected reduction in OM&A expenditures over the next 10 years due to ongoing increased capital funding starting in 2013.
- q) Page 27 – Please provide the calculation of the \$13.3 million to purchase operating spare transformers.
- r) Page 27 - Please a breakdown of the costs that make up the \$7 million expenditure associated with planned and demand driven transformer replacements.
- s) Page 27 – If the \$20.3 million in funding is denied, please provide the calculation for the increase in OM&A.

Response

- a) The number of station failures from 2008 to 2012 are outlined in the table below:

	2008	2009	2010	2011	2012 YTD
Station Failures	22	27	19	27	15

- b) Refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2, part b).
- c) Refer to Exhibit I, Tab 2, Schedule 2.11 Staff 12, part d).
- d) Refer to Exhibit I, Tab 2, Schedule 2.11 Staff 12, part d)

e) The additional capital expenditure details requested are provided in the table below:

Description	2008	2008	2009	2010	2011	2011	2012	2012	2013
	Board Approved	Actual	Actual	Actual	Board Approved	Actual	Forecast	YTD Actual	Proposed
Station Refurbishments	2.5	1.3	2.8	2.7	3.2	2.3	7.0	2.2	29.0
Transformer Spares and Replacements	3.5	2.8	1.0	3.9	4.1	8.7	5.1	1.4	20.3
MUS Reinvestment	1.5	1.0	1.5	1.0	2.8	3.4	2.9	0.2	3.2
Other Station Component Replacements and Demand Programs	2.8	7.4	9.9	6.1	5.2	6.7	4.8	2.6	5.4
Total	10.3	12.5	15.2	13.7	15.3	21.1	19.8	12.0	57.9

f) The iMDS will be an engineered solution provided by an external vendor. Design and prefabrication will occur at the vendor's facility and will be delivered to the Hydro One station ready for connection. Therefore, construction and field-commissioning times are expected to be significantly reduced from past practices, helping deliver on the growing work program. Both of these factors will assist in increasing productivity of Hydro One's work program.

g) Refer to Exhibit I, Tab 2, Schedule 5.12 VECC 15, part b).

h) The increased volume of Station Refurbishments will be accomplished through a combination of the prefabricated iMDS solution, and accelerated application of available design standards utilizing both internal and external engineering resources.

i) The age demographics for the structure types identified as Poor and Very Poor are outlined in the following table:

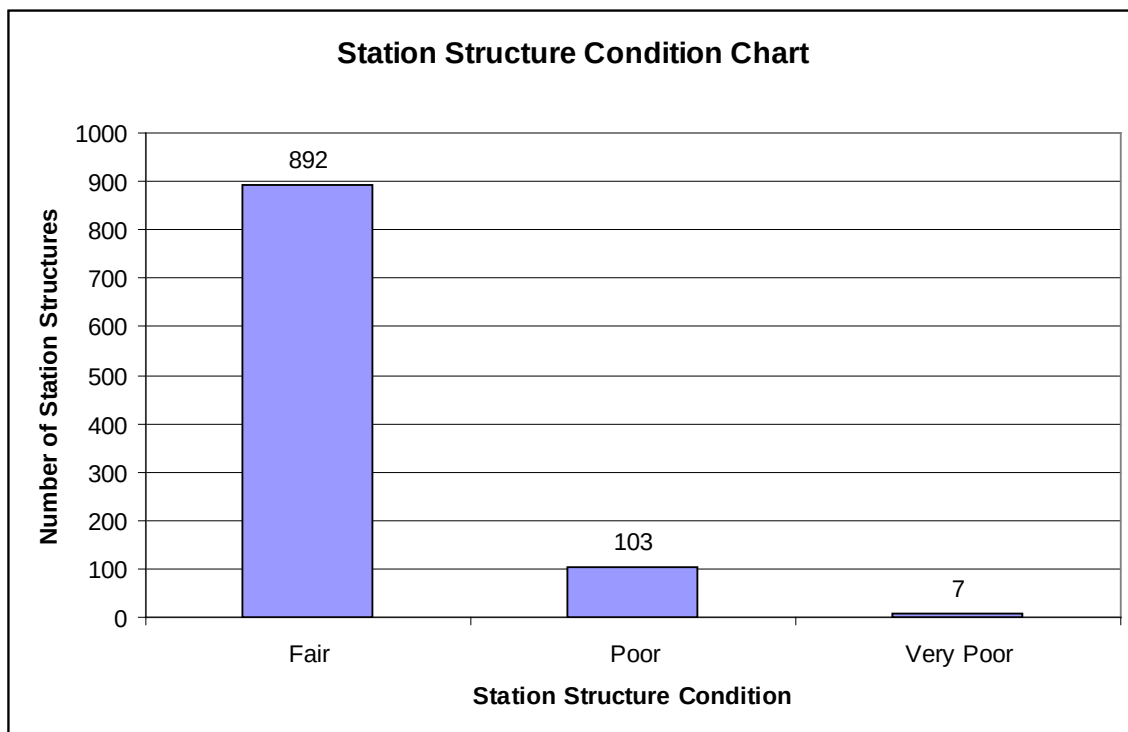
Structure Type	Number of Very Poor or Poor Condition Structures	Average Age of Population
Lattice Type	47	49
Wood Type	30	46
Pipe Type	14	59
Uniform 70	14	38
Uniform 85	5	33
Uniform 90	0	0

j) Assets in “Very Poor” condition are high risk and require replacement, refurbishment or other remedial action at earliest opportunity to correct significant deterioration.

Assets in “Poor” condition are high risk and will require replacement, refurbishment or other remedial action within the next 5 years to correct significant deterioration.

Assets in “Fair” condition have experienced noticeable deterioration but should survive another 5 years with regular maintenance, and future work will be based on subsequent risk assessments.

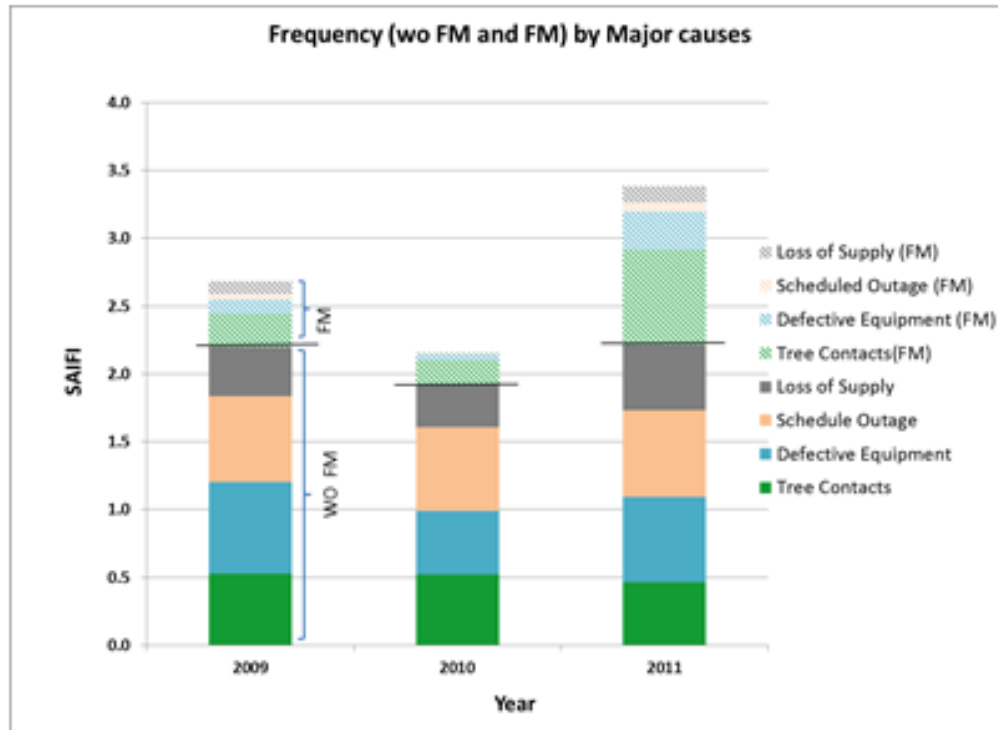
The chart of distribution station structure condition is provided below:



k) Refer to Exhibit I, Tab 2, Schedule 5.14 VECC 17, part c).

l) The following charts show the breakdown of the key causes for distribution outages and their contribution to SAIFI, both including and excluding *Force Majeure** events.

Frequency (wo FM and FM) by Major Causes



* *Force Majeure: Hydro One Distribution deems a force majeure to have occurred when 10% or more of Hydro One customers have been interrupted by an event. An event may be a storm (usually the case), the August 14, 2003 blackout or any other problems that interrupt 10% or more customers and cause a change in the normal restoration business processes.*

- m) Please refer to Exhibit I, Tab 2, Schedule 8.19 SEC 19
- n) For clarification, the iMDS will be designed, manufactured and assembled by an external vendor. The external vendor will also conduct Factory Acceptance Testing prior to delivery to Hydro One. Hydro One staff will conduct all on-site commissioning checks of the iMDS. The iMDS pilot project is currently underway, and detailed costs, are not yet not known.
- o) A detailed summary of the 32 Station Refurbishments and associated planned costs are outlined in Exhibit I, Tab 2, Schedule 1.11 Staff 12, part g). All projects are planned for 2013 in-service and are all non-discretionary as per Exhibit I, Tab 2, Schedule 1.01 Staff 2.
- p) Refer to Exhibit I, Tab 2, Schedule 8.24 SEC 24.

q) Refer to Exhibit I, Tab 2, Schedule 1.14 Staff 15.

r) The \$7.0 million is a combination of the purchase of six transformers for planned replacements, and six transformers for demand replacements, at an assumed average cost of \$0.6 million per unit.

s) If the \$20.3 million for the purchase of operating spares and transformer replacements were denied in its entirety, the approximated increase in 2013 OM&A for planned work would be \$3.5 million as outlined below:

	OM&A with Approval of \$20.3M Capex	OM&A without Approval of \$20.3M Capex	Difference
23 spare transformers require refurb instead of purchase new to address gaps in spare complement	-	\$3,450,000	\$3,450,000
12 aged transformers not replaced with new	\$48,000	\$114,000	\$66,000
			\$3,516,000

In addition to these costs there would also be an increase in O&MA costs due to increased transformer failures, trouble calls, etc resulting from relying on transformers with deteriorating condition and aging demographics.

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

Issue 2 Should the proposed capital projects be approved for ICM treatment?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 3

- a) Page 1 – Please provide the analysis and calculation to arrive at a proposed pole replacement rate of 11,000 in 2013.
- b) Page 1 – Please provide data on the number of wood pole related outages from 2008 to 2012.
- c) Page 2 – Please explain why a subset of poles were not treated to CSA standards.
- d) Page 2 – Please indicate the number subset poles not treated to CSA standards that are included in the pole replacement program for 2013 and provide the associated cost.
- e) Page 2 – Please provide a breakdown of the 13,000 poles installed annually between replaced and newly installed.
- f) Page 3 – Please confirm the number of poles less than 62 years of age and the number of poles greater than 62 years of age.
- g) Page 7 - Please provide a wood pole condition chart similar to Figure 13 on Page 22 to show the number of wood poles in “fair”, “poor” or “very poor” condition.
- h) Page 9 Table 1 – Please add 2008 Board approved, 2008 actual, 2011 actual, 2012 Bridge and 2012 Year To Date (YTD) to Table 1.
- i) Page 10 – HONI indicates each scenario prioritizes the replacement of the subset of poles that were not treated to CSA standard and are deteriorating prematurely. Please provide HONI’s assumption of the number of subset poles to be replaced annually under each scenario.
- j) Page 10 – Did HONI assess a scenario that focuses primarily on the replacement of subset poles to accelerate the replacement timeframe to less than 10 years? If yes, please discuss. If no, please explain.
- k) Page 12 – Please summarize the current risk level referred to at lines 22-24.

- 1
2 l) Please discuss the impact if the current replacement rate of 7,200 poles per year in the
3 Wood Pole Replacement program is not increased until HONI's next COS
4 application.
5
6 m) Page 14 – Please discuss how HONI's resources would manage an increase in the
7 pole replacement rate from 7,200 per year to 11,000 per year.
8
9 n) Please describe the actions HONI will take in the event that the Board does not
10 approve the proposed increase in the wood pole replacement program.
11

12 **Response**
13

- 14 a) The volume of 11,000 is being proposed as a transitional increase.
15
16 b) The number of unplanned wood pole related outages from 2008 to 2012 is provided
17 in the table below:
18

Year	Number of Outages
2008	606
2009	526
2010	558
2011	712
2012 YTD	313

- 19
20 c) Please reference the EDM report in Exhibit B, Tab 2, Schedule 3, Attachment 1 for a
21 detailed assessment on the subset in question.
22
23 d) In 2013, of the 11,000 poles planned for replacement, Hydro One plans to replace a
24 minimum of 2,000 red pine poles that were not treated according to CSA standards.
25 The cost associated with these poles is approximately \$15M.
26
27 e) Approximately 5000 poles are newly introduced into the system per year. This
28 represents approximately 0.3% growth per annum and may be higher or lower based
29 on the economic context.
30
31 f) The volumes of poles less than 62 years and greater than (or equal to) 62 years old are
32 provided below.
33

Age	Volume of Wood Poles
Less than 62	1,530,000
Greater than or equal to 62	170,000

1 g) Please refer to Exhibit I, Tab 2, Schedule 6.12 PWU 13.

2
3 h) The additional capital expenditure details requested are provided in the table below:

4

Year	(\$M)
2008 Board Approved	39.8
2008 Actual	43.0
2009 Actual	50.9
2010 Actual	53.6
2011 Board Approved	58.9
2011 Actual	54.8
2012 Forecast	52.8
2012 YTD Spent	42.8
2013 Proposed	81.8

5
6 i) For illustration purposes, a constant volume of 3,500 poles was assumed for each
7 scenario.

8
9 j) Hydro One did assess a compressed timeline for the removal of the subset of red pine
10 poles from the system but given the aging demographic and the condition of the wood
11 pole population as a whole, Hydro One did not pursue this scenario.

12
13 k) Under Scenario 3, the current level of risk refers to replacing wood poles at a rate that
14 does not allow the number of EOL poles to increase.

15
16 l) The impact is a higher likelihood of pole failures resulting in decreased customer
17 reliability and increased safety risks.

18
19 m) Please refer to Exhibit I, Tab 2, Schedule 1.09 Staff 10, part g).

20
21 n) Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2, part b).

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

Issue 3 Is Hydro One's proposal with respect to the capital contribution allocated to Hydro One Transmission appropriate?

Interrogatory

Ref: Exhibit B/Tab2/Sch1/page2

- a) At line 13 it is stated that the cost of the Commerce Way TS is not being shared equally, although the capacity is split 50-50. Please provide a detailed explanation and the detailed calculation.
- b) Please indicate if this cost sharing is the same as was submitted for the Board's consideration in the Leave to Construct application (EB-2009-0079), and the reasons why the Board should allow this amount if it is different.

Response

- a) The 50/50 split on the capacity between Woodstock Hydro and Hydro One Distribution is based on the forecast usage provided by each LDC during a 25 year revenue horizon. Woodstock Hydro forecasts that it will be using more capacity than Hydro One Distribution during the initial period since its growth rate is higher for the first few years and then decreases to nearly zero as its service territory is expected to be fully built out by then. Hydro One Distribution's forecast growth rate is lower but consistent throughout the planning horizon. The up-front high growth of Woodstock Hydro's load at a lower discount rate generates more revenue which is used to offset the costs it incurs, resulting in lower capital contribution.

Please see the discount cash flow model in Attachment 1 for detailed calculation.

- b) The cost sharing methodology is consistent with what was submitted in EB-2009-0079. The \$9.2 million is calculated based on the revised discount cash flow calculation which reflects the updated project costs estimated by Hydro One Transmission.

Energy Probe (EP) INTERROGATORY #14 List 1

Issue 3 Is Hydro One's proposal with respect to the capital contribution allocated to Hydro One Transmission appropriate?

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 1, Pages 1 - 2

- a) Please provide the economic evaluation referred to in Line 10 on Page 2 that underlies the \$9.2 M capital contribution required of Hydro One Distribution for Commerce Way TS.
- b) Please provide the load forecast of Hydro One Distribution for using its 50% share of the capacity of Commerce Way TS if it is not apparent in the economic evaluation referred to above.

Response

- a) Please refer to Exhibit I, Tab 3, Schedule 1.01 Staff 16, part a, Attachment 1.
- b) The load forecast of Hydro One Distribution can be found in the economic evaluation referred to above.

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

**Issue 3 Is Hydro One's proposal with respect to the capital contribution
allocated to Hydro One Transmission appropriate?**

Interrogatory

Reference: Exhibit B, Tab 2, Schedule 1, pages 1 – 2

- a) Was Woodstock Hydro permitted to recover all of its \$4.4 M capital contribution to HON Transmission through the ICM module? If not, why not?

Response

- a) In its Decision and Order in EB-2011-0207, dated March 22, 2012, the Board granted approval for Woodstock Hydro's proposal to recover, through an ICM, the incremental capital costs of \$4,427,330 associated with a \$4.1 million capital contribution to Hydro One Networks Inc. for the Commerce Way Transmission Station and \$327,330 to purchase and install Woodstock owned wholesale metering assets for the Commerce Way TS.

Hydro One cannot provide further comment on Woodstock Hydro's application.

Consumers Council of Canada (CCC) INTERROGATORY #11 List 1

Issue 3 Is Hydro One's proposal with respect to the capital contribution allocated to Hydro One Transmission appropriate?

Interrogatory

EX. B/T2/S1/P. 2

What is the current status of the Commerce Way TS? Under a cost of service approach, how would this capital contribution be treated? How was the \$9.2 million contribution established?

Response

The Commerce Way TS project is currently in the construction phase.

Under a cost of service approach, Hydro One would apply to recover this capital contribution as part of its development capital expenditure in 2013.

The \$9.2 million was established by conducting an economic evaluation. Please refer to Exhibit I, Tab 3, Schedule 1.01 Staff 16, part a, Attachment 1.

School Energy Coalition (SEC) INTERROGATORY #29 List 1

**Issue 3 Is Hydro One's proposal with respect to the capital contribution
allocated to Hydro One Transmission appropriate?**

Interrogatory

[B/2/1/p. 2] Please provide the full detailed calculation that shows why, with a 50/50 split of available capacity, Hydro One expects to contribute \$9.2 million while Woodstock Hydro only contributed \$4.4 million?

Response

Please refer to Exhibit I, Tab 3, Schedule 1.01 Staff 16, part a, Attachment 1.

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref:

- 1) Exhibit B/Tab3/Sch1/page 5
- 2) Exhibit B/Tab1/Sch1/page 4/Table 1
- 3) Exhibit B/Tab1/Sch1/page 8/Table 2
- 4) Exhibit B/Tab1/Sch1/page 8/line 10

In reference 1, Table 1 indicates a total of \$179.8 million for CIS projects, and Table 2 on the same page indicates \$155.4 million for Total in-service for CIS in 2013. Please explain how these numbers can be reconciled.

The table in Reference 2 shows an amount of \$414 million for Typical Capital in 2013 whereas the table in Reference 3 shows an amount of \$ 451.9 million for 2013 and the text in reference 4 shows \$414 million. Please explain how these numbers can be reconciled.

Response

Table 1 on Page 5 in Exhibit B, Tab 3, Schedule 1 includes all forecast CIS project costs including capital and OM&A. Table 2 on the same page includes only the forecast capital expenditures. The difference between the tables represents the forecast OM&A that will be spent on the project.

Table 1 on Page 4 in Exhibit B, Tab 1, Schedule 1 displays the forecast in-service addition for 2013 of \$414M. Table 2 on Page 8 of the same exhibit displays the forecast capital spending for 2013 of \$451.9M. Differences between the forecast in-service addition and the actual capital spending arise due primarily to multi-year projects wherein spending takes place in years building up to a final in-service amount.

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B/Tab3/Sch1/pages 2-3

Hydro One indicates that its current CIS system, installed in 1998, is now at end of life. Can Hydro One provide examples of CIS systems for similar distributors in Ontario or other jurisdictions and compare their CIS systems in terms of costs and end of life considerations?

Response

Hydro One's current CIS (Customer/1) was purchased from Andersen Consulting, now doing business as Accenture. Accenture no longer develops or supports the Customer/1 application. In contrast to modern, vendor-supported applications like SAP, Customer/1 is not configurable software. Any required changes are therefore custom modifications to the software programs that make up Customer/1, and are made at Hydro One's expense and risk. In addition, Customer/1 requires mainframe hardware which is itself costly to maintain and operate.

Based on the information gathered from the public record, among the larger Ontario electric utilities, Toronto Hydro, Enersource, Hydro Ottawa, London Hydro, EnWin and Powerstream have all recently replaced or are replacing their CIS systems, indicating similar concerns with attempting to fulfill Ontario distributor business requirements based on their legacy CIS systems. The legacy CIS systems that they replaced mostly date from the late 1990s or later. Similarly, Enbridge Gas Distribution replaced their legacy CIS systems with SAP in 2009. The legacy CIS system was implemented in the late 1990s. See the table below for a summary.

In other Canadian jurisdictions, BC Hydro, Fortis BC, Hydro Quebec and SaskPower have all either moved or are moving to an SAP-based CIS in the last 10 years.

1

Utility & Rank in Ontario by # customers (for Electric Utilities)	Date of implementation of legacy CIS	Current CIS Status
Toronto Hydro (2)	SCT Banner implemented 1999/2000	SCT Banner was replaced in 2011 with Oracle CC&B
Hydro Ottawa (4)	CIS Replacement in 2004 (Advanced Utility Systems to SPL)	CIS Upgrade from SPL to CC&B is underway with a planned in-service date of Q4 2013
Enersource (6)	Legacy CIS implemented 1999	Legacy CIS replaced with Oracle CC&B in 2009
London Hydro (7)	CIS Ontario implemented in 2000/2001	SAP implementation 2008/2009
EnWin (10)	SPL system implemented in 2004.	Currently planning to replace
Enbridge Gas Distribution (n/a)	Legacy CIS implemented in 1998/99	Legacy CIS replaced with SAP in 2009

2

3 With respect to costs, it is generally difficult to compare Hydro One's CIS costs with
4 other Ontario utilities using publicly available information. However, for Enbridge's CIS
5 replacement the costs were filed in a template in EB-2011-0226 Exhibit A, Tab 2,
6 Schedule 1 in a form which Hydro One followed in this filing, so the costs can be
7 compared. Per EB-2011-0226 Exhibit N1, Tab 1, Schedule 1 EGD's capital cost of the
8 CIS project was \$118.7M, which was subsequently updated to \$127.2M. Hydro One's
9 capital cost is \$155.4M.

10

11 With respect to the capital costs of EGD's CIS project compared to Hydro One's CIS
12 project, there are significant differences in the requirements of an Ontario electric
13 distribution utility compared to a gas utility, for example, requirements to:

14

- 15 • interact with the IESO's meter data management repository for smart metered
16 customers who are on TOU pricing
- 17 • process time of use meter data and calculate interval bills and TOU bills
- 18 • process the EBTs associated with the interactions with Retailers.

19

20 On a per customer basis EGD's costs are lower given the considerably larger customer
21 base at EGD. Hydro One believes that once a CIS project reaches this magnitude and
22 complexity, the number of customers served is not a significant driver of the overall
23 project cost. The differences between the capital costs of the two projects can be
24 explained by the increased complexity associated with the requirements associated with
25 Ontario electric utilities related to Smart Metering, TOU pricing, and open market
26 interactions via EBTs.

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B/Tab3/Sch1/page 9

Hydro One indicates that bill presentment includes bill messages and bill inserts. How will bill presentment be improved with the new system and what additional capability will be added?

Response

The look and feel of customer's invoices will remain largely unchanged from what they see today. Many of the changes related to the new solution are internal to Hydro One. In the new CIS system, Hydro One will be leveraging software provided by OpenText (formerly StreamServe) for document presentment and management. In the new solution, agents and customers will be able to view PDF versions of invoices. Currently agents are only able to view 2 months of historical bill images and customers are not able to view any bill images within the Hydro One website (eCustomer). There are approximately 100,000 monthly visits to our eCustomer site and there is an increased desire for customers to view their consumption and billing history electronically. This new capability will be a contributor to further improving first call resolution and improved customer satisfaction.

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B/Tab3/Sch1/page 16

Hydro One indicates that it continues to explore opportunities with other Ontario LDCs to look for project cost savings but has insufficient information to quantify the amount of the potential savings. Please provide more detail on these opportunities: What is the progress so far on this initiative? How many LDCs have been approached or have shown interest in the new system? Please provide an estimate of the potential savings or provide a range.

Response

Hydro One and EnWin discussed the possibility of EnWin leveraging Hydro One's CIS implementation or a portion of the development deliverables for its CIS replacement, given that EnWin was considering an SAP-based CIS implementation. The two utilities met on a number of occasions to compare requirements, to consider which aspects of Hydro One's implementation could be leveraged by EnWin, and to discuss cost sharing mechanisms. These discussions concluded with EnWin determining that their needs were better served by approaching their CIS requirements differently, and have subsequently decided to pursue other vendors' CIS software solutions.

Hydro One leveraged the experience of London Hydro's SAP and Itron CIS installation to provide cost effective knowledge transfer and implementation experience. Hydro One has worked with London Hydro to provide resources for expert advisors to assist with testing of the CIS system with the IESO systems and interfaces. London Hydro is the only utility in the Ontario Energy Market that has installed an SAP & Itron based system with interfaces to the IESO similar to those being installed at Hydro One. The estimated saving associated with this partnership is approximately \$180,000, when compared to the estimated cost of completing this work with our outsourcing provider.

Hydro One has also signed a Memorandum of Understanding (MOU) with London Hydro. The objective of the MOU is to formalize ongoing collaboration efforts between the two organizations to reduce project development, testing, training and on-going operational costs associated with the common systems. The collaboration efforts will minimize risks to achieve project timelines, influence vendors and improve the quality of solutions. Collaboration may further help in influencing major project vendors such as SAP & Itron in developing meaningful and reasonable product changes in their core solutions/offerings.

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B/Tab3/Sch1/page 19

Hydro One indicates that due to the complexity of the CIS project, it expects to use the project contingency funds. What were the primary reasons that contingency funds were required? Please provide a table that summarizes the use of the contingency funds by major category.

Response

As the project entered the realization phase of the project, the complexity in certain areas was greater than anticipated. As a result, additional resources were required to help complete the design and build of the system. As the build increased in complexity, other aspects of the project such as data conversion and testing were subject to corresponding increases in resources as required. Specifically:

- The meter data acquisition area of the solution saw a significant increase in complexity based on the requirement to interface with the provincial MDM/R and with HONI's existing Smart Meter Infrastructure. As the detailed solution design associated with these requirements was developed, there was more than a one hundred percent increase in the number of developments required for this aspect of the solution.
- Similarly, the complexity of the solution associated with processing Ontario Electronic Business Transactions increased. In this area the solution requires integrating a new piece of SAP's CIS solution with Hydro One's existing applications. In this area there was an overall fifty percent increase in the number of developments required.
- Other areas of increases included complex billing and settlements, where Hydro One has unique requirements associated with its role as both a transmitter and distributor in Ontario.

The additional complexity in these areas impacted the various project development phases spanning system and interface design, build, test, data conversion, and final preparation. Taken together, the items detailed above have resulted in the in-service date of the project being shifted from Q1 2013 to Q2 2013. The table below shows the breakdown of spend by the above categories.

1 Table 1: CIS Project Costs (Contingency Spend by Category)

Item	Meter Data Acquisition/Meter Device Management	Ontario Deregulation	Other	TOTAL (\$M)
Implementation Effort (discovery, labour/services, commissioning and other support)	\$17.2	\$5.2	\$3.1	\$25.50

2

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B/Tab1/Sch2/page 5

In this table, Hydro One shows a CCA adjustment of \$77.7 million for the CIS project. Please provide further detail on how this adjustment was determined.

Response

In-service additions for CIS for the 2013 ICM Revenue Requirement are forecast to be \$155.4M. Expenditures of this type fall within Class 12 for the purpose of Capital Cost Allowance (CCA). Class 12 expenditures allow for a 100% income tax deduction subject to a 50% inclusion rate on first year expenses. Therefore \$77.7M was deferred to the following year for CCA purposes.

Energy Probe (EP) INTERROGATORY #15 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B, Tab 3, Schedule 1, Pages 5 -7 and Tables 1& 2 Updated

- a) Please provide the total costs (2013) to perform the annual customer meter reading and billing functions on a total cost and per customer basis:
 - i. Under the Legacy CIS and
 - ii. New CIS
- b) Please provide the annual (2013) Costs of Service Order and Work Management:
 - i. Under the legacy CIS and
 - ii. New CIS
- c) Please Provide forecast Credit and Collections Costs (2013)
 - i. Under the legacy CIS
 - ii. Under the new CIS

Response

Hydro One Distribution does not track its costs in the break down requested.

Please refer to Exhibit I, Tab 4, Schedule 2.03 EP 17, part c) for breakdown of the CIS Business Benefits by year and by Line of Business.

Energy Probe (EP) INTERROGATORY #16 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B, Tab 3, Schedule 1, Table 3 Updated

- a) Please complete Rows 8 and 9 for the Legacy CIS
- b) Please explain why 2013 is now (Update) a year in which the legacy system and new CIS will run in series. What has changed since the original filing? Please explain in detail.
- c) Please fill in Line 7 for 2009-2012 and explain in detail the Calculation underling the numbers on Line 7. In particular explain the jump in 2015.
- d) Please undertake a levelized cost per customer calculation for the period 2013-2014. Explain in detail the assumptions used, delineate the differences in carrying costs and the overall coat to ratepayers on a "as spent" dollar and Net Present Value (NPV) basis.
- e) Assume another scenario under which CIS costs per customer escalate at CPI and compare the three scenarios by way of Active Excel Spreadsheet Format:
 - i. As filed
 - ii. Levelized Cost per customer
 - iii. Levelized Cost per customer inflated at CPI

Please list all assumptions
- f) Please compare the three scenarios on a total cost to ratepayers basis.
- g) Please compare the distribution rate impacts 2011-2014 for each class

Response

a)

Additional Detail for CIS Cost Template from Exhibit B, Tab 3, Schedule 1, Table 3					
Line #	Line Description	2009	2010	2011	2012
8	CIS Revenue Requirement	\$0.00	\$0.00	\$0.00	\$0.00
9	OEB Approved Revenue Requirement (\$M)	\$986	\$1,085	\$1,149	\$1,149

The Legacy CIS has been fully depreciated and there is no CIS revenue requirement from 2009 to 2012, Row 9 refers to the total Hydro One Networks Distribution revenue requirement as approved by the OEB.

b) At the time of the original filing of June 15th 2012, the project was anticipated to go into service at the beginning of 2013, but is now targeted for go live in the first half of 2013. As a result Hydro One will incur costs associated with the legacy CIS system for part of 2013, and for the new CIS for the remainder of 2013. For that reason, the table has been split for 2013 to show part year legacy CIS costs in rows 1-3 and part year new CIS costs in rows 4-6.

c) Line 7 depicts the revenue requirement of the CIS project which includes depreciation, the regulated rate of return on invested capital and the associated tax implications, in compliance with OEB methodology. The project expenditures in 2011 and 2012 represent the build phase of the CIS project which is not going into service until 2013. Return on rate base is only calculated when the asset is in-service and deemed used and useful, therefore the 2011 and 2012 cells have been left blank.

The large jump in 2015 is attributable to CRA tax treatment associated with application software (Class 12 CRA asset). Application software has a 100% capital cost allowance claim. Due to the half year rule, half of the 100% capital cost allowance is claimed in 2013 and the remaining half in 2014. The 2015 increase in revenue requirement is due mainly to the exhaustion of the tax credits claimed in 2013 and 2014.

d)

ITEM	2013	2014
CIS Revenue Requirement (\$M)	\$6.80	\$6.80
Total # of Customers (Estimated)	1,231,476	1,243,713
Average Cost per Customer	\$5.52	\$5.47
Levelized Average Cost per Customer	\$5.49	\$5.49

1 The CIS Revenue Requirement as shown in Exhibit B, Tab 3, Schedule 1, Table 3,
2 line 8 only recovers the incremental costs associated with Capital. The inputs into this
3 calculation are as follow:
4

	(\$M)	
In Service Addition	155.40	
Average Rate Base (no half year)	147.22	
Depreciation 10.5%	16.36	(155.4*10.5%)
Return on Debt (blended)	4.19	(147.22*60%*4.75%)
Return on Equity	5.39	(147.22*40%*9.16%)
Tax	<u>(19.15)</u>	
Total Incremental Revenue Requirement	6.80	

5
6
7

e)
Values If Costs Are Levelized on a per Customer Basis (CPI Adjusted*)

ITEM	2013	2014
i. Average Cost per Customer	\$5.52	\$5.47
ii. Levelized Average Cost per Customer	\$5.49	\$5.49
iii. Levelized Average Cost per Customer including CPI*	\$5.49	\$5.6

* 2013 CPI Estimated at 2.1%

8

9 f) The total cost to ratepayers would be the same under all three scenarios. The net
10 effect of what is being requested would be to delay receipt of a small portion of
11 Hydro One's 2013 revenue requirement, which would ultimately be funded in 2014.

12

13 g) Please see Attachment 2 of Exhibit I, Tab 17, Schedule 7.01 CCC27. 26% of the rate
14 impacts shown in the column "Impacts of Incremental Capital Rider" are associated
15 with the Customer Information System.

Energy Probe (EP) INTERROGATORY #17 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit B, Tab 3, Page 16 &
 Exhibit B, Tab 3, Schedule 1, Table 3 Updated-CIS Benefits

- a) Please expand on the details of the Benefits Realization Plan for the new CIS. If this is documented, please file a copy.
- b) Please list all areas of the Business that will benefit from the new CIS and provide short descriptions/examples of these.
- c) Please list by year and Functional Area the Quantitative Benefits that underlie the claimed benefit of \$172 million over seven years for the new CIS.
- d) Please quantify the benefit reductions that have been netted out from the net revenue requirement on Line 8 of the second reference.
- e) How will actual benefits be tracked and how will these, together with variances from Plan, be reported to the Board and Ratepayers? Please provide detailed proposal(s)

Response

a) and e)

Within the project methodology, financial benefits are identified up front as part of the discovery and business case process. Benefits are associated with the CIS requirements so that the relationship between the benefits and the system design is maintained throughout the project.

The benefits are validated with the applicable business leads in each Hydro One Line of Business, and reflected in applicable business plans and budgets. Hence the realization of these benefits is committed via reduction of the applicable budgets. During the Realization and Final Preparation phases of the project, benefits are further validated, benefits reporting is defined, and the actions required to ensure the benefits are realized are identified. These activities are ongoing, and result in for example, documented business process changes, updates to work instructions and updates to relevant training materials.

1 Once the project is live and CIS is in service, benefits will be tracked by Hydro One
2 staff. The Business Transformation Sub-Committee of Hydro One's Board of
3 Directors will receive regular updates on the benefits realized by the CIS Project, and
4 these benefits will be reported to the Board and ratepayers through Hydro One's cost
5 of service rate applications. Benefits will be further validated by Hydro One's
6 Internal Audit team.

- 7
8 b) The areas of the business that will benefit from the new CIS are Customer Care, IT,
9 Finance.

10
11 Customer Care

12 An integrated CIS which provides a more integrated view of the customer profile
13 with enhanced customer issue resolution capability will reduce handling time on calls
14 and correspondences, improve billing timeliness and accuracy, increase first call
15 resolution ("FCR") and improve customer satisfaction. In addition, the new CIS will
16 improve collections and hence reduce bad debt expense by improving HONI's ability
17 to track customers as they move within, or in and out of, HONI's service territory.
18 This is expected to lead to improved ability to collect on receivables associated with
19 premises that the customer has vacated.

20
21 Finally, the new CIS coupled with the Smart Meter network, will allow HONI to
22 disconnect and reconnect service to a meter remotely, without a field technician
23 making a visit to the property. This is expected to both reduce field support costs
24 related to collections and special investigations, and to reduce bad debt.

25
26 Finance

27 Benefits will be realized through reducing the time required to issue bills which will
28 result in cash flow savings. Accounting processes will also be streamlined in the new
29 CIS due to the integrated nature of CIS with the existing SAP ECC platform. Finally,
30 the new system will enable more accurate application of late payment charges to
31 overdue arrears, which is expected to increase late payment revenues.

32
33 IT

34 Benefits will be realized through operational and capital savings from the
35 decommissioning of the mainframe computer on which the current CIS system runs.
36 Rationalization of the hardware environment on which SAP runs will reduce
37 infrastructure management and support costs as well as facility costs and hardware
38 refresh. A common SAP platform for CIS enhances productivity in the area of
39 application maintenance support and enhancement work program across Hydro One
40 and Hydro One's outsourced service provider.

1 c) The business benefits by LOB are shown in the table below.

2

CIS Business Benefit Breakdown by LOB (\$M)								
Line of Business	2013	2014	2015	2016	2017	2018	2019	2020
Customer Service	\$2.3	\$5.5	\$9.3	\$9.5	\$9.5	\$9.5	\$9.5	\$1.9
IT	\$0.0	\$2.9	\$17.7	\$15.2	\$7.6	\$7.7	\$7.6	\$1.5
Finance	\$5.3	\$8.0	\$8.0	\$8.0	\$8.0	\$8.0	\$8.0	\$1.6
TOTAL	\$7.6	\$16.4	\$35.0	\$32.6	\$25.0	\$25.2	\$25.1	\$5.0
CIS Project OM&A costs	(\$13.6)							

3

4 Note that for 2013, there are CIS Project OM&A costs of \$13.6M which more than
5 offset the business benefits forecast to be realized in that year.

6

7 d) Over the period covered in the model, Hydro One has netted out \$239,717,209 of
8 benefits from Line 6 (CIS Project Costs) to derive Line 8 (CIS Revenue
9 Requirement).

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Reference: Exhibit B, Tab 3, Schedule 1, pages 3 - 4
EB-2009-0096, Exhibit D1, Tab 3, Schedule 7

- a) Please confirm that the CIS project is Phase 4 of HON's overall Cornerstone initiative.
- b) Please provide a schedule that sets out HON's distribution business' share of the annual Cornerstone capital spending for the years 2008 – 2011 (both approved and actual).
- c) Please clarify whether this spending (per response to part (b)) was included in the Typical Capital spending for 2008 – 2011 as shown in Table 2 of Exhibit B, Tab 1, Schedule 1, page 8. If it was, please explain why.

Response

a) Yes the CIS project is Phase 4 of Hydro One's Cornerstone initiative.

b)

	2008 Actual	2008 Approved	2009 Actual	2009 Approved	2010 Actual	2010 Approved	2011 Actual	2011 Approved
Minor Fixed Assets	4.1	0	0.1	0	0.2	0.7	5.9	0.8
Development Projects	44.0	28.0	39.9	0	8.3	10.0	7.9	8.5
Total Capital Cost Cornerstone Phases 1,2 and 3	48.1	28.0	40.0	0	8.5	10.7	13.8	9.3
Cornerstone 4 CIS	0	0	0	0	0	0	41.6	0

- c) Cornerstone Phases 1, 2 and 3 spending was included in the Typical capital spending for 2008-2011, since there was an expectation of ongoing capital maintenance costs as with any system of this nature. Cornerstone Phase 4 spending was not included in the Typical capital spending.

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

**Reference: Exhibit B, Tab 3, Schedule 1, page 16
EB-2009-0096, Exhibit D1, Tab 3, Schedule 7**

- a) Please provide a schedule that breaks down the \$172 M in total savings over seven years and shows the savings by year and by OM&A versus Capital (per B/3/1, page 16).
- b) With respect to the Exhibit D1, Tab 3, Schedule 7 from EB-2009-0096, please provide a schedule that extends Table 2 for the full seven years and shows the annual breakdown of the total anticipated savings of \$200 M from Phase 1 of the Cornerstone project.
- c) With respect to the Exhibit D1, Tab 3, Schedule 7 from EB-2009-0096, please provide a schedule that extends Table 3 for the full seven years and shows the annual breakdown of the total anticipated savings of \$50 M from Phase 2 of the Cornerstone project.
- d) With respect to the Exhibit D1, Tab 3, Schedule 7 from EB-2009-0096, please provide a schedule that extends Table 4 for the full seven years and shows the breakdown of the total anticipated savings of \$130 M from Phase 3 of the Cornerstone project.

Response

- a) Please refer to Exhibit I, Tab 4, Schedule 2.03 EP 17 part c. Hydro One expects Distribution Business savings from the CIS implementation to total \$172 million over a 7 year time horizon as shown in the table below. Note that these savings have been incorporated into the current business plan.

Total Cornerstone Phase 4 Savings (\$M) (Distribution)

	2013	2014	2015	2016	2017	2018	2019	2020	Total
OM&A	\$3.30	\$9.20	\$17.62	\$17.79	\$17.62	\$17.80	\$17.73	\$3.58	\$104.65
Capital	\$4.30	\$7.20	\$17.37	\$14.87	\$7.37	\$7.37	\$7.37	\$1.49	\$67.35
Total	\$7.60	\$16.40	\$34.99	\$32.67	\$25.00	\$25.17	\$25.10	\$5.07	\$172.00
Less: CIS Project OM&A costs	(\$13.6)								

Note that for 2013, there are CIS Project OM&A costs of \$13.6M which more than offset the business benefits forecast to be realized in that year.

In addition to the OM&A and Capital savings reflected in the rate impact, there are also approximately \$24.6M in avoided costs savings included in the business case for Cornerstone Phase 4

b), c) and d)

While Hydro One is not requesting recovery for the first three phases of the Cornerstone project in this IRM application, to be helpful, please see the following tables which were included in the recent EB-2012-0031 Hydro One Transmission application. Differences in the tables from the anticipated total savings quoted in the reference are attributable to forecast savings in test years beyond 2014.

Total Cornerstone Phase 1 Savings (\$M) (Transmission & Distribution)

	2009	2010	2011	2012	2013	2014
OM&A	8.9	16.0	18.2	18.2	18.2	18.2
Capital	6.4	11.1	12.9	12.9	12.9	12.9
Total	15.3	27.1	31.1	31.1	31.1	31.1

Total Cornerstone Phase 2 Savings (\$M) (Transmission & Distribution)

	2009	2010	2011	2012	2013	2014
OM&A	1.6	3.8	4.6	4.6	4.6	4.6
Capital	1.2	2.7	3.2	3.2	3.2	3.2
Total	2.8	6.5	7.8	7.8	7.8	7.8

1 **Total Cornerstone Phase 3 Savings (\$M) (Transmission & Distribution)**

	2009	2010	2011	2012	2013	2014
OM&A	-	-	0.2	0.2	5.2	7.2
Capital	-	-	2.3	2.3	10.7	17.0
Total	-	-	2.5	2.5	15.9	24.2

2

Consumers Council of Canada (CCC) INTERROGATORY #12 List 1

Issue 4 **Is Hydro one's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

EX. B/T3/S1/P. 4

The evidence states that Hydro One had planned the CIS in-service date for 2016. What was the expected cost for the 2016 CIS? Please explain how that differs from the current cost. How much has been spent to date in 2012 relative to the forecast of \$103.8 million?

Response

The estimated cost of the 2016 CIS was \$150M with projected benefits of \$90M over seven years. This amount was a high-level estimate and subject to discovery, which involved detailed requirements gathering and RFP, confirmation of requirements, costs and benefits. After the discovery phase of the project, the costs and benefits were updated to the current values of \$180M of cost and \$172M of benefit.

During the recent update to the rate application, Hydro One reduced the projected 2012 capital expenditure from \$103.8M to \$85.7M. The updated table has been reinserted below for your reference. Actual spend to June 30 2012 is \$21.5M

Table 2

CIS Capital 2011– 2013 (\$ Millions)

	2011	2012	2013	Total In-service 2013
Minor Fixed Assets	10.1	0		10.1
Development Project	41.5	85.7	18.1	145.3
Total Capital Cost	51.6	85.7	18.1	155.4

School Energy Coalition (SEC) INTERROGATORY #30 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

[B/3/1/p.5] Please:

- a. Provide the start and end dates for each of the phases listed in Table 1; and
- b. Provide a detailed explanation of each change in cost between the June 15th filing and the August 29th update.

Response

a.

Project Phase	Start Date	End Date
Discovery	Feb-11	May-11
Blueprint	Jun-11	Oct-11
Realization	Nov-11	Dec-12
Final Preparation	Jan-13	May-13
Verification and Stabilization	Jun-13	Sep-13

b. Please Reference the response to Exhibit I, Tab 4, Schedule 1.05 Staff 21

School Energy Coalition (SEC) INTERROGATORY #31 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

[B/3/1/p.11] Please:

- a. Provide details of the cost to extend the existing SAP BI solution;
- b. Confirm that those costs are included in the ICM amount for which recovery is being sought;
- c. Provide any business case or cost/benefit analysis prepared with respect to this project; and
- d. Provide a detailed forecast by year of the OM&A savings that are expected to result from the "two major benefits" listed.

Response

- a. The primary focus of the BI extension in Cornerstone Phase 4 is to bring the data associated with the Cornerstone phase 4 solution (ie customer data) into scope for the reporting and analysis functions that are available through the BI solution. As such, the extension of the existing BI solution is a component of the overall cost of the project, and is executed as an integrated part of the overall CIS project. Based on the relative sizes of different aspects of the project, Hydro One estimates that extending the existing BI solution represents roughly 5% of the total cost of the project, or around \$9M.
- b. Yes, these costs are included in the ICM amount for which recovery is being sought.
- c. The costs and benefits of extending the existing SAP BI solution for CIS purposes are included in the overall CIS business case benefits of \$172M. As described in Exhibit B, Tab 3, Schedule 1, page 11, the implementation of the BI component will provide a reduction in the cost of obtaining reports and information from the CIS solution, which is outlined in the Customer Service benefits and the IT benefits provided in Exhibit I, Tab 4, Schedule 2.02 EP 17 part c. The value of that specific benefit is \$263,000 over 7 years.
- d. See c. above.

School Energy Coalition (SEC) INTERROGATORY #32 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

[B/3/1/p.13] Please confirm that the average annual cost per customer of the CIS (line 7) from the in-service date is expected to be approximately \$30. Please confirm that the Enbridge average annual cost per customer for the same package of costs, as approved by the Board in EB-2011-0226 (Ex. N1/1/1) is approximately \$17. Please explain why the Hydro One CIS appears to be significantly more expensive than the Enbridge CIS

Response

Please refer to Exhibit I, Tab 4, Schedule 1.02 Staff 18.

School Energy Coalition (SEC) INTERROGATORY #33 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

[B/2/3/p.13] Please provide the detailed calculations for each of Rows 4 through 7 for each year.

Response

Row 4: The new CIS Solution leverages vendor supported applications from SAP, Itron, OpenText, Oracle and Group 1. Hydro One pays annual maintenance fees to these vendors for application support and service pack updates. For the purposes of they have been kept consistent from 2014 onward.

Row 5: As part of Hydro One's outsourcing contract with Inergi, Hydro One receives services for application maintenance, infrastructure hosting and support related to the sustaining and maintaining the customer information system. The costs from Inergi LP are bundled into an overall annual application maintenance charge; the CIS costs are an allocation of those charges based on the % of the total cost that is estimated to be attributable to CIS. Server hosting and support charges are per server according to the type of server and the level of support required; the costs for CIS are an allocation of the costs of all the servers required for SAP and the related applications that make up the CIS solution.

Row 6: Hydro One staff are required to support the CIS, together with staff from Inergi LP who provide Customer Service Operations. The costs in this area are derived from an allocation of the headcount in each of these areas applicable to CIS.

Row 7: Please see Exhibit I, Tab 4, Schedule 2.02 EP 16, c).

School Energy Coalition (SEC) INTERROGATORY #34 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

[B/3/1/p. 16] Please provide the detailed calculation of the figure of \$172 million.

Response

Please see Exhibit I, Tab 4, Schedule 2.03 EP 17, part c).

School Energy Coalition (SEC) INTERROGATORY #35 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

[B/3/1/p.18] Please provide details of the incremental FTEs hired as a result of the CIS project, and the roles those incremental personnel filled in each of 2011 through 2013. Please confirm that all of those incremental personnel were temporary, and those FTEs will revert to normal levels in 2014 and beyond.

Response

There are approximately 35-40 Hydro One staff members supporting the CIS project at any given time, drawn primarily from Customer Care and IT. These staff are backfilled. The net effect of the backfilling is for incremental staff to be hired by the base organization, either on contract or temporary employment positions. Staffing will revert back to normal levels in late 2013, after all project activities have been completed.

School Energy Coalition (SEC) INTERROGATORY #36 List 1

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

[B/3/1/Attach. 2, p. 1 and 7] Please explain why the in-service date changed from October 2012. Please explain why there were cost overruns when HCL Axon was on a "fixed price arrangement".

Response

As discussed during the October 19, 2011 Stakeholder session (See Exhibit A, Tab 4, Schedule 1, Appendix D, Notes Page 19) from a regulatory perspective, the go live date may not be the date that the assets go into service. In the original June 15 2012 filing, the in-service date was assumed to be Q1 2013. For an explanation of why the in-service date changed from Q1 to Q2 2013, please refer to Exhibit I, Tab 4, Schedule 1.05 Staff 21.

Given that Hydro One has contracted with HCL Axon on a fixed price basis for the CIS project, the extension of the project has a limited impact on the cost of HCL Axon's work. However, the other parties engaged in the project – Hydro One staff and contractors, and Inergi staff – do not work on a fixed price basis. Hence the impact of the extension of the project is primarily associated with the effort from these other parties.

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

Issue 4 Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?

Interrogatory

Reference: Exhibit B, Tab 3, Schedule 1

- a) Page 4 – The project is expected to be in service in 2013. Please confirm the original start date of the project.
- b) Page 5 Table 2 – Please reproduce Table 2 to show the breakdown of Board Approved and actual costs for the life of the project.
- c) Page 5 Table 2 – Please provide the types of costs included under development costs.
- d) Page 16 – Hydro One expects Distribution Business savings from the CIS implementation to total \$172 million over a 7 year time horizon. Please provide a description of the savings and provide a breakdown of these savings by year.
- e) Page 16 – Please identify the potential opportunities between HONI and other Ontario LDCs to look for project cost savings.
- f) Page 18 Table 4 – Please confirm staff costs began in 2011.
- g) Page 18 Table 4 - Please add additional rows to the Table to provide the number # temporary FTEs by year, number of # external contract staff by year and include other staff categories as required to match total costs for HONI staff on CIS project.
- h) Please confirm the non-typical capital CIS project is non-discretionary.
- i) Please confirm the amounts proposed in 2013 are outside of the base upon which rates are derived.
- j) The Board's Guidelines state that the distributor's decision to incur the amounts must represent the most cost-effective option. Please discuss.
- k) Please confirm that the incremental revenue requested will not be recovered through other means.

- l) The Board's Filing Requirements (June 28, 2012) state on page 7 that the amounts must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Please comment.
- m) Please describe the actions HONI will take in the event that the Board does not approve the proposed non-typical capital CIS spending.

Response

- a) The CIS project Discovery Phase began in February 2011.
- b) The CIS project costs are broken down in Table 1 of Exhibit B, Tab 3, Schedule 1. There were no Board approved amounts for 2011 or 2012 for the CIS project.
- c) Development costs as noted on Page 5 Table 2 include:
- Labour Costs (Hydro One, Inergi & system integrator)
 - Expenditures on software (both licencing & maintenance)
 - Third Party Support Costs (SAP, TD Bank, etc.)
 - Overhead
- d) Please refer to Exhibit I, Tab 4, Schedule 2.03 EP 17, part c).
- e) Please refer to Exhibit I, Tab 4, Schedule 1.04 Staff 20.
- f) Confirmed – staff costs began in 2011.
- g) The number of Hydro One staff supporting the project varies from month to month and has also varied within individual years as various activities ramp up or down. Depending on the exact time of year, there were approximately 25-30 Hydro One staff members supporting the project in 2011 and 35-40 Hydro One staff members in 2012.

Table 4: Costs for HONI Resources on the Project

(\$M)	2011	2012	2013
Hydro One Labour Cost	\$4.70	\$6.80	\$4.70
Min Number of HONI Employees on the Project	25	35	TBD
Max Number of HONI Employees on the Project	30	40	TBD

- 1 h) Yes the non-typical capital CIS project is non-discretionary. Please refer Exhibit I,
2 Tab 2, Schedule 1.01 Staff 2.
3
- 4 i) Yes the amounts proposed in 2013 are outside the base upon which rates are derived.
5
- 6 j) As discussed in Exhibit B, Tab 3, Schedule 1 and in Exhibit I, Tab 2, Schedule 1.01
7 Staff 2, the project is non-discretionary and had to be undertaken now to replace an
8 aging system which is not supported by the vendor. Having established the CIS
9 requirements, the cost of the project was established through a competitive process to
10 select both the software components upon which the CIS system is based, and the
11 integrator costs. HCL Axon, the lowest cost bidder, was selected as the system
12 integrator under a fixed price arrangement, and SAP and Itron were selected as the
13 software providers through this competitive process. Based on the responses to the
14 RFP that was issued Hydro One is confident that it obtained a cost-effective solution.
15
- 16 k) Confirmed. There is no other mechanism to recover the incremental revenue
17 requested.
18
- 19 l) As discussed in Exhibit B, Tab 3, Schedule 1 and in response found in Exhibit I, Tab
20 2, Schedule 1.01 Staff 2, the project is non-discretionary and has to be undertaken
21 now to replace an aging system which is not supported by the vendor. Furthermore,
22 the CIS is a significant investment being brought to the Board's attention as soon as
23 possible. Given the material impact on the Company, Hydro One cannot wait for
24 rebasing to recover these costs.
25
- 26 m) Hydro One believes this project is in the best interest of customers and will be
27 approved by the Board.

Energy Probe (EP) INTERROGATORY #18 List 1

Issue 5 Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 1, Table 3 &
Exhibit B, Tab 1, Schedule 2, Page 1

- a) Please discuss in reference to the Board's Guidelines for ICM why the half year rule should not apply to the base year/starting point.
- b) Please provide a schedule that uses the assumption that the half year rule was to apply for the base year using the actual base year Rate-base and Depreciation and calculating the annual revenue requirement for the three categories of CAPEX and associated rate riders, Compare to the "as filed" RR of \$26 million and Rate riders.
- c) Comment which approach is most appropriate from Hydro One's perspective and from a ratepayer's perspective.

Response

- a) Hydro One is following OEB direction as provided in the Supplemental Report of the Board dated September 17, 2008 under EB-2007-0673. On page 31 it states, "*the Board has determined not to apply the half-year rule so as not to build in a deficiency for subsequent years*". Hydro One has calculated the Revenue Requirement in this proceeding to be in compliance with this direction. Prior calculations leading to the approval of the base year / starting point of 2011 did employ the half-year rule.
- b) The half year rule was in effect for 2011 Base year.
- c) Hydro One agrees with OEB direction that ICM proceedings should generally not employ a half year adjustment so as not to require another ICM filing in the following IRM year to recover the impacts of the second half year.

Energy Probe (EP) INTERROGATORY #19 List 1

Issue 5 Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 2, Page 2 &
 Exhibit B, Tab 2 Schedule 1, Table 3

- a) Please provide an explanation as to why HONI has adopted the half year rule for CIS, given the fact that (per update) in 2013 both the legacy CIS system and new CIS will be operating.
- b) Please provide a calculation of the impact (annual RR) of using this approach rather than the full year rule, using Table 3 in the second reference. Compare the ratepayer impacts from each approach.

Response

- a) Application of the half year rule was only applied to CIS with respect to the treatment of Capital Cost Allowance (CCA) for tax purposes which strictly affects the taxes payable. This was done in order to smooth rate impacts on customers. Hydro One believes this is a fairer application because the CIS falls within Class 12 which is a very favourable treatment allowing for 100% write off subject to inclusion of 50% in year 1 (& the remainder in year 2).
- b) As outlined on Page 2 of Exhibit B, Tab 1, Schedule 2, the rate impacts of CIS from not following the half year rule would be -1.7% in year one and +4.6% in year 2. This is compared to the one-time 0.6% increase currently proposed.

Energy Probe (EP) INTERROGATORY #20 List 1

Issue 5 Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 2, Page 3

- a) Please provide a summary schedule of the cost of Capital Parameters used for Calculation of the ICM revenue requirements.
- b) Please provide the sensitivities of the 2013 ICM RR to each of LT debt, ST debt and Equity.
- c) Conform that the 2014 ICM RR will be updated based on the Boards deemed rates for cost of capital components

Response

- a) Table below is a summary of the cost of Capital Parameters used for Calculation of the ICM revenue requirements.

<i>Cost of Capital</i>	<i>Rate of Return</i>
Return on Long-term debt	4.94%
Return on Short-term debt	2.01%
Return on Debt (blended) ¹	4.75%
Return on Equity	9.16%

- b) Table below illustrates the sensitivities of the revenue requirement associated with 2013 incremental capital via ICM to each of long term debt, short term debt and equity. Each scenario demonstrates the impact on revenue requirement given 100 bps change in one of the cost of capital parameters while holding the other two constant.

¹ The 60% debt component is comprised of 4% short term debt and 56% long term debt.

Cost of Capital Parameter	Rate of Return	ICM Revenue Requirement (\$ million)	Impact on Revenue Requirement (\$ million)
Return on Long-term debt	3.94%	24.3	-1.9
	4.94%	26.2	0.0
	5.94%	28.1	1.9
Return on Short-term debt	1.01%	26.1	-0.1
	2.01%	26.2	0.0
	3.01%	26.3	0.1
Return on Equity	8.16%	24.3	-1.9
	9.16%	26.2	0.0
	10.16%	28.1	1.9

1
 2
 3

c) Hydro One is not applying for 2014 at this time.

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

Issue 5 **Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?**

Interrogatory

Reference: **Exhibit B, Tab 1, Schedule 2, pages 1 - 2**

- a) Is HON committing to filing for 2014 distribution rates based on IRM (as opposed to cost of service)? If not, why is the application of the full year rule for the ICM capital appropriate?

Response

Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2, part d).

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

Issue 5 **Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?**

Interrogatory

Reference: **Exhibit B, Tab 1, Schedule 2, pages 1 - 2**

- a) Assuming HON's 2014 distribution rate application is based on IRM (as opposed to cost of service), what adjustments would be required in order to "account for" the fact that the ½ rule was used for the CIS system for 2013 rates?
- b) If not, why is the application of the full year rule for the ICM capital appropriate?

Response

- a) The half year treatment for CIS was only with respect to CCA. Hydro One used this methodology for the purpose of rate smoothing as discussed in Exhibit I, Tab 5, Schedule 2.02 EP 19. The calculations included 100% of CIS to be added to Rate Base. Therefore, no adjustments would be proposed for CIS in the event of a 2014 filing.
- b) N/A Full year rate base was used for CIS in this filing.

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

Issue 5 **Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?**

Interrogatory

Reference: **Exhibit B, Tab 1, Schedule 2, page 5**

- a) Please re-do Table 1 based on the ½ year rule for both depreciation and rate base for all projects.

Response

Adjusting the referenced table to assume in-serving on a half-year basis and adjusting CCA treatment to allow for 50% inclusion rules on all assets, similar to what would be done as part of a Cost of Service proceeding, yields the revised revenue requirements indicated in the attached table below.

The Board directed distributors to use a full year treatment on in-service additions as part of the ICM process. This treatment was used in order to account ensure recovery of the full amount of the investment rather than only half of it. In a Cost of Service environment, the investment portion not included in year one is picked up in year two.

The table attached to this interrogatory paints an incomplete picture since the omitted half of 2011 is not recovered, the 2012 expenditures are not recovered at all and if a Cost of Service is not held for 2014 rates then the other half of 2013 would not be recovered.

		Typical Capital		Escalated Issue Projects						Non-Typical Capital		Total
				Commerce Way TS								
				Capital		Distributing &		Wood Pole		Subtotal		
				Contribution		Regulating Stns		Replacement		Escalated Issue		
			<u>Micellaneous</u>							Capital	<u>CIS</u>	
In Service Addition			71.0	4.6		21.3		11.4		37.3	77.7	186.0
Average Rate Base (no half year)			69.8	4.6		21.1		11.3		37.0	73.6	180.3
Depreciation	3.5%	2.5		2.0%	0.1	2.0%	0.4	1.9%	0.2	0.7	10.5%	11.4
Return on Debt (blended)		2.0			0.1		0.6		0.3	1.1	2.1	5.1
Return on Equity		2.6			0.2		0.8		0.4	1.4	2.7	6.6
Tax		(0.2)			(0.0)		(0.2)		(0.1)	(0.3)	(22.9)	(23.4)
Total Incremental Revenue Requirement		6.8			0.4		1.6		0.9	2.8	(9.9)	(0.2)
<u>Tax Calculation</u>												
Return		2.3			0.1		0.6		0.3		(20.2)	
Add: Depreciation		2.5			0.1		0.4		0.2		8.2	
less: CCA		(5.7)			(0.4)		(1.7)		(0.9)		(77.7)	
		(0.8)			(0.1)		(0.7)		(0.4)		(89.7)	
Tax rate		0.3			0.3		0.3		0.3		0.3	
		(0.2)			(0.0)		(0.2)		(0.1)		(22.9)	
CCA		142.0			9.2		42.6		22.9		155.4	
half year		(71.0)			(4.6)		(21.3)		(11.4)		(77.7)	
UCC		71.0			4.6		21.3		11.4		77.7	
CCA claimed	8.0%	5.7		8.0%	0.4	8.0%	1.7	8.0%	0.9		100%	77.7
<u>Cost of Capital</u>	<u>2013</u>											
Return on Long-term debt	4.94%											
Return on Short-term debt	2.01%											
Return on Debt (blended)	4.75%											
Return on Equity	9.16%											

School Energy Coalition (SEC) INTERROGATORY #37 List 1

Issue 5 **Is Hydro One's proposal to calculate revenue requirement for all of the proposed ICM projects, except CIS, based on full year depreciation, appropriate? In the event that Hydro One files on a cost of service basis for 2014, is an adjustment required, and if so should a deferral account be set up at this time to capture any such adjustment?**

Interrogatory

[A/3/1, p.3] Please confirm that Hydro One's next cost of service application for distribution will be for rates commencing January 1, 2015.

Response

Please refer to Exhibit I, Tab 2, Schedule 1.01 Staff 2, part d).

School Energy Coalition (SEC) INTERROGATORY #38 List 1

Issue 6 Is the proposed rate implementation for projects approved under the ICM, if any, appropriate?

Interrogatory

[A/3/1, p. 5] Please provide a side by side comparison of the calculation of the revenue requirement associated with the ICM projects using the Board's standard method of ICM calculation, and using the "proposed adjustments" in the Application.

Response

The adjustments relate to RTSR, final step of rate harmonization and the Density Study which do not affect the ICM calculation.

School Energy Coalition (SEC) INTERROGATORY #39 List 1

Issue 6 Is the proposed rate implementation for projects approved under the ICM, if any, appropriate?

Interrogatory

[B/1/2/p. 2] Please confirm that, in calculating the depreciation and CCA for the ICM projects, the Applicant did not use the actual depreciation rates for each project included in Typical Capital or Escalated Issue capital, but used averages instead. If so, please provide the actual depreciation and CCA calculations for each of the projects proposed to be included in the ICM.

Response

Yes, the depreciation and CCA rates used in calculating revenue requirement for the incremental projects are included in Exhibit B, Tab 1, Schedule 2, page 5.

School Energy Coalition (SEC) INTERROGATORY #40 List 1

Issue 6 Is the proposed rate implementation for projects approved under the ICM, if any, appropriate?

Interrogatory

[B/1/2/p. 4] Please confirm that the Applicant proposes to use 2013 interest rates for the ICM projects, but that the remainder of rate base will continue to be recovered at the 2011 interest rates embedded in existing rates.

Response

Hydro One has used current Cost of Capital rates (lower) in determining the recovery required on the 2013 projects to be collected via rate rider. Hydro One proposes no changes to the current rates in place.

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

Issue 7 Is the proposed calculation of the ICM rate rider, including the cost of capital parameters used in the calculation, appropriate?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 2, pages 3 – 4

- a) Please provide a schedule that contrasts the short term debt and long term debt rates and ROE values as approved for HON's 2011 rates with those used in the current Application.
- b) Please provide a schedule that sets out the derivation of the 4.94% long-term debt rate for 2013. In the schedule please clearly distinguish between those debt issues/debt rates that are based on currently issued debt versus forecasted debt issues/rates.
- c) Please provide the basis for the interest rates assumed to be associated with any new debt issues underlying the calculation of the 4.94%.
- d) The Application states (page 4, lines 3-5) forecast interest rates will be updated. Will this include an update of HON's forecast long term debt cost for 2013? If so, when will the update be done?

Response

- a) Table below contrasts the short term debt and long term debt rates and ROE values as approved for HON's 2011 rates with those used in the current Application.

Cost of Capital Parameters	2011 Board Approved	2013 Proposed
Return on Long Term Debt	5.60%	4.94%
Return on Short Term Debt	2.43%	2.01%
Return on Equity	9.66%	9.16%

- b) Please see the attached schedule (Attachment 1) for the derivation of the 4.94% long-term debt rate for 2013. Lines 1 to 39 are based on actual debt issues and line 40 to 45 are based on forecasted debt issues.

- c) Table below provides the derivation of the forecast Hydro One Inc. yield for each of the planned issuance terms for 2012, 2013.

Forecast Yield for 2012-2013 Issuance Terms

	2012		
	5-year	10-year	30-year
<i>Government of Canada</i>	1.48%	2.10%	2.69%
<i>Hydro One Spread</i>	0.81%	1.06%	1.35%
<i>Forecast Hydro One Yield</i>	2.29%	3.16%	4.04%
	2013		
	5-year	10-year	30-year
<i>Government of Canada</i>	1.88%	2.50%	3.09%
<i>Hydro One Spread</i>	0.81%	1.06%	1.35%
<i>Forecast Hydro One Yield</i>	2.69%	3.56%	4.44%

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 2012 is based on the three month out forecast from February 2012 Consensus Forecasts, and for 2013 is based on the twelve month out forecast from February 2012 Consensus Forecasts. The five and thirty year Government of Canada bond yield forecasts are derived by adding the February 2012 actual average spreads (five to ten year for the five year forecast and thirty to ten year for the thirty 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 February 2012 obtained from the Company's Medium Term Note dealer group for each planned issuance term.

- d) Yes, the forecast long term debt rates will be updated based on the latest available consensus forecast and cost of capital parameter update issued by the Board. Hydro One will reflect the updated cost of long term debt rates in the 2013 rate order consistent with the final decision and order from the Board on this application.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
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		Effective Cost Rate	Total Amount Outstanding		Avg. Monthly Averages (\$Millions)	Carrying Cost (\$Millions)	Projected Average Embedded Cost Rates
						Total Amount (\$Millions)	Per \$100 Principal Amount (Dollars)		at 12/31/12 (\$Millions)	at 12/31/13 (\$Millions)			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-10	121.6	1.6	120.0	98.70	7.34%	0.0	0.0	0.0	0.0	
2	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	
3	22-Jun-01	6.400%	1-Dec-11	76.0	(0.2)	76.2	100.28	6.36%	0.0	0.0	0.0	0.0	
4	22-Jun-01	6.930%	1-Jun-32	47.7	0.5	47.3	99.05	7.01%	47.7	47.7	47.7	3.3	
5	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.55	5.83%	0.0	0.0	0.0	0.0	
6	17-Sep-02	6.930%	1-Jun-32	142.0	(5.3)	147.3	103.71	6.64%	142.0	142.0	142.0	9.4	
7	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.48	5.70%	0.0	0.0	0.0	0.0	
8	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	
9	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	
10	23-Jun-03	4.000%	23-Jun-08	210.0	6.1	203.9	97.08	4.66%	0.0	0.0	0.0	0.0	
11	24-Feb-04	3.950%	24-Feb-09	87.5	0.4	87.1	99.55	4.05%	0.0	0.0	0.0	0.0	
12	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	
13	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	
14	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	
15	15-Nov-04	1.853%	15-May-07	14.0	0.1	13.9	99.08	2.24%	0.0	0.0	0.0	0.0	
16	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	
17	19-May-05	3.950%	24-Feb-09	45.0	(0.4)	45.4	100.90	3.69%	0.0	0.0	0.0	0.0	
18	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	
19	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	
20	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	
21	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	
22	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	
23	15-May-07	2.190%	15-May-08	14.0	0.0	14.0	100.00	2.19%	0.0	0.0	0.0	0.0	
24	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	
25	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	
26	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	
27	19-Nov-08	3.890%	19-Nov-10	40.0	0.1	39.9	99.78	4.01%	0.0	0.0	0.0	0.0	
28	13-Jan-09	3.890%	19-Nov-10	35.0	(0.2)	35.2	100.65	3.52%	0.0	0.0	0.0	0.0	
29	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	
30	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	
31	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	
32	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	
33	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	
34	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	
35	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	
36	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	
37	26-Sep-11	4.390%	26-Sep-41	75.0	0.5	74.5	99.36	4.43%	75.0	75.0	75.0	3.3	
38	22-Dec-11	4.000%	22-Dec-51	30.0	0.2	29.8	99.48	4.03%	30.0	30.0	30.0	1.2	
39	13-Jan-12	3.200%	13-Jan-22	126.0	0.6	125.4	99.49	3.26%	126.0	126.0	126.0	4.1	
40	15-Mar-12	4.041%	15-Mar-42	164.2	0.8	163.4	99.50	4.07%	164.2	164.2	164.2	6.7	
41	15-Jun-12	3.164%	15-Jun-22	168.0	0.8	167.2	99.50	3.22%	168.0	168.0	168.0	5.4	
42	15-Sep-12	2.291%	16-Mar-18	168.0	0.8	167.2	99.50	2.39%	168.0	168.0	168.0	4.0	
43	15-Mar-13	4.441%	15-Mar-43	169.0	0.8	168.2	99.50	4.47%	0.0	169.0	130.0	5.8	
44	15-Jun-13	3.564%	15-Jun-23	169.0	0.8	168.2	99.50	3.62%	0.0	169.0	91.0	3.3	
45	15-Sep-13	2.691%	15-Sep-18	50.0	0.3	49.8	99.50	2.80%	0.0	50.0	15.4	0.4	
46		Subtotal							2962.1	3120.2	3163.2	152.5	
47		Treasury OM&A costs										1.2	
48		Other financing-related fees										2.4	
49		Total							2962.1	3120.2	3163.2	156.1	4.94%

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

Issue 7 Is the proposed calculation of the ICM rate rider, including the cost of capital parameters used in the calculation, appropriate?

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 2, pages 3 – 4

- a) Do the Board's ICM module and associated work forms require input of the approved cost of capital (per the last cost of service application) or the current cost of capital parameters in calculating the revenue requirement impacts of approved ICM spending?
- b) If the Board's ICM module and associated work forms require use of the (last) approved cost of capital parameters for the utility, please explain why HON considers it appropriate to use the current cost of capital parameters. In doing so, please clarify whether the rationale is unique to HON's current circumstances.

Response

- a) The Board's work form that is completed by Hydro One is attached to Exhibit I, Tab 2, Schedule 1.01 Staff 2. It uses the current cost of capital parameters rather than the historic rates in place during the original base year.
- b) Hydro One considers the use of current Cost of Capital parameters to be appropriate in determining the Revenue Requirement necessary with ICM projects. This is because the current rates represent the financing costs endured in order to complete the current funding of the described projects in the ICM year. Using a different rate from a past year would introduce an imbalance to the detriment of industry and/or its customers. Use of the 9.16% ROE in this proceeding means a lower return than the 9.66% included in the Base year. Nonetheless, Hydro One feels it is more appropriate to include the lower rate.

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

Issue 7 Is the proposed calculation of the ICM rate rider, including the cost of capital parameters used in the calculation, appropriate?

Interrogatory

**Reference: Exhibit B, Tab 1, Schedule 2, page 1
 Exhibit E1, Tab 3, Schedule 1, page 1
 Board Decision EB-2011-0207, page 19**

- a) Please outline the allocation approach to customer classes approved by the Board for Woodstock's contribution towards the Commerce Way TS. Why hasn't HON adopted a similar approach for its capital contribution?

Response

- a) Please refer to Exhibit I, Tab 3, Schedule 1.01 Staff 16.

Consumers Council of Canada (CCC) INTERROGATORY #13 List 1

Issue 7 Is the proposed calculation of the ICM rate rider, including the cost of capital parameters used in the calculation, appropriate?

Interrogatory

EX. B/T1/S2/P. 4

The proposed long-term debt rate is 4.9% for 2013. It represents the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2012 and 2013. Please provide the calculation. Please provide details of any new debt issues

Response

Please see response to Exhibit I, Tab 7, Schedule 5.01 VECC 36, part b).

Consumers Council of Canada (CCC) INTERROGATORY #14 List 1

Issue 7 Is the proposed calculation of the ICM rate rider, including the cost of capital parameters used in the calculation, appropriate?

Interrogatory

EX. B/T1/S2/P. 5

Please explain how the \$142 million in Miscellaneous Typical Capital was calculated.
Please provide all assumptions.

Response

The derivation of the \$142M is located on Page 4 of Exhibit B1, Tab 1, Schedule 1.

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

**Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and
Variance Accounts appropriate?**

Interrogatory

Ref: Exhibit E1/Tab2/Sch1

The Board approved PILs proxies to be included in rates from 1999 through 2005 for Hydro One Networks Inc. core distribution service area and for the Hydro One acquired distributors. In the Decision in the Combined Proceeding (EB-2008-0381), the Board directed distributors to file PILs tax deferral account evidence in their next application. When does Hydro One expect to file its evidence for disposition of PILs tax variances for the period 1999 through April 30, 2006?

Response

Hydro One did not set up regulatory asset account 1562 and thus will not be requesting disposition. EB-2008-0381 was applicable to the majority of electricity distributors (Municipal Electricity Utilities) that became subject to PILS effective October 1, 2001 with the proclamation of Section 93 of the Electricity Act, 1998 ("the Act"). Hydro One was subject to PILS since April 1, 1999 under section 98 of the Act and as such was not required to maintain Account 1562.

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

**Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and
Variance Accounts appropriate?**

Interrogatory

Ref: Exhibit E2, Tab 2, Schedule 3, Page 6 & 7
Exhibit E2-01-01, Sheet 12, Calc of Def_Var RR

- a) As per Exhibit E2, Tab 2, Schedule 3, Page 6, the GSd rate class draft tariff sheet shows a Global Adjustment Rate rider of \$3.572/kWh and a Volumetric Rate Rider for 2013 Deferral and Variance Account disposition of \$(0.00870)/kW. However, as per Exhibit E2-01-01, Sheet 12, Calc of Def_Var RR, the Global Adjustment Rate rider is calculated to be (\$0.0005)/kWh and the Volumetric Rate Rider for 2013 Deferral and Variance Account disposition is calculated to be (\$0.30666)/kW for this rate class. Please indicate the correct numbers to use. Please update the evidence as appropriate with the correct numbers.
- b) As per Exhibit E2, Tab 2, Schedule 3, Page 7, the UGd rate class draft tariff sheet shows a Global Adjustment Rate rider of \$1.63/kWh. However, as per Exhibit E2-01-01, Sheet 12, Calc of Def_Var RR, the Global Adjustment Rate rider is calculated to be (\$0.0005)/kWh for this rate class. Please indicate the correct number to use. Please update the evidence as appropriate with the correct number.

Response

- a) For the GSd rate class, the correct amount for the Global Adjustment Rate Rider is (\$0.0005)/kWh and the correct amount for the Volumetric Rate Rider for 2013 Deferral and Variance Account disposition is (\$0.30666)/kW. The draft tariff schedules on the Board's website¹ reflect the correct values for both the above mentioned riders.
- b) For the UGd rate class, the correct amount for the Global Adjustment Rate rider is (\$0.0005)/kWh. The draft tariff schedules on the Board's website¹ reflect the correct values for the above mentioned rider.

1

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

**Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and
Variance Accounts appropriate?**

Interrogatory

Ref: EB-2009-0096, Draft Rate Order, Exhibit 2.0
Exhibit E1-02-01, Attachment 4

As per EB-2009-0096, Draft Rate Order, Exhibit 2.0, it appears that a total of (\$31,115,400) was refunded to customers in this proceeding. However, as per Attachment 4 of Exhibit E1-02-01, it appears that (\$28,431,636) in principal and (\$13,483) in carrying charges was transferred to Account 1595 in 2010. It also appears that in Attachment 4, "Adjustments During 2010 –Other", no offsetting amounts (to the amount transferred to Account 1595) were removed from Account 1550, 1580, 1584, 1586, 1588, and 1590 – the amounts cleared in EB-2009-0096.

- a) Please clarify which is the correct number to transfer to Account 1595 in Attachment 4 if Exhibit E1-02-01, representing the balances cleared in EB-2009-0096. Please update the appropriate sections of Hydro One's evidence accordingly.
- b) Please explain why in Attachment 4, "Adjustments During 2010 –Other", no offsetting amounts (to the amount transferred to Account 1595) were removed from Account 1550, 1580, 1584, 1586, 1588, and 1590 – the amounts cleared in EB-2009-0096. If necessary, please update the appropriate sections of Hydro One's evidence.

Response

- a) The correct number to transfer to Account 1595 is \$31.1 million. EB-2009-0096 approved \$31.1 million to transfer to Rider 6, this included, besides the Group 1 accounts listed in Attachment 4, the balances in accounts: 1518 RCVA Retail; 1548 RCVA STR; 1555 Smart Meter Capital and Recovery Offset; and, 1556 Smart Meter OM&A Variance. Please see table below to reconcile.

US of A Account	Account Name	Principal	Interest	Balance
<i>Group 1 Accounts</i>				
1550	LV	(6,928,672)	(57,739)	(6986,411)
1580	RSVA Wholesale	26,508,006	256,312	26,764,318
1584	RSVA Network	9,172,728	250,414	9,423,142
1586	RSVA-STR	5,875,061	32,682	5,907,743
1588	Global Adjustment	(13,176,663)	(81,322)	(13,257,985)
1590	RARA 1	33,858,100	(10,966,270)	22,891,830
Sub-Total Group 1		55,308,559	(10,565,922)	44,742,637
<i>Remaining Accounts Total</i>				
1518	RCVA	2,833,365	113,267	2,946,732
1555	Smart Meter	(11,476,769)	(100,928)	(11,577,697)
1556	Smart Meter OM&A	(4,382,909)	(44,274)	(4,427,183)
Sub-Total Remaining		(13,530,278)	(55,514)	(13,585,892)
Total		41,778,181	(10,621,436)	31,156,745¹

b) Exhibit E1, Tab 2, Schedule 1, Attachment 4 shows the adjustments on an account by account basis. Please see Attachment 1 to this exhibit.

¹ The \$31,156,745 balance differential from approved Rider 6 amount, (\$31,115,400), relates to the difference between the actual and forecast interest.

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-09	Transactions Debit/ (Credit) during 2009 excluding interest and adjustments ⁶	Board-Approved Disposition during 2009	Adjustments during 2009 - other ³
LV Variance Account	1550	\$ 1,863,853	\$ 5,064,819		
RSVA - Wholesale Market Service Charge	1580	-\$ 11,301,124	-\$ 15,206,882		
RSVA - Retail Transmission Network Charge	1584	-\$ 13,821,196	\$ 4,648,468		
RSVA - Retail Transmission Connection Charge	1586	-\$ 2,965,531	-\$ 2,909,530		
RSVA - Power (excluding Global Adjustment)	1588	\$ -			
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 5,531,417	\$ 7,645,247		
Recovery of Regulatory Asset Balances	1590	-\$ 43,004,093	-\$ 10,644,518		
Disposition and Recovery of Regulatory Balances	1595	\$ -	\$ -		
		\$ -	\$ -		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 63,696,675	-\$ 11,402,396	\$ -	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 69,228,092	-\$ 19,047,642	\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 5,531,417	\$ 7,645,247	\$ -	\$ -

Page 2 of 27		2009			
Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009
LV Variance Account	1550	\$ 6,928,672	\$ 24,729	\$ 33,010	
RSVA - Wholesale Market Service Charge	1580	-\$ 26,508,006	-\$ 76,839	-\$ 179,473	
RSVA - Retail Transmission Network Charge	1584	-\$ 9,172,728	-\$ 114,856	-\$ 135,558	
RSVA - Retail Transmission Connection Charge	1586	-\$ 5,875,061	-\$ 4,757	-\$ 27,925	
RSVA - Power (excluding Global Adjustment)	1588	\$ -	\$ -		
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 4,951	\$ 86,273	
Recovery of Regulatory Asset Balances	1590	-\$ 53,648,611	\$ 20,055,015	-\$ 395,399	
Disposition and Recovery of Regulatory Balances	1595	\$ -	\$ -		
		\$ -	\$ -		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 75,099,071	\$ 19,878,342	-\$ 619,073	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 88,275,734	\$ 19,883,292	-\$ 705,346	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 4,951	\$ 86,273	\$ -

Account Descriptions	Account Number	Adjustments during 2009 - other ³	Closing Interest Amounts as of Dec-31-09
LV Variance Account	1550		\$ 57,739
RSVA - Wholesale Market Service Charge	1580		-\$ 256,312
RSVA - Retail Transmission Network Charge	1584		-\$ 250,414
RSVA - Retail Transmission Connection Charge	1586		-\$ 32,682
RSVA - Power (excluding Global Adjustment)	1588		\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588		\$ 81,322
Recovery of Regulatory Asset Balances	1590		\$ 19,659,616
Disposition and Recovery of Regulatory Balances	1595		\$ -
			\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ 19,259,269
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ 19,177,947
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ 81,322

Page 4 of 27				
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
LV Variance Account	1550	\$ 6,928,672	\$ 3,662,812	
RSVA - Wholesale Market Service Charge	1580	-\$ 26,508,006	-\$ 31,720,243	
RSVA - Retail Transmission Network Charge	1584	-\$ 9,172,728	\$ 8,383,765	
RSVA - Retail Transmission Connection Charge	1586	-\$ 5,875,061	\$ 2,397,784	
RSVA - Power (excluding Global Adjustment)	1588	\$ -		
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 4,070,115	
Recovery of Regulatory Asset Balances	1590	-\$ 53,648,611	\$ 8,961,627	
Disposition and Recovery of Regulatory Balances	1595	\$ -	\$ 23,043,182	
		\$ -	\$ -	
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 75,099,071	\$ 10,658,811	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 88,275,734	\$ 14,728,927	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 4,070,115	\$ -

2010					Page 5 of 27
Account Descriptions	Account Number	Adjustments during 2010 - other ³	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	
LV Variance Account	1550	-\$ 6,928,672	\$ 3,662,812	\$ 57,739	
RSVA - Wholesale Market Service Charge	1580	\$ 26,508,006	-\$ 31,720,243	-\$ 256,312	
RSVA - Retail Transmission Network Charge	1584	\$ 9,172,728	\$ 8,383,765	-\$ 250,414	
RSVA - Retail Transmission Connection Charge	1586	\$ 5,875,061	\$ 2,397,784	-\$ 32,682	
RSVA - Power (excluding Global Adjustment)	1588		\$ -	\$ -	
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 13,176,663	-\$ 4,070,115	\$ 81,322	
Recovery of Regulatory Asset Balances	1590	\$ 33,858,100	-\$ 10,828,884	\$ 19,659,616	
Disposition and Recovery of Regulatory Balances	1595	-\$ 41,778,181	-\$ 18,734,999	\$ -	
			\$ -	\$ -	
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ 13,530,378	-\$ 50,909,881	\$ 19,259,269	
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ 26,707,041	-\$ 46,839,766	\$ 19,177,947	
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 13,176,663	-\$ 4,070,115	\$ 81,322	

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Account Descriptions	Account Number	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
LV Variance Account	1550	\$ 33,765		-\$ 57,739	\$ 33,765
RSVA - Wholesale Market Service Charge	1580	-\$ 199,653		\$ 256,312	-\$ 199,653
RSVA - Retail Transmission Network Charge	1584	\$ 34,088		\$ 250,414	\$ 34,088
RSVA - Retail Transmission Connection Charge	1586	\$ 6,770		\$ 32,682	\$ 6,770
RSVA - Power (excluding Global Adjustment)	1588				\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 21,541		-\$ 81,322	-\$ 21,541
Recovery of Regulatory Asset Balances	1590	-\$ 904,074		-\$ 10,966,270	\$ 7,789,273
Disposition and Recovery of Regulatory Balances	1595	-\$ 10,762,293		\$ 10,621,436	-\$ 140,857
					\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 11,812,936	\$ -	\$ 55,514	\$ 7,501,846
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 11,791,395	\$ -	\$ 136,836	\$ 7,523,387
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 21,541	\$ -	-\$ 81,322	-\$ 21,541

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	Other ³ Adjustments during Q1 2011
LV Variance Account	1550	\$ 3,662,812	\$ 3,014,020		
RSVA - Wholesale Market Service Charge	1580	-\$ 31,720,243	-\$ 35,443,413		
RSVA - Retail Transmission Network Charge	1584	\$ 8,383,765	\$ 12,314,151		
RSVA - Retail Transmission Connection Charge	1586	\$ 2,397,784	\$ 7,056,564		
RSVA - Power (excluding Global Adjustment)	1588	\$ -			
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 4,070,115	-\$ 4,669,747		
Recovery of Regulatory Asset Balances	1590	-\$ 10,828,884	\$ 5,593,980		
Disposition and Recovery of Regulatory Balances	1595	-\$ 18,734,999	\$ 18,804,384		
		\$ -			
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 50,909,881	\$ 6,669,938	\$ -	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 46,839,766	\$ 11,339,685	\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 4,070,115	-\$ 4,669,747	\$ -	\$ -

Page 8 of 27		2011			
Account Descriptions	Account Number	Other ³ Adjustments during Q2 2011	Other ³ Adjustments during Q3 20101	Other ³ Adjustments during Q4 2011	Closing Principal Balance as of Dec- 31-11
LV Variance Account	1550				\$ 6,676,832
RSVA - Wholesale Market Service Charge	1580				-\$ 67,163,657
RSVA - Retail Transmission Network Charge	1584				\$ 20,697,915
RSVA - Retail Transmission Connection Charge	1586				\$ 9,454,348
RSVA - Power (excluding Global Adjustment)	1588				\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588				-\$ 8,739,863
Recovery of Regulatory Asset Balances	1590				-\$ 5,234,904
Disposition and Recovery of Regulatory Balances	1595				\$ 69,385
					\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ -	\$ -	-\$ 44,239,943
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ -	\$ -	-\$ 35,500,080
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ -	\$ -	-\$ 8,739,863

Account Descriptions	Account Number	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other ³
LV Variance Account	1550	\$ 33,765	\$ 76,851		
RSVA - Wholesale Market Service Charge	1580	-\$ 199,653	-\$ 724,535		
RSVA - Retail Transmission Network Charge	1584	\$ 34,088	\$ 206,236		
RSVA - Retail Transmission Connection Charge	1586	\$ 6,770	\$ 74,289		
RSVA - Power (excluding Global Adjustment)	1588	\$ -			
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 21,541	-\$ 134,564		
Recovery of Regulatory Asset Balances	1590	\$ 7,789,273	-\$ 92,906		
Disposition and Recovery of Regulatory Balances	1595	-\$ 140,857	-\$ 136,491		
		\$ -			
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ 7,501,846	-\$ 731,120	\$ -	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ 7,523,387	-\$ 596,556	\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 21,541	-\$ 134,564	\$ -	\$ -

Account Descriptions	Account Number	Closing Interest Amounts as of Dec-31-11
LV Variance Account	1550	\$ 110,616
RSVA - Wholesale Market Service Charge	1580	-\$ 924,188
RSVA - Retail Transmission Network Charge	1584	\$ 240,324
RSVA - Retail Transmission Connection Charge	1586	\$ 81,060
RSVA - Power (excluding Global Adjustment)	1588	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 156,105
Recovery of Regulatory Asset Balances	1590	\$ 7,696,367
Disposition and Recovery of Regulatory Balances	1595	-\$ 277,348
		\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ 6,770,727
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ 6,926,831
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 156,105

		2011		Page 11 of 27	
Account Descriptions	Account Number	Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31- 11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted during 2012 Disposition
LV Variance Account	1550			\$ 6,676,832	\$ 110,616
RSVA - Wholesale Market Service Charge	1580			-\$ 67,163,657	-\$ 924,188
RSVA - Retail Transmission Network Charge	1584			\$ 20,697,915	\$ 240,324
RSVA - Retail Transmission Connection Charge	1586			\$ 9,454,348	\$ 81,060
RSVA - Power (excluding Global Adjustment)	1588			\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588			-\$ 8,739,863	-\$ 156,105
Recovery of Regulatory Asset Balances	1590			-\$ 5,234,904	\$ 7,696,367
Disposition and Recovery of Regulatory Balances	1595			\$ 69,385	-\$ 277,348
				\$ -	\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 44,239,943	\$ 6,770,727
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 35,500,080	\$ 6,926,831
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ -	-\$ 8,739,863	-\$ 156,105

Page 12 of 27		Projected Interest on Dec-31-11 Balances			2.1.7 RRR
Account Descriptions	Account Number	Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -1 balance adjusted for disposition	Total Claim	As of Dec 31-11 ⁴
LV Variance Account	1550			\$ 6,787,448	\$ 6,787,448
RSVA - Wholesale Market Service Charge	1580			-\$ 68,087,844	-\$ 68,087,844
RSVA - Retail Transmission Network Charge	1584			\$ 20,938,239	\$ 20,938,239
RSVA - Retail Transmission Connection Charge	1586			\$ 9,535,408	\$ 9,535,408
RSVA - Power (excluding Global Adjustment)	1588			\$ -	
RSVA - Power - Sub-Account - Global Adjustment	1588			-\$ 8,895,967	-\$ 8,895,967
Recovery of Regulatory Asset Balances	1590			\$ 2,461,463	\$ 2,461,463
Disposition and Recovery of Regulatory Balances	1595			-\$ 207,963	-\$ 207,963
				\$ -	
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 37,469,217	-\$ 37,469,217
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 28,573,249	-\$ 28,573,249
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ -	-\$ 8,895,967	-\$ 8,895,967

Account Descriptions	Variance RRR vs. 2011 Balance <i>(Principal + Interest)</i>
LV Variance Account	\$ -
RSVA - Wholesale Market Service Charge	\$ -
RSVA - Retail Transmission Network Charge	\$ -
RSVA - Retail Transmission Connection Charge	\$ -
RSVA - Power (excluding Global Adjustment)	\$ -
RSVA - Power - Sub-Account - Global Adjustment	\$ -
Recovery of Regulatory Asset Balances	\$ -
Disposition and Recovery of Regulatory Balances	\$ -
	\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588 \$ -

Entry by USofA	Principal	Interest	Total
1518 RCVA	2,833,365	113,367	2,946,732
1548 RCVA STR	(504,065)	(23,678)	(527,743)
1550 LV	(6,928,672)	(57,739)	(6,986,411)
1555 Smart Meter	(11,476,769)	(100,928)	(11,577,697)
1556 Smart Meter	(4,382,909)	(44,274)	(4,427,183)
1580 RSVA-Wholesale	26,508,006	256,312	26,764,318
1584 RSVA-Network s	9,172,728	250,414	9,423,142
1586 RSVA-STR	5,875,061	32,682	5,907,743
1588 GA	(13,176,663)	(81,322)	(13,257,985)
1590 RARA 1	33,858,100	(10,966,270)	22,891,830
	<u>41,778,181</u>	<u>(10,621,436)</u>	<u>31,156,745</u>
Sum green	55,308,559	(10,565,922)	44,742,637
Sum not included	(13,530,378)	(55,514)	(13,585,892)
Total	41,778,181	(10,621,436)	31,156,745

	Principal open	Principal Trans	Principal Principal	Principal Adjstments	Principal close	Interest open	Interest Trans	Interest	Interest Adjstments	Interest close
1550	\$ 6,928,672	-\$ 3,662,812		(6,928,672)	-\$ 3,662,812	\$ 57,739	33764.75		(57,739)	\$ 33,765
1580	-\$ 26,508,006	-\$ 31,720,243		26,508,006	-\$ 31,720,243	-\$ 256,312	-199652.56		256,312	-\$ 199,653
1584	-\$ 9,172,728	\$ 8,383,765		9,172,728	\$ 8,383,765	-\$ 250,414	34088.29		250,414	\$ 34,088
1586	-\$ 5,875,061	\$ 2,397,784		5,875,061	\$ 2,397,784	-\$ 32,682	6770.46		32,682	\$ 6,770
1588	\$ -				\$ -	\$ -				\$ -
1588	\$ 13,176,663	-\$ 4,070,115		(13,176,663)	-\$ 4,070,115	\$ 81,322	-21540.59		(81,322)	-\$ 21,541
1590	-\$ 53,648,611	\$ 8,961,627		33,858,100	-\$ 10,828,884	\$ 19,659,616	-904073.5		(10,966,270)	\$ 7,789,273
1595	\$ -	\$ 23,043,182		(41,778,181)	-\$ 18,734,999	\$ -	(10,762,293)		10,621,436	-\$ 140,857
1595	\$ -				\$ -	\$ -				\$ -
				<u>13,530,378</u>					<u>55,514</u>	
				<u>55,308,559</u>					<u>(10,565,922)</u>	

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-09	Transactions Debit/ (Credit) during 2009 excluding interest and adjustments ⁶	Board-Approved Disposition during 2009	Adjustments during 2009 - other ³
LV Variance Account	1550	\$ 1,863,853	\$ 5,064,819		
RSVA - Wholesale Market Service Charge	1580	-\$ 11,301,124	-\$ 15,206,882		
RSVA - Retail Transmission Network Charge	1584	-\$ 13,821,196	\$ 4,648,468		
RSVA - Retail Transmission Connection Charge	1586	-\$ 2,965,531	-\$ 2,909,530		
RSVA - Power (excluding Global Adjustment)	1588	\$ -			
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 5,531,417	\$ 7,645,247		
Recovery of Regulatory Asset Balances	1590	-\$ 43,004,093	-\$ 10,644,518		
Disposition and Recovery of Regulatory Balances	1595	\$ -	\$ -		
	1595	\$ -	\$ -		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 63,696,675	-\$ 11,402,396	\$ -	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 69,228,092	-\$ 19,047,642	\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 5,531,417	\$ 7,645,247	\$ -	\$ -

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Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009
LV Variance Account	1550	\$ 6,928,672	\$ 24,729	\$ 33,010	
RSVA - Wholesale Market Service Charge	1580	-\$ 26,508,006	-\$ 76,839	-\$ 179,473	
RSVA - Retail Transmission Network Charge	1584	-\$ 9,172,728	-\$ 114,856	-\$ 135,558	
RSVA - Retail Transmission Connection Charge	1586	-\$ 5,875,061	-\$ 4,757	-\$ 27,925	
RSVA - Power (excluding Global Adjustment)	1588	\$ -	\$ -		
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 4,951	\$ 86,273	
Recovery of Regulatory Asset Balances	1590	-\$ 53,648,611	\$ 20,055,015	-\$ 395,399	
Disposition and Recovery of Regulatory Balances	1595	\$ -	\$ -		
	1595	\$ -	\$ -		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 75,099,071	\$ 19,878,342	-\$ 619,073	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 88,275,734	\$ 19,883,292	-\$ 705,346	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 4,951	\$ 86,273	\$ -

Account Descriptions	Account Number	Adjustments during 2009 - other ³	Closing Interest Amounts as of Dec-31-09
LV Variance Account	1550		\$ 57,739
RSVA - Wholesale Market Service Charge	1580		-\$ 256,312
RSVA - Retail Transmission Network Charge	1584		-\$ 250,414
RSVA - Retail Transmission Connection Charge	1586		-\$ 32,682
RSVA - Power (excluding Global Adjustment)	1588		\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588		\$ 81,322
Recovery of Regulatory Asset Balances	1590		\$ 19,659,616
Disposition and Recovery of Regulatory Balances	1595		\$ -
	1595		\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ 19,259,269
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ 19,177,947
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ 81,322

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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	Adjustments during 2010 - other ³
LV Variance Account	1550	\$ 6,928,672	-\$ 3,265,860		
RSVA - Wholesale Market Service Charge	1580	-\$ 26,508,006	-\$ 5,212,237		
RSVA - Retail Transmission Network Charge	1584	-\$ 9,172,728	\$ 17,556,492		
RSVA - Retail Transmission Connection Charge	1586	-\$ 5,875,061	\$ 8,272,844		
RSVA - Power (excluding Global Adjustment)	1588	\$ -			
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 17,246,778		
Recovery of Regulatory Asset Balances	1590	-\$ 53,648,611	\$ 42,819,727		
Disposition and Recovery of Regulatory Balances	1595	\$ -	\$ 9,696,637		-\$ 28,431,636
	1595	\$ -	\$ -		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 75,099,071	\$ 52,620,826	\$ -	-\$ 28,431,636
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 88,275,734	\$ 69,867,604	\$ -	-\$ 28,431,636
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 13,176,663	-\$ 17,246,778	\$ -	\$ -

2010				
Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10
LV Variance Account	1550	\$ 3,662,812	\$ 57,739	-\$ 23,974
RSVA - Wholesale Market Service Charge	1580	-\$ 31,720,243	-\$ 256,312	\$ 56,659
RSVA - Retail Transmission Network Charge	1584	\$ 8,383,765	-\$ 250,414	\$ 284,502
RSVA - Retail Transmission Connection Charge	1586	\$ 2,397,784	-\$ 32,682	\$ 39,452
RSVA - Power (excluding Global Adjustment)	1588	\$ -	\$ -	
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 4,070,115	\$ 81,322	-\$ 102,863
Recovery of Regulatory Asset Balances	1590	-\$ 10,828,884	\$ 19,659,616	-\$ 11,870,343
Disposition and Recovery of Regulatory Balances	1595	-\$ 18,734,999	\$ -	-\$ 127,374
	1595	\$ -	\$ -	
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 50,909,881	\$ 19,259,269	-\$ 11,743,939
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 46,839,766	\$ 19,177,947	-\$ 11,641,077
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 4,070,115	\$ 81,322	-\$ 102,863

Account Descriptions	Account Number	Board-Approved Disposition during 2010	Adjustments during 2010 - other ³	Closing Interest Amounts as of Dec-31-10
LV Variance Account	1550			\$ 33,765
RSVA - Wholesale Market Service Charge	1580			-\$ 199,653
RSVA - Retail Transmission Network Charge	1584			\$ 34,088
RSVA - Retail Transmission Connection Charge	1586			\$ 6,770
RSVA - Power (excluding Global Adjustment)	1588			\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588			-\$ 21,541
Recovery of Regulatory Asset Balances	1590			\$ 7,789,273
Disposition and Recovery of Regulatory Balances	1595		-\$ 13,483	-\$ 140,857
	1595			\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	-\$ 13,483	\$ 7,501,846
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	-\$ 13,483	\$ 7,523,387
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ -	-\$ 21,541

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	Other ³ Adjustments during Q1 2011
LV Variance Account	1550	\$ 3,662,812	\$ 3,014,020		
RSVA - Wholesale Market Service Charge	1580	-\$ 31,720,243	-\$ 35,443,413		
RSVA - Retail Transmission Network Charge	1584	\$ 8,383,765	\$ 12,314,151		
RSVA - Retail Transmission Connection Charge	1586	\$ 2,397,784	\$ 7,056,564		
RSVA - Power (excluding Global Adjustment)	1588	\$ -			
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 4,070,115	-\$ 4,669,747		
Recovery of Regulatory Asset Balances	1590	-\$ 10,828,884	\$ 5,593,980		
Disposition and Recovery of Regulatory Balances	1595	-\$ 18,734,999	\$ 18,804,384		
	1595	\$ -			
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-\$ 50,909,881	\$ 6,669,938	\$ -	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-\$ 46,839,766	\$ 11,339,685	\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 4,070,115	-\$ 4,669,747	\$ -	\$ -

		2011			
Account Descriptions	Account Number	Other ³ Adjustments during Q2 2011	Other ³ Adjustments during Q3 20101	Other ³ Adjustments during Q4 2011	Closing Principal Balance as of Dec- 31-11
LV Variance Account	1550				\$ 6,676,832
RSVA - Wholesale Market Service Charge	1580				-\$ 67,163,657
RSVA - Retail Transmission Network Charge	1584				\$ 20,697,915
RSVA - Retail Transmission Connection Charge	1586				\$ 9,454,348
RSVA - Power (excluding Global Adjustment)	1588				\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588				-\$ 8,739,863
Recovery of Regulatory Asset Balances	1590				-\$ 5,234,904
Disposition and Recovery of Regulatory Balances	1595				\$ 69,385
	1595				\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ -	\$ -	-\$ 44,239,943
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ -	\$ -	-\$ 35,500,080
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ -	\$ -	-\$ 8,739,863

Account Descriptions	Account Number	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other ³
LV Variance Account	1550	\$ 33,765	\$ 76,851		
RSVA - Wholesale Market Service Charge	1580	-\$ 199,653	-\$ 724,535		
RSVA - Retail Transmission Network Charge	1584	\$ 34,088	\$ 206,236		
RSVA - Retail Transmission Connection Charge	1586	\$ 6,770	\$ 74,289		
RSVA - Power (excluding Global Adjustment)	1588	\$ -			
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 21,541	-\$ 134,564		
Recovery of Regulatory Asset Balances	1590	\$ 7,789,273	-\$ 92,906		
Disposition and Recovery of Regulatory Balances	1595	-\$ 140,857	-\$ 136,491		
	1595	\$ -			
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ 7,501,846	-\$ 731,120	\$ -	\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ 7,523,387	-\$ 596,556	\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 21,541	-\$ 134,564	\$ -	\$ -

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Account Descriptions	Account Number	Closing Interest Amounts as of Dec-31-11
LV Variance Account	1550	\$ 110,616
RSVA - Wholesale Market Service Charge	1580	-\$ 924,188
RSVA - Retail Transmission Network Charge	1584	\$ 240,324
RSVA - Retail Transmission Connection Charge	1586	\$ 81,060
RSVA - Power (excluding Global Adjustment)	1588	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 156,105
Recovery of Regulatory Asset Balances	1590	\$ 7,696,367
Disposition and Recovery of Regulatory Balances	1595	-\$ 277,348
	1595	\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ 6,770,727
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ 6,926,831
RSVA - Power - Sub-Account - Global Adjustment	1588	-\$ 156,105

		2011		Page 25 of 27	
Account Descriptions	Account Number	Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31- 11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted during 2012 Disposition
LV Variance Account	1550			\$ 6,676,832	\$ 110,616
RSVA - Wholesale Market Service Charge	1580			-\$ 67,163,657	-\$ 924,188
RSVA - Retail Transmission Network Charge	1584			\$ 20,697,915	\$ 240,324
RSVA - Retail Transmission Connection Charge	1586			\$ 9,454,348	\$ 81,060
RSVA - Power (excluding Global Adjustment)	1588			\$ -	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588			-\$ 8,739,863	-\$ 156,105
Recovery of Regulatory Asset Balances	1590			-\$ 5,234,904	\$ 7,696,367
Disposition and Recovery of Regulatory Balances	1595			\$ 69,385	-\$ 277,348
	1595			\$ -	\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 44,239,943	\$ 6,770,727
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 35,500,080	\$ 6,926,831
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ -	-\$ 8,739,863	-\$ 156,105

Page 26 of 27		Projected Interest on Dec-31-11 Balances			2.1.7 RRR
Account Descriptions	Account Number	Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -1 balance adjusted for disposition	Total Claim	As of Dec 31-11 ⁴
LV Variance Account	1550			\$ 6,787,448	\$ 6,787,448
RSVA - Wholesale Market Service Charge	1580			-\$ 68,087,844	-\$ 68,087,844
RSVA - Retail Transmission Network Charge	1584			\$ 20,938,239	\$ 20,938,239
RSVA - Retail Transmission Connection Charge	1586			\$ 9,535,408	\$ 9,535,408
RSVA - Power (excluding Global Adjustment)	1588			\$ -	
RSVA - Power - Sub-Account - Global Adjustment	1588			-\$ 8,895,967	-\$ 8,895,967
Recovery of Regulatory Asset Balances	1590			\$ 2,461,463	\$ 2,461,463
Disposition and Recovery of Regulatory Balances	1595			-\$ 207,963	-\$ 207,963
	1595			\$ -	
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 37,469,217	-\$ 37,469,217
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -	\$ -	-\$ 28,573,249	-\$ 28,573,249
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -	\$ -	-\$ 8,895,967	-\$ 8,895,967

Account Descriptions	Account Number	Variance RRR vs. 2011 Balance (Principal + Interest)
LV Variance Account	1550	\$ -
RSVA - Wholesale Market Service Charge	1580	\$ -
RSVA - Retail Transmission Network Charge	1584	\$ -
RSVA - Retail Transmission Connection Charge	1586	\$ -
RSVA - Power (excluding Global Adjustment)	1588	\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -
Recovery of Regulatory Asset Balances	1590	\$ -
Disposition and Recovery of Regulatory Balances	1595	\$ -
	1595	\$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		\$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		\$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ -

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

**Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and
Variance Accounts appropriate?**

Interrogatory

Ref: Exhibit E1/Tab 2/Sch1/page 4

As per Exhibit E1/Tab 2/Schedule 1/page 4, Footnote 2, Hydro One is proposing to recover approximately \$11.445 million of Account 1590 – Hydro One stated it is associated with the disposition of other regulatory balances, primarily associated with RARA 2. It also would like to refund approximately (\$8.984) million of Account 1590 – Hydro One stated it is associated with the disposition of 2008 Regulatory balance.

- a) Please explain why there is a residual balance of (\$8.984) million in Account 1590 with respect to regulatory balances cleared in 2008 when the account was cleared in EB-2007-0681.
- b) Please explain why there is a residual balance of \$11.445 million in Account 1590 with respect to “other regulatory balances, primarily associated with RARA 2”, considering RARA 2 involved amounts cleared in EB-2005-0378 and Hydro One had the an opportunity to clear the account in EB-2007-0681 and EB-2009-0096.
- c) Please describe the “other regulatory balances” to which the \$11.445 million balance in Account 1590 can be attributed.

Response

- a) The credit balance \$9.0M in Account 1590 relates to RARA 3. This account was drawn down on a volumetric basis over 27 months between February 1, 2009 and April 30, 2011. The \$9.0M balance consists of \$6.2 million relating to volumetric variances from forecast and \$2.7M interest on the principal balance.
- b) The \$11.4M remaining in Account 1590 is composed of \$11.0M from RARA 2 and \$0.5M from RARA 4. RARA 2 was drawn down over a 4 year period from May 2006 to April 2010, and RARA 4 was drawn down over 27 months from February 2009 to April 2011. As the drawdown period was in still in effect, it was not appropriate to clear the accounts in EB-2007-0681 nor in EB-2009-0096. The majority of the balance outstanding is interest on the principal balance.
- c) See part b) above.

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

**Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and
Variance Accounts appropriate?**

Interrogatory

Ref: ExhibitE1/Tab 2/Sch1/Table 1
EB-2009-0096 Decision, page 55

Hydro One is proposing not to clear the balance in Account 1588 RSVA Power, Excluding Global Adjustment. As per EB-2009-0096 Decision, page 55, the Board stated the following:

The Board directs Hydro One to track the dollar value of variances between the Board approved losses recovered in rates, and actual line losses, commencing January 1, 2010. The Board expects that the information related to wholesale purchases, as well as line losses recovered in rates, are currently available to Hydro One through its wholesale meters, and its billing systems. The Board further expects that Hydro One can obtain the dollar value of recoveries of losses in rates from its billing system; and can convert the kWh information of actual line losses (which are measured and reported to the Board under RRR 2.1.5) to dollar values, although other approaches, such as the allocation method identified by Hydro One, may be appropriate. Hydro One is directed to bring this analysis to its next cost of service proceeding so that this issue may be further examined.

- a) Does Hydro One plan to bring forward the above noted analysis in its next cost of service proceeding? If this is not the case, please explain.
- b) Did Hydro One begin to track the dollar value of variances between the Board approved losses recovered in rates, and actual line losses, and record these amounts in its general ledger, RRR 2.1.7, and audited financial statements from January 1, 2010 forward? If this is not the case, please explain.

Response

- a) Yes. Hydro One will bring forward the above noted analysis of line loss actuals and the associated revenue variances in its next cost of service proceeding.
- b) Hydro One is attempting to estimate line losses experienced on the system. However, this estimation is based upon a system assessment. An exact calculation of the revenue amount would require that the data be linked to the actual time that the

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Exhibit I

Tab 8

Schedule 1.05 Staff 27

Page 2 of 2

- 1 energy was provided. While an attempt to track the dollar value of the variance is
- 2 underway, there has been nothing recorded in the general ledger.

Energy Probe (EP) INTERROGATORY #21 List 1

Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and Variance Accounts appropriate?

Interrogatory

Ref: Exhibit E1, Tab 2, Schedule 1, Pages 4 and 5 and Table 1 &
Exhibit E1, Tab 2, Schedule 1, Attachment 4 &
Exhibit E1, Tab 3, Schedule 1, Table 1

- a) Please explain the \$7.7 million Carrying Charge on the 1590 Account.
- b) Please show the rate and Bill Impact of disposing the Group 1 Account balance in 2013 rather than 2013-2014 based on projected revenue requirements including rate riders.
- c) What is the forecast for the 2013 and 2014 for account 1580 RSVA Wholesale Market Charge.?
- d) If the forecast is for another large negative balance, why would splitting the 2011 1580 balance be appropriate?
- e) Please provide a schedule that shows the recovery shares of the Group1 accounts by rate class.
- f) Indicate where changes have been made what those changes are relative to the last approved disposition, and the effect on the disposition amounts.

Response

- a) The \$7.7M carrying charge in Account 1590 is applicable to the following three regulatory asset recover accounts. Interest is applied on the net principal balance at the Board's approved interest rate.

Account	Amount	Drawdown Period
RARA 2	\$10.1 M	48 months (May 2006 – April 2010)
RARA 3	(\$2.7 M)	27 months (Feb. 2009 – April 2011)
RARA 4	\$0.4 M	27 months (Feb. 2009 – April 2011)

- 1
- 2 b) See the response in Exhibit I, Tab 8, Schedule 5.01 VECC 39 for the average
- 3 distribution rate impacts resulting from the disposition of the Group 1 accounts over 1
- 4 and two years. The Total Bill impacts are about 1/3 of the distribution impacts
- 5 shown.
- 6
- 7 c) Account 1580, RSVA Wholesale Market Service Charge, records the difference
- 8 between the amount billed to customers using the OEB-approved rate and the amount
- 9 charged by the IESO through its monthly settlement invoice. Hydro One does not
- 10 have the ability to accurately forecast 2013 and 2014 RSVA-WMSC balances
- 11 because the IESO's invoices cannot be forecast.
- 12
- 13 d) Hydro One anticipates that there will remain a large negative balance in this account
- 14 unless the OEB changes the RSVA approved rate to charge distribution customers.
- 15 Disposing of the balance over a two year period mitigates rate impacts as shown in
- 16 Exhibit I, Tab 8, Schedule 5.01 VECC 39.
- 17
- 18 e) The recovery share for the Group 1 accounts by rate class are shown on "Sheet 11" of
- 19 the output from the OEB 2013 GIRM model, which is provided at Exhibit E2, Tab 1,
- 20 Schedule 1.
- 21
- 22 f) The disposition of the Group 1 accounts follows the process prescribed in the OEB's
- 23 3GIRM model with some changes proposed by HONI as detailed on pages 5-7 of
- 24 Exhibit E1, Tab 2, Schedule 1. With the changes as proposed by HONI, there would
- 25 be no difference in the proposed disposition of Group 1 accounts relative to the last
- 26 approved disposition under EB-2009-0096.

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

Issue 8 **Is Hydro One's proposed disposition of Group 1 Deferral and Variance Accounts appropriate?**

Interrogatory

Reference: **Exhibit A, Tab 3, Schedule 1, page 4**
Exhibit E1, Tab 2 Schedule 1, page 5

Preamble: HON is proposing to refund the Group 1 balance over two years "in order to mitigate rate volatility".

- a) Please demonstrate how the two-year disposition mitigates rate volatility as opposed to a one year disposition period, in the context of the overall rate increases anticipated over the next two years.

Response

- a) The table below illustrates the average rate impacts for the disposition of the Group 1 balance over one-year and two-year periods. The highlighted rows illustrate that the proposed two-year disposition smooths out the average rate impact on the customer.

	2012	2013	2014	2015
Revenue Requirement (\$M)	\$1,148.9	\$1,159.0*	\$1,169.2**	\$1,169.2***
Group1 accounts balance - Disposed over two years		-\$18.7	-\$18.7	\$0.0
Total revenue requirement with rider: Two year disposition		\$1,140.3	\$1,150.5	\$1,169.2
Average impact on rates with two year disposition		-0.75%	0.89%	1.63%
Group1 accounts balance - Disposed over one year		-\$37.5	\$0.0	\$0.0
Total revenue requirement with rider: One year disposition		\$1,121.5	\$1,169.2	\$1,169.2
Average impact on rates with one year disposition		-2.38%	4.25%	0.00%

* Base IRM Revenue Requirement (RR) = 2012 RR*1.0088

** Illustrative RR assuming 2014 IRM increase is the same as 2013.

*** Illustrative RR assuming 2015 RR remains at 2014 level.

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

Issue 8 Is Hydro One's proposed disposition of Group 1 Deferral and Variance Accounts appropriate?

Interrogatory

**Reference: Exhibit E1, Tab 2, Schedule 1, page 6 and Attachment 4
 Exhibit E2, Tab 1, Schedule 1, Sheets 9 and 11**

- a) The balances shown for Accounts 1590 and 1595 in E1/T2/S1, page 6 don't match those in Sheets 9 and 11. For example, the balance for Account 1590 in Table 1 is \$2,461,463 whereas in Sheets 9 and 11 it is \$11,444,981. Please reconcile.

Response

- a) Accounts 1590 and 1595 balances for December 31, 2011 are \$2,461,463 and (\$207,963) respectively, as shown in Exhibit E1, Tab 2, Schedule 1, Page 4, Table 1.

Exhibit E2, Tab 1, Schedule 1, Sheet 9, of the Board's model requires that the disposition of the regulatory balance be shown separately by year. As such, \$8,983,518 was subtracted from the 1590 account balance and shown on "Disposition and Recovery of Regulatory Balances 2008 – Account 1595" line. The remaining balance of \$11,444,981 is associated with other regulatory balances and remains to be shown in Account 1590 on Sheet 9. The same applies to Sheet 11.

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

Issue 9 Hydro One's proposed rate rider to share the impact of the income tax decrease with customers appropriate?

Interrogatory

Ref: Exhibit E2/Tab1/Sch1/Sheet 12, Calc of Def_Var RR Attachment 3, Calculation of Shared Tax Savings Rate Rider- Variable

In column P(Billed kW) of Attachment 3, filed June 15, Calculation of Shared Tax Savings Rate Rider- Variable, 35,499,080 kW is shown for the Sub-Transmission rate class. However, the Billed kW at Exhibit E2-01-01, Sheet 12, Calc of Def_Var RR, is calculated to be 33,188,719 kW for the Sub-Transmission rate class.

Please indicate the correct number to use. Please update the evidence as appropriate with the correct number.

Response

The correct number for the ST class Billed kW is 35,499,081 kW.

As shown in Exhibit E2, Tab 1, Schedule 1, Sheet 12 (Calc of Def_Var RR), Cell D116, the charge determinant used to calculate the Deferral Variance Account rate rider is 35,499,081 kW, which is same as that used in the calculation of the Shared Tax Savings rate rider.

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

Issue 9 **Hydro One's proposed rate rider to share the impact of the income tax decrease with customers appropriate?**

Interrogatory

Reference: **Exhibit A, Tab 3, Schedule 1, page 4**

Preamble: HON has not updated its Application for the reduction in the tax savings amount from \$1.7 M to \$1.1 M

- a) How material is this reduction in terms of the overall bill impacts customers will experience from HON's Application as set out in Exhibit E1, Tab 3, Schedule 1 and Exhibit E2, Tab 3, Schedule 1?

Response

The impact of the reduction in the tax savings amount will be reflected in the Draft Rate Order to be submitted after the Board Decision on this Application. The impact of the \$600,000 reduction in the tax savings amount will increase distribution rates on average by about 0.05%, with a total bill impact of less than 0.02%.

Ontario Energy Board (Board Staff) INTERROGATORY #29 List 1

Issue 10 Is Hydro One's proposed smart grid rate adder appropriate?

Interrogatory

Ref: Exhibit C/Tab1/Sch1/page 2

Hydro one indicates that it has installed a base of new smart grid assets including a distribution management system. Please describe or provide further detail on these assets and the cost of each

Response

Hydro One has installed new smart grid assets at both the Ontario Grid Control Centre and in the Owen Sound area.

At the Ontario Grid Control Centre a Distribution Management system was installed. The Distribution Management System is a control system that monitors and controls the distribution system. It also provides a series of power applications focused on the distribution system. Specifically the DMS meets the business objectives set out in the Green Energy Plan through:

- Distributed Generation Integration - Provides state estimation of the distribution system while factoring in the effects of renewable generation and providing operators with information on the direction of power flows.
- Distribution Reliability - Provides a control system for operators to monitor and control the distribution system.
- Outage Optimization – Provides fault location allowing field crews to find faults faster and restore outages quicker.
- Asset Planning – Provides load flow functionality so Hydro One can study the distribution system for planned and forced outages.

The Distribution Management system implementation involved the implementation of a control system (software and computer hardware) at the control centre as well as gathering data for the distribution network model.

On the power system in the Owen Sound area, Hydro One installed a series of assets to pilot various smart grid functionalities. Specifically, enhancements have been made to one transmission station, four distribution stations and various smart devices (e.g. remote-controlled tie-switches, line regulators, etc.) have been installed on distribution feeders.

Hydro One's implementation of these projects is consistent with the Smart Grid portion of the Green Energy Plan filed in 2009.

The expenditures on the Distribution Management System are provided below:

DMS Expenditures	2010	2011	2012 YTD*	Total
Actuals	0	14.5	21.8	36.3

*2012 Actuals as at June 30, 2012

The total Smart Grid costs, including the Smart Zone Pilot project and Smart Grid Studies (to June 30, 2012) are \$81.5 M (OM&A and Capital). Please see Exhibit I, Tab 10, Schedule 1.02 Staff 30.

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

Issue 10 Is Hydro One's proposed smart grid rate adder appropriate?

Interrogatory

Ref: Exhibit C/Tab1/Sch1/page 3

At Table 2 on this page, Hydro One shows approved Smart Grid Capital and OM&A expenditures approved for 2010 and 2011. Please provide similar statistics for actual expenditures for 2010 and 2011, including year to date 2012 expenditures.

Response

The expenditures approved by the Board for Phase 1 in 2010 and 2011 are shown in the table below along with the actual and forecast expenditures in 2010, 2011 and 2012.

Smart Grid Capital	2010	2011	2012 Actuals*	2012 Forecast	Total Actuals*	Total Forecast
Approved	30.0	62.0			92.0	92.0
Actuals*	18.0	29.9	25.2	39.4	73.1	87.3

Smart Grid OM&A	2010	2011	2012 Actuals*	2012 Forecast	Total Actuals*	Total Forecast
Approved	10.0	10.0			20.0	20.0
Actuals*	2.5	3.1	2.8	14.6	8.4	20.2

*Actuals as of June 30, 2012.

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

Issue 10 Is Hydro One's proposed smart grid rate adder appropriate?

Interrogatory

Ref: Exhibit CfTab1/Sch1/page 3

Hydro One indicates that a significant proportion of the proposed smart grid expenditures were with respect to the Smart Zone Pilot project. Please provide a report of the status of the Smart Zone project, including accomplishments and a breakdown of Capital and OM &A costs incurred. What were the major learnings realized from this pilot so far?

Response

The Smart Zone Pilot project is a multi-year, multi-release project through which Hydro One is piloting new smart grid solutions and validating business benefits prior to a provincial deployment. Hydro One is currently finishing Release 1 of the Smart Zone Pilot project. Release 1 was focused on laying the core infrastructure for the smart grid in the Smart Zone Pilot area and on the integration of renewable energy generation. The accomplishments of Release 1 to date are:

- The installation of the Distribution Management System at the control centre that is going through its final rounds of testing and full implementation of the DMS system is on-track for completion by year-end 2012.
- The installation of smart grid field devices in the Smart Zone Pilot area that are going through their final rounds of commissioning.
- Enhancements to the Owen Sound transmission station, as well as four distribution stations in the Smart Zone Pilot area.

A breakdown of the capital and OM&A costs in the Smart Zone Pilot incurred to date is provided below:

Smart Zone Expenditures	2010	2011	2012 YTD*	Total
Capital Actuals	18.0	29.9	25.2	73.1
OM&A Actuals	2.2	0.4	0.4	3.0
Totals Actuals	20.2	30.3	25.6	76.1

*2012 Actuals as at June 2012

As noted, the Smart Zone Pilot project is still under way and key learnings are not yet available but the major accomplishments are provided above.

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

Issue 10 Is Hydro One's proposed smart grid rate adder appropriate?

Interrogatory

Ref: Exhibit CfTab1/Sch1/page 6

Hydro One indicates that with addition renewable generation, its control room will evolve into separate transmission and distribution operator's functions. Why would these functions be separated into transmission and distribution and not integrated into a common function as generation is added to the distribution system?

Response

The Smart Zone Pilot is taking the initial approach of establishing separate distribution workstations but staffed by the same pool of operator resources. All past synergies remain with a single integrated control centre and a common pool of resources. There are no plans for a separate distribution control room for distribution operations. Through the course of the pilot, Hydro One will apply its learnings to ensure that the final control room configuration optimizes efficiency and operational synergies prior to provincial deployment.

Energy Probe (EP) INTERROGATORY #22 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 1, Pages 2 - 4

This page refers to the new Distribution Management System ("DMS") that Hydro One has installed.

- a) When did this system become operational?
- b) What was the installed cost of the system?
- c) What is the upgrade referred to on Line 20 Page 4, how much will it cost and why is an upgrade necessary so soon after implementation of the original system?
- d) How did Hydro One manage the distribution system without the DMS since the advent of distributed generation on its lines? Please describe the problems encountered before the new DMS was installed and how they were dealt with.

Response

- a) Please see Exhibit I, Tab 10, Schedule 1.03 Staff 31
- b) Please see Exhibit I, Tab 10, Schedule 1.01 Staff 29
- c) The DMS is supported by regular releases of updated software. These releases provide additional/improved functionality for the Distribution Management System. The planned software updates are part of the maintenance agreement Hydro One has with the DMS vendor and there are no incremental costs for the software. There are additional costs for the implementation of the releases. These costs are not known at this time and will be determined as part of the Smart Zone Pilot.
- d) Hydro One uses established engineering guidelines to limit the number of distributed generators that can connect to the system. To this point we have been able to handle the volume of distributed generators connected but as the number of distributed generators grows, this approach will no longer be tenable. We have already had to constrain the number of connections based on these guidelines and these constraints will only increase as we connect more distributed generators.

Energy Probe (EP) INTERROGATORY #23 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 1, Pages 5 - 6

Page 5 shows sustainment funding of \$7.0 M required for new smart grid systems.

- a) Will this level of funding be required on an ongoing basis?
- b) Is this funding entirely for the DMS or does it also support other new systems? If the latter please elaborate and quantify the part of the \$7.0 M that will be devoted to other than the DMS.
- c) Is the "extensive infrastructure (servers, networking devices, firewalls)" referred to in Lines 19-20 all installed or is more yet to be done? If the latter, please describe the work remaining and the estimated cost. Where is the capital cost included?
- d) How many FTEs will be needed for the maintenance team referred to in Lines 22-23? Will this be an ongoing requirement for the life of the DMS system?
- e) Line 11 on Page 6 refers to the "limited points of telemetry currently available". Please explain what the telemetry points are and what Hydro One's plans are to expand the number of points. How much will the expansion of telemetry points cost? Where is the cost included?

Response

- a) Yes, this level of funding will be required on an ongoing basis to support the systems and functionality delivered as part of Release 1 of the Smart Zone Pilot.
- b) The funding supports the DMS as well as new systems. Please see Exhibit I, Tab 10, Schedule 5.01 VECC 42 for a breakdown of the \$7.0 million.
- c) The only infrastructure installed to date is that required for the Smart Zone Pilot. Hydro One will make incremental investments in the future to support provincial deployment. The size and scope of this infrastructure will be determined through experience in the Smart Zone Pilot, so the costs for the additional infrastructure are not known at this time.

1 d) While the final number of staff is yet to be determined and will be verified during the
2 Smart Zone Pilot, the forecast is for eight staff to maintain the DMS in 2013. Yes,
3 this staff level will be needed on an ongoing basis.
4

5 e) The telemetry points are pieces of equipment on the transmission and distribution
6 system that capture information such as device state, and real-time voltage and
7 amperage readings and communicate this information back to control centre.
8

9 Most of the smart grid devices that are being installed in the Smart Zone Pilot are
10 capable of providing telemetry along with their other smart grid function (e.g. provide
11 fault location, provide motorized remote control of tie-switch, etc.).
12

13 Hydro One does not have a final plan on the number of telemetry points. We are
14 looking to leverage the existing investments in smart meters and Advanced Metering
15 Infrastructure to provide telemetry. Hydro One will also extend the deployment of
16 smart grid devices on a provincial basis once the technology and the business case is
17 validated. Deployment will be via augmentation of existing replacement and
18 refurbishment programs based on the new standards developed for the equipment as
19 part of the project. It is through these programs that Hydro One will augment other
20 devices with the ability to provide telemetry.

Energy Probe (EP) INTERROGATORY #24 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 1, Page 6

Lines 15-24 describe the expected transition to separation of OGCC operators into transmission and distribution.

- a) How many additional operators will be needed per line 23?
- b) What is the estimated cost of these new operators?
- c) Will a separate control room ultimately be needed for distribution operators? If yes, when does Hydro One expect it will be required?
- d) Reference is made to other utilities with this separated control room structure. Was this done in response to distributed generation and smart grid demands at these other utilities or for some other reason? Please elaborate.

Response

- a) It is not known at this time how many operators will be needed in the future. Further information will be gathered once the DMS is commissioned and it will also depend on the number of generators that connect to the system.
- b) See part a)
- c) See Exhibit I, Tab 10, Schedule 1.04 Staff 32.
- d) Other utilities have separate transmission operations and distribution operations for a variety of reasons. Distribution operations typically use a different control system from the transmission operations, requiring a different skill set.

Energy Probe (EP) INTERROGATORY #25 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 1, Page 8

Table 3 lists Release 2 Smart Grid Capabilities.

- a) Identifying energy theft refers to current capability of manually analyzing energy use patterns. Since smart meters provide hourly data, can this manual analysis be better performed by computers using the smart meter data?
- b) Please describe the proposed use of smart meters and localized line loss analysis referred to in the release 2 section. Will this proposal require additional telemetry on the system? If yes, please estimate the cost per feeder km. How will this be an improvement over the existing analysis system converted to computer analysis?
- c) Increased energy efficiency refers to managing the voltage along a feeder so that all customers are receiving power at the low end of the acceptable voltage range. Please explain how this will be accomplished in light of inherent I^2R losses of feeders.

Response

- a) Yes. Current capability has not incorporated the full use of smart meter data. Utilization of smart meter data as one input into effective theft analysis will be improved by the use of computer systems.
- b) By comparing the amount of energy flowing along the feeder (from telemetry devices) with the amount of energy measured at the smart meters, adjusted for local line loss, Hydro One will be able to mathematically isolate areas of feeders that have a high-probability of theft. It is not currently envisioned that Hydro One will install additional permanent telemetry points to catch energy theft; the use of temporarily installed telemetry points will be considered on a case-by-case basis as warranted. In general, Hydro One will leverage the permanent telemetry points installed as integral components of the smart grid.
- c) This will be accomplished through remote monitoring and control of existing voltage regulating devices on distribution system feeders, and only on feeders which would respond to lower voltage levels with lower customer loads. In those cases, line losses would also be reduced.

Energy Probe (EP) INTERROGATORY #26 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 1, Page 11

Table 4 shows Smart Grid Studies.

- a) The last study on Page 11 and the first study on Page 12 appear to be very similar. Please explain the differences.
- b) The Clean Energy Initiatives study on Page 11 mentions that it is sponsored by Pollution Probe and the Center for Clean Energy. What is Hydro One's role in this study? How much is it contributing in comparison to the other sponsors?
- c) Page 14 refers to sharing the information gained from studies with other distributors. Are the other distributors contributing to the cost of these studies? If yes, please elaborate. If no, please explain why Hydro One customers should pay the entire cost and other distributor customers get benefits from the studies.

Response

- a) The last study identified on page 11 and the first study identified on page 12 are referred to below as "Study 1" and "Study 2". They are two separate investment items planned for 2013, and the differences between the two are identified in the areas below:

1- Time Constraints

Study 1 addresses mostly imminent issues emanating from field application challenges and requiring urgent solutions usually within an 8-12 month term. Study 2 involves multiyear engagements for assessment of emerging technologies and applied research work.

2- Focus of Approach

Study 1 provides a micro focus on individual issues in isolation whereas the focus of Study 2 is at both micro and macro levels to assess the technology including development of overarching application needs of the system relevant to the impact of the integration of renewable distributed generation on Hydro One's grid.

3- Service Providers

Study 1 mostly involves short term services of an external technical research company in addressing the imminent issues currently facing the distribution system. Study 2 involves efforts of faculty staff at the research centers of Ontario Universities.

4- Project Structuring

Study 1 mostly employs external expertise and development with participation of Hydro One advisory staff to meet specific needs and applications. Study 2 entails independent technology assessment, modeling, simulations and laboratory pilot testing at Ontario Universities with participation from funding agencies and industry over multiple years supported by a coordinating project manager.

- b) Hydro One participates in the Conference Board of Canada's Centre for Clean Energy in developing technologies which integrate clean energy supply sources with end-users to advance the understanding of the transition to practical and sustainable clean energy for Canadian utilities.

Hydro One's role is to co-fund the initiative to support the development of the technology in partnership with universities, distribution companies, the Ontario Power Authority and industry partners. Hydro One's cash contribution does not exceed 50% of the total project cost.

- c) Yes. Some Distributors are contributing to Smart Grid studies which are undertaken by Hydro One on a multi-year and collaborative partnership basis with industry partners and universities.

Balsam Lake Coalition (BLC) INTERROGATORY #1 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Ref. Exhibit E1-2-1, Attachments 2-4, pages 1-4.

What is the basis for assigning the Smart Grid rider as a volumetric charge instead of a fixed charge?

Response

The Smart Grid Rider collects incremental 2013 revenue associated with Smart Grid OM&A expenses as detailed in Exhibit C1, Tab 1, Schedule 1. Hydro One proposes using a variable rate rider to be consistent with the approach used by the Board in collecting incremental revenue in their Decisions on Guelph's (EB-2010-0130), Oakville's (EB-2010-0104) and Kingston Hydro's (EB-2011-0178) IRM applications.

Balsam Lake Coalition (BLC) INTERROGATORY #2 List 1

Issue 10 **Is Hydro One's proposed Smart Grid rate adder appropriate?**

Interrogatory

Ref. Exhibit E1-2-1, Attachments 2-4, pages 1-4.

If indeed a volumetric charge is appropriate, why was it not set uniformly across all rate classes?

Response

See the response at Exhibit I, Tab 10, Schedule 7.06 CCC 20.

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

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Reference: Exhibit C, Tab 1, Schedule 1, page 5

a) Please provide a breakdown of the \$7.0 M as between:

- Licensing Fees
- Computer Infrastructure Maintenance and
- Staff to maintain the DMS system and other equipment.

Please also explain the source of additional Computer Infrastructure maintenance costs there are over above the cost of staff to maintain the system.

b) Were the ongoing costs associated with Release 1 of the ADS provided/flagged during the EB-2009-0096 proceeding? If so, please provide the references.

Response

a) Licensing fees directly associated with the DMS:	\$0.7M.
Computer Infrastructure Maintenance for DMS:	\$2.3M.
Staff to maintain the DMS system:	\$1.9M.
Staff to maintain other smart grid systems/devices:	\$2.1M.

In addition to the licensing fees associated with the DMS software, there are additional systems needed to support the DMS that have ongoing maintenance costs. These include cyber security systems, data backup systems, server operating systems licensing and database licensing.

b) Yes. They were included in the OM&A costs for 2012 - 2014 shown in the table in EB-2009-0096, Exhibit A, Tab 14, Schedule 2, Page 1.

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

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Reference: Exhibit C, Tab 1, Schedule 1, page 7 (lines 13-14)

- a) Please indicate precisely what investments (equipment/software and dollars) HON is planning on making in order to provide each of the additional capabilities set out in Table 3 and what the currently planned timing is for such investments.

Response

- a) The specific investments and the 2013 OM&A costs associated with the additional capabilities set out in Table 3 of the evidence is provided below.

Business Objective	Investments	2013 OM&A Budget (\$M)
Enable More Distributed Generation using Existing Assets	Design, build, test, integrate, and commission a system that will monitor and send dispatch signals to distributed generators in real time as well as install power system devices at the point of common connection that communicates with this system.	2.2
Use Energy Storage to Integrate DG	Design, build, test, integrate, and commission a system that will monitor and send dispatch signals to the pilot energy storage devices. Interface the control centre with the local controller for the energy storage device.	0.5
Improve Outage Restoration Times and Efficiency	Integrate and commission a system that will use the smart meter real-time power outage notifications to locate outages as well as provide for power outage confirmation by the dispatcher.	2.0
Catch & Reduce Energy Theft	Design, build, test, integrate, and commission a system that will find energy theft using meter and SCADA data combined with real-time local loss calculations. Pilot temporarily installed telemetry devices that communicate back with this system.	0.7

Business Objective	Investments	2013 OM&A Budget (\$M)
Demand Response for Consumers	Design, build, test, integrate, and commission a system that will monitor current demand response capacity and dispatch that capacity as needed on a manual or automated basis.	2.6
Increase Energy Efficiency	Design, build, test, integrate and commission a system that monitors voltage in real-time and sends command signals to voltage regulating devices along feeders. Install voltage regulating devices along pilot feeders that can take commands from the central system.	0.6
	TOTAL	\$8.6

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #44 List 1

Issue 10 **Is Hydro One's proposed Smart Grid rate adder appropriate?**

Interrogatory

Reference: **Exhibit C, Tab 1, Schedule 1, pages 7 and 8**

- a) Please provide a breakdown of the \$8.6 M OM&A expense as between the various initiatives set out on page 8, Table 3.

Response

- a) Please see Exhibit I, Tab 10, Schedule 5.02 VECC 43.

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

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Reference: Exhibit C, Tab 1, Schedule 1, page 8

- a) Apart from the energy storage initiative and the trial use of voltage regulating devices, are any of the other planned capabilities "pilots/trials" or are they all being introduced for use across HON's entire system?
- b) Why is the Demand Response for Consumers a "Smart Grid Initiative" as opposed to a CDM program?
- c) Did HON consult at all with the OPA regarding its "Demand Response for Consumers" initiative? If not, why not? If yes, did the OPA provide any indication that this initiative overlapped with any trials or programs the OPA will be or is considering implementing?
- d) Please discuss the extent to which HON has attempted to and/or is collaborating with other electricity distributors in the province in pursuing each of the initiatives set out in Table 3.
- e) What are the annual savings (kWh) from theft reduction anticipated as a result of the "Catch and Reduce Energy Theft" initiative?
- f) Based on the 2011 approved revenue requirement and rates what is the cost of a purchased kWh?
- g) Will cost savings from loss reductions be captured in HON's RSVA accounts and eventually refunded to customers? If not, why not?

Response

- a) Yes. All capabilities will be piloted and trialed before being introduced for use across Hydro One's entire system.
- b) Hydro One is an active participant in OPA programs and program development and as such consults with the OPA on an ongoing basis. The OPA and the Residential Working Group prefer to have Peaksaver (including in-home displays and future functionality) integrated with the various utility AMI systems. However the OPA does not fund any up front development of technologies aimed at achieving such integrations, which are by necessity LDC specific. Hence, Demand Response for

1 Consumers, which is designed to provide that integration, does not overlap with any
2 activities of the OPA.

3
4 c) Hydro One did meet with the OPA to provide an overview of all of its smart grid
5 activities, including our Demand Response for Consumers initiative. The OPA did
6 not provide any indication of overlap.

7
8 d) In pursuing its Smart Grid initiative, Hydro One is collaborating with other electricity
9 distributors in the province through the Ontario Smart Grid Forum and is a founding
10 member and an ongoing participant since 2010. In addition Hydro One participates in
11 a working group of large electricity distributors to collaborate on grid modernization
12 initiatives and share learnings. The large electricity distributors working group
13 includes Ottawa Hydro, Powerstream, Toronto Hydro, Veridian Connections,
14 Horizon Utilities, Enersource, Burlington Hydro, Waterloo North Hydro and the
15 Electricity Distributors Association. Participation in the working group is voluntary,
16 organized in a round table discussion format, with the role of Chair being shared
17 among participants. Most recently, to streamline the sharing of knowledge, this group
18 merged with Toronto's E8 grid modernization working group as almost all of its
19 members participate in both forums.

20
21 With respect to energy efficiency and demand response, in July 2011, Hydro One
22 issued an RFP seeking supplier (s) of Customer Information Displays (real time in-
23 home power monitors). Hydro One included members from Horizon Utilities, Hydro
24 Ottawa, Toronto Hydro, Powerstream, Milton Hydro, Peterborough Distribution,
25 Cambridge and North Dumfries Hydro, and Veridian Connections on its technical
26 advisory team in order to leverage their collective expertise in the emerging Customer
27 Information Display marketplace and to assist the utilities in making their own
28 Customer Information Display procurement decisions. The result was that Hydro
29 One was able to share with its technical advisory team the specific technical details
30 (i.e., non-pricing aspects) that were provided in the vendor submissions. The
31 technical advisory team members were free to share any opinions formed in the
32 course of participation on the team and with participating LDCs.

33
34 e) Hydro One is looking to reduce energy theft by one-third through energy theft
35 detection and the resulting deterrence effect of increased enforcement. Hydro One
36 will be piloting the new technology and will be better able to estimate the amount of
37 current theft as well as our ability to effectively reduce theft.

38
39 f) It is unclear what is meant by "purchased kWh" with reference to the 2011 approved
40 revenue requirement and rates. If the reference is to the cost of kWh "purchased"
41 from the electricity market, Hydro One's 2011 Weighted Average Hourly Spot Price
42 (WAHSP) was \$0.070459 /kWh.

- 1 g) Yes. The RSVA accounts capture the differences between the amount Hydro One
- 2 collects from customers and the amount Hydro One is invoiced from the IESO.

Consumers Council of Canada (CCC) INTERROGATORY #15 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

Ex. C/T1/S1/p. 3

Please provide the detailed Smart Grid budget approved by the Board in EB-2009-0096 and the actuals for each year of the project. What amounts have been recovered from customers? Was there a true-up? If not, why not?

Response

See Exhibit I, Tab 10, Schedule 1.04 Staff 30 for the Smart Grid budget approved by the Board in EB-2009-0096 and the actuals for each year of the project.

The amounts recovered from customers are as follows:

Table A

Actual Smart Grid Rider Recoveries 2010 and 2011			
	2010	2011	Total
Revenue Recovered	(7,961,678)	(18,357,245.16)	(26,318,923)

There has been no true-up at this time. Account 1536, Smart Grid Funding Adder deferral Account, is not included as a Type-1 Account for IRM filing purposes. As such it is not eligible for disposition during an IRM rate filing year. The account balance will be put forward for disposition at the next Cost of Service hearing.

Consumers Council of Canada (CCC) INTERROGATORY #16 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

EX. C/T1/S1/P. 3

Please provide a detailed budget for HON's smart grid activities in 2012. Will there be a true-up mechanism to ensure only actual expenditures are recovered from customers?

Response

Please see Exhibit I, Tab 10, Schedule 1.02 Staff 30 and Schedule 1.03 Staff 31 for smart grid activities and costs in 2012. Hydro One will be required to clear the Smart Grid variance account where costs are recorded through an application to the Board in the future and that process will incorporate a “true-up” mechanism.

Consumers Council of Canada (CCC) INTERROGATORY #17 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

EX. C1/T1/S1

Please provide the business cases for all 2012 Smart Grid projects.

Response

Phase 1, Release 1 of the Smart Grid project spans over 2010, 2011 and 2012. There are no separate business cases for the 2012 portion of the project. Please see the Business Case for Phase 1, Release 1 in Attachment 1 to this exhibit.



Investment Driver: N.D.C.2.06

Date: November 24, 2010

AR Number: 20140, 20141

Title: Advanced Distribution System Phase 1 Release 1

AR21040, AR21100, AR21101, AR21102

Hydro One Networks - Business Case Summary - 50001041

Advanced Distribution System Phase 1 Release 1

Investment Driver:

In-Service date: December 31, 2012

N.D.C.2.06 - Smart Grid (2011 - \$60.1M, 2012 - \$88.2M, 2013 - \$79.7M)

N.T.C.2.06 - Smart Grid (2011 - \$9.5M, 2012 - \$7.0M, 2013 - \$1.3M)

N.D.M.2.06 - Smart Grid (2011 - \$5.0M, 2012 - \$10.4M, 2013 - \$11.8M)

N.T.M.2.06 - Smart Grid (2011 - \$4.0M, 2012 - \$4.0M, 2013 - \$3.2M)

This Release: \$96.0M

Previous Release: \$0

Future Release: \$0

Project Total: \$96.0M

Need:

The broader ADS Phase 1 investment will accomplish the following:

1. The integration of the DMS into the Ontario Grid Control Centre;
2. Within the Smart Zone, two TSs and four DSs will be converted to utilize the IEC 61850 protection and control protocol through various intelligent station devices;
3. Installation of various field devices (e.g. smart reclosers, switches, cap banks) at points along feeders emanating from the stations listed above. These automated "smart" field devices will utilize a combination of existing protocols and test utilization of IEC 61850 over the WiMax network in the Smart Zone;
4. The end to end solution will include Privacy and Security principles throughout the design, build and commissioning stages.

This ADS Phase 1 Release 1 investment will implement a core set of infrastructure to establish the foundational DMS supporting 1 TS, related DS(s) and related "smart" field devices. Not proceeding with this investment will result in Hydro One not meeting the Ministry's expectations.

Investment Summary:

In Phase 1 Release 1 HONI will implement Telvent's Distribution Management System (DMS), a new application that will be a foundational component of an integrated end-to-end solution. The DMS will have awareness of the condition of the distribution system and have access to communicate with any enabled device through the SCADA system. The early focus will be on the integration of the DMS to the power system intelligent electronic devices to support DG. Subsequent Phase 1 releases will build functionality to integrate with the existing network management system, the outage management system including smart meters, the GIS, and work dispatch and accomplishment reporting through a mobile gateway enabled by WiMAX.

Results:

Phase 1 will utilize an industry-leading holistic integration of field and back office solution in a limited deployment in the Owen Sound Smart Zone. At the completion of Phase 1, cost and benefit elements for full provincial rollout will be validated.

Costs:

	2011 M	2012 M	Total M
Capital* and MFA	63.2	17.4	80.6
OM&A and Removals	5.0	10.4	15.4
Gross Investment Cost*	68.2	27.8	96.0
Recoverable	0.0	0.0	0.0
Net Investment Cost	68.2	27.8	96.0

* Cost includes overhead and AFUDC at current rates.

Investment Driver: N.D.C.2.06

Date: November 24, 2010

AR Number: 20140, 20141

Title: Advanced Distribution System Phase 1 Release 1

21040, 21100, 21101, 21102

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

The provincial government, through its Green Energy and Green Economy Act, 2009 and various policy statements, directed Hydro One to develop a strategy that fosters the growth of renewable energy projects by establishing and implementing a smart grid. The solution sets required to mitigate the effect of DG's require a significant (2 year) lead time to implement. Furthermore, OEB funding approval was obtained through the most recent Distribution & Transmission rate filings. As a result, the do-nothing alternative is rejected.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

The proposed expenditures will result in the implementation of a core set of infrastructure to achieve the broader ADS objectives of DG Integration, Dx Automation, Outage Restoration Optimization, and Dx Planning / Tools. In particular, Phase 1 Release 1 will see:

1. The integration of the DMS into the Ontario Grid Control Centre
2. A Transformer Station and associated Distribution Station(s) will be converted to utilize the IEC 61850 protection and control protocol through various intelligent station devices
3. The installation of various field devices (e.g. smart reclosers, switches, cap banks) at points along feeders emanating from stations. These automated "smart" field devices will utilize a combination of existing protocols and test utilization of IEC 61850 over the WiMax communications network
4. The end to end solution will include Privacy and Security principles throughout the design, build and commissioning stages

The rationale for recommending this alternative include the following:

Strategic Significance: Smart Meters, Conservation and Demand Management and Distributed renewable generation are forcing a paradigm shift in the distribution sector. A system that was originally designed for economical one-way power flow over large distances is now taxed with the accommodation of these "green" initiatives. The proposed investment will leverage our smart meter system, core IT systems (Network Management System (NMS) / GIS / Outage Management / Work Execution as well as other enterprise systems), and WiMAX to address the following.

Support for the Provincial Energy Strategy: Hydro One's Smart Grid investments will support the Provincial energy policy objectives, in terms of clean, reliable, and affordable power supply. The Smart Zone implementation will facilitate low-carbon policies that encourage investment in renewable distributed generation by developing controls integrated through its Smart Grid that will have the potential to enable/allow more DGs to connect to the distribution system. With the increase in smaller and more distributed generation, leading to two way power flows and increased variability in power quality, there is a need to implement Smart Grid concepts which will support continued reliable and safe operation of the distribution system. The DMS and integrated "smart" devices will provide visibility and control of the growing numbers of distributed generators.

Improved Worker and Public Safety: Hydro One is committed to creating and sustaining an injury-free workplace and maintaining public safety. Continued safe operation of the distribution system will be facilitated by the automatic control and communications infrastructure of the Smart Grid that will reduce windshield time, and the need for manual switching and other field work.

Technological Innovation and Risk Management: In line with Hydro One's philosophy of embracing innovative approaches and new technologies, Phase 1 maintains a prudent perspective and keeps focus on flexibility as we deal with technology choices. The Smart Zone implementation is a limited deployment focused on validating identified solution sets (e.g. utilization of IEC 61850 communication standard using WiMAX). Phase 1 will balance off-the shelf technologies, new applications and integrated process designs to provide an innovative end-to-end solution. Most of the industry is still pursuing single point applications toward a single outcome.

Investment Driver: N.D.C.2.06

Date: November 24, 2010

AR Number: 20140, 20141

Title: Advanced Distribution System Phase 1 Release 1

21040, 21100, 21101, 21102

Alternatives Compared

Business Value	Project Level Risk		Comparison
	Current Risk	Alt1	
Reliability	MED	LOW	Reliability: The introduction of DG's on the Distribution Network is impacting voltage regulation. The system (DMS) is designed to provide both visibility and control tools to mitigate voltage and frequency fluctuations as well as improve outage duration and frequency statistics.
Customer	MED	LOW	Customer service and satisfaction will increase with improved reliability and reduced outage response times.
Competitiveness	HIGH	MED	The recommended alternative is more cost-effective because the do-nothing alternative, in order to accommodate the current forecast of DGs who are planning to connect to the Hydro One grid, would result in more substantial expenditures for express feeder builds.
Safety and environment	MED	LOW	Continued safe operation of the distribution system will be facilitated by the automatic control and communications infrastructure of the Smart Grid - will reduce windshield time & the need for manual switching & other field work.
Regulatory / Legal	HIGH	LOW	No significant regulatory issues are anticipated. The project need and prudence justification was reviewed by the OEB. In its Decision with reasons on the Hydro One 2010-2011 Dx Rate Submission the OEB approved aggregate Smart Grid expenditures of \$112M.
Reputation	MED	LOW	H1 is deploying an industry-leading solution to address the impact of DG connections.
Initial Cost (\$M)		96.0	Costs estimates includes interest, overhead, and funds allocated for risk mitigation. A 5 year cost estimate was included in Hydro One's Green Energy Plan (GEP) that was filed with the OEB in the most recent Dx hearing. A further \$15M is contained in the current Tx filing. Cumulative estimates of the ADS initiative are included in the 2011-15 business plan. Costs include contingency; e.g. Release 1 includes approximately \$8M contingency
Financial: PV Cost / NPV (\$M)			NPV was not calculated, as there is only one viable alternative and the decision was not primarily based on financial factors. It was based on the fact that this initiative is government-mandated and has no quantifiable benefit stream at this stage.

Investment Driver: N.D.C.2.06

Date: November 24, 2010

AR Number: 20140, 20141

Title: Advanced Distribution System Phase 1 Release 1

21040, 21100, 21101, 21102

Project Risk and Mitigation:

Cost:

Cost estimates include interest, overhead, and funds allocated for risk mitigation.

The ADS Project has been structured such that the foundational DMS is deployed during Phase 1 Release 1 with limited test implementation of field equipment. This varies compared to the OEB/GEP submissions which solely envisioned pilots during Phase 1. The continued increase in DGs, and emerging power quality issues, has necessitated an approach where a scalable production ready solution is delivered as part of the full Phase 1.

Business Planning:

This investment is in the 2011-2015 business plan and was included in the Green Energy Plan (five year) filed with the OEB.

Regulatory Considerations:

No significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y		Redirection Required: N		Planner: Bill Cole	
This Release(\$M): 96.0	Previous Release(\$M): 0	Future Release(\$M): 0	Current Est. of Total Cost(\$M): 96.0		
Signature Block:					
Submitted by: Carmine Marcello		Title: Executive VP Strategy		Date: DEC 08 2010	
Reviewed by: Sandy Struthers		Title: Executive VP & CFO		Date: Dec 17/10	
Recommended by: Laura Formusa		Title: President and CEO		Date: Dec 22/10	
Approved by:		Title: Board of Directors Advice		Date:	

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a **Technological Advancement**? N
- Do you anticipate that the initiative will resolve a **Technological Uncertainty**? Y

Consumers Council of Canada (CCC) INTERROGATORY #18 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

EX. C1/T1/S1

Please explain, in detail, what HON is doing with respect to home energy management technologies. Is HON working with the OPA on this initiative? If not, why not?

Response

Hydro One's current activities with respect to home energy management technologies are aimed at working jointly with universities, industry associations and other entities on technologies that leverage utilities' capabilities to integrate with their AMI networks. Please see Exhibit C, Tab 1, Schedule 1, page 11, Table 4. The Energy Hub Management System (EHMS) undertaken by the Ontario Centre of Excellence (OCE) with participation by Hydro One, University of Waterloo, the OPA, local distribution companies and the industry will allow energy users in the future to effectively manage their energy requirements. The initiative is intended to empower energy hubs so that they can contribute to the development of real time management and control of energy usage.

As noted in Exhibit I, Tab 10, Schedule 5.04 VECC 45 part b, the OPA is not funding any research or development for integration of home energy management technologies with individual utility AMI systems. However, once integration is achieved, any field deployment of such devices can then be part of an OPA funded CDM program.

Consumers Council of Canada (CCC) INTERROGATORY #19 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

EX. C1/T1/S1

Please explain how HON ensures that its Smart Grid initiatives will bring value to its customers.

Response

Hydro One Networks is mindful of the substantial investment required to develop and implement Smart Grid for the benefit of its customers. Hydro One has adopted the approach of developing and trialling Smart Grid by way of a limited pilot in advance of a provincial deployment so the results and learnings of the pilot can inform the planning of the larger Smart Grid deployment and ensure that each release will bring value to Hydro One's customers province-wide.

Hydro One is looking to meet its established Smart Grid business objectives through:

- Distributed Generation Integration
 - Use DG Dispatch to enable more generation on our existing assets saving costs.
 - Use energy storage technology to improve power quality to customers. This may also provide a future opportunity to reduce surplus base load generation and potentially the ability for energy arbitrage.
- Distribution Reliability
 - Improve distribution system reliability so customers experience fewer and shorter outages.
- Outage Optimization
 - Reduce trouble call costs and improve outage response times.
- Asset Planning
 - Better identify and reduce energy theft to lower the loss charges passed through to customers.
- Customer Enablement
 - Reduce line losses and save customers money on energy related costs.
 - Provide customers with real-time in-home monitoring and new demand response programs so they can better manage their electricity consumption.

Consumers Council of Canada (CCC) INTERROGATORY #20 List 1

Issue 10 Is Hydro One's proposed Smart Grid rate adder appropriate?

Interrogatory

EX. E2/T2/S2

Please explain why Seasonal Customers have a higher smart grid charge than HON's other residential rate classes. Please explain how the volumetric charges were developed.

Response

The magnitude of the Smart Grid volumetric charge for each rate class is established using the Board's IRM methodology. The Board's methodology determines the amount of Smart Grid Revenue to be collected from each rate class based on the total revenue share by rate class as shown in column A of Exhibit E1, Tab 2, Schedule 1, Attachment 2 and determines the volumetric charge by dividing the revenue to be collected from each class by the forecast volumetric billing determinant (e.g. kWh consumption for residential rate classes). The charge for Seasonal customers is higher because of the relatively low kWh consumption of the Seasonal rate class.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #5

List 1

Issue 10 **Is Hydro One's proposed Smart Grid rate adder appropriate?**

Interrogatory

Reference: Exhibit C, Tab 1, Schedule 1

- a) Page 1 Table 1– Please summarize how the amounts will have a significant influence on the operation of HONI.
- b) Page 2 – Please describe the Distribution Management System and confirm when it was installed.
- c) Please confirm the number of FIT and MicroFit connections to date and forecast for 2013.
- d) Page 3 Table 2 – Please provide the amounts for 2010 actual, 2011 actual, 2012 Bridge and 2012 YTD. Please explain any variances.
- e) Page 4 – Please confirm the acronym OGCC.
- f) Page 4 – Please provide the number of energy storage systems in the Tillsonburg area.
- g) Page 4 - Please advise of any further direction provided to Hydro One regarding its Smart Grid Plan.
- h) Page 5 – Please provide a breakdown of the \$7 million (Sustainment of New Smart Grid Systems costs).
- i) Page 6 shows the OM&A component of Additional Smart Grid Deployment as \$8.6 million. Page 7 shows the amount as \$8.7 million. Please reconcile.
- j) Page 7 – Please provide a breakdown of the \$8.6 million (OM&A Component of Release 2 Project).
- k) Page 8 Table 3 – Please provide the driver for each business objective in Table 3.
- l) Page 9 – Please provide a breakdown of the \$4.2 million in Smart Grid Studies Program for 2013.
- m) Please provide the 2013 smart grid OM&A expenditures in base rates.

n) Please discuss the actions HONI will take in the event this spending is not approved.

Response

a) The amount requested for Smart Grid OM&A will enable Hydro One to continue its smart grid initiatives which will include maintaining the new smart grid assets that will be coming into service by the end of 2012. It will also enable Hydro One to continue the smart grid studies that are being undertaken with our funding partners.

b) Please see Exhibit I, Tab 10, Schedule 1.01 Staff 29 and Schedule 1.03 Staff 31

c) The number of FIT and MicroFIT connections in 2012 and 2013 is provided below.

	2012 Connected	2012 MW	2013 Forecast	2013 MW
FIT CAE	171*	26.4	24	6.2
FIT CAR	11*	64.7	28	183
MICROFIT	9564*	91.9	3500	34

*as of September 28, 2012

The inclusion of distributed generators installed under the RESOP program brings the total installed generating capacity to over a thousand MW as noted in Exhibit C, Tab 1, Schedule 1, page 6.

d) Please see Exhibit I, Tab 10, Schedule 1.02 Staff 30.

e) OGCC = Ontario Grid Control Centre

f) Hydro One is planning for the installation and piloting of a 5 MW flywheel energy storage system in the Tilsonburg area along with the required control systems integration with the DMS. The specific numbers and details are in the development stage.

g) Hydro One has not received any further direction on its Smart Grid Plan.

h) Please see Exhibit I, Tab 10, Schedule 5.01 VECC 42.

i) No discrepancy exists between the two pages.

j) Please see Exhibit I, Tab 10, Schedule 5.02 VECC 43.

k) The business objectives set out in Table 3 are consistent with Hydro One's overall business values. It is unclear what the word "driver" refers to.

1
2

l)

SMART GRID STUDIES - PROGRAM – 2013	FUNDING (\$M)
Energy Storage Systems Technologies.	1.6
Energy Hub Management – Automated Home Energy Networks	0.1
Inverter, Flexible Alternating Current Distribution System (FACDS) Technology /Devices Studies	0.2
NSERC Micro Grid Networks by British Columbia Institute of Technology (BCIT) to develop and demonstrate Micro Grid Networks in a Canadian context	0.1
Advanced Grid Studies (various technology assessment and validation on distributed generation as well as advanced grid options)	0.5
Clean Energy Initiatives (Geothermal, Combined Heat and Power, Pollution Probe, Center for Clean Energy, EV)	0.1
Green Energy Impact / Integration Studies (Wind, Solar, Biomass Generation connections impact studies)Hierarchical Management, Control and Optimization)	1.4
Studies – Universities (Solar , Wind generator Modeling, Validations), Green Energy Impact / Integration Studies (Wind, Solar, Biomass Generation connections impact studies)	0.1
Energy Research Initiatives ERI Program (Solar Generation Connections / Micro Grid Impact Studies)	0.1

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m) Hydro One is seeking a rate rider to fund the full amount of 2013 OM&A expenditures. No portion of these expenditures is included in base rates.

n) Hydro One would be forced to delay any further smart grid activities.

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

Issue 11 Are the proposed adjustments to the Retail Transmission Service rates appropriate?

Interrogatory

Ref: Exhibit C/Tab2/Sch1

Please complete the RTSR Adjustment Workform as found on the Board's website under Filing Requirements for Distribution and Transmission Applications.

Response

Separate RTSR rates for Network, Line Connection and Transformation Connection have been approved by the Board for the Sub-Transmission (ST) rate class. The RTSR Adjustment Workform does not accommodate three different billing determinants for developing RTSR rates and cannot be completed.

The RTSR Adjustment methodology proposed by Hydro One was approved by the Board under 3rd Generation IRM proceeding EB-2008-0187, and it achieves a similar result to the Board's Workform by increasing the current RTSR rates in proportion to the increase in Uniform Transmission Rates.

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

Issue 11 Are the proposed adjustments to the Retail Transmission Service rates appropriate?

Interrogatory

Reference: Exhibit C, Tab 2, Schedule 1, page 1

- a) Did the Board not also approve 2011 loads at each of the transmission connections as part of EB-2009-0096? If yes, why weren't these used in the calculation and what would be the results if they were?

Response

- a) No, the Board did not approve 2011 loads at each of the transmission connections as part of EB-2009-0096.

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

2
3 **Issue 11 Are the proposed adjustments to the Retail Transmission Service**
4 **rates appropriate?**

5
6 **Interrogatory**

7
8 **Reference: Exhibit C, Tab 2, Schedule 1, page 2 (lines 12-14)**

- 9
10 a) Please confirm that the billing parameters used were those approved for 2010. If
11 not, please recalculate using the 2010 billing parameters.

12
13
14 **Response**

- 15
16 a) Yes. The billing parameters referred to in this interrogatory were those approved for
17 2010.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #48 List 1

Issue 11 Are the proposed adjustments to the Retail Transmission Service rates appropriate?

Interrogatory

Reference: Exhibit C, Tab 1, Schedule 1, page 3

- a) Please provide a schedule that compares the UTRs used to set the “current rates” with those used to calculate the “proposed rates”.

Response

- a) The table below provides the requested information.

Uniform Transmission Rates (UTRs)	Current Rates (Based on 2010 Approved UTR rates as part of Rate Order under EB-2008-0272)	Proposed Rates (Based on 2012 Approved UTR rates as part of Rate Order under EB-2011-0268)
Network	\$2.97 per kW per month	\$3.57 per kW per month
Line Connection	\$0.73 per kW per month	\$0.80 per kW per month
Transformation Connection	\$1.71 per kW per month	\$1.86 per kW per month

Energy Probe (EP) INTERROGATORY #27 List 1

Issue 12 Is Hydro One's proposal to implement the final adjustments of the Harmonization Plan in accordance with the Board's directions?

Interrogatory

Ref: Exhibit E1, Tab 1, Schedule 1, Page 1 &
Exhibit E1, Tab 3, Schedule 1, Page 2, Table 1

- a) Why is Hydro one proposing to eliminate the Low Use Secondary Service in 2013 with a bill impact of 9.07% rather than doing this over 2013 and 2014?
- b) Please estimate the change in Revenue Requirement and the LUSS Bill impacts of a two year transition

Response

- a) In its decision in proceeding EB-2007-0681, the Board approved Hydro One's proposal to mitigate the impacts of eliminating the Low Use Secondary Services (LUSS) class by extending the harmonization period from four years to five years. The LUSS harmonization was intended to be completed in 2012, but was extended to 2013 as a result of HONI choosing to maintain its 2011 rates for 2012. The proposed bill impact of 9.07% is already within the Board's guidelines.
- b) The revenue requirement for the LUSS rate class will not change as a result of a two-year transition.

Since the volumetric rate for the LUSS class has already been harmonized with the GSe class, the two-year transition will only apply to the fixed charge. The total bill impact of transitioning the fixed charge over two years is 5.25% in 2013 and 3.20% in 2014.

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

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit A /Appendix E/page 14 and Exhibit D/Tab1/Sch1/page 10

With the proposed DSA IRM increase of \$6.22 for R2 customers, has Hydro One taken any steps to request that the Rural Rate Protection amount be increased from the current amount of \$28.50?

Response

The increase to R2 customer bills as a result of the Density Study Adjustment (DSA) is \$2.17. The \$6.22 referenced in the question is the combination of IRM increases, Retail Transmission Service Rates increases, and the DSA. The amount of rural rate protection funding available to Hydro One Networks is fixed through Ontario Regulation 442/01 at \$127M, and the Board approved RRRP credit of \$28.50 reflects the fixed funding available. Hydro One Networks is unaware of any intent to change the regulated \$127M amount available to fund rural rate protection.

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

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit A/Appendix E/pages 14-16

The Stakeholder Consultation Notes include a description of two options for the definition of per-customer cost at the top of page 14, labeled Option A and B, and later on page 14 there are two options for ratio re-balancing labeled 1 and 2. The discussion which follows on pages 14-16 refers to Options A and B, but it appears that it may actually concern Options 1 and 2 instead. Please provide any clarification that might be helpful in understanding the notes.

Response

After Option 1 and Option 2 are described at the bottom of page 14, all subsequent references to "Options" are with reference to Options 1 and 2. That is, starting with the bottom paragraph on page 14, and through pages 15 and 16, all references to "Option A" should read "Option 1" and all references to "Option B" should read "Option 2".

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

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D/Tab1/Sch1/Tables 2 & 4; and, EB-2009-0096/Draft Rate Order/Exhibit 2.0/page 1

- a) Please confirm that the density weights that were used in the 2010 Cost Allocation model are the amounts shown in the second table of Exhibit 2.0 of the 2010 Draft Rate Order, and that those weights are the basis for the relative costs (OM&A and FA Cost per Customer) that are found in the last row of Table 2.
- b) Are there revised Density Weights that form the basis for the relative costs found in the first row of Table 4? If so, please provide the revised density weights in a format similar to the format in Exhibit 2.0 of the Draft Rate Order.
- c) For four rate classes, all of the density weights in Exhibit 2.0 of the DRO are equal to 1.00, which appears to be a neutral default value. Please explain whether Hydro One intends to re-examine the Density Weights that are equal to 1.00, as part of its next re-basing application, in particular the factors applicable to the Sub-Transmission and Distributed Generation classes.

Response

- a) Confirmed.
- b) No, the density weights used in the 2010 cost allocation model were not revised. The relative cost ratios shown in the first row of Table 4 are based on the results shown in Figure 27 of the Density Study.
- c) The purpose of Density Weights is to redistribute the costs within a customer segment that has both urban and rural customers (i.e. residential and general service customers). Hydro One has no plans to subdivide its Sub-Transmission and Distributed Generation classes into urban and rural sub-classes, and as such the density weights for these classes will remain as 1.0.

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

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D-1-1/Attachment 1/pages 9 & 37; and, EB-2009-0096/Draft Rate Order/Exhibit 3.0/page 4

- a) The analysis of distribution service costs is based on total number of customers per circuit kilometre, whereas the density zones in the Hydro One tariff are defined in terms of customers per kilometre.
- b) Are the density zones defined by total customers per circuit kilometre, or by some other definition (less inclusive definition of customer, different definition of line kilometre)?
- c) If the definitions of customer density are not identical, please provide a comment on whether the direct cost assignment analysis performed by London Economics and PowerNex Associates would be affected, as it relates to the demarcation points between UR and R1, and/or R1 and R2 density zones.

Response

- a) Hydro One assumes the statement in part a) is the basis for questions b) and c)
- b) The density zone definition of "customer per kilometer" used in the tariff should more precisely read as "total number of customers per circuit kilometer".
- c) The definitions are identical.

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

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D/Tab1/Sch1/page 10

Please provide a row in Table 8 for the R1 class.

Response

Below is an update to Table 8 that includes a row for the R1class.

Customer Type		Monthly Consumption (kWh, kW)	Current Total Monthly Bill (\$)	Proposed Total Monthly Bill (\$)	Change (\$)	Change (%)
Residential - Urban Density (UR)	IRM	800 kWh	132.26	134.75	2.49	1.88%
	DSA IRM	800 kWh	132.26	129.22	-3.05	-2.30%
Residential - Medium Density (R1)	IRM	800 kWh	141.55	144.50	2.95	2.08%
	DSA IRM	800 kWh	141.55	144.50	2.95	2.08%
Residential - Low Density (R2)	IRM	800 kWh	151.74	155.79	4.05	2.67%
	DSA IRM	800 kWh	151.74	157.96	6.22	4.10%
Residential - Seasonal	IRM	500 kWh	116.61	120.24	3.63	3.11%
	DSA IRM	500 kWh	116.61	118.92	2.30	1.98%
Urban GSe	IRM	2,000 kWh	296.95	300.27	3.32	1.12%
	DSA IRM	2,000 kWh	296.95	282.18	-14.77	-4.97%
GSe	IRM	2,000 kWh	351.09	357.28	6.19	1.76%
	DSA IRM	2,000 kWh	351.09	357.28	6.19	1.76%
Urban GSd	IRM	36,000 kWh and 117 kW	5,241.08	5,296.43	55.35	1.06%
	DSA IRM	36,000 kWh and 117 kW	5,241.08	5,130.74	-110.34	-2.11%
GSd	IRM	36,000 kWh and 117 kW	5,519.56	5,592.20	72.63	1.32%
	DSA IRM	36,000 kWh and 117 kW	5,519.56	5,652.48	132.92	2.41%
Street Lights	IRM	1,320 kWh	241.11	244.79	3.68	1.53%
	DSA IRM	1,320 kWh	241.11	248.30	7.19	2.98%
Sentinel Lights	IRM	62 kWh	11.76	12.04	0.28	2.37%
	DSA IRM	62 kWh	11.76	12.29	0.52	4.45%

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

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D-1-1/Attachment 1/ pp. 42-43

In preparation for its next re-basing application, please describe any plan that Hydro One has formulated to follow up on the discussion in the study by London Economics and PowerNex Associates, related to:

- a) analysis of additional low density rate classes
- b) lowering the demarcation point for the high density rate classes, for example to a high-density zone of 2000 customers.

Response

- a) Hydro One currently has no plans for additional low density rate classes.
- b) Hydro One currently has no plans for changing the demarcation point for the high density rate class.

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

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D-1-1/Attachment 1

In Section 6 (page 42) of the Density Study, there is a discussion of Alternative Rate Structures. What is Hydro One's view on its current rate structure? Is it regarded as appropriate/adequate or does Hydro One have concerns with its current rate classes? Does Hydro One plan to investigate other rate structures (municipal boundaries, regional rates, etc) in future years?

Response

Hydro One believes that its current rate structure provides for an appropriate differentiation of rates among the various customer classes it serves. Hydro One does not see a need to investigate other rate structures.

Energy Probe (EP) INTERROGATORY #28 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit E2, Tab2, Schedule 2 and Schedule 3, Pages 1-9 (updated)

- a) Please clarify whether the proposed rates for 2013 are as proposed in Schedule 2 or Hydro One will implement the density study based rates in Schedule 3?
- b) Please provide a consolidated set of Rate schedules with columns for Pre and Post Density study rates
- c) Please Provide Bill comparisons between Base rates, Proposed 2013/2014 rates pre and post density study.
- d) Please comment on the conclusion of LSE PNXA (page 48) that more work is required before implementing new density based rates.
- e) What is HONI's plan for density based rates going forward? Please provide details.

Response

- a) Please see Exhibit I, Tab 17, Schedule 8.01 SEC 43
- b) Pre and Post Density Study fixed and variable rates for all rate classes impacted by the Density Study are provided side-by-side in Table 7 of Exhibit D, Tab 1, Schedule 1. All other elements of the rate schedules would be identical for pre and post density study.
- c) A comparison of the total current bill ("base rates") and the total bill without the Density Study Adjustment ("pre density study") and with the Density Study Adjustment ("post density study") is provided in Table 8 of Exhibit D, Tab 1, Schedule 1.
- d) Hydro One cannot find a reference to more work being required before implementing new density based rates in the reference provided.
- e) See Exhibit I, Tab 13, Schedules 1.06 Staff 39 and 1.07 Staff 40.

Energy Probe (EP) INTERROGATORY #29 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 1, Attachment 1, Pages 10-13, Figures 3-7

- a) Please Provide the Regression Model specifications for each of the OM&A and OM&A plus capital proxy formulae.
- b) Please populate each model formula with best fit data for illustrative purposes. List all parameter definitions and sources of input assumptions.
- c) Please explain what parameters were tested other than the four listed on page 10 provide the parameter estimates and T Statistic.
- d) Discuss why these other variables were dropped from the regression e.g. low T-statistic or other reasons
- e) Were runs done using Total OM&A rather than the direct OM&A? If so, provide information on the effect of including/excluding the Total OM&A
- f) Why is the Time variable at/below the T statistic threshold of 1.96 in the cases with customers per square kilometre (fig 4 and 6)? Please discuss. Was a lagged variable examined?
- g) Please explain how the 95% confidence levels High and Low were derived. What other statistical tests were applied and what were the results?

Response

- a) Regression Model for Figure 3:

$$\ln(toma_{i,t}) = \beta_0 + \beta_1 \times \ln(tq\_tc_{i,t}) + \beta_2 \times \ln(tc_{i,t}) + \beta_3 \times \ln(cpkm_{i,t}) + \beta_4 \times yr\_d_t + \beta_5 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t}) + e_{i,t}$$

Regression Model for Figure 4:

$$\ln(toma_{i,t}) = \beta_0 + \beta_1 \times \ln(tq\_tc_{i,t}) + \beta_2 \times \ln(tc_{i,t}) + \beta_3 \times \ln(cpkm2_{i,t}) + \beta_4 \times yr\_d_t + \beta_5 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t}) + e_{i,t}$$

Regression Model for Figure 5:

$$\ln(tc_{i,t}) = \beta_0 + \beta_1 \times \ln(tq\_tc_{i,t}) + \beta_2 \times \ln(tc_{i,t}) + \beta_3 \times \ln(cpkm_{i,t}) + \beta_4 \times yr\_d_t + \beta_5 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t}) + e_{i,t}$$

Regression Model for Figure 6:

$$\ln(tc_{i,t}) = \beta_0 + \beta_1 \times \ln(tq_{i,t}) + \beta_2 \times \ln(tc_{i,t}) + \beta_3 \times \ln(cpkm2_{i,t}) + \beta_4 \times yr_d_t + \beta_5 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t}) + e_{i,t}$$

In all instances, the subscript “i” denotes operating area i, and the subscript “t” denotes the year.

b) Regression Model for Figure 3:

$$\ln(toma_{i,t}) = -5.641 - 0.109 \times \ln(tq_{i,t}) + 3.756 \times \ln(tc_{i,t}) - 0.299 \times \ln(cpkm_{i,t}) + 0.021 \times yr_d_t - 0.297 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t})$$

Regression Model for Figure 4:

$$\ln(toma_{i,t}) = -13.285 - 0.072 \times \ln(tq_{i,t}) + 5.072 \times \ln(tc_{i,t}) - 0.100 \times \ln(cpkm2_{i,t}) + 0.018 \times yr_d_t - 0.426 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t})$$

Regression Model for Figure 5:

$$\ln(tc_{i,t}) = -7.335 - 0.026 \times \ln(tq_{i,t}) + 3.975 \times \ln(tc_{i,t}) - 0.287 \times \ln(cpkm_{i,t}) - 0.023 \times yr_d_t - 0.305 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t})$$

Regression Model for Figure 6:

$$\ln(tc_{i,t}) = -16.804 + 0.028 \times \ln(tq_{i,t}) + 5.596 \times \ln(tc_{i,t}) - 0.121 \times \ln(cpkm2_{i,t}) + 0.020 \times yr_d_t - 0.460 \times 0.5 \times \ln(tc_{i,t}) \times \ln(tc_{i,t})$$

Parameter	Definition	Source of Data
toma	Total direct OM&A cost	Hydro One
tcost	Total direct OM&A cost plus capital proxy	Hydro One, LEI/PNXA calculation
cpkm2	Total customers per square kilometre	Hydro One, LEI/PNXA calculation
cpkm	Total customers per circuit kilometre	Hydro One, LEI/PNXA calculation
tc	Total customers	Hydro One
tq_tc	Energy density (i.e. average energy consumption per customer)	LEI/PNXA calculation
yr_d	Year minus 2006	n/a

c) LEI/PNXA considered a wide range of parameter, including:

Category	Parameter	Definition
Business Condition	age_nbv	Age index (scale from 0 to 1), calculated as the net book value divided by the acquired value of total assets
Business Condition	dist	Average customer distance from the nearest service centre
Business Condition	cs	Canadian shield (binary 0 or 1)
Business Condition	ug_tcon	Percentage of total circuit kilometres that are underground
Output	tcon_km	Total circuit kilometres
Output	mva_tra	Total installed transformer megavolt-ampere rating
Output	num_h1poles	Total number of Hydro One owned poles
Output	num_poles	Total number of poles
Output	num_ds	Total number of distribution stations
Input	tca	Total annual capital expenditure (CAPEX)
Trend	cpi	Consumer price index

d) These parameters were not included in the final model specification for a number of reasons. LEI/PNXA found that the additional “output” and “input” variables were highly correlated with the total number of customers, and hence were introducing issues related to multicollinearity.

LEI/PNXA also tested the inclusion of the age_nbv, dist, cs, ug_tcon variables. The inclusion of these variables did not result in much change in the signs, values, or standard errors of the main parameters of interest.

e) No, LEI/PNXA only considered direct OM&A expenses. This was done intentionally to limit the use of allocated costs in the econometric analysis. For the most part, the non-direct OM&A expenses (i.e. those not specifically tracked at the operating-area level) represent customer care, billing and collections, regulatory, and administrative overhead. These costs tend not to vary with customer density and would have to have been manually allocated to the individual operating areas using allocation factors, e.g., the total number of customers. If the allocation factors were also independent variables in the regression model, the impact would be captured in the magnitude of the coefficient estimates for those parameters.

f) For any variable, the T-statistic's proximity to 1.96 relates to the statistical significance of the estimated coefficient at the 5% confidence level. The fact that the T-statistic for the time trend is at or slightly lower than 1.96 in the regression models based on the square-kilometre density variable does not have a material impact on the interpretation of the regression results.

With five years of observations, the inclusion of a lagged variable would have reduced the number of usable observations by 20%. Any additional explanatory power provided would likely be offset by this reduction. As such, lagged variables were not examined.

g) The 95% confidence intervals were obtained as follows:

$$\hat{\beta} \pm (t_{0.025, n-2} \times \text{standard error}(\hat{\beta}))$$

Durbin-Watson test statistics calculated for the various regression equations mean that the hypothesis of "no error serial correlation" must be rejected. That is, there exists evidence that the model errors are serially correlated. This is not of great concern, because although positive error serial correlation will lead to underestimates of standard errors, if there is no lagged dependent variable in the regression, the model will still be unbiased.

Energy Probe (EP) INTERROGATORY #30 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D, Tab1, Schedule 1, Page 23 Attachment 1

- a) In examining the location of service centres relative to driving distance/time did LEI/PNXA find examples where location of centres was not optimal? If so, please provide a list of these.
- b) Please discuss the significance and use of the IRNS and IRS parameters in the direct assignment analysis and also whether these variables were tested in the models.
- c) What is the relationship between Service Quality SAIDI, SAIFI etc. and Density?
 - i. Was this examined in the study?
 - ii. Is there an inverse relationship between density and service quality?

Please discuss whether this is/is not a significant omission.

- d) Please provide System Wide Average SAIDI, SAIFI and any other reported SQIs for existing Density classifications. The Last 10 years data will suffice.
- e) Please provide an analysis of the Relationship between Service Quality and Density. If appropriate, use the three High/Medium/Low density groups used by LEI/PXNA. Please provide the result as Graphical presentation.
- f) If the above responses and analyses indicate that service quality is lower in medium and low density areas relative to High density urban, has HIONI considered how this should be compensated for?

Response

- a) LEI/PNXA's analysis did not attempt to identify whether service centres were optimally or sub-optimally located, as this was beyond the scope of the engagement.
- b) The IRS and IRNS allocation factors were used to allocate "Trouble Call" and "Storm" related operations and maintenance expenses to the individual sample areas. A description of the method used to calculate IRS and IRNS and the resulting values

1 for each sample area are provided in Exhibit D, Tab 1, Schedule 1, Attachment 1 on
2 Page 69 and 70.

3
4 c)

5 i. The purpose of the the density study was to analyze how Hydro One's cost to
6 serve is impacted by customer density (or vice versa). It did not attempt to
7 analyze how customer density impacts service quality (or vice versa).

8
9 ii. Please see part e) for a response to the first part of this question. No, this is not
10 believed to be a significant omission. Current practice in Ontario is to establish
11 rates for individual customer classes based on the cost to serve the customers
12 within each class. The OEB's cost allocation model does not allow for
13 differentiation in the allocated costs based on the quality of service received by
14 customers.

15
16 In general, this is consistent with the practice in other jurisdictions where rates are
17 set based on cost of service and reliability standards or targets are established
18 separately.

19
20 d) Hydro One does not track system reliability measures by rate class.

21
22 e) The data collected and analyzed for the density study does not lend itself to
23 examining the relationship between service quality and customer density. There are
24 ways that this relationship could be examined, however, they are not feasible in the
25 time allotted for responding to interrogatories. This question is perhaps better dealt
26 with in the context of the Board's ongoing policy initiative dealing with Electricity
27 Distribution System Reliability Standards (EB-2010-0249).

28
29 f) Service quality varies across rate classes and between customers across the province
30 within the same rate class. Hydro One does not believe it is appropriate to
31 compensate customers for variations in the reliability of their service and has not
32 considered how this should be done. This question is perhaps better dealt with in the
33 context of the Board's ongoing policy initiative dealing with Electricity Distribution
34 System Reliability Standards (EB-2010-0249).

Energy Probe (EP) INTERROGATORY #31 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 1, Attachment 1, Pages 32-33 and Figures 23, 24 and 25 & Exhibit A, Page 92, LEI/PNXA Stakeholder Presentation

- a) Please provide the density demarcation points for each of the existing classes based on both customers per km² and per line circuit km.
- b) Please provide Tables Similar to the Slide Deck page 5 from the Stakeholder Presentation that shows the with and w/o \$/customer per month by Class. Add the Weighting Ratios:
 - i. Current CAM
 - ii. Proposed post Density Study
- c) Did LEI/PNXA attempt to fit exponential function(s) to the data in figures 24 and 25? If not why not?

Response

- a) The density demarcation points are not based on customer per km², but rather on the *number of customers* and *customers per circuit km*. The density demarcation points of the existing rate classes are as follows:
 - UR – year round residential customers in areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer
 - R1 – year round residential customers in areas containing 100 or more customers with a line density of at least 15 customers per circuit kilometer
 - R2 – All other year-round residential customers
 - Seasonal – Seasonal residential occupancy customers
 - Urban GSe – General Service Energy Billed customers in areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer
 - GSe – General Service Energy Billed customers not located in an urban area
 - Urban GSd – General Service Demand Billed customers in areas containing 3,000 or more customers with a line density of at least 60 customers per circuit kilometer
 - GSd – General Service Demand Billed customers not located in an urban area
 - ST, DGen, Streetlight and Sentinel Light – no density demarcation

b) i. Current CAM

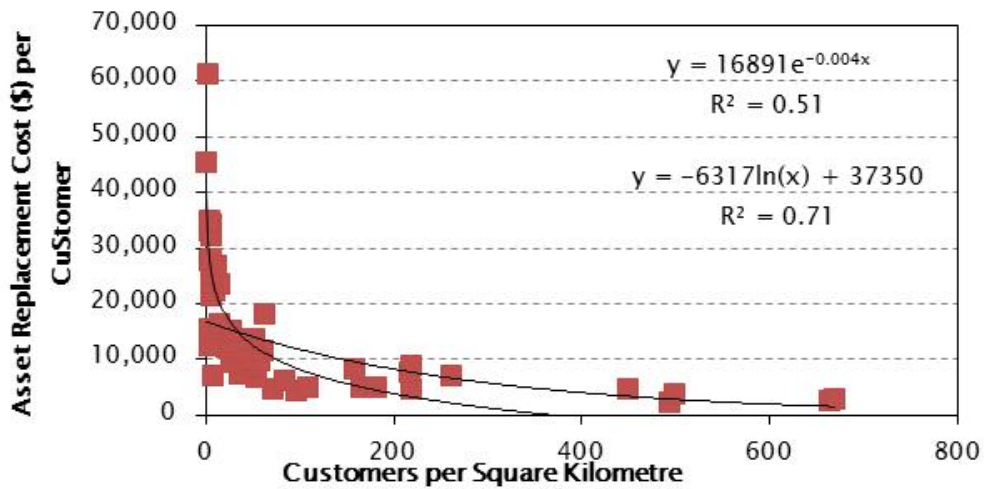
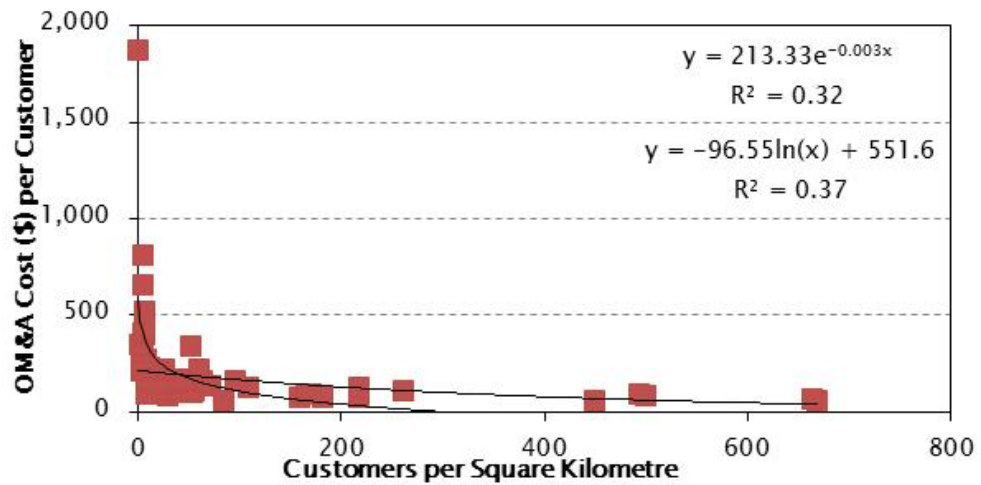
The table on slide 5 of the referenced Stakeholder Presentation provides the information requested based on the current CAM.

ii. Proposed post Density Study

Below is the requested table.

	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd
w/ Density Weighting Factors (\$M)	48.1	239.2	488.8	83.9	6.2	124.0	10.9	130.4
\$ per customer per month	28.5	48.3	111.0	44.5	48.6	104.6	806.0	1,476.2
w/o Density Weighting Factors (\$M)	52.8	246.0	480.6	82.8	6.8	122.9	11.5	128.1
\$ per customer per month	31.3	49.7	109.1	44.0	53.5	103.6	850.7	1,449.9
Percent Increase/Decrease	10%	3%	-2%	-1%	10%	-1%	6%	-2%

c) Yes, both exponential and logarithmic functions were fit to the data (please see below).



Energy Probe (EP) INTERROGATORY #32 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D, Tab1, Schedule1 Attachment 1 Page 38 and 41 and Figures 26 and 29

- a) Please map the Direct Assignment Results in Figure 29 to the CAM rate class density ratios in Figure 26.
- b) Please discuss whether the Direct Assignment results indicate that changes are/are not required to the CAM on a rate class basis and if so, how should this be done.
- c) It is unclear what HONI's response to the Density Study is for 2013/14 rates. Please provide a detailed response to plans actions arising from the study.

Response

- a) Mapping of the Direct Assignment results in Figure 29 to the CAM rate classes shown in Figure 26 is provided in the row labeled "Target Cost per Customer Ratio" of Table 3, Exhibit D, Tab 1, Schedule 1.
- b) The results of the direct cost assignment analysis suggest that the existing density weighting factors may not capture the full difference between the average cost to serve Hydro One's density-based residential and general service rate classes. As such, changes to Hydro One's cost allocation model are warranted. With respect to how this should be done, please see Exhibit I, Tab 13, 5.20 VECC 68.
- c) Hydro One's proposal for addressing the Density Study in 2013 rates is documented in Exhibit D, Tab 1, Schedule 1 of this application. Hydro One does not propose to make any further Density Study adjustments until it submits a new CAM as part of its next re-basing application.

Balsam Lake Coalition (BLC) INTERROGATORY #3 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Ref. Exhibit D, Tab 1, Schedule 1, pages 5-10.

When developing the Density Study – Adjusted (DSA) CA Model Results, why did Hydro One recommend the inclusion of OM&A and Fixed Costs (Table 4, page 5), versus the Total Costs (Table 3, page 5)?

Response

Hydro One proposed aligning the CA model's OM&A and Fixed Asset costs to the Density Study results as this approach was supported by stakeholders and provides a better alignment between the costs specifically addressed by the Density Study and the costs to be adjusted in the CA model.

Balsam Lake Coalition (BLC) INTERROGATORY #4 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Ref. Exhibit D, Tab 1, Schedule 1 Table 5 & Table 6

What is the total revenue impact by Rate Class (UR, R1, R2, Seasonal) of Hydro One's recommendation to adopt the Revenue Adjustment from Option 1 (Table 5) versus the Revenue Adjustment from Option 2 (Table 6)?

Response

The requested information is provided below.

(All \$ in millions)	UR	R1	R2	Seasonal
Revenue Impact under Option 1 (Table 5)	- \$9.2	None	+ \$11.3	- \$2.1
Revenue Impact under Option 2 (Table 6)	- \$11.9	None	+ \$23.0	- \$12.5

Balsam Lake Coalition (BLC) INTERROGATORY #5 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref. Exhibit D, Tab 1, Schedule 1, Table 7

Please provide a similar analysis as displayed in 'Proposed 2012 Density Adjusted IRM Rates' (Table 7 Page 9 of 10) using the 'Revenue Adjustments Required to Bring R/C Ratios to Previously Approved R/C Ratios (Exhibit D, Tab 1, Schedule 1, Table 6)

Response

The table below provides the Density Study Adjusted IRM Rates using the "Revenue Adjustments Required to Bring R/C Ratios to Previously Approved R/C Ratio".

Rate Class	Current Rates			Density Study Adjusted IRM Rates		
	Fixed Charge	Variable Charge		Fixed Charge	Variable Charge	
	\$/month	\$/kWh	\$/kW	\$/month	\$/kWh	\$/kW
UR	14.52	0.02918		11.95	0.02401	
R1	19.72	0.03317		19.89	0.03346	
R2	55.69	0.03600		59.06	0.03818	
Seasonal	19.71	0.08205		17.37	0.07229	
GSe	35.49	0.03938		35.80	0.03973	
GSd	47.72		10.499	50.61		11.132
UGe	14.08	0.02325		10.13	0.01673	
UGd	33.62		8.173	29.48		7.174
St Light	1.05	0.05219		1.11	0.05534	
Sen Light	1.05	0.06972		1.11	0.07390	

Balsam Lake Coalition (BLC) INTERROGATORY #6 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref. Exhibit E2, Tab 3, Schedule 1

Please provide a similar analysis of 'Customer Impacts Based on Density Study Proposed Rates' for Residential Classes UR, R2 & Seasonal using the 'Revenue Adjustments Required to Bring R/C Ratios to Previously Approved R/C Ratios' (Exhibit D, Tab 1, Schedule 1, Table 6)

Response

Below are bill impact calculations as per Exhibit E2, Tab 3, Schedule 2 for UR, R2, and Seasonal customers using the "Revenue Adjustments Required to Bring R/C Ratios to Previously Approved R/C Ratios".

Residential – Urban [UR]

Monthly Rates and Charges	Current Rate	Applied For Rate
Service Charge	14.52	11.95
Smart Meter Funding Adder	3.92	3.92
Service Charge Rate Rider(s)	-	-
Distribution Volumetric Rate	0.029180	0.02401
Distribution Volumetric Rate Rider(s)	0.00000	0.00087
Low Voltage Volumetric Rate	0.00000	0.00000
Retail Transmission Rate – Network Service Rate	0.00575	0.00696
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.00456	0.00500
Wholesale Market Service Rate	0.0052	0.0052
Rural Rate Protection Charge	0.0011	0.0011
Standard Supply Service – Administration Charge (if applicable)	0.25	0.25
Debt Retirement Charge (DRC)	0.0070	0.0070
Loss Factor	1.0780	1.0780

Consumption	800	kWh	kW
RPP Tier One	600	kWh	Load Factor

Current Loss Factor	1.0780
Proposed Loss Factor	1.0780

Residential – Urban [UR]	Volume	Current Rate (\$)	Current Charge (\$)	Volume	Proposed Rate (\$)	Proposed Charge (\$)	Change (\$)	Change (%)	% of Total Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	31.74%
Energy Second Tier (kWh)	262.40	0.0880	23.09	262.40	0.0880	23.09	0.00	0.00%	16.29%
Sub-Total: Energy			68.09			68.09	0.00	0.00%	48.03%
Service Charge	1	14.52	14.52	1	11.95	11.95	-2.57	(17.70)%	8.43%
Service Charge Rate Rider(s)	1	3.92	3.92	1	3.92	3.92	0.00	0.00%	2.77%
Distribution Volumetric Rate	800	0.0292	23.34	800	0.0240	19.21	-4.14	(17.72)%	13.55%
Low Voltage Volumetric Rate	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate Rider(s)	800	0.0000	0.00	800	0.0009	0.69	0.69	0.00%	0.49%
Total: Distribution			41.78			35.77	-6.01	(14.39)%	25.23%
Retail Transmission Rate – Network Service Rate	862.40	0.0058	4.96	862.40	0.0070	6.00	1.04	21.04%	4.23%
Retail Transmission Rate – Line and Transformation Connection Service Rate	862.40	0.0046	3.93	862.40	0.0050	4.31	0.38	9.65%	3.04%
Total: Retail Transmission			8.89			10.31	1.42	16.00%	7.28%
Sub-Total: Delivery (Distribution and Retail Transmission)			50.68			46.09	-4.59	(9.05)%	32.51%
Wholesale Market Service Rate	862.40	0.0052	4.48	862.40	0.0052	4.48	0.00	0.00%	3.16%
Rural Rate Protection Charge	862.40	0.0011	0.95	862.40	0.0011	0.95	0.00	0.00%	0.67%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%
Sub-Total: Regulatory			5.68			5.68			4.01%
Debt Retirement Charge (DRC)	800.00	0.00700	5.60	800	0.0070	5.60	0.00	0.00%	3.95%
Total Bill before Taxes			130.05			125.46	-4.59	(3.53)%	88.50%
HST		13%	16.91		13%	16.31	-0.60	(3.53)%	11.50%
Total Bill			146.96			141.77	-5.18	(3.53)%	100.00%
Ontario Clean Energy Benefit (OCEB)		(10%)	-14.70		(10%)	-14.18			
Total Bill (less OCEB)			132.26			127.59	(4.67)	(3.53)%	

Residential – Low Density [R2]

Monthly Rates and Charges	Current Rate	Applied For Rate
Service Charge	55.69	59.06
Smart Meter Funding Adder	3.92	3.92
Rural or Remote Rate Protection Credit	(28.50)	(28.50)
Distribution Volumetric Rate	0.036000	0.0381800
Distribution Volumetric Rate Rider(s)	0.00000	0.00235
Low Voltage Volumetric Rate	0.00000	0.00000
Retail Transmission Rate – Network Service Rate	0.00574	0.00690
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.00440	0.00480
Wholesale Market Service Rate	0.0052	0.0052
Rural Rate Protection Charge	0.0011	0.0011
Standard Supply Service – Administration Charge (if applicable)	0.25	0.25
Debt Retirement Charge (DRC)	0.0070	0.0070
Loss Factor	1.0920	1.0920

Consumption	800	kWh	kW
RPP Tier One	600	kWh	Load Factor

Current Loss Factor	1.0920
Proposed Loss Factor	1.0920

Residential – Low Density [R2]	Volume	Current Rate (\$)	Current Charge (\$)	Volume	Proposed Rate (\$)	Proposed Charge (\$)	Change (\$)	Change (%)	% of Total Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	25.28%
Energy Second Tier (kWh)	273.60	0.0880	24.08	273.60	0.0880	24.08	0.00	0.00%	13.52%
Sub-Total: Energy			69.08			69.08	0.00	0.00%	38.80%
Service Charge	1	55.69	55.69	1	59.06	59.06	3.37	6.05%	33.17%
Smart Meter Funding Adder	1	3.92	3.92	1	3.92	3.92	0.00	0.00%	2.20%
Rural or Remote Rate Protection Credit	1	-28.50	(28.50)	1	-28.50	(28.50)	0.00	0.00%	(16.01)%
Distribution Volumetric Rate	800	0.0360	28.80	800	0.0382	30.54	1.74	6.06%	17.16%
Low Voltage Volumetric Rate	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate Rider(s)	800	0.0000	0.00	800	0.0024	1.88	1.88	0.00%	1.06%
Total: Distribution			59.91			66.90	6.99	11.67%	37.58%
Retail Transmission Rate – Network Service Rate	873.60	0.0057	5.01	873.60	0.0069	6.03	1.01	20.21%	3.39%
Retail Transmission Rate – Line and Transformation Connection Service Rate	873.60	0.0044	3.84	873.60	0.0048	4.19	0.35	9.09%	2.36%
Total: Retail Transmission			8.86			10.22	1.36	15.38%	5.74%
Sub-Total: Delivery (Distribution and Retail Transmission)			68.77			77.13	8.36	12.15%	43.32%
Wholesale Market Service Rate	873.60	0.0052	4.54	873.60	0.0052	4.54	0.00	0.00%	2.55%
Rural Rate Protection Charge	873.60	0.0011	0.96	873.60	0.0011	0.96	0.00	0.00%	0.54%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%
Sub-Total: Regulatory			5.75			5.75			3.23%
Debt Retirement Charge (DRC)	800.00	0.00700	5.60	800	0.0070	5.60	0.00	0.00%	3.15%
Total Bill before Taxes			149.20			157.56	8.36	5.60%	88.50%
HST		13%	19.40		13%	20.48	1.09	5.60%	11.50%
Total Bill			168.59			178.04	9.44	5.60%	100.00%
Ontario Clean Energy Benefit (OCEB)		(10%)	-16.86		(10%)	-17.80			
Total Bill (less OCEB)			151.74			160.23	8.50	5.60%	

Seasonal Residnetial

Monthly Rates and Charges	Current Rate	Applied For Rate
Service Charge	19.71	17.37
Smart Meter Funding Adder	3.92	3.92
Service Charge Rate Rider(s)	-	-
Distribution Volumetric Rate	0.082050	0.0722900
Distribution Volumetric Rate Rider(s)	0.00000	0.00445
Low Voltage Volumetric Rate	0.00000	0.00000
Retail Transmission Rate – Network Service Rate	0.00543	0.00652
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.00431	0.00470
Wholesale Market Service Rate	0.0052	0.0052
Rural Rate Protection Charge	0.0011	0.0011
Standard Supply Service – Administration Charge (if applicable)	0.25	0.25
Debt Retirement Charge (DRC)	0.0070	0.0070
Loss Factor	1.0920	1.0920

Consumption	500	kWh		kW
RPP Tier One	600	kWh	Load Factor	

Current Loss Factor	1.0920
Proposed Loss Factor	1.0920

Seasonal Residnetial	Volume	Current Rate (\$)	Current Charge (\$)	Volume	Proposed Rate (\$)	Proposed Charge (\$)	Change (\$)	Change (%)	% of Total Bill
Energy First Tier (kWh)	500.00	0.0750	37.50	500.00	0.0750	37.50	0.00	0.00%	30.04%
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	0.00%	0.00%
Sub-Total: Energy			37.50			37.50	0.00	0.00%	30.04%
Service Charge	1	19.71	19.71	1	17.37	17.37	-2.34	(11.87)%	13.91%
Service Charge Rate Rider(s)	1	3.92	3.92	1	3.92	3.92	0.00	0.00%	3.14%
Distribution Volumetric Rate	500	0.0821	41.03	500	0.0723	36.15	-4.88	(11.90)%	28.95%
Low Voltage Volumetric Rate	500	0.0000	0.00	500	0.0000	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate Rider(s)	500	0.0000	0.00	500	0.0045	2.23	2.23	0.00%	1.78%
Total: Distribution			64.66			59.66	-4.99	(7.72)%	47.79%
Retail Transmission Rate – Network Service Rate	546.00	0.0054	2.96	546.00	0.0065	3.56	0.60	20.07%	2.85%
Retail Transmission Rate – Line and Transformation Connection Service Rate	546.00	0.0043	2.35	546.00	0.0047	2.57	0.21	9.05%	2.06%
Total: Retail Transmission			5.32			6.13	0.81	15.20%	4.91%
Sub-Total: Delivery (Distribution and Retail Transmission)			69.97			65.79	-4.18	(5.98)%	52.70%
Wholesale Market Service Rate	546.00	0.0052	2.84	546.00	0.0052	2.84	0.00	0.00%	2.27%
Rural Rate Protection Charge	546.00	0.0011	0.60	546.00	0.0011	0.60	0.00	0.00%	0.48%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%
Sub-Total: Regulatory			3.69			3.69			2.96%
Debt Retirement Charge (DRC)	500.00	0.00700	3.50	500	0.0070	3.50	0.00	0.00%	2.80%
Total Bill before Taxes			114.66			110.48	-4.18	(3.65)%	88.50%
HST		13%	14.91		13%	14.36	-0.54	(3.65)%	11.50%
Total Bill			129.57			124.84	-4.73	(3.65)%	100.00%
Ontario Clean Energy Benefit (OCEB)		(10%)	-12.96		(10%)	-12.48			
Total Bill (less OCEB)			116.61			112.36	(4.26)	(3.65)%	

Balsam Lake Coalition (BLC) INTERROGATORY #7 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Please provide a summary of the number of Seasonal class customers located in each of the Residential density zone (i.e. UR, R1 & R2)

Response

"UR", "R1", "R2", and "Seasonal" are customer rate classes, not density zones. These four rate classes account for all residential customers in Hydro One's distribution service territory. By definition, there are no Seasonal customers in UR, R1, and R2 rate classes.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #1 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 1, page 10 of 10, Table 8

Table 8 provides a Comparison of Proposed 2013 Density Study Adjusted IRM Total Bill Impacts. The percentage change of the total bill impacts ranges between -4.97% to 4.45%. CME wishes to understand the potential "worse case" impact which the proposed rate schedules based on the density study adjusted IRM rates will have on individual customers. To this end:

- (a) Is Hydro One able to estimate the largest percentage change that the proposed rate schedules based on the density study adjusted IRM rates will have on any single customer in each rate class? If so, please set out that percentage change for each rate class.
- (b) If Hydro One is not able to estimate the largest percentage change that the proposed rate schedules based on the density study adjusted IRM rates will have on any single customer, please confirm whether any individual customers will experience a percentage change of 10% or greater as a result of those proposed rate schedules. If any customers will experience a 10% or greater percentage change, please identify the rate classes where this will occur.
- (c) If any individual customers will experience a 10% or greater change as a result of the proposed rate schedules based on the density study adjusted IRM rates, please confirm whether Hydro One Distribution has considered the issue of potential rate shock and/or whether any mitigation measures are necessary. If Hydro One Distribution has considered potential rate shock and/or mitigation measures, please provide details of such considerations. If Hydro One Distribution has not considered rate shock and potential mitigation measures, please explain why not.

Response

- a) In Exhibit I, Tab 13, Schedule 7.02 CCC 22, Option 1 Table, Hydro One has provided total bill impacts and distribution bill impacts at low, average, and high consumption levels for the rate classes included in Table 8.
- b) As shown in the response to interrogatory at Exhibit I, Tab 13, Schedule 7.02 CCC 22, Option 1 Table, none of the rate classes in Table 8 will experience a percentage change of 10% or greater as a result of the proposed rate schedules based on the density adjusted rates.

Filed: October 11, 2012

EB-2012-0136

Exhibit I

Tab 13

Schedule 4.01 CME 1

Page 2 of 2

- 1 c) Hydro One does not forecast any customers impacted by the proposed Density Study
- 2 Adjusted IRM rates to have total bill impacts exceeding 10%.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #49 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, page 1

- a) What is HON's understanding as to the direction it received from the Board in EB-2009-0096 in terms of the task(s) to be completed regarding "density" and when?
- b) Please confirm that "density" was not the only cost allocation-related issue that the Board's EB-2009-0096 Decision directed HON to address in its next cost of service application (e.g. per pages 63-64).
- c) Please indicate what the current status is of these remaining issues and why they too were not included in the current Application.

Response

- a) Hydro One's understanding of the direction it received from the Board was to work cooperatively with stakeholders in determining how best to conduct the study taking into consideration timing, feasibility and cost. Hydro One engaged with Stakeholders four times (as discussed in Exhibit A, Tab 4, Schedule 1) during the course of completing the Density Study. Hydro One's intention was to have the Density Study completed in time for inclusion as part of a cost of service (COS) application for 2012 rates. While Hydro One was not eligible to file a COS application in 2012, the results of the Density Study clearly demonstrated a disparity in the existing revenue-to-cost ratios of the density-based rate classes that merits this issue being addressed as part of the current IRM application.
- b) Hydro One confirms that in addition to the Density Study, the Board directed Hydro One to consider several issues raised by VECC as part of its normal course in considering potential improvements to its cost allocation methodology. The Board also directed Hydro One to prepare evidence on the revenue to cost ratio for unmetered scattered load (USL) customers.
- c) Hydro One has been looking at the issues raised by VECC for consideration at Hydro One's next COS application, as directed by the Board. Hydro One also intends to create a USL rate class for inclusion as part of its next COS application as per the direction in the Report of the Board, "Review of Electricity Distribution Cost

- 1 Allocation Policy”. Hydro One has not included these issues as part of the current
- 2 IRM application as the required adjustment cannot be made without re-running the
- 3 cost allocation model, whereas the Density Study findings can be accommodated via
- 4 a bottom line adjustment to the output of the existing cost allocation model.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #50 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Reference: **Exhibit D, Tab 1, Schedule 1, Attachment 1, page iii, 35 and 37**

Preamble: The Study concludes that "three density differentiated rate classes appears justified". The Study also states "there does not appear to be an immediate or pressing need to change the number of existing density-based rate classes"

- a) As this conclusion is based the fact that the Study showed there were statistically significant differences between the mean costs assigned to high-, medium-, and low-density sample areas, is it not reasonable to conclude that the use of at least three density differentiated rate classes appears justified (i.e., it is not known if the use of four, five or even more density differentiated sample areas would have yielded statistically significant differences in costs between all of them as well)? If not, why not?

Response

- a) The study does not provide direct evidence to support or oppose more than three density differentiated rate classes.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #51 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages vi-vii and 21

- a) For each of the sample areas, please provide a breakdown of the customer numbers by customer class, including DG, Street Lights, Sentinel Lights and ST.
- b) Please explain what is meant by the statement – “the density of HONI's service territory containing seasonal customers is expected to fall somewhere between that of service territory containing R2 and R1 customers”. Are there not seasonal customers in all three service territories (i.e., those containing UR, R1 and R2 customers)?

Response

a)

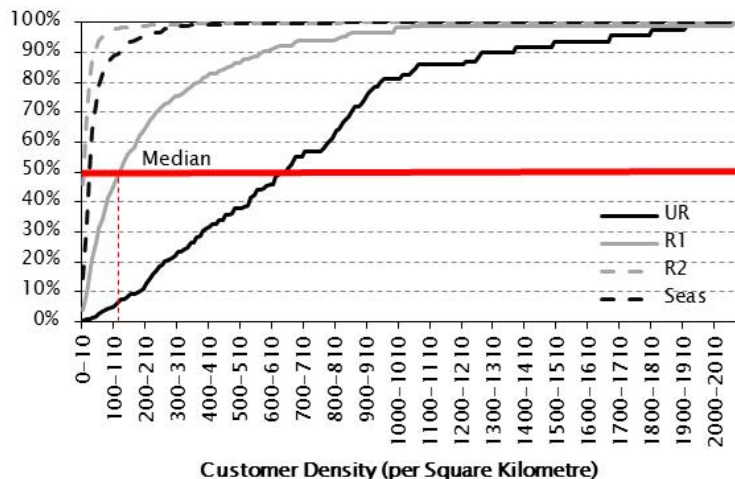
Operating Area	Sample Area	Total	UR	R1	R2	Seasonal	UGd	UGe	GSD	GSe
Bracebridge	LD1	154			13	139				2
Bracebridge	LD2	102			98	1				3
Bracebridge	LD3	111		5	96	5				5
Bracebridge	MD1	1,125		365	145	432			10	173
Bracebridge	MD2	1,417		410	55	840			4	108
Bracebridge	MD3	727		100	189	382			3	53
Dryden	LD1	103		2	39	36				26
Dryden	LD2	20								20
Dryden	MD1	872		650	8	73			3	138
Dryden	MD2	1,057		768	30	5			33	221
Dryden	HD1	3,608	2	3,023	14	6		2	44	517
Essex	LD1	179		72	93				1	13
Essex	LD2	174		6	144				1	23
Essex	MD1	886	1	625	68	105		1	11	75
Essex	MD2	912		293	43	1			166	409
Essex	HD1	2,279	1	1,898	111	25			60	184
Essex	HD2	1,973		1,844	57	7			5	60
Kingston	LD1	84			71	7				6
Kingston	LD2	84			68	6				10
Kingston	MD1	662	2	403	200				3	54
Kingston	MD2	858	1	543	212	7			7	88
Kingston	HD1	11,260	6,536	3,651	13	1	58	861	20	120
Newmarket	LD1	259	1	16	199	1		1	0	41
Newmarket	LD2	271	0	40	215	0		0	4	12
Newmarket	LD3	164		15	132	1				16
Newmarket	MD1	911	28	496	219	15		5	15	133
Newmarket	HD1	3,593	3	2,884	29	404			17	256
Newmarket	HD2	8,956	7,602	837	19	97	17	250	20	114
Newmarket	HD3	8,463	5,257	2,510	83	1	33	413	13	153
Newmarket	HD4	3,876	3,645	95	5	2	8	104	2	15
Owen Sound	LD1	78		8	62	6				2
Owen Sound	LD2	63		2	44	3			2	12
Owen Sound	MD1	598		427	103	1			2	65
Owen Sound	MD2	514		242	40	209				23
Owen Sound	HD1	10,062	8,373	362	29	11	108	1,099	19	61
Perth	LD1	92		1	86					5
Perth	LD2	130		2	108	10				10
Perth	MD1	810		422	145	229				14
Perth	MD2	547		163	165	167				52
Perth	HD1	3,811	2,840	252	147	1	31	428	12	100
Perth	HD2	5,366	4,041	552	34		44	599	4	92
Peterborough	LD1	126		7	105	1				13
Peterborough	LD2	162		5	131				1	25
Peterborough	MD1	949		527	314	11			8	89
Peterborough	MD2	1,182		868	208	1			4	101
Peterborough	MD3	1,237		1,102	70	6			4	55
Simcoe	LD1	153		1	139				1	12
Simcoe	LD2	128		1	112				1	14
Simcoe	MD1	938		160	586	3			14	175
Simcoe	MD2	936		247	21	606			1	61
Simcoe	MD3	446		90	320				2	34
Sudbury	LD1	137	3		114	13			1	6
Sudbury	LD2	90	4		83					3
Sudbury	MD1	938		680	200	4			5	49
Sudbury	MD2	808		543	158	56				51
Sudbury	HD1	4,674	4,126	166	39	5	19	276	8	35
Sudbury	HD2	3,361		2,983	105				24	249
Sudbury	HD3	2,032		1,726	172	12			17	105
Timmins	LD1	123			56	62				5
Timmins	LD2	39			33	2			1	3
Timmins	HD1	113,057	11,639	64	13	26	103	1,111	24	77
Timmins	HD2	2,983	6	2,743	11	1			25	197

Distributed Generation, Street Lights, Sentinel Lights, and Sub-transmission customers were not included in the direct cost assignment analysis. These customers have not yet been incorporated into Hydro One's GIS database.

- b) While there are seasonal customers dispersed across the province in areas containing UR, R1, and R2 customers, they are primarily located in areas containing R1 and R2 customers.

The median density is the point at which the cumulative distribution equals 50%. At most, half of the customers in a given class have a density higher than the median and, at most, half of the customers in a given class have a density less than the median. As can be seen in Exhibit D, Tab 1, Schedule 1, Attachment 1, Figures 63, 64, and 65, (and as illustrated again below) the median density of the service territory containing seasonal customers is greater than the median density of the service territory containing R2 customers and less than the median density of the service territory containing R1 customers.

Cumulative Density of Hydro One's UR, R1, R2, and Seasonal Customers
(based on 11 operating areas)



Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #52 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 8–10 and 25

- a) Please confirm that asset vintage will impact the value for NBV and thus the capital proxy value as determined by Equation #1.
- b) Please confirm that asset vintage is likely to have an impact on OM&A costs.
- c) Did the Study authors assess at all the extent to which the vintage of the assets in-service varied across the 48 service areas? If yes, what were the findings?
- d) Did the Study authors test the inclusion in the regression model (i.e., Equation #2) of any variables that indicated asset vintage? If not, why not? If yes, what were the results?
- e) Please provide more details regarding the analysis done of correlation between customer density and age referenced on page 25.
- f) In the view of the Study authors what level of R-squared value is required in order for one to conclude that the overall model satisfactorily explains variations in the "dependent variable"?
- g) What customer classes were included in the determination of the customer count for purposes of establishing "Customer Density" and "Energy Density"? If some classes of customers were excluded, please explain why.

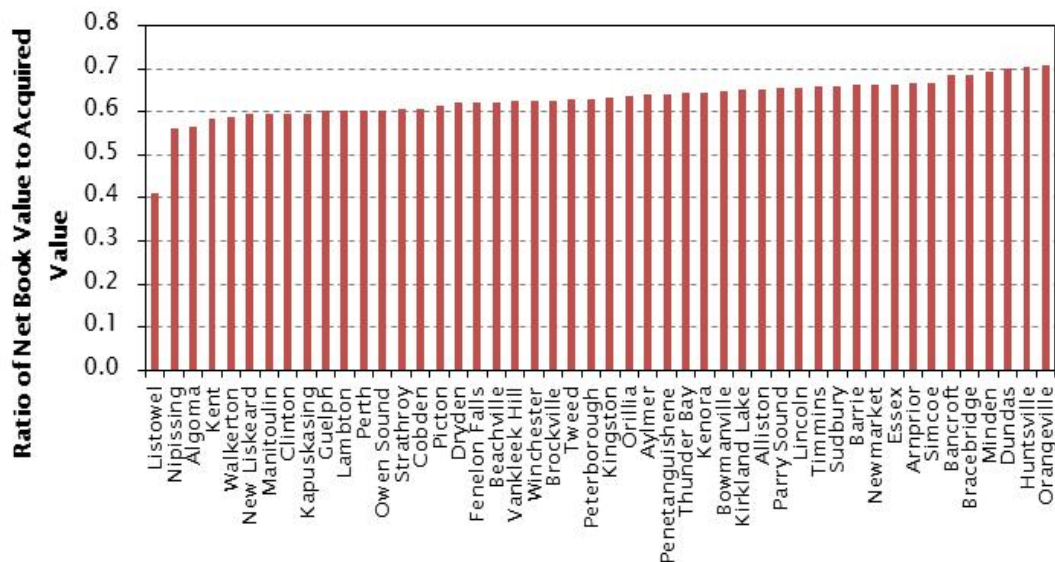
Response

- a) Yes, the age of distribution assets will affect the Net Book Value of assets and hence the capital proxy value in Equation #1.
- b) Yes, the age of distribution assets generally tends to affect operations and maintenance costs. Administration costs are generally less affected by the age of assets.
- c) Yes, the study authors did attempt to analyze the extent to which the vintage of assets in-service varied across Hydro One's operating areas. Hydro One provided data on

the acquired value and accumulated depreciation of assets placed in-service in each year from 1950 to 2010. LEI/PNXA assigned these assets to each of the operating areas. LEI/PNXA generated two variables intended to reflect the “average vintage of assets” in each of the operating areas. The two variables are:

- Net Book Value of Assets (NBV) / Acquired Value of Assets (AQV) (“age_nbv”); and
- Total 2010 Real Acquired Value of Assets / Total Nominal Acquired Value of Assets

The two variables are almost perfectly correlated (0.99). The 2010 values for the age_nbv variable are provided below. The average value is 0.63 and the standard deviation is 0.05.



- d) Inclusion of the age_nbv variable did not lead to much change in the signs, values, or standard errors of the main parameters of interest and the estimated parameter of the age_nbv variable was itself not practically significant.
- e) This analysis was conducted at the operating area level. The correlation coefficient between the 2010 age_nbv variable and the 2010 customers per square kilometre variable was calculated to be 0.26.
- f) The R-squared value is only one of the elements considered when determining the “fit” of econometric model and there is generally no value above which the results “satisfactorily” explain the variations in the dependent variable.

1 For example, it is not always critical to be able to explain all of the variation in the
2 dependent variable. Transformations, such as taking the logarithm, may drastically
3 change the variation of the modelled dependent variable, relative to its initial raw
4 form. Hence, if the dependent variable has already been transformed in some way, it
5 is possible that much of the variance has already been "explained" merely by the
6 choice of an appropriate transformation. Furthermore, in addition to the R-squared
7 value, it is equally important to consider the magnitude and stability of the T-statistic
8 and the sign of coefficient for the independent variables.

9
10 In the case of the four models presented, the R-squared is above 0.7 and is a
11 reasonable value.

- 12
13 g) The customer classes used to establish the customer density and energy density
14 variables include Residential Urban High Density (UR), Residential Medium Density
15 (R1), Residential Low Density (R2), Seasonal Residential (Seasonal), Urban General
16 Service Energy Billed (UGe), General Service Energy Billed (GSe), Urban General
17 Service Demand Billed (UGd), General Service Demand Billed (GSd), as well as
18 Sub-Transmission customers.

19
20 The calculation did not take into account Street Lighting, Sentinel Lighting, and
21 Distributed Generation customers. These represent less than 4% of Hydro One's total
22 customers. Given the relatively even distribution of these customers across Hydro
23 One's service territory, their exclusion was not expected to bias the results.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Reference: **Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 12 - 13**

- a) Please confirm that the econometric analysis found that the effect of customer size on OM&A was statistically significant.
- b) Were any regression equations estimated using only the capital proxy as the "dependent" variable? If yes, please provide the results.

Response

- a) The coefficient on customer size, measured as the average volume of energy consumed per customer in each operating area, was found to be statistically significant (i.e. statistically different from zero) at the 5% confidence level in the models considering OM&A costs only.
- b) No, regression equations using only the capital proxy were not estimated.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #54 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 19 - 21

- a) What "types" of customers are included in the determination of the "Number of Customers" for each sample area? If certain customer classes were excluded, please explain why.
- b) Please provide a schedule that is similar to Figure 10 but also includes the total energy for each sample area along with the "Number of Customers" (as defined by the Study) and the total number of customers (from all classes if different). Note: As well as hard copy, please provide the data in a live excel spreadsheet.
- c) Please provide a schedule that is similar to the upper part of Figure 11 but also includes the total energy for each density class along with the "Number of Customers" (as defined by the Study) and the total number of customers (from all classes if different).

Response

- a) The customer types include all year-round and seasonal residential customers as well as all general service customers. Distributed Generation, Street Lights, Sentinel Lights, and Sub-Transmission customers are not included. The customers not included are those for whom information is not currently available in Hydro One's GIS, and as such could not be mapped to a geographic location within the Province in the same manner as those included in the GIS.
- b) Energy consumption data was not collected for each sample area. Attachment 1 is the hard copy of the requested schedule. The live version can be found at [http://www.hydroone.com/RegulatoryAffairs/Pages/2013DistributionRates\(EB-2012-0136\).aspx](http://www.hydroone.com/RegulatoryAffairs/Pages/2013DistributionRates(EB-2012-0136).aspx)
- c) Energy consumption data was not collected for each sample area.

		Number of Customers												
Operating Area	Sample Area	Total	UR	R1	R2	Seasonal	UGd	UGe	GSd	GSe	km ²	Circuit km	Customers per km ²	Customers per Circuit km
Bracebridge	LD1	154			13	139				2	18.2	25.7	8.5	6.0
Bracebridge	LD2	102			98	1				3	21.4	27.9	4.8	3.6
Bracebridge	LD3	111		5	96	5				5	19.2	31.9	5.8	3.5
Bracebridge	MD1	1,125		365	145	432			10	173	21.7	94.5	51.9	11.9
Bracebridge	MD2	1,417		410	55	840			4	108	22.5	74.7	62.9	19.0
Bracebridge	MD3	727		100	189	382			3	53	28.8	77.2	25.2	9.4
Dryden	LD1	103		2	39	36				26	22.4	43.4	4.6	2.4
Dryden	LD2	20								20	29.4	47.9	0.7	0.4
Dryden	MD1	872		650	8	73			3	138	16.9	43.5	51.6	20.1
Dryden	MD2	1,057		768	30	5			33	221	17.4	65.0	60.7	16.3
Dryden	HD1	3,608	2	3023	14	6		2	44	517	22.7	106.1	158.8	34.0
Essex	LD1	179		72	93				1	13	22.8	38.0	7.8	4.7
Essex	LD2	174		6	144				1	23	15.0	73.9	11.6	2.4
Essex	MD1	886	1	625	68	105		1	11	75	21.0	49.4	42.2	17.9
Essex	MD2	912		293	43	1			166	409	17.9	44.7	50.9	20.4
Essex	HD1	2,279	1	1898	111	25			60	184	20.9	95.1	109.2	24.0
Essex	HD2	1,973		1844	57	7			5	60	20.5	111.7	96.1	17.7
Kingston	LD1	84			71	7				6	19.3	36.9	4.4	2.3
Kingston	LD2	84			68	6				10	18.8	34.8	4.5	2.4
Kingston	MD1	662	2	403	200				3	54	22.8	52.2	29.1	12.7
Kingston	MD2	858	1	543	212	7			7	88	24.0	63.1	35.7	13.6
Kingston	HD1	11,260	6536	3651	13	1	58	861	20	120	16.9	237.3	667.9	47.5
Newmarket	LD1	259	1	16	199	1		1	0	41	17.4	56.6	14.9	4.6
Newmarket	LD2	271	0	40	215	0		0	4	12	19.4	33.8	14.0	8.0
Newmarket	LD3	164		15	132	1				16	18.5	21.7	8.9	7.6
Newmarket	MD1	911	28	496	219	15		5	15	133	16.7	68.7	54.4	13.3
Newmarket	HD1	3,593	3	2884	29	404			17	256	16.5	91.2	218.1	39.4
Newmarket	HD2	8,956	7602	837	19	97	17	250	20	114	18.0	170.6	498.7	52.5
Newmarket	HD3	8,463	5257	2510	83	1	33	413	13	153	17.2	168.2	492.7	50.3
Newmarket	HD4	3,876	3645	95	5	2	8	104	2	15	21.3	145.7	181.9	26.6
Owen Sound	LD1	78		8	62	6				2	19.7	22.1	4.0	3.5
Owen Sound	LD2	63		2	44	3			2	12	17.4	30.7	3.6	2.1
Owen Sound	MD1	598		427	103	1			2	65	22.0	76.7	27.2	7.8
Owen Sound	MD2	514		242	40	209				23	19.5	75.2	26.3	6.8
Owen Sound	HD1	10,062	8373	362	29	11	108	1099	19	61	22.4	237.9	448.7	42.3
Perth	LD1	92		1	86					5	20.7	37.6	4.4	2.4
Perth	LD2	130		2	108	10				10	20.6	33.2	6.3	3.9
Perth	MD1	810		422	145	229				14	24.3	69.5	33.3	11.7
Perth	MD2	547		163	165	167				52	24.8	80.1	22.0	6.8
Perth	HD1	3,811	2840	252	147	1	31	428	12	100	17.5	132.4	217.5	28.8
Perth	HD2	5,366	4041	552	34		44	599	4	92	20.5	193.9	261.2	27.7
Peterborough	LD1	126		7	105	1				13	24.4	64.8	5.2	1.9
Peterborough	LD2	162		5	131				1	25	24.7	54.7	6.6	3.0
Peterborough	MD1	949		527	314	11			8	89	20.1	58.9	47.2	16.1
Peterborough	MD2	1,182		868	208	1			4	101	20.9	71.6	56.5	16.5
Peterborough	MD3	1,237		1102	70	6			4	55	23.2	63.5	53.4	19.5
Simcoe	LD1	153		1	139				1	12	20.9	25.2	7.3	6.1
Simcoe	LD2	128		1	112				1	14	20.5	40.3	6.2	3.2
Simcoe	MD1	938		160	586	3			14	175	24.4	54.8	38.5	17.1
Simcoe	MD2	936		247	21	606			1	61	13.2	17.5	70.9	53.6
Simcoe	MD3	446		90	320				2	34	20.0	34.9	22.3	12.8
Sudbury	LD1	137	3		114	13			1	6	18.2	32.2	7.5	4.3
Sudbury	LD2	90	4		83					3	19.5	30.9	4.6	2.9
Sudbury	MD1	938		680	200	4			5	49	22.2	57.0	42.2	16.4
Sudbury	MD2	808		543	158	56				51	20.5	52.0	39.4	15.5
Sudbury	HD1	4,674	4126	166	39	5	19	276	8	35	21.5	106.4	217.7	43.9
Sudbury	HD2	3,361		2983	105				24	249	20.3	100.2	165.7	33.5
Sudbury	HD3	2,032		1726	172	12			17	105	24.2	51.4	83.9	39.5
Timmins	LD1	123			56	62				5	20.9	25.8	5.9	4.8
Timmins	LD2	39			33	2			1	3	24.2	26.8	1.6	1.5
Timmins	HD1	13,057	11639	64	13	26	103	1111	24	77	19.7	164.2	663.5	79.5
Timmins	HD2	2,983	6	2743	11	1			25	197	17.4	55.1	171.1	54.1

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #55 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

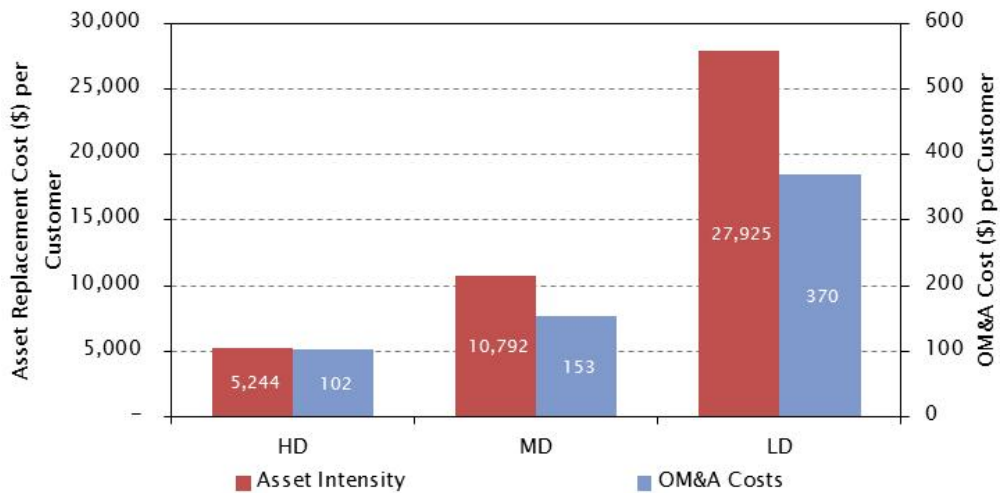
Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 22 - 24

- a) Please confirm that the value for CDR is based on the distance to customers as determined by the distance between each customer and HON's operating centre. If not, what is the basis?
- b) Please confirm that the value for CDR for a particular sample area will depend entirely upon where HON has located its operating centre(s) within the operating area.
- c) How would Figure 16 and the results in Figure 19 change if costs allocated on the basis of CDR were excluded from the analysis?
- d) With respect to Figure 13, please provide a listing of the USOA accounts whose costs were mapped/assigned to the sample areas for purposes of the analysis.

Response

- a) Yes, the value for CDR was calculated based on the distance between customers and the nearest service centre within an operating area.
- b) Yes, CDR depends on the location of the service centre.
- c) The following figures (comparable to Figure 16 and Figure 19) illustrate the results if applicable costs were allocated using CROA instead of CDR. The average high-density sample area OM&A cost per customer increases by 14% from 89 to 102. The average medium-density sample area OM&A cost per customer decreases by 2% from 156 to 153. The average low-density sample area OM&A cost per customer decreases by 2% from 379 to 370. The asset replacement cost results are not affected.



	OM&A			Asset Intensity		
	t-Stat	1 Tail	2 Tail	t-Stat	1 Tail	2 Tail
Low versus Medium	3.0683	0.0026	0.0053	7.3518	0.0000	0.0000
Medium versus High	4.3919	0.0001	0.0001	6.6359	0.0000	0.0000

- d) The costs were assigned to the sample areas with reference to Hydro One's program costs, not costs by USOA. The USOA accounts associated with the program costs assigned by the Density Study are provided in the interrogatory at Exhibit I, Tab 13, Schedule 5.21 VECC 69.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #56 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 25 - 26

- a) Why were all HVDSs assigned the same replacement cost? Wouldn't the cost vary depending upon the capacity (i.e. MVA) of the associated transformers?
- b) Why were all LVDSs assigned the same replacement cost? Wouldn't the cost vary depending upon the capacity (i.e. MVA) of the associated transformers?
- c) Why were smart meter-related costs included?
- d) Why was number of customers used to determine the proportion of a distribution station's cost to be allocated to the service area as opposed to energy or some other measure of the load/capacity requirements of the sample area vs. the total supplied by the station?
- e) If the distribution station supplying the sample area's customers was located outside the sample area was a portion of the station's costs still assigned to the sample area?

Response

- a) In order to comply with the Board's direction while concurrently considering issues related to timing, feasibility, and cost, a handful of simplifying assumptions were integrated into the analysis. In reality, replacement costs for individual assets will vary based on a number of factors. Overall, these simplifying assumptions are not expected to bias the results of the study.
- b) Please see response to a).
- c) Smart-meter related costs were included for completeness. Their inclusion does not have a material impact on the results as they represent a small proportion of the total asset replacement value for a sample area/operating area.
- d) Similar to the response provided in a) above, in order to comply with the Board's direction while concurrently considering issues related to timing, feasibility, and cost, a handful of simplifying assumptions were integrated into the analysis.

Filed: October 11, 2012
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Exhibit I
Tab 13
Schedule 5.08 VECC 56
Page 2 of 2

- 1 e) Yes. LEI/PNXA identified all of the distribution stations serving customers in a
- 2 sample area and a portion of the replacement cost for each was assigned to the sample
- 3 area.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #57 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 25 - 26

- a) Did the asset intensity determination include secondary, primary and sub-transmission conductor?
- b) Why was the same cost for overhead conductor used regardless of the voltage? Does the cost of conductor vary materially by voltage?
- c) If a feeder was used 100% to supply customers in the sample area was its total (replacement) cost included in the asset intensity determination? If not, what costs were included?
- d) If a feeder supplied customers outside as well as inside the sample area was a portion of the feeder's cost included in the asset intensity determination? If yes, please explain how this portion was determined. If not, why not?

Response

- a) The asset intensity determination included overhead, underground, and submarine conductor at primary and sub-transmission voltages (4.16, 13.8, 28, and 44 kV) on Hydro One's or shared rights-of-way. Conductor located on customer premises was not included.
- b) Please see Exhibit I, Tab 13, Schedule 5.08 VECC 56, part a).
- c) Feeder replacement costs were assigned based on the ratio between the length of a feeder physically located within the sample area and the total length of the feeder.
- d) Yes, see response to c).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #58 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 32 - 33

- a) Please fully describe the "density" treatment of HON's other customer classes.
- b) Please provide a schedule that sets out the number of customers in each of the 12 customer rate classes.

Response

- a) Please see Exhibit I, Tab 13, Schedule 2.04 EP 31.
- b) The number of customers by rate class as per the Cost Allocation model submitted in Hydro One's application under EB-2009-0096 are as follows:

Rate Class	Number of customers
UR	140,540
R1	412,455
R2	367,107
Seasonal	156,901
GSe	98,776
GSd	7,361
UGe	10,577
UGd	1,130
St Lgt	5,234
Sen Lgt	37,506
DGen	88
ST	607

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #59 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Reference: **Exhibit D, Tab 1, Schedule 1, Attachment 1, page 35**

Preamble: The Study concludes that three density based classes are warranted in the case of Residential as there are over 1,000,000 customers but not warranted in the case of GS<50 (i.e. GSe) as there are just over 100,000 customers. However, the Study also determined that two rate classes are reasonable for the GS<50 class.

Note: In responding please include the views of the Study authors for parts (a) and (b).

- a) It is noted (D/1/1, page 3) that the GS>50 class has less than 10,000 customers. Are two density classes also reasonable in this case as well? If yes, please explain why.
- b) It is noted that there are over 150,000 seasonal customers. If two density classes are reasonable in the case of >100,000 and also in the case of <10,000 customers, would it be reasonable to have two density-based seasonal classes? If not, why not?
- c) If the response to part (b) is yes, why is HON proposing to maintain only one Seasonal class?

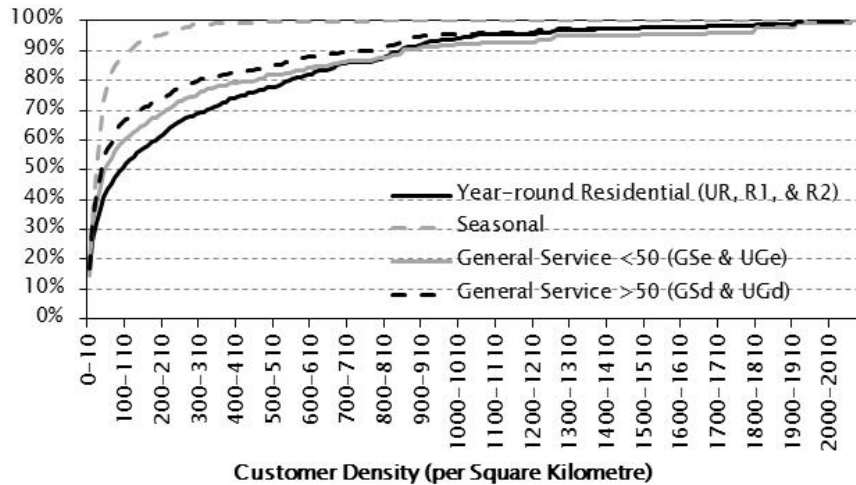
Response

- a) The appropriate number of density-differentiated sub-classes within the Year-round Residential, Seasonal Residential and General Service classes (both >50 and <50) is driven only in part by the total number of customers in each class. Other factors such as the distribution (i.e. range and variability) of customer densities within each class should also be considered.

The figure below shows the cumulative distribution of customer densities exhibited by the four main classes of customers served by Hydro One across the 11 operating areas included in the direct cost assignment analysis:

- Year-round Residential;
- Seasonal Residential;
- General Service <50; and

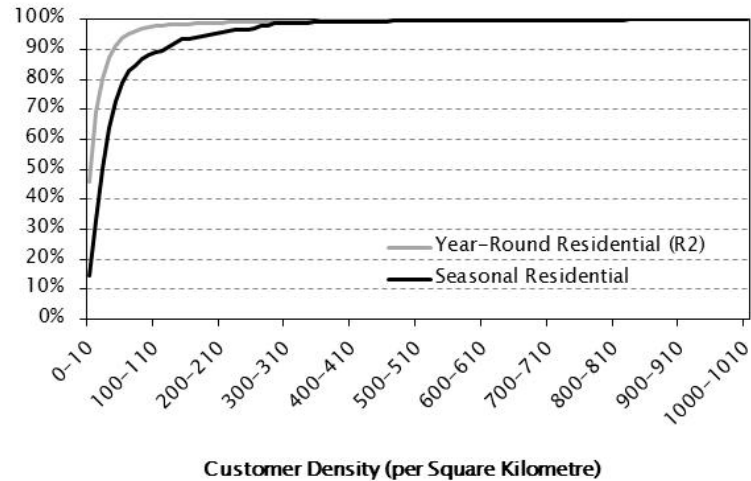
- General Service >50.



As illustrated by this figure, the year-round residential customers exhibit the widest range (i.e. the greatest dispersion) of customer densities, followed by the General Service <50, General Service >50 and finally the Seasonal Residential customers. The slope of the cumulative distribution line is illustrative of the width (or dispersion) of the distribution. For example, the year-round residential cumulative distribution increases gradually from approximately 50% to 90% as the customer density increases from 100-110 to 1000-1010 customers per km². This implies that 50% of the customers have a customer density of less of than 100 customers per km², 40% have a customer density between 100 and 1010 customers per km² and 10% have a customer density above 1010 customers per km². Conversely, the seasonal cumulative distribution increases to approximately 90% before the customer density increases beyond 100. This implies that 90% of the customers in the seasonal class are in service territories that have a customer density of less than 100 customers per km².

As the study concluded, there is clear evidence to support three density-differentiated sub-classes for Year-round Residential customers. The chart above also suggests that the wide-range of customer densities exhibited by the General Service >50 customers warrant multiple density-differentiated sub-classes. However, as indicated in the question, there are a limited number of customers in this class, and hence two density-differentiated sub-classes appear reasonable.

- b) As illustrated in the figure provided in response to a) above, Seasonal Residential customers do not exhibit a wide-range of customer densities. In fact, the distribution of customer densities for Seasonal Residential customers is similar to the distribution for the R2 class of Year-round Residential customers (see figure below).



1

2 Hence, regardless of the total number of customers in the class, multiple density-
3 differentiated sub-classes for the Seasonal Residential customers do not appear to
4 be warranted.

5 Hydro One also notes that as part of the harmonization of Hydro One's rate
6 classes proposed in EB-2007-0681 the Board approved harmonizing the previous
7 High density (R3) and Low density (R4) Seasonal rate classes into a single
8 Seasonal rate class, which was generally supported by stakeholders. The
9 harmonization of the R3 and R4 Seasonal rate classes was completed in 2011.

10 c) See response to b).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #60 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Reference: **Exhibit D, Tab 1, Schedule 1, Attachment 1, page 35**

Preamble: The Study concludes that maintaining two density-based rate classes is reasonable for the GS<50 class.

Note: In responding please include the views of the Study authors for parts (a) and (b).

- a) If there are to be only two GS<50 density-based rate classes why is it appropriate to combine the medium and low density areas for purposes of creating one rate class as is HON's current practice (as opposed to combining the high and medium density classes)?
- b) Why wouldn't combining the high and medium density areas be more reasonable given (D/1/1, page 3) that the relative cost differences between these two areas is much less than in the case of the medium and low density areas.
- c) If the current GS<50 classes were restructured into a "Normal Density Class" that included GS<50 customers from both the Urban and Medium density areas (as currently defined by HON) and a "Low Density Class" based on HON's low density definition what would be the number of customers in each class? (Note: Please use the customer count base set out in D/1/1, Table 2)

Response

- a) The density study showed that there is a statistically significant difference in the mean cost to serve high- and medium- and low- density customers. While Hydro One's practice of combining the medium- and low- density general service energy billed customers in the GSe class may not minimize cross-subsidization amongst these customers it is still an appropriate rate design given the results of the density study.

The data analyzed in the density study suggests, for the 11 operating areas considered in the direct-cost assignment analysis, there may be a substantial number of GSe customers who could potentially be classified as medium density. Re-evaluating the assignment of a large group of customers is not a trivial task for Hydro One. The

- 1 implementation of Hydro One's GIS is, in the long-term, making these types of
2 analysis easier, but it will always involve a significant undertaking.
- 3 b) The density study results do suggest that the cost to serve high- and medium-density
4 areas is closer together than the cost to serve medium- and low-density areas.
5 However, this alone is not sufficient to determine whether grouping medium- and
6 high- or low- and medium-density customers is more reasonable.
- 7 If a large number of customers were to move from the GSe rate class to the UGe rate
8 class, the rate impact on remaining customers in the GSe class could be material.
9 These factors need to be carefully explored before making a final determination on
10 the reasonableness of reclassification.
- 11 c) Hydro One does not currently have information on the number of GS<50 customers
12 located within medium density areas. It is estimated that Hydro One would require
13 several months to carry out a detailed analysis leveraging information on customers'
14 geographic locations available through its GIS system in order to provide the
15 requested information.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #61 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, page 35

Note: In responding please include the views of the Study authors for parts (a) and (b).

- a) If there are to be only two GS>50 density-based rate classes why is it appropriate to combine the medium and low density areas for purposes of creating one rate class as is HON's current practice (as opposed to combining the high and medium density classes)?
- b) Why wouldn't combining the high and medium density areas be more reasonable given (D/1/1, page 3) that the relative cost differences between these two areas is much less than in the case of the medium and low density areas.
- c) If the current GS>50 classes were restructured into a "Normal Density Class" that included GS>50 customers from both the Urban and Medium density areas (as currently defined by HON) and a "Low Density Class" based on HON's low density definition what would be the number of customers in each class? (Note: Please use the customer count base set out in D/1/1, Table 2)

Response

- a) Please see Exhibit I, Tab 13, Schedule 5.12 VECC 60, part a).
- b) Please see Exhibit I, Tab 13, Schedule 5.12 VECC 60, part b).
- c) Please see Exhibit I, Tab 13, Schedule 5.12 VECC 60, part c).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #62 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, page 37

- a) What additional data and analysis would be required in order to determine the cut-off points between the density-based rate classes?

Response

- a) With data comparable to that used in the density study, a study could be designed to analyze the impact on cost of service of changes to the cut-off points between rate classes. One approach would be to incorporate sample areas consisting of a uniform class of customers. Costs would be assigned to these sample areas in a manner similar to the density study. The sample area boundaries could then be re-drawn to reflect new cut-off points and the cost reassigned. This process of expanding or contracting the boundaries could be repeated for an individual sample area, and for multiple sample areas, to provide an indication of the rate of change in the cost to serve.

This is the type of data and analysis that LEI/PNXA refer to on page 37 of the study.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #63 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Reference: **Exhibit D, Tab 1, Schedule 1, Attachment 1, page 37**

Preamble: The Study states that it "did not provide strong evidence to support changing the existing demarcation points".

- a) Does the Study provide strong evidence (or indeed any evidence) that supports the existing demarcation points?
- b) What types of results from the current Study would have supported a change in the existing demarcation points?

Response

- a) Yes, there is evidence within the study to support the existing demarcation points. The primary result of the study was that the average costs to serve the low-, medium-, and high-density sample areas are statistically different and inversely correlated. As per the methodology reviewed with stakeholders at the March 22, 2011 session, the sample areas were selected with indifference to the type of customers contained within them. To assess the reasonableness of the existing demarcation points, LEI/PNXA performed the same statistical tests whose results are reported in Figure 19 of the density study on a subset of the sample areas where a single class of year-round residential customer makes up more than 75% of the total. While this reduces the size of the sample, the results are consistent with the broader study, thus providing support for the existing demarcation points.
- b) A number of factors would need to be considered before recommending a change to the existing demarcation points. The results discussed in a) above are one such factor.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #64 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Reference: **Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 37 - 38**

Preamble: The Study judged the reasonableness of the existing density factors by comparing the results of HON's CAM to the results of the direct cost assignment analysis.

- a) Please confirm that the results of HON's CAM (Figure 26) reflect not only the application of HON's density factors but also but also the relative loads (i.e. CP and NCP factors) of the different classes as well as each class' use of primary and secondary voltage facilities in allocating costs.
- b) Since the costs allocated to each class by the CAM also reflect these other factors (e.g., the relative loads of each class and the use of primary vs. secondary facilities) as well as HON's density factors, why is it appropriate to look at the results of the CAM on a per customer basis to test the appropriateness of HON's current density factors?
- c) Please provide a live excel version of the CAM used for Figure 26 and confirm it was the CAM underlying the Draft Rate Order from EB-2009-0096.
- d) Please provide a schedule that sets out the USOA account numbers for the shared services and customer care activities that were excluded.
- e) Did the OM&A accounts excluded include those associated with: i) cable locates, ii) field meter reading and ancillary services, iii) sentinel light maintenance, or iv) field collections and special investigations? If yes, please reconcile this with the fact that costs for these activities were included in OM&A costs assigned to the sample areas (per page 24).

Response

a) This is confirmed.

b) The total cost allocated to each rate class by the CAM is the combined impact of all of the factors driving the cost allocation methodology used in the Board's model. Looking at the CAM results on a per customer basis simply recasts the net output of the model in terms of the total cost per customer taking into account all of the factors driving costs in the CAM. The Density Study assessed the determination of costs to serve areas of different density from a different perspective, by looking at Hydro One's actual costs incurred in serving those customers.

Hydro One's proposed Density Study Adjustment does not change the total costs allocated by the CAM to the density differentiated customer segments (i.e. residential customers, GS<50 customers, GS>50 customers), but rather it re-distributes the total costs allocated by the CAM to those customer segments in order to better align with the relative cost of serving density-differentiated customers as demonstrated by the Density Study.

c) It is confirmed that the basis of the data in Figure 26 is the CAM underlying the Draft Rate Order from EB-2009-0096. A live excel version of the model is provided in electronic form only and is available at [http://www.hydroone.com/RegulatoryAffairs/Pages/2013DistributionRates\(EB-2012-0136\).aspx](http://www.hydroone.com/RegulatoryAffairs/Pages/2013DistributionRates(EB-2012-0136).aspx)

d) The table below provides the list of USoA account numbers for shared services and customer care activities that were excluded from the density study adjustment that considered only OM&A and Fixed Asset costs.

USoA Account Number	Account
5315	Customer Billing
5320	Collecting
5325	Collecting- Cash Over and Short
5330	Collection Charges
5335	Bad Debt Expense
5340	Miscellaneous Customer Accounts Expenses
5405	Supervision
5410	Community Relations - Sundry
5415	Energy Conservation
5420	Community Safety Program
5425	Miscellaneous Customer Service and Informational Expenses
5505	Supervision
5510	Demonstrating and Selling Expense

USoA Account Number	Account
5515	Advertising Expense
5520	Miscellaneous Sales Expense
5605	Executive Salaries and Expenses
5610	Management Salaries and Expenses
5615	General Administrative Salaries and Expenses
5620	Office Supplies and Expenses
5625	Administrative Expense Transferred Credit
5630	Outside Services Employed
5635	Property Insurance
5640	Injuries and Damages
5645	Employee Pensions and Benefits
5650	Franchise Requirements
5655	Regulatory Expenses
5660	General Advertising Expenses
5665	Miscellaneous General Expenses
5670	Rent
5675	Maintenance of General Plant
5680	Electrical Safety Authority Fees
6105	Taxes Other Than Income Taxes
6205	Donations
6210	Life Insurance
6215	Penalties
6225	Other Deductions

1

- 2 e) The OM&A accounts excluded did not include those associated with i) cable
3 locates, ii) field meter reading and ancillary services, and iii) sentinel light
4 maintenance. Some of the field collections and special investigations costs were
5 allocated to excluded USOA 5320, but these costs make up less than half of the
6 total costs tracked in 5320. Also, the excluded field collections and special
7 investigation costs account for only about 2% of the total costs assigned to the
8 sample areas.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #65 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 39 - 40

- a) Are all of the low density sample areas located in areas where Residential customers would be classified as R2? If not, how many of these sample areas represent service territory where Residential customers would be classified as R1?
- b) Please break the medium density sample areas down and indicate how many of them represent areas where Residential customers would be classified as UR, R1 and R2. If any of the sample areas do not fall entirely into one of these groupings please list them separately and indicate which two or three Residential classifications could be found in the sample area.
- c) Please confirm that the ratios shown in Figure 27 for OM&A costs and Asset Intensity are derived by taking the relevant ratios from the costs shown in Figure 16.
- d) Please explain more fully how the uniform adjustment for shared services and customer care OM&A was done in order to obtain Figure 28.

Response

- a) Of the approximately 2,700 residential customers located in the 22 low-density sample areas, 74% are classified as R2 and 15% are classified as R1. Out of the 22 low-density sample areas, only two consist of a majority of R1 customers.
- b) Of the approximately 13,650 year-round residential customers located in the 22 medium-density sample areas, 26% are classified as R2, 74% are classified as R1, and less than 1% is classified as UR.

Operating Area	Sample Area	UR	R1	R2	Seasonal
Bracebridge	MD1	0%	39%	15%	46%
Bracebridge	MD2	0%	31%	4%	64%
Bracebridge	MD3	0%	15%	28%	57%
Dryden	MD1	0%	89%	1%	10%
Dryden	MD2	0%	96%	4%	1%
Essex	MD1	0%	78%	9%	13%
Essex	MD2	0%	87%	13%	0%
Kingston	MD1	0%	67%	33%	0%
Kingston	MD2	0%	71%	28%	1%
Newmarket	MD1	4%	65%	29%	2%
Owen Sound	MD1	0%	80%	19%	0%
Owen Sound	MD2	0%	49%	8%	43%
Perth	MD1	0%	53%	18%	29%
Perth	MD2	0%	33%	33%	34%
Peterborough	MD1	0%	62%	37%	1%
Peterborough	MD2	0%	81%	19%	0%
Peterborough	MD3	0%	94%	6%	1%
Simcoe	MD1	0%	21%	78%	0%
Simcoe	MD2	0%	28%	2%	69%
Simcoe	MD3	0%	22%	78%	0%
Sudbury	MD1	0%	77%	23%	0%
Sudbury	MD2	0%	72%	21%	7%

As per the methodology reviewed with stakeholders at the March 22, 2011 stakeholder session, there was a desire to maintain a uniform sample area size of approximately 20 square kilometres. In some of the sample areas this required expanding the boundary beyond an initial cluster of customers.

c) This is confirmed.

d) The OM&A costs in Figure 16 do not include overhead expenses such as shared services and customer care. LEI/PNXA estimated these expenses on a per-customer basis using data from Hydro One's previous rate applications. This cost was added to the average OM&A cost per customer for the high-, medium-, and low-density sample areas. The ratios in Figure 28 were then calculated using the adjusted "total OM&A" in the same manner as the ratios in Figure 27.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #66 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 40-41

- a) Please provide a schedule that sets out the density weights used for each class in the CAM underpinning HON's currently approved rates.
- b) Based on the values provided in part (a) please indicate the relative relationship between the values for each class with the UR values set at 1.0.
- c) Please provide a schedule (similar to Figure 29) that compares the results from part (b) with the relative values established through the Study's analysis of low-, medium- and high-density sample areas.

Response

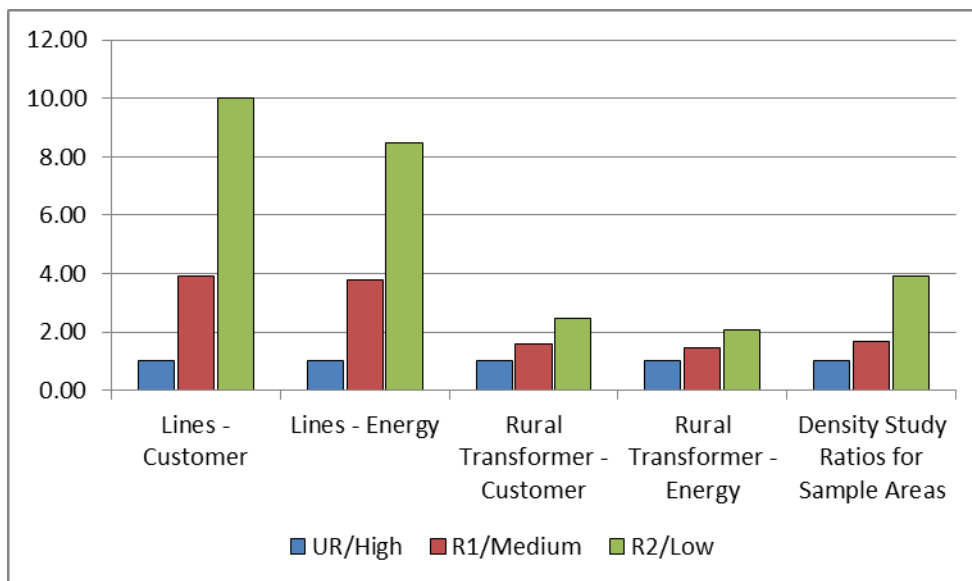
- a) The table below provides the density weights used for each class in the CAM underpinning HON's currently approved rates.

Rate Class	Lines - Customer	Lines - Energy	Rural Transformer - Customer	Rural Transformer - Energy
UR	0.16	0.17	0.54	0.57
R1	0.64	0.63	0.86	0.84
R2	1.64	1.42	1.33	1.18
Seasonal	1.22	1.56	1.02	1.39
UGe	0.20	0.17	0.56	0.51
GSe	1.09	1.14	1.05	1.08
UGd	0.32	0.27	0.59	0.65
GSd	1.11	1.15	1.07	1.07
Street Lights	1.00	1.00	1.00	1.00
Sentinel Lights	1.00	1.00	1.00	1.00
DGen	1.00	1.00	1.00	1.00
ST	1.00	1.00	1.00	1.00

- b) The table below provides the relative relationship between the values for each class with the urban values set at 1.0, where applicable.

Rate Class	Lines - Customer	Lines - Energy	Rural Transformer - Customer	Rural Transformer - Energy
UR	1.00	1.00	1.00	1.00
R1	3.91	3.77	1.57	1.47
R2	10.02	8.46	2.45	2.07
Seasonal	7.45	9.30	1.87	2.44
UGe	1.00	1.00	1.00	1.00
GSe	5.40	6.88	1.86	2.13
UGd	1.00	1.00	1.00	1.00
GSd	3.48	4.28	1.81	1.65
Street Lights	1.00	1.00	1.00	1.00
Sentinel Lights	1.00	1.00	1.00	1.00
DGen	1.00	1.00	1.00	1.00
ST	1.00	1.00	1.00	1.00

- c) The figure below compares the results from part b) with the relative values established through the Density Study's analysis of low-, medium- and high-density sample areas.



Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #67 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

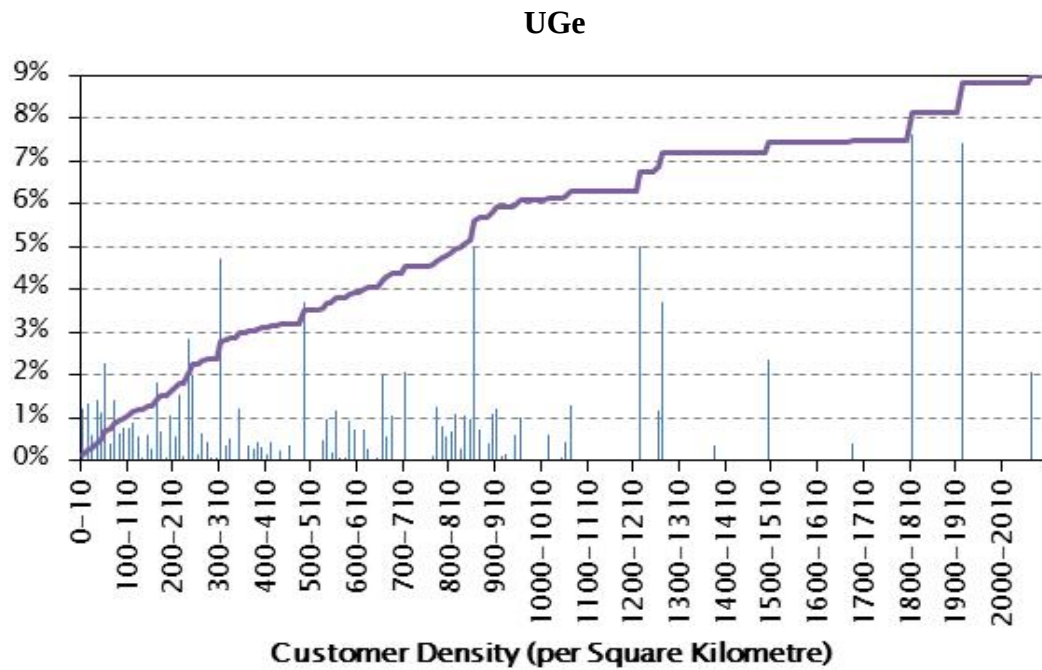
Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, Attachment 1, pages 40-41

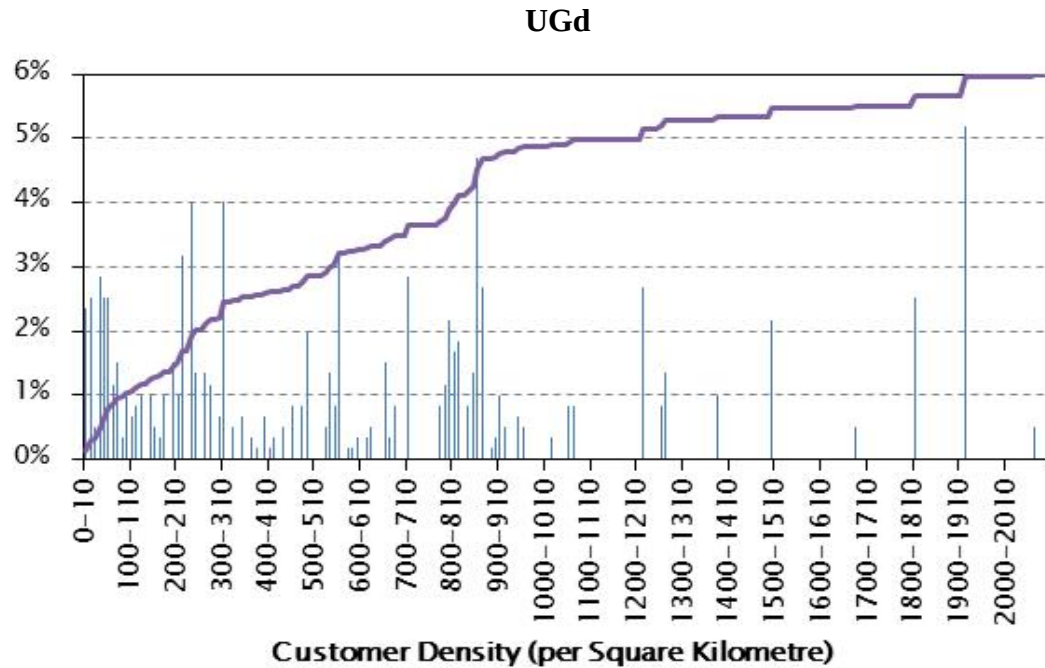
- a) Please provide graphs similar to Figure 65 for: i) the Street Light class, ii) the Sentinel Light class, iii) the DG class, and iv) the ST class.
- b) Based on the results from part (a), please provide comments (similar to those provided for the Seasonal class) as to where the average density for each of these four classes falls relative to the UR, R1 and R2 classes.
- c) Why are UGe and UGd combined in Figure 66? Please reproduce Figure 66 showing each class separately.
- d) Why are GSe and GSd combined in Figure 67? Please reproduce Figure 67 showing each class separately.
- e) Please re-do Figure 62 with just the "cumulative line" also include the cumulative lines for UGe and UGd.
- f) Please comment separately on the relative density of the UGe and UGd classes as compared to the UR.
- g) Please re-do Figure 63 with just the "cumulative line" also include the cumulative lines for GSe, GSd and R2.
- h) Please comment separately on the relative density of GSe and GSd as compared to R1 and R2.

Response

- a) This data was not collected as part of the study.
b) Please see response to a).
c) The figures below provide the requested information.



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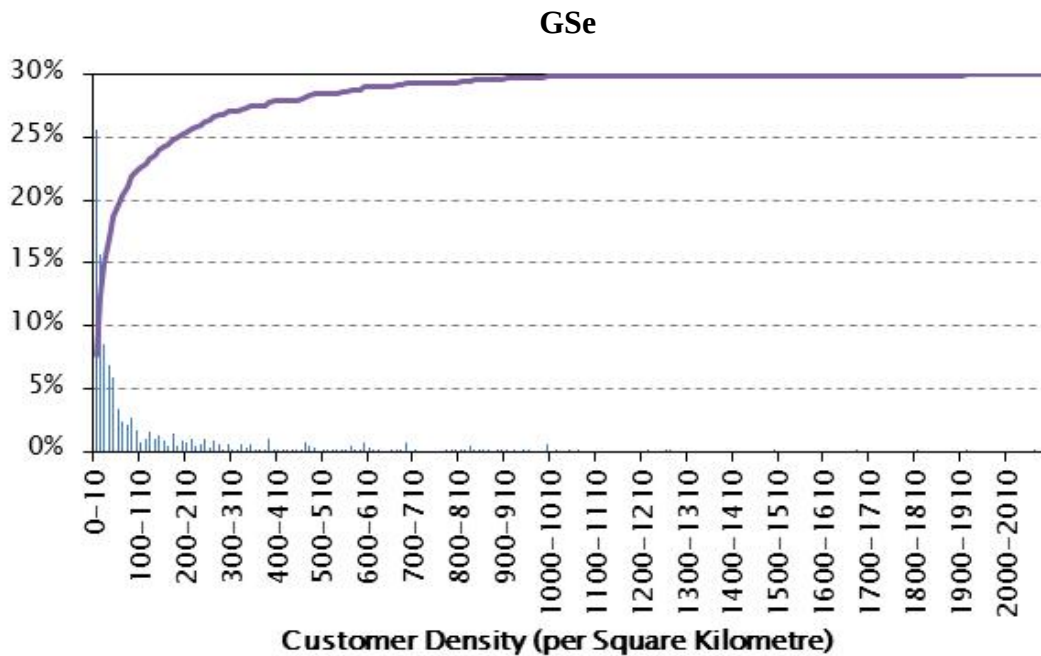
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d) The figures below provide the requested information.

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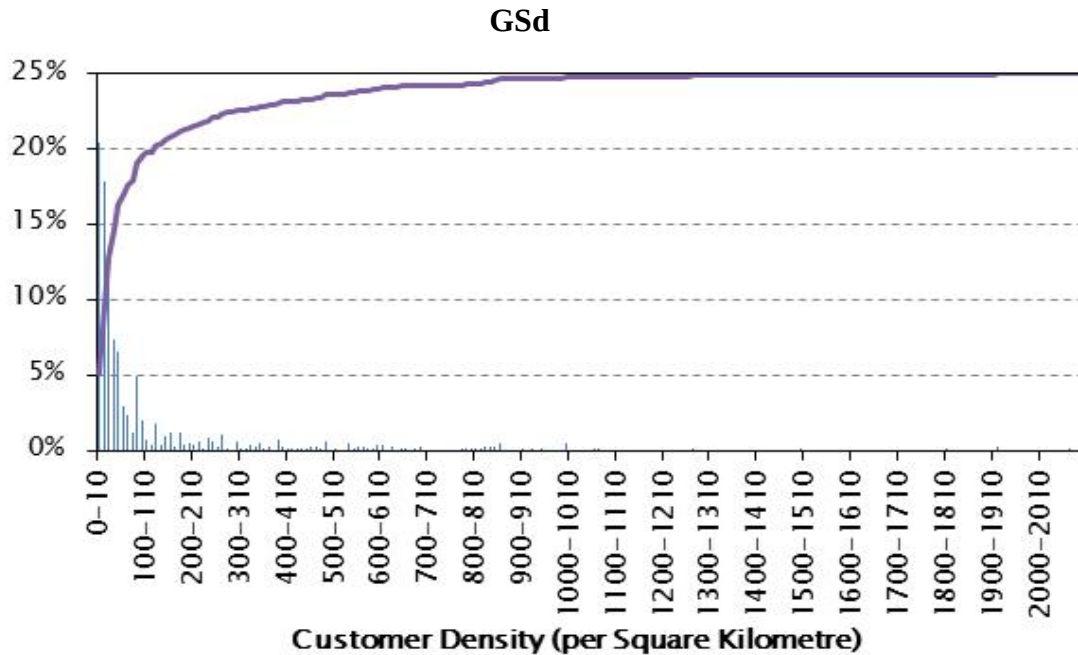
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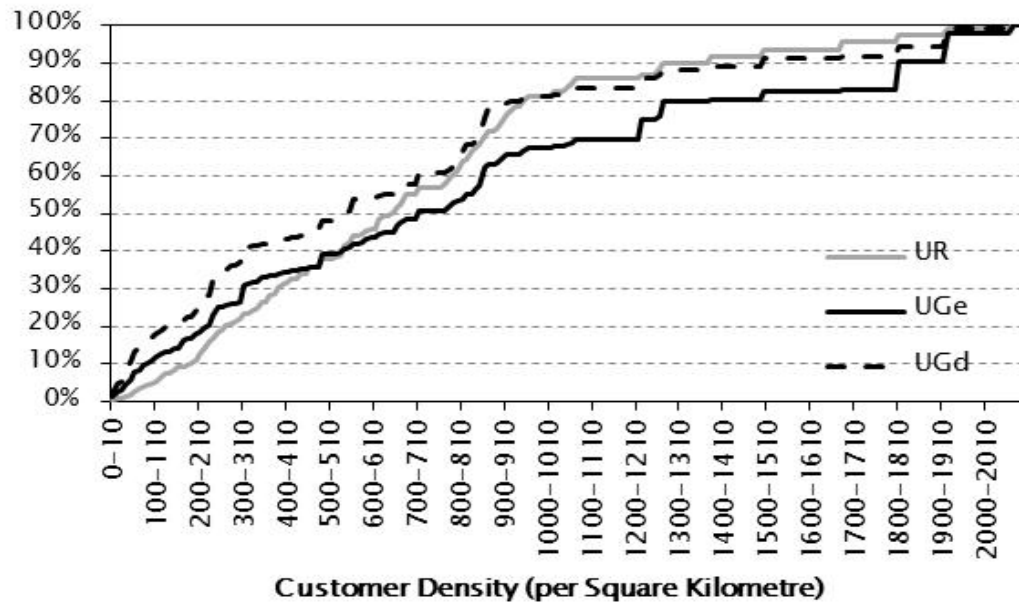
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e) The figure below provides the requested information.



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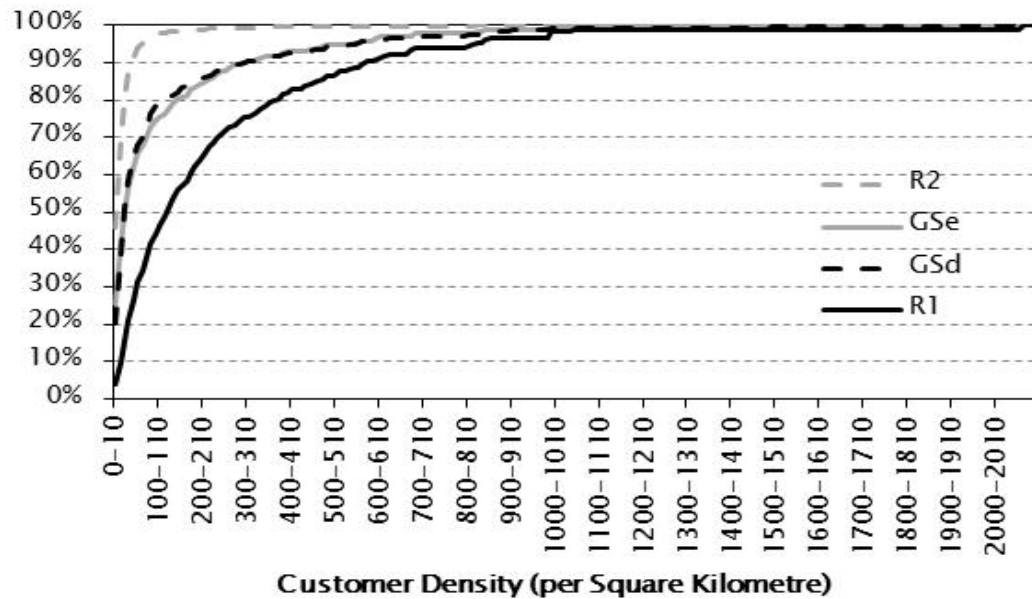
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f) Based on the figure provided in response to e) above, both the UGe and UGd classes have comparable densities relative to the UR class.

g) The figure below provides the requested information.



h) Based on the figure provided in response to g) above, the GSe and GSd classes have comparable densities to each other. The GSe and GSd classes fall in between the less dense R2 class and the denser R1 class.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #68 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

Reference: **Exhibit D, Tab 1, Schedule 1, Attachment 1, page 48**

Preamble: The Study's conclusions state that "adjustments to the weighting factors used in HONI's CAM could be justified to better capture the differences between the costs to serve high-, medium- and low-density customers"

- a) Based on the results of the Study how would the Study's authors suggest the weighting factors currently used in the CAM for the various customer classes (see response to 13-VECC #66 a)) be changed relative to the weighting factor used for UR?

Response

- a) The study authors would not propose changing the density weighting factors (DWFs) currently used in the cost allocation model. The DWFs are calculated using a very specific methodology and the density study was not specifically focused on developing an alternative to this approach.

The DWFs flow through the cost allocation model, and, ultimately direct more costs to the low-density rate classes than would otherwise be allocated based on the number of customers and/or peak demand alone. However, the specific effect of a small change to a single DWF is difficult to determine upfront. Hence, the study authors would either recommend an approach that relies on a bottom-line adjustment, similar to the proposal put forward by Hydro One, or a complete revision to the way density factors are incorporated into the cost allocation model.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #69 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, page 3

- a) Please confirm that in determining the relative costs for low-, medium- and high-density areas, the Study did not take into account differences in load density in assigning OM&A or Asset costs to sample areas. If the Study did so, please indicate how this was done.
- b) Please provide a schedule that compares: i) the USOA accounts currently subject to density weightings in HON's CAM with ii) the USOA accounts used to determine the relative costs of low-, medium- and high-density sample areas in the Consultant's Study.
- c) Please provide an expanded version of Table 2 that includes all of HON's customer classes.
- d) Please confirm that part of the reason for the difference seen in the cost per customer in Table 2 for the different customer classes is due to the fact that load intensity (e.g., NCP/customer) varies across the customer classes and load by customer class is also used to allocate a portion of the costs to customer classes.
- e) Please provide a schedule that sets out the CAM allocation to all customer classes of only the customer-related portion of the costs associated with the USOA accounts considered by the Consultants in their assessment of the costs per customer for serving the 48 different sample areas. In the same schedule please provide the total of such costs by customer class, the number of customers by class and the resulting costs per customer for these costs.
- f) Please comment on whether the results from part (e) are or are not a better basis for determining if the costs allocated by the CAM over/understate the relative costs of serving density-based rates classes as determined by the Density Study.

Response

- a) This is confirmed.
- b) Please see the table below.

1 c)

USofA Accounts	Account Description	USofA Accounts Currently Subject to Density Weights	USofA Accounts Included in Program Costs Considered by Density Study
1830	Poles, Towers and Fixtures	Yes	
1835	Overhead Conductors and Devices	Yes	
1850	Line Transformers	Yes	
4235	Miscellaneous Service Revenues	Yes	
5005	Operation Supervision and Engineering	Yes	Yes
5010	Load Dispatching	Yes	Yes
5012	Station Buildings and Fixtures Expense		Yes
5014	Transformer Station Equipment - Operation Labour		Yes
5015	Transformer Station Equipment - Operation Supplies and Expenses		Yes
5016	Distribution Station Equipment - Operation Labour		Yes
5017	Distribution Station Equipment - Operation Supplies and Expenses		Yes
5020	Overhead Distribution Lines and Feeders - Operation Labor	Yes	Yes
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Yes	Yes
5030	Overhead Sub transmission Feeders - Operation	Yes	Yes
5035	Overhead Distribution Transformers- Operation	Yes	
5055	Underground Distribution Transformers - Operation	Yes	
5065	Meter Expense		Yes
5070	Customer Premises - Operation Labour		Yes

USofA Accounts	Account Description	USofA Accounts Currently Subject to Density Weights	USofA Accounts Included in Program Costs Considered by Density Study
5075	Customer Premises - Materials and Expenses		Yes
5085	Miscellaneous Distribution Expense	Yes	Yes
5095	Overhead Distribution Lines and Feeders - Rental Paid	Yes	
5105	Maintenance Supervision and Engineering	Yes	Yes
5112	Maintenance of Transformer Station Equipment		Yes
5114	Maintenance of Distribution Station Equipment		Yes
5120	Maintenance of Poles, Towers and Fixtures	Yes	Yes
5125	Maintenance of Overhead Conductors and Devices	Yes	Yes
5135	Overhead Distribution Lines and Feeders - Right of Way	Yes	Yes
5145	Maintenance of Underground Conduit		Yes
5150	Maintenance of Underground Conductors and Devices		Yes
5160	Maintenance of Line Transformers	Yes	Yes
5170	Sentinel Lights - Labour		Yes
5172	Sentinel Lights - Materials		Yes
5175	Maintenance of Meters		Yes
5310	Meter Reading Expense		Yes
5320	Collecting		Yes
5420	Community Safety Program		Yes

c) The requested information is provided in the table below.

	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd	Street Lights	Sentinel Lights	DGen	ST
# of Customer Accounts	140,540	412,455	367,107	156,901	10,577	98,776	1,130	7,361	5,234	37,506	88	607
Total Cost (\$M)	\$59.0	\$273.4	\$431.7	\$96.0	\$8.7	\$121.5	\$12.6	\$128.8	\$9.5	\$7.6	\$0.4	\$31.9
Total Cost per Customer	\$420	\$663	\$1,176	\$612	\$818	\$1,230	\$11,128	\$17,491	\$1,809	\$203	\$4,668	\$52,645
Ratio of Total Cost per Cust relative to Urban	1.0	1.6	2.8	1.5	1.0	1.5	1.0	1.6	N/A	N/A	N/A	N/A
OM&A and Fixed Asset (FA) Cost (\$M)	\$44.7	\$223.0	\$367.4	\$84.0	\$6.7	\$99.9	\$11.1	\$115.4	\$8.4	\$7.4	\$0.4	\$28.3
OM&A and FA Cost per Customer	\$318	\$541	\$1,001	\$535	\$633	\$1,011	\$9,826	\$15,679	\$1,596	\$197	\$4,490	\$46,599
Ratio of OM&A and FA Cost per Cust relative to Urban	1.0	1.7	3.1	1.7	1.0	1.6	1.0	1.6	N/A	N/A	N/A	N/A

d) Hydro One Confirms that part of the reason for the difference in costs allocated to customer classes is that customer load impacts the allocation of some costs in the CAM.

e) The table below provides the requested information.

USoA Account #	Account Description	Customer Related Costs												
		UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST	Total
5005	Operation Supervision and Engineering	\$90,672	\$425,028	\$648,605	\$219,570	\$134,986	\$11,924	\$5,002	\$1,012	\$7,552	\$4,514	\$37	\$8,970	\$1,557,872
5010	Load Dispatching	\$34,805	\$163,151	\$248,972	\$84,284	\$51,816	\$4,577	\$1,920	\$388	\$2,899	\$1,733	\$14	\$3,443	\$598,002
5012	Station Buildings and Fixtures Expense	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5014	Transformer Station Equipment - Operation Labour	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5016	Distribution Station Equipment - Operation Labour	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	\$151,438	\$977,784	\$1,866,318	\$618,749	\$355,131	\$22,130	\$12,497	\$975	\$19,508	\$11,840	\$87	\$3,248	\$4,039,703
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	\$23,587	\$152,291	\$290,682	\$96,371	\$55,312	\$3,447	\$1,946	\$152	\$3,038	\$1,844	\$14	\$506	\$629,190
5030	Overhead Subtransmission Feeders - Operation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5065	Meter Expense	\$407,509	\$1,195,951	\$1,064,462	\$454,937	\$283,555	\$169,090	\$60,725	\$25,962	\$0	\$0	\$843	\$360,112	\$4,023,145
5070	Customer Premises - Operation Labour	\$2,603,966	\$7,642,074	\$6,801,865	\$2,907,098	\$1,830,146	\$136,393	\$195,969	\$20,938	\$108,065	\$65,585	\$1,632	\$11,244	\$22,324,973
5075	Customer Premises - Materials and Expenses	\$382,161	\$1,121,560	\$998,250	\$426,649	\$268,594	\$20,017	\$28,761	\$3,073	\$15,860	\$9,625	\$239	\$1,650	\$3,276,441
5085	Miscellaneous Distribution Expense	\$367,788	\$1,724,019	\$2,630,901	\$890,629	\$547,537	\$48,366	\$20,290	\$4,104	\$30,632	\$18,311	\$150	\$36,385	\$6,319,113
5105	Maintenance Supervision and Engineering	\$431,036	\$2,020,498	\$3,083,336	\$1,043,791	\$641,697	\$56,684	\$23,779	\$4,810	\$35,900	\$21,460	\$176	\$42,642	\$7,405,809
5112	Maintenance of Transformer Station Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5114	Maintenance of Distribution Station Equipment	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5120	Maintenance of Poles, Towers and Fixtures	\$467,009	\$3,015,319	\$5,755,409	\$1,908,117	\$1,095,163	\$68,244	\$38,538	\$3,007	\$60,160	\$36,511	\$268	\$10,017	\$12,457,762
5125	Maintenance of Overhead Conductors and Devices	\$1,359,391	\$8,777,134	\$16,753,117	\$5,554,236	\$3,187,852	\$198,649	\$112,178	\$8,753	\$175,118	\$106,279	\$779	\$29,157	\$36,262,642
5135	Overhead Distribution Lines and Feeders - Right of Way	\$3,713,390	\$23,976,125	\$45,763,782	\$15,172,271	\$8,708,122	\$542,642	\$306,432	\$23,910	\$478,361	\$290,317	\$2,128	\$79,648	\$99,057,128
5145	Maintenance of Underground Conduit	\$20,394	\$59,853	\$53,273	\$22,769	\$14,334	\$212	\$1,535	\$33	\$846	\$514	\$1	\$0	\$173,764
5150	Maintenance of Underground Conductors and Devices	\$98,898	\$290,243	\$258,332	\$110,410	\$69,508	\$1,030	\$7,443	\$158	\$4,104	\$2,491	\$4	\$0	\$842,622
5160	Maintenance of Line Transformers	\$168,455	\$778,157	\$1,078,487	\$352,294	\$228,546	\$17,280	\$0	\$0	\$12,846	\$7,796	\$70	\$7,956	\$2,651,887
5175	Maintenance of Meters	\$226,465	\$664,627	\$591,554	\$252,828	\$159,070	\$56,603	\$18,062	\$8,691	\$0	\$0	\$360	\$82,861	\$2,061,121
5310	Meter Reading Expense	\$1,942,520	\$6,840,163	\$9,918,738	\$1,322,305	\$1,592,711	\$353,116	\$147,387	\$45,846	\$0	\$0	\$0	\$0	\$22,162,786
5320	Collecting	\$1,340,438	\$3,776,048	\$3,422,216	\$486,644	\$1,758,800	\$495,182	\$203,410	\$80,083	\$54,381	\$3,300	\$1,753	\$55,943	\$11,678,198
5420	Community Safety Program	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Customer Related Costs		\$13,829,921	\$63,600,024	\$101,228,299	\$31,923,951	\$20,982,881	\$2,205,587	\$1,185,872	\$231,894	\$1,009,271	\$582,120	\$8,554	\$733,783	\$237,522,157
Number of Customers		140,540	412,455	367,107	156,901	98,776	7,361	10,577	1,130	5,234	37,506	88	607	
Cost per Customer		\$98	\$154	\$276	\$203	\$212	\$300	\$112	\$205	\$193	\$16	\$97	\$1,209	

- 1 f) Hydro One believes that comparing all the CAM costs that were specifically
- 2 considered in the Density Study provides the best basis for assessing the relative costs
- 3 of serving density-differentiated rate classes. Since the results from part e consider
- 4 only the customer related sub-set of OM&A costs, Hydro One does not believe it is a
- 5 better basis for determining the relative split of those costs within the density-
- 6 differentiated customer segments.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #70 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

**Reference: Exhibit D, Tab 1, Schedule 1, page 4
 Exhibit D, Tab 1, Schedule 1, Attachment 1, page 41**

- a) Please confirm that one of the purposes of the Consultant's Study was to determine if the density weighting used and the resulting relative cost ratios produced by the CAM for the different customer classes were appropriate (per Section 5.2 of the Consultant's Study)? If not, what were the specific purposes of the Study?
- b) Why is it appropriate to use the results of the CAM (in terms of the relative costs for the Seasonal and R1 classes) to set the target ratio for the Seasonal class?
- c) The Consultant's Study concluded (page 41) that the average customer density for the Seasonal class was between R1 and R2. Given this conclusion why isn't it appropriate to set the target ratio for the Seasonal class somewhere between R1 and R2 as opposed to at the same value as for the R1 class?
- d) Please provide a schedule that clearly sets out the principles and methodology used in Footnote #1 to determine the target ratio for the GSe class.
- e) Per footnotes 1 and 2 on page 4, please provide a schedule that sets out the relative density of each of the customer classes (UR, R1, R2, UGe, UGd, GSe, GSd, Seasonal, ST, Street Lights, Sentinel Lights and DG) based on an assessment of number of customers per km. In reporting the relative values please use UR=1.0 as the base.
- f) Based on the preceding results (part (e)), the results of the Density Study and the principles used in Footnote #1 what would be an appropriate target ratio for the Seasonal class?

Response

- a) Hydro One confirms that one of the Density Study objectives was to assess whether HONI's existing density based rate classes and density weighting factors appropriately reflect the relationship between customer density and distribution service costs.
- b) As part of its Decision in EB-2009-0096 the Board concluded that it was appropriate that the Seasonal rate class be density weighted, as such, the Seasonal rate class is treated as part of the residential customer segment whose costs are being redistributed to align with the findings of the Density Study. Hydro One's rationale for setting the Seasonal target ratio equal to that of the R1 class is provided in Exhibit D, Tab 1, Schedule 1, Page 4, lines 18 to 22.
- c) Hydro One believes it is appropriate to set the Seasonal target ratio equal to the R1 target ratio recognizing that the CAM methodology results in about the same per customer cost for both the R1 and Seasonal rate classes despite the fact that the density weighting factors for these two classes are already roughly aligned with the recommendation of the Density Study. Setting the Seasonal target ratio equal to that of the R1 class recognizes that increasing the density weight differential between rate classes will not alter the fact that the CAM methodology will drive the R1 and Seasonal cost per customer to be roughly equal.
- d) The target ratio for the GSe class is calculated by comparing the relative line customer density weighting of the GSe customers as compared to the urban GSe customers and interpolating a result based on the relative density weights and target ratios recommended by the Density Study, using the methodology shown below.

	Approved Line Customer Density Weighting (A)	Weighting Relative to Urban Class (B)
UR	0.16	1.0
R1	0.64	3.9
R2	1.64	10.0
Seasonal	1.22	7.5
UGe	0.20	1.0
GSe	1.09	5.4
UGd	0.32	1.0
GSd	1.11	3.5

1 Using the relative weighting values in column B above and the relative target cost
2 ratios determined by the Density Study for customers in high, medium and low
3 density areas (per Figure 27), the GSe target ratio is calculated as illustrated
4 below.

5	Relative	Urban	R1	GSe	R2
6	Weighting	1.0	3.9	5.4	10.0
7					
8					
9	Target	1.0	1.9	x	4.8
10	Ratio	High	Medium		Low

11

12 Solve for GSe target ratio x:

$$\frac{5.4}{10.0} = \frac{x}{4.8}$$

$$x = 2.6$$

13

14 e) Footnotes 1 and 2 are not intended to suggest that the relative density for all classes
15 can be measured relative to the UR residential rate class.

16 The data requested is provided in the table provided with the response to part d) for
17 those classes that can be measured relative to an urban classification. Relative
18 density weights are not available for the ST, DG, Street Lights and Sentinel light rate
19 classes.

20 f) Application of the methodology shown in the response to part d) would result in a
21 target ratio of 3.6 for the Seasonal class. However, has noted in the response to part
22 c), Hydro One believes that the proposed Seasonal target ratio of 1.9 is the most
23 appropriate.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #71 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

**Reference: Exhibit D, Tab 1, Schedule 1, page 4
 Exhibit D, Tab 1, Schedule 1, Attachment 1, page 41**

- a) The Consultant's Study (page 41) concluded that the average density for both the GSe and GSd classes was between that of R1 and R2. HON has adopted this finding in the determination of the target ratio for GSe but not for GSd (which has been set equivalent to that of R1). Why were the findings of the Study not adopted for purposes of setting the target ratio for the GSd class?
- b) Please confirm that (per Footnote #2) HON has used its previous measure of customer density (number of customers per km of line) to set the target ratio for GSd relative to UGd, as opposed to the results of the Consultant's Study. If not, please explain how the results of the Consultant's Study were used to set the target ratio for GSd relative to that for UGd.
- c) Using the same principles and methodology as were employed for the GSe class (per Footnote #1), what would be an appropriate target ratio for the GSd class?
- d) Using a similar approach and the results from VECC #67 e), what would be the appropriate target ratios for UGe and UGd relative to UR?
- e) Using a similar approach and the results from VECC #67 a), what would be the appropriate target ratios for the Street Lighting, Sentinel Lighting, ST and DG classes?

Response

- a) Hydro One has used the Density Study results on the relative cost ratios for the three different density sample areas, as well as information about the relative number of customer per km of line for its density-based customer classes, to quantify the appropriate target ratios for both the GSe and GSd customer classes. In the case of the GSd rate class, because the relative weighting of the GSd to the UGd class was about the same as the relative weighting of the R1 class to UR class, a simplification was made to use the medium density target ratio determined by the Density Study.
- b) See response to part a).

- 1 c) Application of the methodology described in the response to Exhibit I, Tab 13,
2 Schedule 5.22 VECC 70, part d) would have resulted in a target ratio of 1.7 for the
3 GSd class as compared to the value of 1.9 that was used.
- 4 d) Hydro One is unclear as to how the results from VECC #67 could be used to set
5 target ratios for the UGe and UGd general service classes relative to UR residential
6 class. Consistent with the currently approved CAM, Hydro One's proposed Density
7 Study Adjustment does not re-distribute the total costs allocated by the CAM across
8 the density-differentiated customer segments (i.e. residential customers, GS<50
9 customers, GS>50 customers).
- 10 e) See response to part d).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #72 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, page 5

- a) Please confirm whether the R/C ratios set out in the last row of Table 3 and the last row of Table 4 are: i) the approved ratios for 2010 after inter-class revenue adjustments or ii) the ratios actually produced by the initial CAM.
- b) Please provide expanded versions of Tables 3 and 4 that include all customer classes.

Response

- a) The R/C ratios set out in the last row of Table 3 and the last row of Table 4 are the ratios actually produced by the initial CAM.
- b) Below are the expanded versions of Table 3 and Table 4

Table 3

	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd	Street Lights	Sentinel Lights	DGen	ST
Target Cost per Customer Ratio	1.0	1.7	3.9	1.7	1.0	2.2	1.0	1.7	1.0	1.0	1.0	1.0
DSA Total Cost per Customer	\$339	\$576	\$1,320	\$576	\$571	\$1,257	\$10,359	\$17,609	\$1,809	\$203	\$4,672	\$52,635
DSA Total Cost (\$M)	\$47.6	\$237.4	\$484.7	\$90.3	\$6.0	\$124.1	\$11.7	\$129.6	\$9.5	\$7.6	\$0.4	\$31.9
Revenue Collected (\$M)	\$64.5	\$253.8	\$450.0	\$98.6	\$10.4	\$130.1	\$15.7	\$113.4	\$6.5	\$5.1	\$0.6	\$32.4
DSA Revenue to Cost (R/C) Ratio	1.36	1.07	0.93	1.09	1.73	1.06	1.34	0.87	0.68	0.67	1.35	1.01
2010 R/C Ratio per CA Model	1.09	0.93	1.04	1.03	1.21	1.07	1.25	0.88	0.68	0.67	1.35	1.01

Table 4

	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd	Street Lights	Sentinel Lights	DGen	ST
Target Cost per Customer Ratio	1.0	1.9	4.8	1.9	1.0	2.6	1.0	1.9	1.0	1.0	1.0	1.0
DSA OM&A and FA Cost per Customer	\$241	\$458	\$1,157	\$458	\$399	\$1,037	\$8,370	\$15,903	\$1,596	\$197	\$4,493	\$46,590
DSA OM&A and FA Costs (\$M)	\$33.9	\$188.8	\$424.6	\$71.8	\$4.2	\$102.4	\$9.5	\$117.1	\$8.4	\$7.4	\$0.4	\$28.3
DSA Total Cost (\$M)	\$48.1	\$239.2	\$488.8	\$83.9	\$6.2	\$124.0	\$10.9	\$130.4	\$9.5	\$7.6	\$0.4	\$31.9
Revenue Collected (\$M)	\$64.5	\$253.8	\$450.0	\$98.6	\$10.4	\$130.1	\$15.7	\$113.4	\$6.5	\$5.1	\$0.6	\$32.4
DSA Revenue to Cost (R/C) Ratio	1.34	1.06	0.92	1.17	1.69	1.05	1.44	0.87	0.68	0.67	1.35	1.01
2010 R/C Ratio per CA Model	1.09	0.93	1.04	1.03	1.21	1.07	1.25	0.88	0.68	0.67	1.35	1.01

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #73 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, page 5, Tables 3 and 4

- a) Please confirm that:
- The target ratios for R1, R2 and Seasonal are relative to the ratio for UR,
 - The target ratio for GSe is relative to that for UGe, and
 - The target ratio for GSd is relative to that for UGd.
- If not, please explain the relationships between the various values.
- b) Please confirm that in implementing the results of the Density Study the total costs to be recovered from the Residential class (i.e., UR, R1, R2 and Seasonal) was held constant and equivalent to the results of the CAM. If not, please explain.
- c) Please confirm that in implementing the results of the Density Study the total costs to be recovered from the UGe and GSe classes was held constant and equivalent to the results of the CAM. If not, please explain.
- d) Please confirm that in implementing the results of the Density Study the total costs to be recovered from the UGd and GSd classes was held constant and equivalent to the results of the CAM. If not, please explain.
- e) If parts (b) – (d) are confirmed, please confirm that this means the allocation of cost to these three broad customer classes still based entirely on HON's previous density weightings.
- f) If yes, please explain why the results of the Density Study were not/could not be used to determine the appropriateness of the current allocation between these broad customer classes.

Response

- a) This is confirmed.
- b) This is confirmed.
- c) This is confirmed.
- d) This is confirmed.

- 1 e) The costs to the three customer segments are based on the existing density weights
2 and the costs allocated to those customer segments by the current CAM. It is the
3 costs to the individual classes within those three customer segments that have been
4 re-distributed to better align with the findings of the Density Study.
- 5 f) The Density Study only confirmed the relative costs of serving customers within
6 high, medium, and low density areas. It did not address differences in the cost of
7 serving different customer types. HONI believes it is appropriate to maintain the
8 principles implicit in the Board's CAM with respect to allocation of costs across
9 customer segments.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #74 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, pages 5-6

- a) Based on the results of the Density Study and the responses to VECC #70 and #71 what would be the target cost ratios for HON's remaining 11 customer classes (relative to UR)?
- b) Please re-run HON's CAM using these target ratios to weight the allocation of the customer-related costs associated with the USOA accounts for those OM&A and Capital-related costs that were allocated to sample areas in the Study (per Attachment 1, pages 22-26) and provide both the actual CAM model run and a summary of the Sheet O1 results. Note: These would be the only costs subject to any "density weighting".
- c) Please re-run HON's CAM using these target ratios to weight the allocation of the customer- and demand-related costs associated with the USOA accounts for those OM&A and Capital-related costs that were allocated to sample areas in the Study (per Attachment 1, pages 22-26) and provide both the actual CAM model run and a summary of the Sheet O1 results. Note: These would be the only costs subject to any "density weighting".
- d) Please explain why the approach set out in parts (b) and/or (c) aren't a more appropriate way of implementing the findings of the Density Study.

Response

- a) Hydro One is unclear on how it could use the results of the Density Study and the responses to VECC #70 and #71 to set target cost ratios for the remaining 11 customer classes relative to the UR residential class. The target cost ratios for the R1, R2 and Seasonal residential rate classes have been established relative to the UR residential rate class, but Hydro One does not believe it is appropriate to do the same across customer segments as discussed in the response to the interrogatory at Exhibit I, Tab 13, Schedule 5.23 VECC 71, part d).
- b) See response to part a).
- c) See response to part a).
- d) See response to part a).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #74 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Reference: Exhibit D, Tab 1, Schedule 1, pages 6-9

- a) Please confirm that Option #1 (i.e., move the ratios to limits of the Board's approved ranges) is consistent with the Board's Decisions regarding 2011 Rates for Horizon (EB-2010-0131, Toronto Hydro (EB-2010-0142) and Brant County (EB-2010-0219).
- b) Please re-do Table 5 to include HON's other customer classes (i.e. DG and ST) and apply the adjustment process as proposed by HON.
- c) Please provide an alternative version of Table 5 (expanded to include all customer classes) where revenue shortfall is made up from the class with the lowest R/C ratio, until that class' ratio is equivalent to that of the class with the next lowest ratio and then both of these ratios are increased to the next lowest ratio, etc. – until the revenue shortfall has been addressed.
- d) Using the results from part (c), please provide revised versions of Tables 7 and 8.

Response

- a) Hydro One confirms that Option #1 is consistent with the Board's Decisions regarding 2011 Rates for Horizon (EB-2010-0131) , Toronto Hydro (EB-2010-0142).and Brant County (which is filed under case number EB-2010-0125 by the Board)

b) The table below provides the requested information.

(All \$ in millions)	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd	Street Lights	Sentinel Lights	DGen	ST
2010 CA Model Revenues	\$64.5	\$253.8	\$450.0	\$98.6	\$10.4	\$130.1	\$15.7	\$113.4	\$6.5	\$5.1	\$0.6	\$32.4
DSA Total Cost	\$48.1	\$239.2	\$488.8	\$83.9	\$6.2	\$124.0	\$10.9	\$130.4	\$9.5	\$7.6	\$0.4	\$31.9
Target R/C Ratio	1.15	1.06	0.94	1.15	1.20	1.05	1.20	0.91	0.71	0.70	1.00	1.01
Target Revenue to be recovered	\$55.3	\$253.8	\$461.3	\$96.5	\$7.4	\$130.1	\$13.1	\$118.6	\$6.8	\$5.3	\$0.4	\$32.4
Revenue Adjustment Required to achieve Target R/C	-\$9.2	None	+\$11.3	-\$2.1	-\$3.0	None	-\$2.6	+\$5.2	+\$0.3	+\$0.2	-\$0.1	None
Average Rate Impacts	-14.3%	None	+2.5%	-2.1%	-29.1%	None	-16.4%	+4.6%	+4.6%	+4.6%	-26.2%	None

c) The table below provides the requested information.

(All \$ in millions)	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd	Street Lights	Sentinel Lights	DGen	ST
2010 CA Model Revenues	\$64.5	\$253.8	\$450.0	\$98.6	\$10.4	\$130.1	\$15.7	\$113.4	\$6.5	\$5.1	\$0.6	\$32.4
DSA Total Cost	\$48.1	\$239.2	\$488.8	\$83.9	\$6.2	\$124.0	\$10.9	\$130.4	\$9.5	\$7.6	\$0.4	\$31.9
Target R/C Ratio	1.15	1.06	0.93	1.15	1.20	1.05	1.20	0.93	0.93	0.93	1.00	1.01
Target Revenue to be recovered	\$55.3	\$253.8	\$454.8	\$96.5	\$7.4	\$130.1	\$13.1	\$121.3	\$8.8	\$7.1	\$0.4	\$32.4
Revenue Adjustment Required to achieve Target R/C	-\$9.2	None	+\$4.7	-\$2.1	-\$3.0	None	-\$2.6	+\$8.0	+\$2.4	+\$2.0	-\$0.1	None
Average Rate Impacts	-14.3%	None	+1.1%	-2.1%	-29.1%	None	-16.4%	+7.0%	+36.5%	+39.9%	-26.2%	None

- 1 d) Below are the updated versions of Table 7 and Table 8 which reflect the results of
2 part c) of this interrogatory.

3

Table 7

Rate Class	Current Rates			Density Study Adjusted IRM Rates		
	Fixed Charge	Variable Charge		Fixed Charge	Variable Charge	
	\$/month	\$/kWh	\$/kW	\$/month	\$/kWh	\$/kW
UR	14.52	0.02918		12.56	0.02524	
R1	19.72	0.03317		19.89	0.03346	
R2	55.69	0.03600		56.87	0.03676	
Seasonal	19.71	0.08205		19.46	0.08101	
GSe	35.49	0.03938		35.80	0.03973	
GSd	47.72		10.499	51.60		11.347
UGe	14.08	0.02325		10.07	0.01663	
UGd	33.62		8.173	28.35		6.900
St Light	1.05	0.05219		1.44	0.07195	
Sen Light	1.05	0.06972		1.47	0.09857	

4

5

1

Table 8

Customer Type		Monthly Consumption (kWh and/or kW)	Current Total Monthly Bill (\$)	Proposed Total Monthly Bill (\$)	Change in Total Monthly Bill(\$)	Change in Total Monthly Bill(\$)
Residential - High Density [UR]	IRM	800 kWh	132.26	134.75	2.49	1.88%
	DSA IRM	800 kWh	132.26	129.22	-3.05	-2.30%
Residential - Medium Density [R1]	IRM	800 kWh	141.55	144.50	2.95	2.08%
	DSA IRM	800 kWh	141.55	144.50	2.95	2.08%
Residential - Low Density [R2]	IRM	800 kWh	151.74	155.79	4.05	2.67%
	DSA IRM	800 kWh	151.74	156.85	5.12	3.37%
Residential - Seasonal	IRM	500 kWh	116.61	120.24	3.63	3.11%
	DSA IRM	500 kWh	116.61	118.92	2.30	1.98%
Urban GSe	IRM	2,000 kWh	296.95	300.27	3.32	1.12%
	DSA IRM	2,000 kWh	296.95	282.18	-14.77	-4.97%
GSe	IRM	2,000 kWh	351.09	357.28	6.19	1.76%
	DSA IRM	2,000 kWh	351.09	357.28	6.19	1.76%
Urban GSd	IRM	36,000 kWh and 117 kW	5,241.08	5,296.43	55.35	1.06%
	DSA IRM	36,000 kWh and 117 kW	5,241.08	5,130.74	-110.34	-2.11%
GSd	IRM	36,000 kWh and 117 kW	5,519.56	5,592.20	72.63	1.32%
	DSA IRM	36,000 kWh and 117 kW	5,519.56	5,685.62	166.06	3.01%
Street Lights	IRM	1,320 kWh	241.11	244.79	3.68	1.53%
	DSA IRM	1,320 kWh	241.11	273.44	32.33	13.41%
Sentinel Lights	IRM	62 kWh	11.76	12.04	0.28	2.37%
	DSA IRM	62 kWh	11.76	14.24	2.48	21.06%

2

Consumers Council of Canada (CCC) INTERROGATORY #21 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ex. A/T4/S1/ Appendix E (Stakeholder Consultation Notes, June 5, 2012)

In the consultation notes Mr. Andre stated that with respect to Option A and Option B more evidence and data would be required to support Option A. Please indicate what further evidence and data would be required.

Response

The statement refers to the data that would be required to update the cost allocation model using the latest available information in order to re-establish the revenue-to-cost ratios for all rate classes before making any further Density Study adjustments beyond moving to within the Board approved range.

Consumers Council of Canada (CCC) INTERROGATORY #22 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ex. D/T1/S1/p. 8-10

The distribution rate impacts for Option 1 and Option 2 are set out. Please provide a more detailed assessment of the impact for each customer class. Please set out the distribution rate impacts and total bill impacts for three customers within each rate class, including low-volume, average volume and high volume usage.

Response

The tables below provide distribution bill impacts and total bill impacts for low, average, and high consumption levels, by rate class, for Option 1 and Option 2.

Option 1: Adjusting the R/C Ratios to Limits of the Board Approved Ranges

Customer Type		Consumption Level	Monthly Consumption (kWh and/or kW)	Current Total Monthly Bill (\$)	Proposed Total Monthly Bill (\$)	Change in Total Monthly Bill (\$)	Change in Total Monthly Bill (%)	Current Monthly Distribution Bill (\$)	Proposed Monthly Distribution Bill (\$)	Change in Monthly Distribution Bill (\$)	Change in Monthly Distribution Bill (%)
Residential - Urban Density [UR]	IRM	Low	100 kWh	32.14	32.56	0.43	1.32%	21.36	21.60	0.24	1.13%
		Average	800 kWh	132.26	134.75	2.49	1.88%	41.78	42.81	1.03	2.46%
		High	2,000 kWh	314.04	320.07	6.04	1.92%	76.80	79.18	2.38	3.10%
	DSA IRM	Low	100 kWh	32.14	30.01	-2.12	-6.61%	21.36	19.09	-2.27	-10.62%
		Average	800 kWh	132.26	129.22	-3.05	-2.30%	41.78	37.37	-4.42	-10.57%
		High	2,000 kWh	314.04	309.42	-4.62	-1.47%	76.80	68.70	-8.10	-10.55%
Residential - Medium Density [R1]	IRM	Low	100 kWh	37.86	38.38	0.52	1.38%	26.96	27.29	0.33	1.24%
		Average	800 kWh	141.55	144.50	2.95	2.08%	50.18	51.63	1.45	2.89%
		High	2,000 kWh	329.33	336.44	7.11	2.16%	89.98	93.34	3.36	3.74%
	DSA IRM	Low	100 kWh	45.72	46.66	0.94	2.06%	34.71	35.47	0.76	2.18%
		Average	800 kWh	151.74	155.79	4.05	2.67%	59.91	62.53	2.62	4.38%
		High	2,000 kWh	343.40	352.79	9.39	2.73%	103.11	108.93	5.82	5.65%
Residential - Low Density [R2]	IRM	Low	100 kWh	45.72	48.18	2.46	5.38%	34.71	36.96	2.25	6.48%
		Average	800 kWh	151.74	157.96	6.22	4.10%	59.91	64.66	4.75	7.94%
		High	2,000 kWh	343.40	356.07	12.67	3.69%	103.11	112.16	9.05	8.78%
	DSA IRM	Low	100 kWh	42.75	43.62	0.87	2.03%	31.84	32.53	0.69	2.17%
		Average	500 kWh	116.61	120.24	3.63	3.11%	64.66	67.42	2.76	4.27%
		High	1,000 kWh	222.46	229.54	7.08	3.18%	105.68	111.03	5.35	5.06%
Seasonal Residential	IRM	Low	100 kWh	42.75	43.01	0.26	0.60%	31.84	31.93	0.09	0.29%
		Average	500 kWh	116.61	118.92	2.30	1.98%	64.66	66.11	1.46	2.25%
		High	1,000 kWh	222.46	227.32	4.86	2.19%	105.68	108.84	3.16	2.99%
	DSA IRM	Low	1,000 kWh	190.75	194.01	3.25	1.71%	78.79	80.72	1.93	2.45%
		Average	2,000 kWh	351.09	357.28	6.19	1.76%	118.17	121.72	3.55	3.01%
		High	15,000 kWh	2,435.44	2,479.80	44.35	1.82%	630.11	654.72	24.61	3.91%
Urban General Service Energy Billed (less than to 50kW) [GSe-metered]	IRM	Low	1,000 kWh	152.80	154.52	1.72	1.13%	41.25	41.62	0.37	0.90%
		Average	2,000 kWh	296.95	300.27	3.32	1.12%	64.50	65.12	0.62	0.96%
		High	15,000 kWh	2,170.94	2,194.99	24.06	1.11%	366.75	370.59	3.84	1.05%
	DSA IRM	Low	1,000 kWh	152.80	143.37	-9.42	-6.17%	41.25	30.66	-10.59	-25.67%
		Average	2,000 kWh	296.95	282.18	-14.77	-4.97%	64.50	47.34	-17.16	-26.61%
		High	15,000 kWh	2,170.94	2,086.68	-84.26	-3.88%	366.75	264.08	-102.67	-27.99%
General Service Demand Billed (50kW and above) [GSd]	IRM	Low	15,000 kWh and 60 kW	2,474.56	2,512.01	37.45	1.51%	681.58	694.22	12.64	1.85%
		Average	36,000 kWh and 117 kW	5,519.56	5,592.20	72.63	1.32%	1,280.02	1,304.27	24.25	1.89%
		High	1,500,000 kWh and 4,000 kW	216,592.47	219,061.42	2,468.95	1.14%	42,047.64	42,862.60	814.96	1.94%
	DSA IRM	Low	15,000 kWh and 60 kW	2,474.56	2,544.04	69.48	2.81%	681.58	725.70	44.12	6.47%
		Average	36,000 kWh and 117 kW	5,519.56	5,652.48	132.92	2.41%	1,280.02	1,363.55	83.53	6.53%
		High	1,500,000 kWh and 4,000 kW	216,592.47	221,047.28	4,454.81	2.06%	42,047.64	44,815.26	2,767.62	6.58%
Urban General Service Demand Billed (50kW and above) [UGd]	IRM	Low	15,000 kWh and 60 kW	2,324.76	2,353.29	28.53	1.23%	527.92	530.51	2.59	0.49%
		Average	36,000 kWh and 117 kW	5,241.08	5,296.43	55.35	1.06%	993.78	998.55	4.77	0.48%
		High	1,500,000 kWh and 4,000 kW	207,547.58	209,429.79	1,882.21	0.91%	32,729.54	32,882.68	153.14	0.47%
	DSA IRM	Low	15,000 kWh and 60 kW	2,324.76	2,265.56	-59.20	-2.55%	527.92	444.25	-83.67	-15.85%
		Average	36,000 kWh and 117 kW	5,241.08	5,130.74	-110.34	-2.11%	993.78	835.63	-158.16	-15.91%
		High	1,500,000 kWh and 4,000 kW	207,547.58	203,952.98	-3,594.60	-1.73%	32,729.54	27,497.43	-5,232.11	-15.99%
Street Lights	IRM	Low	200 kWh	31.44	31.96	0.52	1.65%	11.49	11.78	0.30	2.58%
		Average	1,320 kWh	241.11	244.79	3.68	1.53%	76.20	78.28	2.08	2.72%
		High	2,000 kWh	337.45	342.55	5.11	1.51%	105.43	108.31	2.88	2.73%
	DSA IRM	Low	200 kWh	31.44	32.48	1.04	3.32%	11.49	12.30	0.81	7.06%
		Average	1,320 kWh	241.11	248.30	7.19	2.98%	76.20	81.73	5.53	7.26%
		High	2,000 kWh	337.45	347.42	9.97	2.95%	105.43	113.09	7.66	7.27%
Sentinel Lights	IRM	Low	10 kWh	3.01	3.06	0.05	1.76%	1.75	1.79	0.04	2.37%
		Average	62 kWh	11.76	12.04	0.28	2.37%	5.37	5.58	0.21	3.88%
		High	100 kWh	18.16	18.61	0.44	2.45%	8.02	8.35	0.33	4.12%
	DSA IRM	Low	10 kWh	3.01	3.13	0.13	4.23%	1.75	1.86	0.11	6.54%
		Average	62 kWh	11.76	12.29	0.52	4.45%	5.37	5.82	0.45	8.35%
		High	100 kWh	18.16	18.98	0.81	4.48%	8.02	8.71	0.69	8.64%

Note: DSA = Density Study Adjustment

Option 2: Adjusting the R/C Ratios to the Previously Approved Values

Customer Type		Consumption Level	Monthly Consumption (kWh and/or kW)	Current Total Monthly Bill (\$)	Proposed Total Monthly Bill (\$)	Change in Total Monthly Bill (\$)	Change in Total Monthly Bill (%)	Current Monthly Distribution Bill (\$)	Proposed Monthly Distribution Bill (\$)	Change in Monthly Distribution Bill (\$)	Change in Monthly Distribution Bill (%)
Residential - Urban Density [UR]	IRM	Low	100 kWh	32.14	32.56	0.43	1.32%	21.36	21.60	0.24	1.13%
		Average	800 kWh	132.26	134.75	2.49	1.88%	41.78	42.81	1.03	2.46%
		High	2,000 kWh	314.04	320.07	6.04	1.92%	76.80	79.18	2.38	3.10%
	DSA IRM	Low	100 kWh	32.14	29.27	-2.87	-8.93%	21.36	18.36	-3.00	-14.05%
		Average	800 kWh	132.26	127.59	-4.67	-3.53%	41.78	35.77	-6.01	-14.39%
		High	2,000 kWh	314.04	306.29	-7.75	-2.47%	76.80	65.63	-11.17	-14.55%
Residential - Medium Density [R1]	IRM	Low	100 kWh	37.86	38.38	0.52	1.38%	26.96	27.29	0.33	1.24%
		Average	800 kWh	141.55	144.50	2.95	2.08%	50.18	51.63	1.45	2.89%
		High	2,000 kWh	329.33	336.44	7.11	2.16%	89.98	93.34	3.36	3.74%
	DSA IRM	Low	100 kWh	45.72	46.66	0.94	2.06%	34.71	35.47	0.76	2.18%
		Average	800 kWh	151.74	155.79	4.05	2.67%	59.91	62.53	2.62	4.38%
		High	2,000 kWh	343.40	352.79	9.39	2.73%	103.11	108.93	5.82	5.65%
Residential - Low Density [R2]	IRM	Low	100 kWh	45.72	49.78	4.06	8.88%	34.71	38.53	3.82	11.01%
		Average	800 kWh	151.74	160.23	8.50	5.60%	59.91	66.90	6.99	11.67%
		High	2,000 kWh	343.40	359.50	16.11	4.69%	103.11	115.54	12.43	12.06%
	DSA IRM	Low	100 kWh	42.75	43.62	0.87	2.03%	31.84	32.53	0.69	2.17%
		Average	500 kWh	116.61	120.24	3.63	3.11%	64.66	67.42	2.76	4.27%
		High	1,000 kWh	222.46	229.54	7.08	3.18%	105.68	111.03	5.35	5.06%
Seasonal Residential	IRM	Low	100 kWh	42.75	40.00	-2.75	-6.44%	31.84	28.96	-2.87	-9.02%
		Average	500 kWh	116.61	112.36	-4.26	-3.65%	64.66	59.66	-4.99	-7.72%
		High	1,000 kWh	222.46	216.33	-6.13	-2.76%	105.68	98.03	-7.65	-7.23%
	DSA IRM	Low	1,000 kWh	190.75	194.01	3.25	1.71%	78.79	80.72	1.93	2.45%
		Average	2,000 kWh	351.09	357.28	6.19	1.76%	118.17	121.72	3.55	3.01%
		High	15,000 kWh	2,435.44	2,479.80	44.35	1.82%	630.11	654.72	24.61	3.91%
General Service Energy Billed (less than to 50kW) [GSe-metered]	IRM	Low	1,000 kWh	152.80	154.52	1.72	1.13%	41.25	41.62	0.37	0.90%
		Average	2,000 kWh	296.95	300.27	3.32	1.12%	64.50	65.12	0.62	0.96%
		High	15,000 kWh	2,170.94	2,194.99	24.06	1.11%	366.75	370.59	3.84	1.05%
	DSA IRM	Low	1,000 kWh	152.80	143.54	-9.26	-6.06%	41.25	30.82	-10.43	-25.28%
		Average	2,000 kWh	296.95	282.45	-14.50	-4.88%	64.50	47.60	-16.90	-26.21%
		High	15,000 kWh	2,170.94	2,088.27	-82.67	-3.81%	366.75	265.64	-101.11	-27.57%
General Service Demand Billed (50kW and above) [GSd]	IRM	Low	15,000 kWh and 60 kW	2,474.56	2,512.01	37.45	1.51%	681.58	694.22	12.64	1.85%
		Average	36,000 kWh and 117 kW	5,519.56	5,592.20	72.63	1.32%	1,280.02	1,304.27	24.25	1.89%
		High	1,500,000 kWh and 4,000 kW	216,592.47	219,061.42	2,468.95	1.14%	42,047.64	42,862.60	814.96	1.94%
	DSA IRM	Low	15,000 kWh and 60 kW	2,474.56	2,547.51	72.95	2.95%	681.58	729.12	47.54	6.98%
		Average	36,000 kWh and 117 kW	5,519.56	5,659.03	139.47	2.53%	1,280.02	1,369.99	89.97	7.03%
		High	1,500,000 kWh and 4,000 kW	216,592.47	221,263.13	4,670.66	2.16%	42,047.64	45,027.50	2,979.86	7.09%
Urban General Service Demand Billed (50kW and above) [UGd]	IRM	Low	15,000 kWh and 60 kW	2,324.76	2,353.29	28.53	1.23%	527.92	530.51	2.59	0.49%
		Average	36,000 kWh and 117 kW	5,241.08	5,296.43	55.35	1.06%	993.78	998.55	4.77	0.48%
		High	1,500,000 kWh and 4,000 kW	207,547.58	209,429.79	1,882.21	0.91%	32,729.54	32,882.68	153.14	0.47%
	DSA IRM	Low	15,000 kWh and 60 kW	2,324.76	2,283.43	-41.33	-1.78%	527.92	461.82	-66.10	-12.52%
		Average	36,000 kWh and 117 kW	5,241.08	5,164.49	-76.59	-1.46%	993.78	868.81	-124.97	-12.57%
		High	1,500,000 kWh and 4,000 kW	207,547.58	205,068.76	-2,478.82	-1.19%	32,729.54	28,594.56	-4,134.98	-12.63%
Street Lights	IRM	Low	200 kWh	31.44	31.96	0.52	1.65%	11.49	11.78	0.30	2.58%
		Average	1,320 kWh	241.11	244.79	3.68	1.53%	76.20	78.28	2.08	2.72%
		High	2,000 kWh	337.45	342.55	5.11	1.51%	105.43	108.31	2.88	2.73%
	DSA IRM	Low	200 kWh	31.44	32.56	1.12	3.56%	11.49	12.37	0.89	7.71%
		Average	1,320 kWh	241.11	248.78	7.67	3.18%	76.20	82.20	6.00	7.88%
		High	2,000 kWh	337.45	348.08	10.63	3.15%	105.43	113.74	8.31	7.89%
Sentinel Lights	IRM	Low	10 kWh	3.01	3.06	0.05	1.76%	1.75	1.79	0.04	2.37%
		Average	62 kWh	11.76	12.04	0.28	2.37%	5.57	5.58	0.01	0.18%
		High	100 kWh	18.16	18.61	0.45	2.45%	8.02	8.35	0.33	4.12%
	DSA IRM	Low	10 kWh	3.01	3.15	0.14	4.68%	1.75	1.87	0.13	7.31%
		Average	62 kWh	11.76	12.32	0.56	4.73%	5.37	5.85	0.48	8.94%
		High	100 kWh	18.16	19.02	0.86	4.73%	8.02	8.76	0.74	9.20%

Note: DSA = Density Study Adjustment

Consumers Council of Canada (CCC) INTERROGATORY #23 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ex. D/T1/S1/p. 8

Please explain how HON made the decision to adopt Option 1 vs. Option 2. Was it primarily because some participants at the June 5 Stakeholder Session supported a "staged approach" to the implementation of the Density Study findings? Did HON consider other options? If not, why not? If so, why were those options rejected?

Response

HONI is proposing Option 1 because it agrees with stakeholders that a staged approach to the implementation of the Density Study findings under IRM is appropriate, and HONI also recognizes that adjusting the revenue-to-cost ratios to be within the Board approved range is consistent with the approach approved by the Board in other applications (Horizon EB-2010-0131, Toronto Hydro EB-2010-0142, Brant County EB-2010-0125). HONI considered only the two options presented as they are suitable approaches for implementation of the Density Study findings under an IRM proceeding.

Consumers Council of Canada (CCC) INTERROGATORY #24 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ex. D/T1/S1/p. 4

Please explain how HON determines the rates for seasonal customers relative to the rates for its other residential classes.

Response

The rates for all customer classes, including the Seasonal rate class, are established by:

- 1) Determining the revenue to be collected from each rate class using the Board's cost allocation model,
- 2) Splitting the revenue to be collected between fixed and variable components, and
- 3) Setting the rates by dividing the revenue to be collected by the forecast billing determinants (i.e. # of customers, kWh or kW)

Consumers Council of Canada (CCC) INTERROGATORY #25 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ex. D/T1/S1/p. 10

Please include R1 in the attached table.

Response

Please see the total bill impacts, for average consumption, in the Option 1 Table provided in Exhibit I, Tab 13, Schedule 7.02 CCC 22.

Consumers Council of Canada (CCC) INTERROGATORY #26 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

Ex. D/T1/S1/p. 10

Please recast Table 8 to include 3 consumption levels for each rate class - high volume and low volume. In effect we are looking for the range of impacts within each class.

Response

Please see the total bill impacts in the Option 1 Table provided in Exhibit I, Tab 13, Schedule 7.02 CCC 22.

School Energy Coalition (SEC) INTERROGATORY #41 List 1

Issue 13 Is Hydro One's proposal for the implementation of the Density Study findings appropriate?

Interrogatory

[D/1/1/Attach 1, p. 35] Please advise what the rates would be for 2013 if General Service Energy and Demand billed customers were split into three classes at the same density breakpoints as residential.

Response

Hydro One is not able to determine what the rates would be for three classes of General Service Energy and Demand billed customers as this would require a number of inputs to re-run the Board's cost allocation model that are not readily available, including the following:

- Information on the number of customers that would fall into the new classes
- Load forecasts and load shapes for the new customer classes
- Services, Billing, Meter Reading and Density weighting factors for the new customer classes

School Energy Coalition (SEC) INTERROGATORY #42 List 1

Issue 13 **Is Hydro One's proposal for the implementation of the Density Study findings appropriate?**

Interrogatory

[D/1/1/Attach 1, p. 40] Please explain why it is appropriate to use cost ratios that "likely understate" the difference in cost to serve between the density-based classes

Response

Hydro One believes it is appropriate to use the cost ratios identified in the Density Study as it represents best quantifiable data available on the relationship between density and cost-to-serve.

TAB 14

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

Issue 15 If new rates cannot be implemented by January 1, 2013, should Hydro One's rates be declared interim, and if so, from and after what date?

Interrogatory

Ref: Exhibit A/Tab2/Sch1

It appears that the timing of the Board's decision on Hydro One's distribution rates for 2013 may not facilitate the implementation of rates on January 1, 2013. How does Hydro One propose to address this issue?

Response

If the Board's decision on Hydro One's distribution rates for 2013 does not facilitate the implementation of rates on January 1, 2013, Hydro One proposes that its rates be declared interim as per its letter "Request for Declaring Existing Approved Rates as Interim" submitted to the Board on September 27, 2012. Any foregone revenue associated with declaring rates interim would be cleared by means of a rate rider over the remainder of 2013.

TAB 16

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Canadian Manufacturers & Exporters (CME) INTERROGATORY #2 List 1

Issue 17 Is the proposed Tariff of Rates and Charges for 2013 appropriate?

Interrogatory

Preamble

In prior proceedings, most recently in the Renewed Regulatory Framework for Electricity ("RRFE") proceeding, CME and others sponsored and presented the year-over-year 5-year electricity price forecasts that electricity consumers are likely facing. The latest price increase forecast presented in the RRFE proceeding covers the period December 2011 to December 2016. The Report, dated March 21, 2012, was prepared by Bruce Sharp of Aegent Energy Advisors Inc. ("Aegent"). Its preparation was sponsored by CME, Consumers Council of Canada ("CCC"), Federation of Rental-housing Providers of Ontario ("FRPO"), School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC"). The Report can be found by following the link below, or by clicking on the RRFE link found under "OEB Initiatives" under "Quick Links" on the Ontario Energy Board's ("OEB") Home Page (bottom left-hand corner):

http://www.ontarioenergyboard.ca/OEB/ Documents/EB-2010-0377/CME_SUB_Ontario%20Elec%20Price%20Increase%20Forecast%202012.pdf

Ontario manufacturers are particularly sensitive to large year-over-year increases in their total electricity bills. Significant year-over-year total bill increases have a demand destruction potential that CME regards as material.

CME wishes to ascertain the extent to which Hydro One Distribution monitors the prospective year-over-year total electricity bill increases that consumers will likely be facing over 2013 and over a multi-year planning cycle.

Questions

Having regard to the foregoing and in the context of the total bill impacts, and the customer impacts set out at Exhibit E1, Tab 3, Schedule 1, CME seeks the following further information from Hydro One:

- (a) Please produce copies of any electricity price forecasts that Hydro One has in its possession that include 2013 and beyond. CME seeks production of such price increase forecasts in Hydro One's possession that have been prepared by or on behalf of the OEB, the Minister of Energy, the Ontario Power Authority Inc. ("OPA"), Hydro One and/or Ontario Power Generation Inc. ("OPG").
- (b) Please advise whether Hydro One accepts as reasonable the 5-year price increase forecasts faced by different categories of electricity consumers between

- December 2011 and December 2016, as described by Mr. Sharp in his Report dated March 21, 2012, as follows:
- (i) Large consumers who qualify for a demand-related allocation of the Global Adjustment ("GA") and served directly off transmission are facing increases over the next 5 years totalling between 36% and 46%;
 - (ii) Similar large consumers served by LDC's are facing year-over-year increases for the next 5 years of between 39% and 48%;
 - (iii) Consumers who neither qualify for the demand-related allocation of the GA, nor the Ontario Clean Energy Benefit ("OCEB") are facing increases over the next 5 years totalling between 41% and 49%; and
 - (iv) The remaining customers, consisting primarily of residential consumers, are facing price increases over the next 5 years ranging between 46% and 58% assuming the discontinuance of the OCEB by 2016.
- (c) As in prior cases, please produce, in confidence, unredacted copies of the presentations made to Hydro One's Board of Directors during the course of the planning process for this IRM application including the written and slide presentations that provide Hydro One's Business Plans for 2013 and beyond.
- (d) Having regard to the communications that Hydro One has with its customers please provide any information Hydro One has in its possession related to the level of total electricity bill increases to Ontario industrial consumers, including manufacturers, that are likely to trigger material demand destruction.

Response

- a) Hydro One is providing a summary of all price forecasts for the 2013 and 2014 time period that are available and in its possession. These forecasts are from three sources:
1. **Ontario Energy Board (OEB):** The two most recent Ontario Wholesale Electricity Market Price Forecast Reports prepared by Navigant Consulting on behalf of the OEB (April 2012 and October 2011) include price forecasts for the 2013 period. The reports can be found on the OEB website: [http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Regulated+Price+Plan/Regulated+Price+Plan+\(RPP\)#20120419](http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Regulated+Price+Plan/Regulated+Price+Plan+(RPP)#20120419)
 2. **Ontario Ministry of Energy (MoE):** Section 7 of Ontario's Long Term Energy Plan prepared by the Ontario Ministry of Energy includes price projections for

1 residential and industrial customers for the 2010-2030 time period. The report can
2 be found on the MoE website: <http://www.energy.gov.on.ca/en/ltep/>
3

4 3. **Hydro One Networks:** The forecasted wholesale spot power prices for Ontario
5 from IHS CERA Market Briefing Northeast Power Market Fundamentals,
6 December 2011 are shown below.
7

Ontario Wholesale Spot Power Prices (Annual Average)		
(nominal dollars per megawatt-hour)		
Year	On-peak	Off-peak
2006	56.8	37.4
2007	60.3	36.9
2008	64.0	40.0
2009	37.3	25.3
2010	38.7	28.7
2011	36.5	27.9
2012	34.5	25.4
2013	36.6	23.7
2014	44.2	28.5
2015	45.9	28.9
2016	49.2	35.4

IHS CERA Market Briefing *Northeast Power Market Fundamentals*, December 2011.

Notes: On-peak is defined as Monday through Friday, 7:00 AM to 11:00 PM; off-peak is defined as Monday through Friday, 00:00 AM to 7:00 AM and 11:00 PM to 00:00 AM, and all day Saturday and Sunday.

8
9

10 b) Hydro One is unable to comment on the reasonableness of the 5-year price increase
11 forecasts in Mr. Sharp's Report dated March 21, 2012 for the four categories of
12 customers as described in parts i) to iv). Key assumptions presented in the appendix
13 to the report are based on estimated values (i.e. capacity factors and various rates for
14 generation additions; cost escalators and installed capacities for current generation;
15 NUG prices and energy generation; 2011 CDM expenditure and CDM cost
16 escalators; transmission and distribution cost escalators; increases for Wholesale
17 Market Service Charges). Hydro One cannot verify how Mr. Sharp arrived at these
18 estimates and as such cannot comment on the final results of the report.
19

20 c) Please refer to Exhibit I, Tab 1, Schedule 7.01 CCC 1.
21

22 d) In reference to Exhibit A, Tab 15, Schedule 2, pages 17 and 18 of Hydro One's
23 Transmission Application (EB-2012-0031) Hydro One is not aware of any customers
24 reporting material demand destruction due to the level of total bill increases.

Consumers Council of Canada (CCC) INTERROGATORY #27 List 1

Issue 17 Is the proposed Tariff of Rates and Charges for 2013 appropriate?

Interrogatory

E1/T3/S1/p. 2

Do the Total Monthly Bill Impacts set out in Table 1 include all components of the application? If so, please break out the impacts related to the Price Cap Index, the ICM, the Smart Grid Adder and the Deferral and Variance Account credit. Please do the same for each of the distribution rate increases by rate class.

Response

Yes, the Total Monthly Bill Impacts set out in Exhibit E1, Tab 3, Schedule 1, Table1 include all components of the application.

The tables below show the impacts of the individual components of the application on the total monthly bill and distribution portion of the monthly bill.

Total Monthly Bill Impacts

Customer Type	Monthly Consumption (kWh and/or kW)	Current Total Monthly Bill (\$)	Impacts of Price Cap Index on Total Monthly Bill		Impacts of Incremental Capital Rate Rider on Total Monthly Bill		Impacts of Smart Grid Rate Rider on Total Monthly Bill		Impacts of Shared Tax Savings Rate Rider on Total Monthly Bill		Impacts of Deferral and Variance Account Rate Rider on Total Monthly Bill		Impacts of RTSR on Total Monthly Bill		Total Impact on Monthly Bill	
			(\$)	%	(\$)	%	(\$)	%	(\$)	%	(\$)	%	(\$)	%	(\$)	%
Residential - Urban Density [UR]	800 kWh	132.26	0.34	0.26%	0.89	0.68%	0.65	0.49%	-0.08	-0.06%	-0.76	-0.57%	1.45	1.09%	2.49	1.88%
Residential - Medium Density [R1]	800 kWh	141.55	0.41	0.29%	1.06	0.75%	0.81	0.57%	-0.08	-0.06%	-0.73	-0.52%	1.47	1.04%	2.95	2.08%
Residential - Low Density [R2]	800 kWh	151.74	0.76	0.50%	1.55	1.02%	1.14	0.75%	-0.08	-0.05%	-0.69	-0.46%	1.39	0.91%	4.05	2.67%
Seasonal Residential	500 kWh	116.61	0.54	0.47%	1.53	1.31%	1.17	1.00%	-0.10	-0.09%	-0.33	-0.28%	0.82	0.70%	3.63	3.11%
General Service Energy Billed (less than to 50kW)	2,000 kWh	351.09	1.02	0.29%	2.64	0.75%	2.03	0.58%	-0.20	-0.06%	-1.88	-0.54%	2.58	0.73%	6.19	1.76%
General Service Energy Billed (less than to 50kW) [GSe - Quinte West]	2,000 kWh	344.21	7.90	2.29%	2.64	0.77%	2.03	0.59%	-0.20	-0.06%	-1.88	-0.55%	2.58	0.75%	13.06	3.80%
General Service Energy Billed (less than to 50kW) [GSe - Smith Falls]	2,000 kWh	349.30	2.81	0.81%	2.64	0.76%	2.03	0.58%	-0.20	-0.06%	-1.88	-0.54%	2.58	0.74%	7.98	2.28%
General Service Energy Billed (less than to 50kW) [GSe - unmetered]	500 kWh	99.25	0.44	0.44%	0.66	0.67%	0.51	0.51%	-0.05	-0.05%	-0.47	-0.47%	0.64	0.65%	1.73	1.74%
Urban General Service Energy Billed (less than to 50kW) [UGe]	2,000 kWh	296.95	0.54	0.18%	1.22	0.41%	1.02	0.34%	0.00	0.00%	-2.15	-0.72%	2.69	0.91%	3.32	1.12%
General Service Demand Billed (50kW and above) [GSD]	36,000 kWh and 117 kW	5,519.56	11.42	0.21%	29.43	0.53%	22.24	0.40%	-1.94	-0.04%	-36.49	-0.66%	47.97	0.87%	72.63	1.32%
Urban General Service Demand Billed (50kW and above) [UGd]	36,000 kWh and 117 kW	5,241.08	8.86	0.17%	22.69	0.43%	17.15	0.33%	-1.49	-0.03%	-42.36	-0.81%	50.50	0.96%	55.35	1.06%
Distributed Generation [DGen]	7,700 kWh and 200 kW	2,175.84	10.85	0.50%	29.76	1.37%	22.50	1.03%	-1.95	-0.09%	-9.67	-0.44%	15.11	0.69%	66.59	3.06%
Street Lights	1,320 kWh	241.11	0.68	0.28%	1.76	0.73%	1.32	0.55%	-0.15	-0.06%	-1.50	-0.62%	1.57	0.65%	3.68	1.53%
Sentinel Lights	62 kWh	11.76	0.05	0.41%	0.13	1.13%	0.10	0.86%	-0.01	-0.05%	-0.06	-0.54%	0.07	0.57%	0.28	2.37%
Low Use Secondary Service	500 kWh	102.28	7.99	7.81%	0.66	0.65%	0.51	0.50%	-0.05	-0.05%	-0.47	-0.46%	0.64	0.63%	9.28	9.07%
Sub-Transmission [ST]	36,000 kWh and 117 kW	4,782.87	3.28	0.07%	2.45	0.05%	1.86	0.04%	-0.17	0.00%	32.67	0.68%	88.58	1.85%	128.68	2.69%

Distribution Bill Impacts

Customer Type	Monthly Consumption (kWh and/or kW)	Current Distribution Bill (\$)*	Impacts of Price Cap Index on Distribution Bill*		Impacts of Incremental Capital Rate Rider on Distribution Bill*		Impacts of Smart Grid Rate Rider on Distribution Bill*		Impacts of Shared Tax Savings Rate Rider on Distribution Bill*		Impacts of Deferral and Variance Account Rate Rider on Distribution Bill*		Total Impact on Distribution Bill*	
			(\$)	%	(\$)	%	(\$)	%	(\$)	%	(\$)	%	(\$)	%
Residential - Urban Density [UR]	800 kWh	41.78	0.33	0.80%	0.88	2.11%	0.64	1.53%	-0.08	-0.19%	-0.75	-1.78%	1.03	2.46%
Residential - Medium Density [R1]	800 kWh	50.18	0.41	0.81%	1.04	2.07%	0.80	1.59%	-0.08	-0.16%	-0.72	-1.43%	1.45	2.89%
Residential - Low Density [R2]	800 kWh	59.91	0.74	1.24%	1.52	2.54%	1.12	1.87%	-0.08	-0.13%	-0.68	-1.13%	2.62	4.38%
Seasonal Residential	500 kWh	64.66	0.53	0.83%	1.50	2.32%	1.15	1.78%	-0.10	-0.15%	-0.32	-0.50%	2.76	4.27%
General Service Energy Billed (less than to 50kW)	2,000 kWh	118.17	1.01	0.85%	2.60	2.20%	2.00	1.69%	-0.20	-0.17%	-1.85	-1.57%	3.55	3.01%
General Service Energy Billed (less than to 50kW) [GSe - Quinte West]	2,000 kWh	111.41	7.77	6.97%	2.60	2.33%	2.00	1.80%	-0.20	-0.18%	-1.85	-1.66%	10.31	9.26%
General Service Energy Billed (less than to 50kW) [GSe - Smith Falls]	2,000 kWh	116.41	2.77	2.38%	2.60	2.23%	2.00	1.72%	-0.20	-0.17%	-1.85	-1.59%	5.31	4.56%
General Service Energy Billed (less than to 50kW) [GSe - unmetered]	500 kWh	48.75	0.43	0.88%	0.65	1.33%	0.50	1.03%	-0.05	-0.10%	-0.46	-0.95%	1.07	2.19%
Urban General Service Energy Billed (less than to 50kW) [UGe]	2,000 kWh	64.50	0.53	0.83%	1.20	1.86%	1.00	1.55%	0.00	0.00%	-2.11	-3.28%	0.62	0.96%
General Service Demand Billed (50kW and above) [GSd]	36,000 kWh and 117 kW	1,280.02	11.23	0.88%	28.93	2.26%	21.87	1.71%	-1.91	-0.15%	-35.88	-2.80%	24.25	1.89%
Urban General Service Demand Billed (50kW and above) [UGd]	36,000 kWh and 117 kW	993.78	8.71	0.88%	22.31	2.25%	16.86	1.70%	-1.46	-0.15%	-41.65	-4.19%	4.77	0.48%
Distributed Generation [DGen]	7,700 kWh and 200 kW	1,216.44	10.67	0.88%	29.26	2.41%	22.12	1.82%	-1.92	-0.16%	-9.51	-0.78%	50.62	4.16%
Street Lights	1,320 kWh	76.20	0.67	0.88%	1.73	2.27%	1.30	1.70%	-0.14	-0.19%	-1.47	-1.94%	2.08	2.72%
Sentinel Lights	62 kWh	5.37	0.05	0.88%	0.13	2.42%	0.10	1.85%	-0.01	-0.12%	-0.06	-1.16%	0.21	3.88%
Low Use Secondary Service	500 kWh	51.73	7.86	15.19%	0.65	1.26%	0.50	0.97%	-0.05	-0.10%	-0.46	-0.90%	8.49	16.42%
Sub-Transmission [ST]	36,000 kWh and 117 kW	370.72	3.23	0.87%	2.41	0.65%	1.83	0.49%	-0.16	-0.04%	32.13	8.67%	39.43	10.64%

* Excludes taxes and OCEB credit.

School Energy Coalition (SEC) INTERROGATORY #43 List 1

Issue 17 Is the proposed Tariff of Proposed Rates and Charges appropriate?

Interrogatory

[E2/2/3] Please confirm that Hydro One is seeking approval of the rates and charges set forth in Exhibit 2, Tab 2, Schedule 3, to the extent that they are different from the rates and charges set forth in Exhibit 2, Tab 2, Schedule 2.

Response

This is confirmed.

For rate classes that will not be impacted by Density Study Adjustments (R1, GSe-metered, GSe-Unmetered, DGen, ST, and MicroFIT), Hydro One is seeking approval of the rates and charges set forth in Exhibit 2, Tab 2, Schedule 2.

For rate classes that will be impacted by Density Study Adjustments (UR, R2, Seasonal, UGe, GSd, UGd, Street Lights, and Sentinel Lights), Hydro One is seeking approval of the rates and charges set forth in Exhibit 2, Tab 2, Schedule 3.