Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #001

Reference:

A/T5/S3/Attachment 1 Schedule 'A' – no (PDF p.124)

Interrogatory:

a) Please provide a breakdown of the "President/CEO/Chairman services for 2017 and 2018 into the components: a) salaries and benefits; b) facilities; c) other (please specify).

b) Please provide the same for the Chief Financial Officer and General Counsel services.

Response:

a) Please see the table below for a breakdown of the total costs. "Burdens" refer to statutory deductions, pension and other post-employment benefits. "Non-labour costs" include travel, similar expenses, and budgets for consultants.

		2017	2018
CEO, Chair, Board Services	*Labour Cost*	5,409,941	5,117,482
	Burdens	640,667	561,864
	Non-Labour Cost	300,000	300,000

b) The tables below breakdown of the total costs.

		2017	2018
CFO Services	*Labour Cost*	1,510,000	1,530,200
	Burdens	289,865	297,963
	Non-Labour Cost	30,000	30,000

		2017	2018
General Counsel & Secretary Services	*Labour Cost*	764,940	779,238
	Burdens	222,835	229,186
	Non-Labour Cost	110,000	110,000

Witness: Glenn Scott

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #002

Reference:

A/T3/S1/pg.6

> At the noted reference it states "*Reliability risk is a metric that is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure or replacement…..The reliability risk model is not used to identify specific asset needs and investments. Instead, these are determined by condition assessments and other asset-specific information…*"

Interrogatory:

a) How has this model been tested using past data?

b) If the model does not inform specific investment then what is its purpose?

Response:

a) Please refer to Board Staff #14 (c).

b) Please refer to Board Staff #14 (f).

Witness: Mike Penstone

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #003

Reference:

Exhibit B1/T2/S2/pg.5

Interrogatory:

a) What are the incremental costs of the changed BES definitions?

Response:

Please see Exhibit I, Tab 3, Schedule 9.

Witness: Bing Young

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #004

Reference:

B1/T1/S3/pgs.23-

Interrogatory:

a) The Figures 8-13 show reliability figures in comparison to the CEA composite. Does this composite include Hydro One data?

b) If yes please restate the figures showing the CEA composite excluding Hydro One data.

Response:

a) Yes, the CEA composite includes Hydro One data.

b)

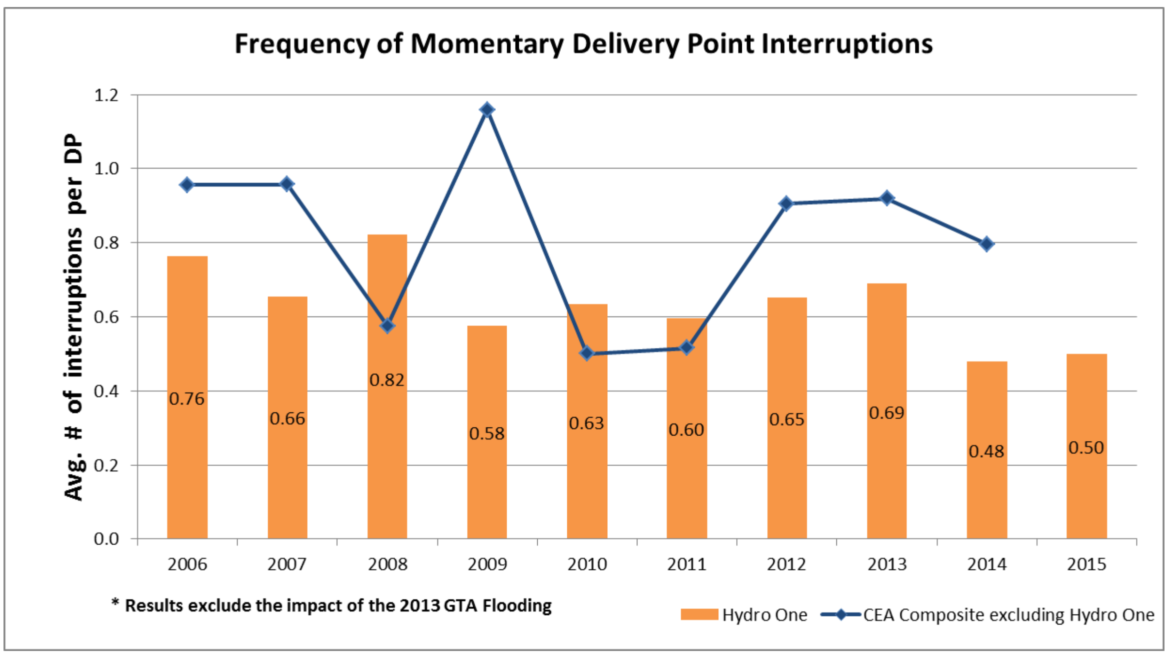


Figure 8a: Comparison of Hydro One Frequency of Momentary Interruptions to CEA Composite excluding Hydro One

Witness: Mike Penstone

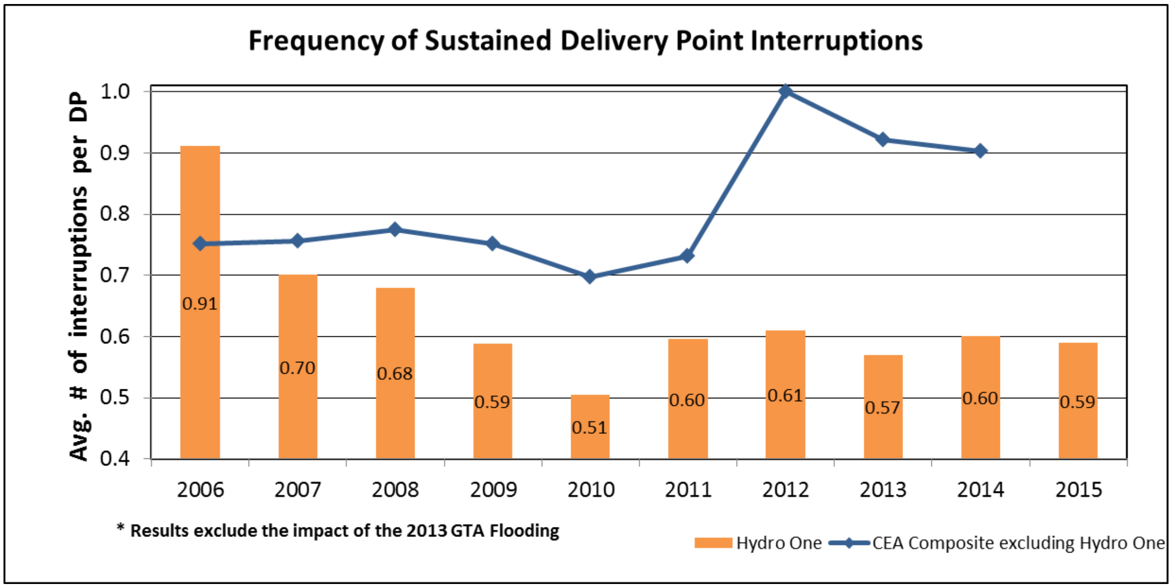


Figure 8b: Comparison of Hydro One Frequency of Sustained Interruptions to CEA Composite excluding Hydro One

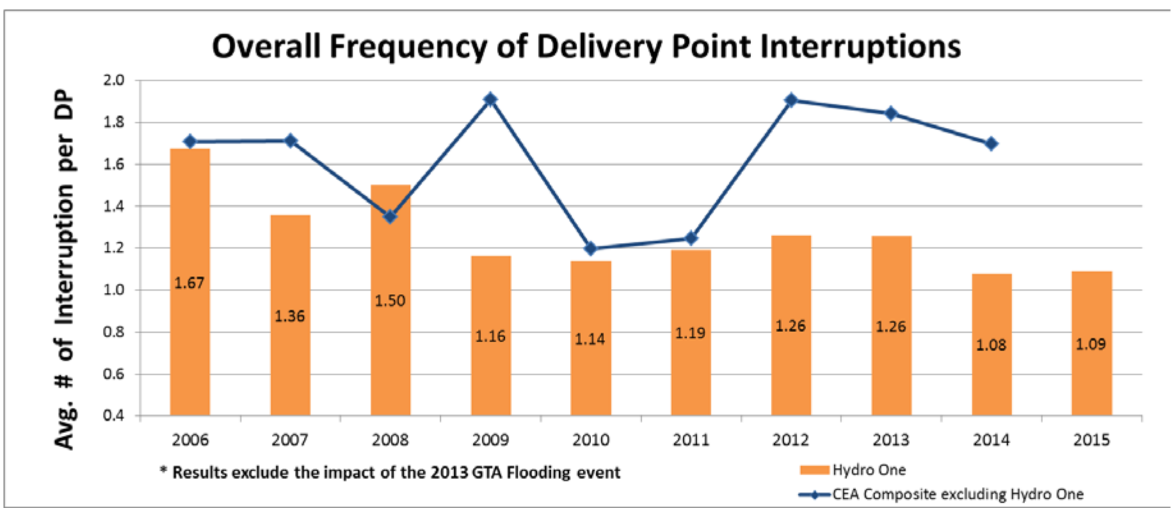


Figure 9: Comparison of Hydro One Overall Frequency of Interruptions to CEA Composite excluding Hydro One

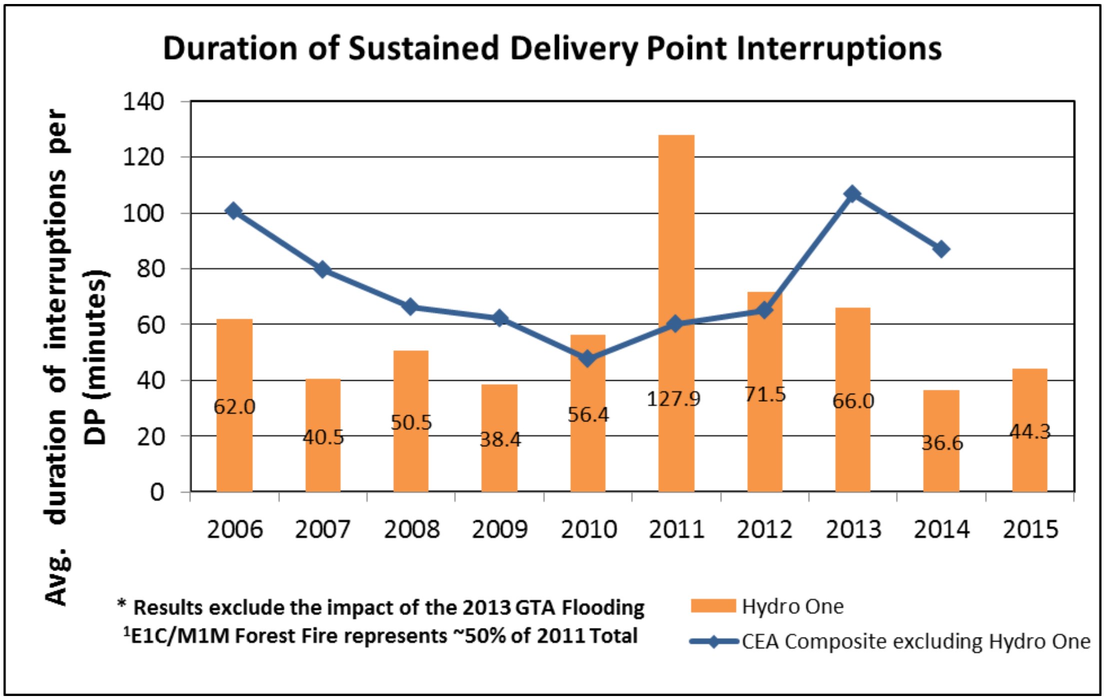


Figure 10: Comparison of Hydro One Duration of Sustained interruptions to CEA Composite excluding Hydro One

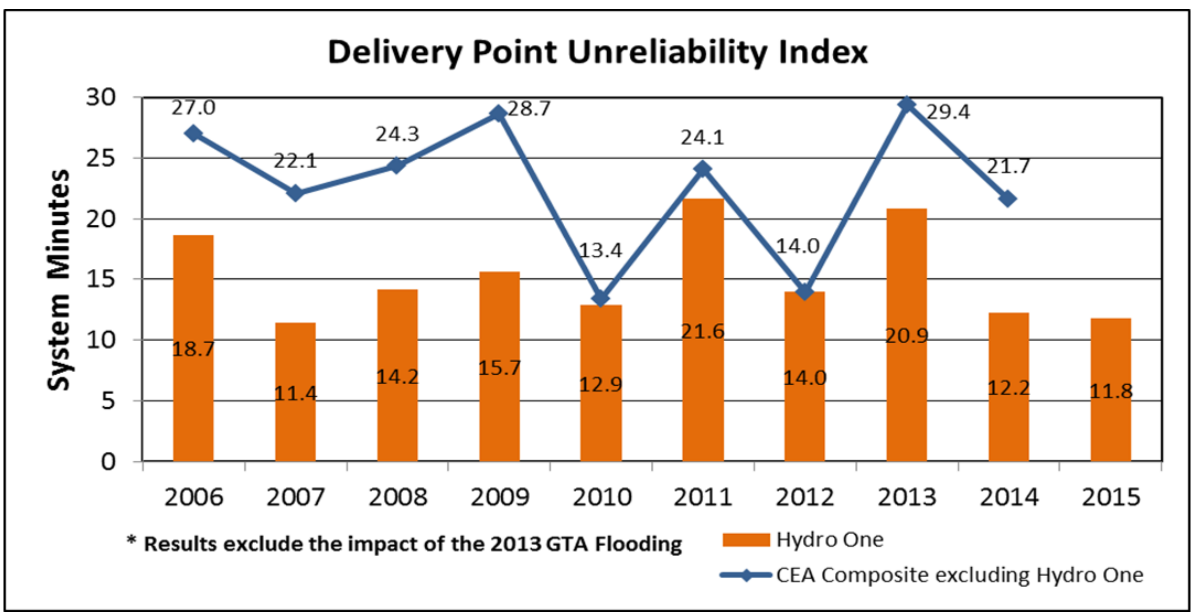


Figure 11: Comparison of Hydro One Delivery Point Unreliability Index to CEA Composite excluding Hydro One

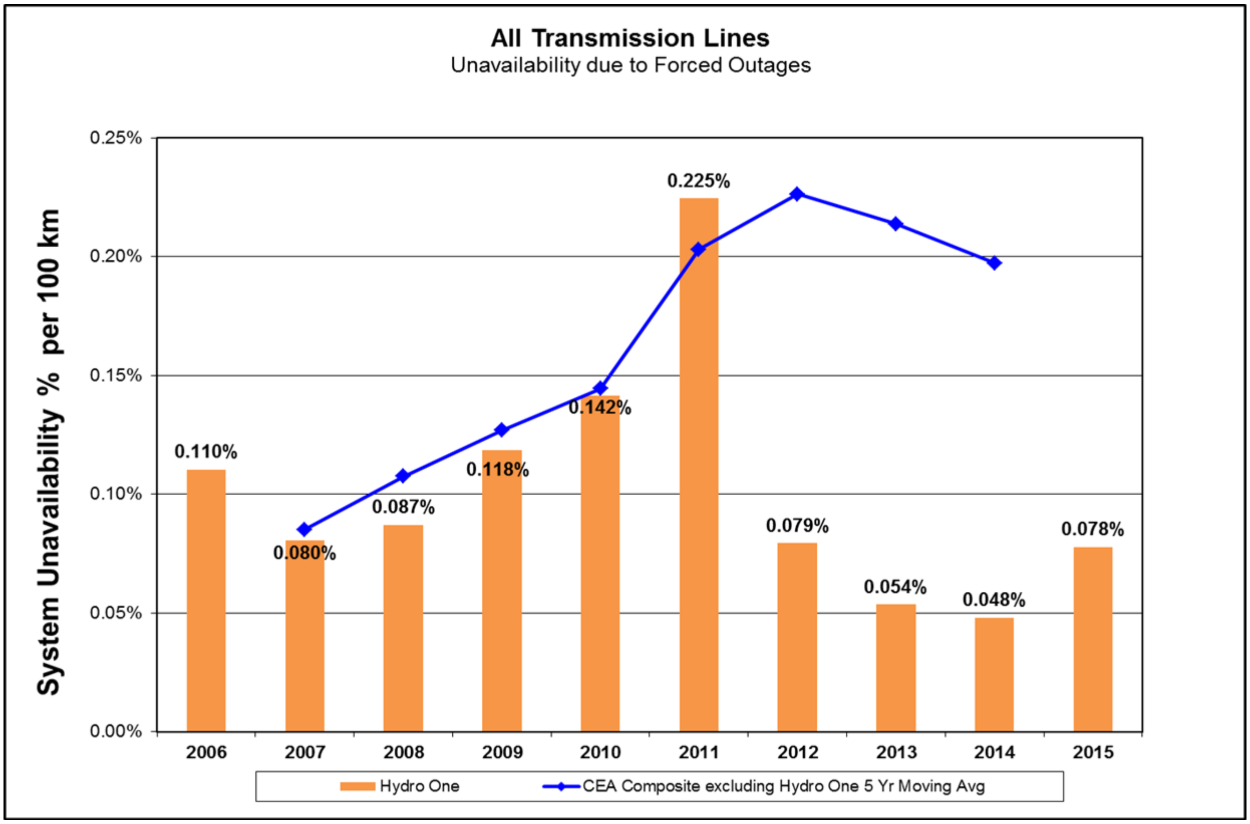


Figure 12: Comparison of Hydro One Unavailability of Transmission Lines to CEA Composite excluding Hydro One

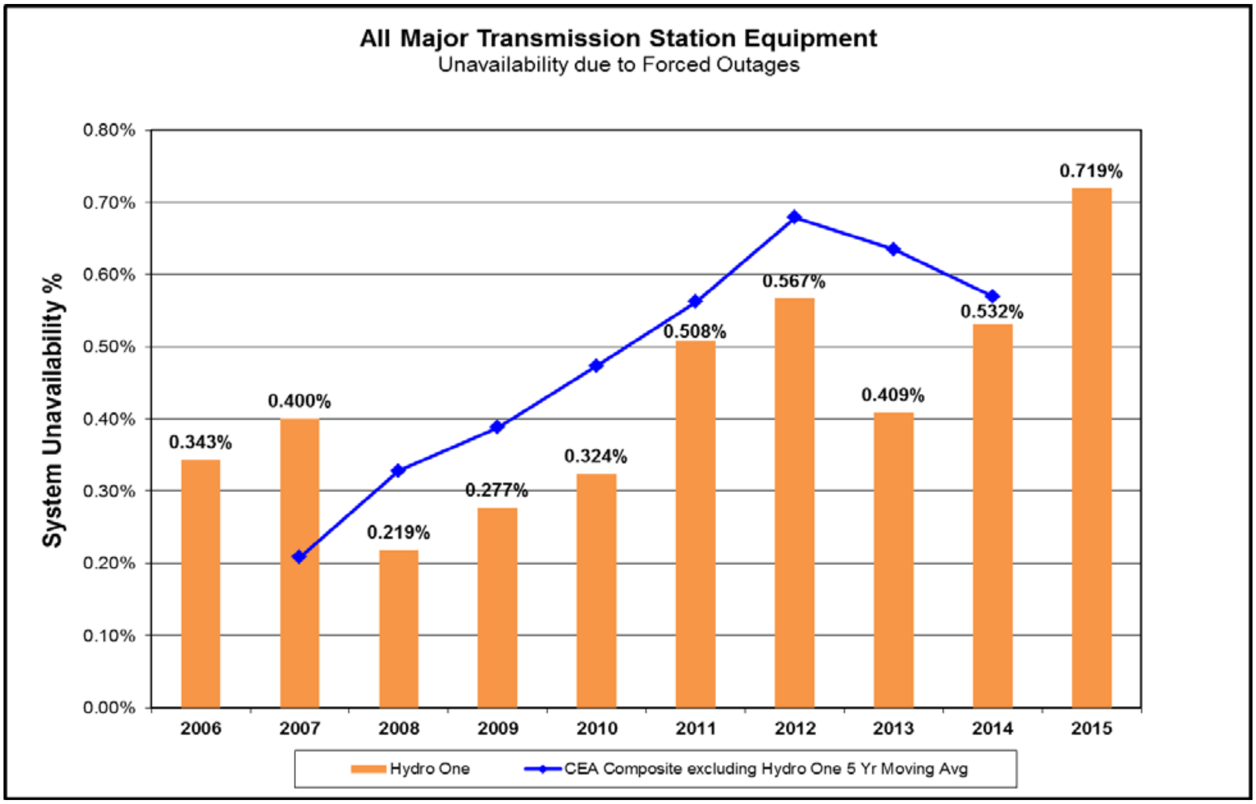


Figure 13: Comparison of Hydro One Unavailability of Major Transmission Station Equipment to CEA Composite excluding Hydro One

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #005

Reference:

Exhibit B1/T1/S3/Attachment 1

Interrogatory:

a) Please explain the rationale for different customer delivery point performance standards based on load size.

b) Please explain why the standards are based on a 1991-2000 performance and not more recent data (e.g. 2006-2015).

c) Please provide the standards if based on the most recent 10 year data set available.

Response:

a) The Customer Delivery Point Performance (CDPP) Standard is based on load size in order to meet the Transmission System Code requirement to establish acceptable bands of performance at the customer delivery point level. Please refer to Exhibit B1, Tab 1, Schedule 3, Attachment 1, Page 1, Line 13.

b) The CDPP standard as approved by the OEB in RP-1999-0057/EB-2002-0424 is based on the historical 1991-2000 performance. There is no approval for a CDPP standard for other time periods.

c) The standard is based on the 1991-2000 performance.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #006

Reference:

Exhibit B1/T1/S3/Attachment 1

Interrogatory:

a) Please clarify Table 1 by defining what is meant by "standard average performance" and "minimum standard of performance". Specifically, is the former the actual average performance (and if so for what period) and is the latter the 1991-2000 performance?

Response:

a) The "Standard (Average Performance)" is the average delivery point frequency of interruption, or average delivery point interruption duration for a given load group or band based on 1991-2000 performance.

The "Minimum Standard of Performance", for each of the four load size groups or bands, is used as a trigger by Hydro One. The trigger occurs when the three-year rolling average of the delivery point performance falls below the Minimum Standard of Performance for its load size group or band (referred to as a performance outlier or outlier) and is also based on 1991-2000 performance.

There is no approval for a CDPP standard for other time periods.

Witness: Mike Penstone

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #007

Reference:

Exhibit B1/T2/S4 & Attachment 1

Interrogatory:

a) Please explain how “reliability risk” is related to “reliability performance”. Specifically, please show how Hydro One reviews actual performance to test past reliability risk forecasts (i.e. how is the accuracy of the model tested).

b) If this is not available (for example, due to the newness of the approach) please explain how the other jurisdictions referenced (at page 6) have tested the relationship between reliability risk (i.e. forecast) and actual reliability.

c) Please explain how Hydro One intends to test the accuracy of its reliability risk approach.

Response:

a) Reliability performance is defined in Exhibit B1, Tab 2, Schedule 4, Section 3. Reliability performance is a measure of frequency and average duration of delivery point interruptions. Reliability risk, as defined in Exhibit B1, Tab 2, Schedule 4, Section 3.1, is the output of a model that is helps gauge the impact of investments on future reliability. This is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of asset failure or retirement. The relationship between these concepts is such that over time, as reliability risk increases, reliability performance will deteriorate. The model has been built using Hydro One historical information and actual asset performance. Past reliability risk has not been calculated or tested.

b) Please refer to Board Staff #14 (b).

c) Hydro One’s risk model is based on failure rates derived from historical data. As more assets fail and are retired from the system, these models will be updated and refined accordingly. The reliability risk approach will be tested and measured based on Hydro One’s ability to maintain top quartile reliability performance.

Witness: Mike Penstone

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #008

Reference:

Exhibit B1/T1/S3/Attachment 1

Interrogatory:

a) Please explain the relationship between “reliability risk” and the “hazard rate”. Specifically is the reliability risk the summation of asset hazard rates?

Response:

Refer to Exhibit I, Tab 1, Schedule 15, part a) and Exhibit I, Tab 1, Schedule 22, part a) and b).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #009

Reference:

Exhibit B1/T2/S6/pg.54/Table 11

Interrogatory:

a) Please clarify if Table 11 shows both steel structure replacement and recoating.

b) Please provide separate tables for each activity (replacement and recoating/refurbishment).

Response:

a) Table 11 shows both steel structure member replacement and recoating.

b) As there is no steel member replacement planned for test years, the provided quantities are for tower recoating.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #010

Reference:

Exhibit B1/T2/S6/pgs. 9-

Interrogatory:

a) Please amend Tables 3,5,8,9,10,11 (as adjusted for question 9 above), 12 and 13 to show the actual and forecast capital expenditure for these activities.

b) Please include the years 2019 through 2021 (as per Table 5/1 Summary of Transmission Capital Budget (A/T3/S1/pg.13/B1/T3/S1/Table 1) to the amended tables

c) Please reconcile (if different) the capital budgets for Table 3 et al and the amounts shown in the Summary Table 5.

Response:

a) Please refer to Exhibit I, Tab 6, Schedule 20 for updated Tables 3, 5, 8, 9, 10, 11, 13.

Updated Table 12 below:

Table 12: Insulator Portfolio Replacement

Insulator Portfolio	**Historic**				**Bridge**	**Test**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
# of circuit structures	210	433	233	155	2100	4030	3880
% of Fleet	0.15%	0.3%	0.2%	0.1%	1.4%	2.7%	2.6%
Capital ($M)	3.3	6.9	3.8	2.8	26.1	63.9	61.4

b) & c) Hydro One has provided forecasts that meet the filing requirements and also provide the full detail relating to the costs for which rate recovery is sought in this application (Test Years 2017 and 2018).

Witness: Chong Kiat Ng

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #011

Reference:
Exhibit B1/T2/S/Table 2

Interrogatory:
a) Please clarify whether the Global Insight cost escalator forecasts incorporate forecasts of the costs of Hydro One.

Response:
a) No, they do not. However, these indices represent costs that any transmitter in the region, including Hydro One, would face.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #012

Reference:

Exhibit B2/T1/S1/

Interrogatory:

a) Please explain what mechanisms (incentives) are in place which would incent the lowering of the implementation (actual vs forecast) costs of the proposed capital budget.

Response:

a) Hydro One does not have any formal incentives in place to bring costs in lower than budgeted/estimated; however, it does drive a culture of cost control. As stated in the Cost Efficiencies, Productivity and Key Performance Indicators evidence (Exhibit B2, Tab 1, Schedule 1); Hydro One has developed a transmission scorecard and key performance indicators, several of which focus on cost control, in an effort to drive a culture of continuous improvement and excellence in execution. Hydro One also has a robust variance identification and approval process that governs both spending and schedule variances against approved budget as described in Exhibit B1, Tab 2, Schedule 7.

   Hydro One is also evaluating different delivery and contract models for the work that is externally constructed to evaluate if it may result in increased cost efficiencies for rate payers. For more information on enhanced delivery and contract models please refer to Exhibit B1, Tab 4, Schedule 1.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #013

Reference:
Exhibit B2/T1/S1/

Interrogatory:
a) Why has Hydro One not included the RCE as part of its new scorecard?

Response:
a) The RCE is a relatively new metric to Hydro One. Hydro One is currently refining its proposed scorecard metrics to ensure they are driving behaviours that are consistent with Hydro One's goals and business objectives as a newly commercial entity and aligned with the RRFE. The RCE metric is being used as a Tier 2 metric under OM&A/Gross Fixed Asset within the Cost Control performance category.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #014

Reference:
Exhibit B2-2-1 Attachment 1/Benchmarking Study/3.5 Staffing

Interrogatory:
a) Please explain the meaning of "4-10s" schedule referred to in section 3.5 of the Report.

Response:
a) "4-10s" refers to a work schedule consisting of four, ten hour shifts.

Witness: Ben Grunfeld

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #015

Reference:

Exhibit B1/T2/S7, pages 4-5

Interrogatory:

a) With respect to Table 2, is there a more recent forecast from Global Insight regarding transmission cost escalation? If so, please provide.

Response:

a) Please see the updated Table 2 below.

Table 2: Global Insight's June 2016 forecast (%)

	Historical Years				**Bridge Year**	**Test Years**	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Transmission Cost Escalation for Construction	-0.1	2.0	2.2	1.2	1.2	1.8	2.4
Transmission Cost Escalation for Operations & Maintenance	2.1	0.9	0.4	-0.7	-0.5	0.9	1.5

Witness: Mike Penstone

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #016

Reference:

Exhibit B1/T2/S3/pg.20

Interrogatory:

a) Please provide the 5 year cost (by year) for each of the Regional Infrastructure Plans / Needs Assessment Reports shown at page 20.

b) Are these costs integrated into the proposed capital budget? If yes please explain where.

Response:

a) Hydro One is only one of the participants in the Regional Infrastructure Planning process for the areas shown in Table 1 in Exhibit B1, Tab 2, Schedule 3. The scope of the regional plans include both transmission and distribution assets and therefore include some costs that are not Hydro One's responsibility. Please refer to Exhibit I, Tab 13, Schedule 12 for further details on investments identified in the Regional Infrastructure Plans within the test years.

b) Yes, the costs of the Hydro One investments identified in part (a) have been included in Hydro One's capital plan, please refer to Exhibit B1, Tab 3, Schedule 3, Tables 2 to 4.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #017

Reference:

C1/T3/S1/pg.2

Interrogatory:

a) Please explain the cost increase trend in Common Corporate Functions Services from $80.5 million in 2012 to the forecast $98.4 million in 2018.

b) Please explain the relationship between the CCFS costs shown at Table 1 at T3/S1/pg.2 and Table 1 shown at C1/T3/S3/pg. 2 entitled CCFS costs (i.e. why re the amounts not the same e.g. for 2012 Table 1/S1 = $80.5 ; Table 1/S3 = $152.0?)

Response:

a) Please refer to Exhibit I, Tab 4, Schedule 12.

b) Table 1 in Exhibit C1, Tab 3, Schedule 3 reflects Hydro One's total CCFS costs as well as the costs allocated to Hydro One Transmission for the test years 2017 and 2018. Table 1 in Exhibit C1, Tab 3, Schedule 1 reflects only Hydro One Transmission's portion of Common Corporate OM&A costs.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #018

Reference:

C1/T3/S2/pg.5

Interrogatory:

a) Please explain what the "purchased services agreement with the Power Worker's Union" refers to.

b) Please outline any restrictions to outsourcing included in current labour agreements. If such restrictions do exist please explain when they expire.

Response:

a) Contracting under the Hydro One-Power Workers' Union ("PWU") collective agreement is governed by the applicable purchased services agreement. When PWU work arises that Hydro One would like to contract out, the process requires Hydro One to provide the PWU with information regarding the nature and value of the work. The parties then discuss and evaluate all alternatives using established criteria and thresholds, considering the impact on the customer, employees and the business. If the parties agree, then the work is contracted out; however, if they cannot agree the grievance/arbitration process is initiated by the PWU. The parties have negotiated purchased services agreements in certain key areas, such as Facilities and Grounds & Sites, Drafting, and Locates.

b) The purchase services agreement with the Society of Energy Professionals permits Hydro One to contract out Society represented work as long as no Society represented employee are laid off. In most cases involving building trades unions, work can be contracted out or subcontracted as long as the "labour requirements" practice is followed. This means that the contractor/subcontractor is required to apply the terms and conditions of the relevant building trades union agreement if and when the work being performed falls under that collective agreement.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #019

Reference:

C1/T3/S3

Interrogatory:

a) Please explain the trend cost increase as between 2012 and 2018 for the total costs of:
- People and Culture
- Corporate Communications
- Regulatory Affairs.

Response:

Please see Exhibit I, Tab 4, Schedule 12 for explanations regarding the People and Culture and Regulatory Affairs organizations.

For Corporate Communications, increases over the planning period can be attributed to higher expenditures for the First Nations and Métis Relations function and the outsourcing services function. The level of customer service provided to First Nations and Métis communities has increased to ensure their unique needs are addressed. Furthermore, additional effort has been required for communication and consultation regarding new projects. Costs for the outsourcing services function are relatively constant, except for significant fluctuations in 2014 and 2018 which are associated with re-tendering Hydro One's largest outsourcing arrangement.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #020

Reference:

C1/T4/S1

Interrogatory:

a) What (if any) performance requirements are included in the share grant program.

b) Please provide the terms of the share grant program.

Response:

a) The PWU and the Society share grant program does not have any specified performance requirements. Eligible employees receive common shares beginning April 1, 2017 (PWU) and April 1, 2018 (Society). The value of these shares will be determined by the stock performance.

b) See Attachment #1 for the PWU and Society Share Grant Plan from the 2016 Hydro One Management Information Circular.

Witness: Keith McDonell

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #021

Reference:

C1/T4/S1

Interrogatory:

a) Please explain the increase in employees from 2015 (7,283) to 2018 (7,489). Please show how many positions related to overlapping due to forecast retirements and how many are new (long-term incremental) positions.

Response:

a) The increase in employees between 2015 and 2018 would be a result of an increasing work program. Due to the data limitations, it is very difficult to show a direct correlation between hires due to retirements and hires due to new incremental positions. When an employee retires, it is often the case that the vacated position is filled by internal resources and the resulting backfill may be an external hire. In an effort to monitor and control headcount, all internal and external vacancies must be approved by the Line of Business Vice President and then approved by the SVP, People and Culture, Health Safety and Environment.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #022

Reference:

D1/T5/S1/Table 2

Interrogatory:

a) Please update the long-term debt calculation for any debt issuances made after the filing of the application.

Response:

a) No long-term debt issuances have been made after the filing of the application.

Witness: Samir Chhelavda

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #023

Reference:

D1/T5/S1/pgs.3-

Hydro One was able to issue 5, 10 and 30 year debt in February 2016 at coupon rates of 1.84%, 2.77% and 3.91%. It forecasts the 2017 and 2018 coupon rates for these to be significantly higher (3.22% / 3.97-3.10% / 4.30-5.10% respectively). The basis for this forecast is shown in Table 4.

Interrogatory:

a) Please provide the long-term forecast that was relied upon for Table 4.

b) Please provide analysis which shows the accuracy of this forecast using the past forecasts and actuals.

c) Please explain how the Hydro One spread is calculated (i.e. show the calculation).

Response:

a) The long-term forecast that was relied upon for Table 4 is the April 2016 Long Term Consensus Forecast from Consensus Economics Inc., for forecasting the 10 Year Government of Canada yield, as stated in Exhibit D1, Tab 5, Schedule 1, Page 6, lines 6 and 7. Consensus Economics Inc. restricts reproduction (complete or partial) or redistribution of the forecast to persons other than the subscriber.

b) Consensus Economics surveys prominent financial and economic forecasters and reports the survey mean of the forecasters. Consensus Economics does not measure the accuracy of the survey mean. However, Consensus Economics does discuss the accuracy of the survey mean on their website (http://www.consensuseconomics.com/how_accurate.htm). Consensus Economics' Consensus Forecasts are used by the OEB in their Cost of Capital Parameters annual update.

c) An explanation for how the Hydro One spread is calculated can be found in Exhibit D1, Tab 5, Schedule 1, Page 6, lines 11 to 13. Hydro One spreads are provided by the MTN dealer group on a weekly basis. The average spreads for the two weeks in April are shown in the below table.

Indicative Average New Issue Spreads from Hydro One's Medium Term Note Dealer Group			
Date	**5 year**	**10 year**	**30 year**
April 4, 2016	1.05%	1.28%	1.66%
April 11, 2016	1.03%	1.27%	1.65%
April 4 and 11 Average	**1.04%**	**1.27%**	**1.65%**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #024

Reference:

Exhibit E1/T2/S1, pages 2-5

Interrogatory:

a) With reference to Table 1, please explain why the forecast 2016-2018 annual revenues from Secondary Land Use are materially less than the historic annual revenues for 2012-2014.

b) Please provide a schedule that sets out:
- The forecast Station Maintenance revenue for 2014-2016 as filed with HON's 2015-16 Cost of Service Application
- The forecast Station Maintenance revenue for 2012-2014 as filed with HON's 2013-2014 Cost of Service Application.

c) With reference to Table 1, please explain why the forecast 2016-2018 annual revenues from Other External Revenues is materially less than the historic annual revenues for 2013-2015.

Response:

a) Please see response to Exhibit I, Tab 1, Schedule 142.

b) The schedule that sets out the forecasted Station Maintenance revenue for the bridge and test years as filed for 2013-2014, and 2015-2016 is below:

Station Maintenance Revenue ($M)	2012	2013	2014	2015	2016
EB-2014-0140			7.1	7.2	7.3
EB-2012-0031	10.2	8.1	8.1		

c) The Other External Revenues historic figures are higher than the forecasted years primarily due to one-time sales and easement transactions as a result of major projects that have been completed. In addition, royalty revenues that were received historically have ceased at the end of 2015.

Witness: Glenn Scott

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #025

Reference:

Exhibit E1/T3/S1, pages 1 (Table 1) and 20 (Table 3)
Exhibit H1/T2/S1, page 1 (Table 1) and pages 3-4

Interrogatory:

a) Do the charge determinants for Line Connection and Transformation Connection set out in Table 1 of Exhibit E1 and Table 1 of Exhibit H1 include the demand for the generators as discussed in Exhibit H1 (pages 3-4)?
- If yes, what is the amount included for generators for each year?
- If no, what is the amount that needs to be added to account for these generators?

b) With reference to Tables 1 and 3 of Exhibit E1, please explain how the forecasts for each of the three charge determinants are derived from the forecast for Ontario Demand.

Response:

a) Yes, the charge determinants for Line Connection and Transformation Connection set out in Exhibit H1, Tab 2, Schedule 1, Table 1, include the demand for the transmission connected generators. The following table shows the amount included for transmission connected generators each year.

Year	**Line Connection (MW)**	**Transformation Connection (MW)**
2017	357,706	144,552
2018	373,340	151,486

b) The methodology for deriving Hydro One's charge determinants from the Ontario peak demand is explained in detail in Section 5 in Exhibit E1, Tab 3, Schedule 1. In summary, the Ontario peak growth rates, prior to Embedded Generation and CDM deductions, were applied to the 2015 charge determinants. Then the corresponding Embedded Generation and CDM impacts were deducted to arrive at charge determinants net of those impacts.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #026

Reference:

Exhibit E1/T3/S1, pages 3-6

Interrogatory:

a) What are the sources used for the forecasts for Commercial Floor Space (Section 3.4) and Industrial Production/GDP (Section 3.5)? If more recent forecasts for either are now available, please provide.

Response:

a) For forecast sources, please see Exhibit I, Tab 1, Schedule 143. Hydro One does not have a more recent update for these forecasts.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #027

Reference:

Exhibit E1/Tab 3/Schedule 1, pages 6-8 (Table 2)

Interrogatory:

a) With reference to Table 2, please confirm that the values for 2006-2015 are actual values and those for 2016-2018 are forecast.

b) Please provide the source and supporting documentation for the actual values reported.

c) Please provide a breakdown of the actual values reported for each year as between the three CDM categories described on page 7 (lines 8-11).

d) Please clarify whether the actual results reported for each year represent actual savings or annualized savings assuming all initiatives implemented during the year were in place as of January 1.

e) Please confirm whether the demand response savings reported for each year (per the response to part c)) represent the actual load reductions achieved through the of activation demand response contracts or the MW of demand response under contract. In responding please provide the references/documentation supporting the response.

Response:

a) The values in Table 2 for 2006-2014 are actual figures and those for 2015-2018 are forecast as discussed with the IESO.

b) The requested information is provided below.

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
EE	289	778	893	997	1167	1318	1470	1621	1820	1942	2167	2099	2391
Data Source	OPA 2011 IPSP (Integrated Power Sysetm Plan)							OPA 2013 LTEP (Long Term Energy Plan)					
Actual /Forecast	IESO Assumes the savings from EE programs in 2006-2014 are same as forcast in the IPSP and LTEP												

c) The requested information is provided below. Please note that a breakdown for energy efficiency programs ("EE") and codes and standards ("C&S") is not available for the years 2006 to 2012.

Peak Demand Reduction Associated with Energy Savings Targets

Peak Demand Saving (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
EE								1,248	1,435
C&S								373	386
Total of EE + C&S in LTEP	289	778	893	997	1,167	1,318	1,470	1,621	1,820
IESO assumed Actual	289	778	893	997	1,167	1,318	1,470	1,621	1,820

**peak savings from EE and C&S assume the same as forecast in LTEP (Slide 7, http://www.ieso.ca/Documents/LTEP/2014-Actual-vs-2014-Forecast-in-LTEP.pdf)*

Peak Reduction from Existing and Future Demand Response Resources

Peak Demand Saving (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
LTEP 2013	305	388	646	609	504	498	519	1352	1399
Actual Impact (as of December 2015)	305	388	646	609	504	498	519	1613*	1589**

** IESO, "LTEP: Comparison of 2013 Forecast vs 2013 Actual Results", Slide 8 (http://www.ieso.ca/Documents/LTEP/LTEP-module-update-2013-forecast-to-actual-20150617-final-June-17-2015.pdf)*

*** IESO, "LTEP: Comparison of 2014 Forecast vs 2014 Actual Results", Slide 8 (http://www.ieso.ca/Documents/LTEP/2014-Actual-vs-2014-Forecast-in-LTEP.pdf)*

d) Based on consultation with the IESO, the actual peak saving results reported by the IESO for each year represent actual savings.

e) The demand management savings reported for each year, as reflected in c) above, represent the actual load reductions achieved through the activation of demand response programs (e.g. DR2, DR3, and peaksaverPLUS), time-of-use peak reduction, and industrial conservation initiative on peak days. Please see c) above for the supporting references.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #028

Reference:

Exhibit E1/Tab 3/Schedule 1, pages 6-8

Interrogatory:

a) It is not clear what information was provided by the IESO in early 2016 (per lines 11-14) and if it included the IESO's latest province-wide conservation forecast (per lines 6-8). Please provide copies of both: i) the IESO's latest conservation forecast and ii) the information provided by the IESO in early 2016.

b) In doing so, please clarify the point of measurement (e.g. at generation, transmission delivery or end use customer delivery point) that the IESO actual and forecast information is based on and, if different from the point of measurement used in Table 2, indicate what adjustments are required to make the two comparable.

c) In order to provide context to the IESO CDM forecast, please also provide the IESO's pre-CDM load forecast that underpins its latest CDM forecast.

d) Does Table 2 account for loss of persistence of previous years' CDM impacts?

e) Please provide a schedule that sets out the first year impacts of CDM programs for each year (2006-2015) and the persisting values in subsequent years that result in the cumulative impacts shown in Table 2.

f) Please provide a schedule that sets out: i) the OPA's CDM forecast per the 2013 LTEP and ii) the IESO's latest CDM forecast (with each broken down by CDM category) and demonstrate that Hydro One's forecast is consistent with both (per page 7, lines 16-18).

g) Does the IESO's forecast of demand response, as included in its latest CDM forecast, represent forecasted contract amounts or forecast demand response activated under <u>normal</u> weather conditions?

h) Please explain how the CDM impact on the 12-month Average Peak Demand is determined from the IESO CDM forecast.

i) Please confirm that Hydro One Transmission is not proposing a LRAMVA for 2017-

2018 and therefore no LRAMVA reference values are required.

Response:

a)

i) The IESO's latest conservation forecast is same as the LTEP 2013. The details can be found at the following website : http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013

The 2013 and 2014 actual results can be found at the following website: http://www.ieso.ca/Pages/Ontario's-Power-System/LTEP/Actual-vs-Forecast-Data.aspx

ii) The information provided by the IESO is what is shown in i) above.

b) The savings provided by the IESO are at the generator level. The value in Table 2 is also at the generator level.

c) IESO uses the CDM forecast from the 2013 LTEP. Hydro One does not have IESO's pre-CDM load forecast. The IESO 18 month load forecast can be found in the following website: http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-&-18-Month-Outlooks.aspx

d) Yes.

e) The requested information is not available from the IESO.

f)

i) The OPA's CDM forecast per the 2013 LTEP is as follows:

Type	Program	2016	2017	2018
Peak Demand Reduction Associated with Energy Savings Targets	EE (historical and future programs)	1662	1575	1752
	Codes and Standards (existing and forecast)	505	525	639
	Total of EE and C&S	**2167**	**2099**	**2391**
Peak Reduction from Existing and Future Demand Response Resources	Dispatchable Load	377	377	377
	Industrial Conservation Initiative	300	300	300
	Time-of-Use Rates	232	239	239
	Existing DR Programs (assume capacity maintained)	528	528	528
	Total of DR resources	**1437**	**1444**	**1444**

ii) The IESO's latest CDM forecast is same as the OPA forecast in the 2013 LTEP.

Hydro One's CDM peak savings used in load forecasting is the same as the peak reduction associated with energy saving targets. Considering there is no incremental peak reduction from existing and further demand response resources over the forecast period, Hydro One uses the implicit method to incorporate demand response impacts in load forecasting.

The following table demonstrates that Hydro One's forecast is consistent with IESO's forecast.

Source	Program	2016	2017	2018
2013 LTEP	EE (historical and future programs)	1662	1575	1752
	Code and Standard (existing and forecast)	505	525	639
	Total of EE and C&S	2167	2099	2391
Hydro One forecast (table 2, Exhibit E1/Tab 3/Schedule 1)	CDM impact on peak demand	2167	2099	2391

"EE" refers to energy efficiency programs. "C&S" refers to codes and standards.

g) In the 2013 LTEP, the IESO's forecast of demand response represents the summer activated capacity under normal system peaking conditions. As of the end of 2015, the demand response (DR2 and DR3) program is no longer active and has been replaced by the capacity-based demand response program. As mentioned in f) above, there is no incremental demand response impact for the forecast period, and Hydro One uses the implicit method to incorporate it in load forecasting.

h) The IESO (formerly, the OPA) provided hourly load shapes by program types (e.g. energy efficiency, codes and standards). The annual peak savings is from LTEP and then applied to these load shapes to derive the monthly peak savings by program.

i) Hydro One confirms that it is not proposing a LRAMVA for 2017 to 2018.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #029

Reference:

Exhibit E1/Tab 3/Schedule 1, page 8

Interrogatory:

a) For the years 2014 - 2016 please contrast the level of CDM savings in the current Application with those used in EB-2014-0140 and explain the variance for each year.

Response:

a) As indicated in response f) in Exhibit I, Tab 12, Schedule 28, Hydro One uses the implicit method to incorporate demand response impacts in load forecasting. Column (2) in the table below was presented in Table 2 of Exhibit E1, Tab 3, Schedule 1. Column (3) reflects the demand response impact from the 2013 LTEP, and the total of peak saving from energy efficiency ("EE") and demand response ("DR") programs is calculated in column (4). Column (1) should be compared to column (4), and there is no variance between the total peak savings due to EE, codes and standards ("C&S") and DR for these two applications.

	EB-2014-0140	EB-2016-0160		
	(1)	(2)	(3)	(4)=(2)+(3)
	Peak saving (EE, C&S, DR)	Peak saving (EE, C&S only)	DR impact (implicit in the actual load)	total of EE, C&S and DR
2014	2,865	1,820	1,045	2,865
2015	3,014	1,942	1,072	3,014
2016	3,250	2,167	1,083	3,250
2017		2,099	1,088	3,187
2018		2,391	1,088	3,479

Witness: Bijan Alagheband

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #030

Reference:

Exhibit E1/Tab 3/Schedule 1, pages 8-9

Interrogatory:

a) Please provide a schedule indicating what the actual embedded generation for the years 2006-2015 assumed for purposes of the load forecast and indicate the source of values.

Response:

a) The requested schedule is set out below. The source of the data is the IESO. Hydro One used the IESO's peak values and profile to arrive at 12-monthly peak values and calculated the 12-month average peak.

Actual Embedded Generation
(12-Month Average Peak in MW)

Year	Embedded Generation
2006	0
2007	33
2008	63
2009	163
2010	255
2011	325
2012	381
2013	455
2014	608
2015	716

Witness: Bijan Alagheband

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #031

Reference:

Exhibit E1/Tab 3/Schedule 1, pages 11-14

Interrogatory:

a) Please explain why it is appropriate to use a 31 year definition for weather normal when HON's weather correction methodology only uses four years' worth of data (per page 11, lines 9-13).

b) Please explain more fully how Figures 3 and 4 indicate that the 20-year trend has been broken when: i) the comparator used appears to be the average for the 31 years and ii) the values for 2014 and 2015 are well within the historical range of results.

Response:

a) 31 years of weather data is used as input into the relationship between load and weather conditions. This yields different values for load under different weather conditions that could have happened in 2015, for example. Such different values are averaged out to arrive at estimated normal load. The reason for using 31 years is that, following weather organizations (e.g., Environment Canada and NOAA in U.S.), weather is assumed to be stationary over three decades. Using less than three decades of weather data would yield a less stable estimate of normal load. As detailed in the Exhibit noted above, Hydro One's weather correction methodology uses four years of daily load and weather data to capture the latest load mix (e.g., the amount of space-heating and cooling load, which varies over time).

b) i) The 20-year trend suggests that there is an upward sloping trend line reflecting warmer and warmer temperature over the past 20 years so that, for 2014 and 2015, this hypothetical line (not shown on the graphs) would be above the average line shown on the graphs. During the past two years, both the maximum and minimum temperature values were below the corresponding average, contrary to the 20-year "trend" prediction that they would be above the 31-year average.

ii) Temperature values shown on the graphs are well within the historical range during the past 31 years as well as the past 20 years.

Witness: Bijan Alagheband

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #032

Reference:
Exhibit E1/Tab 3/Schedule 1, pages 12-20

Interrogatory:
a) Please provide schedule that set out the actual 2012-2014 total transmission system load prior to deducting for CDM and embedded generation (consistent with Table 3)

b) Please provide a schedule that for 2016-2018 sets out the total transmission system load forecast based on each of the three models discussed (prior to the CDM adjustments) and Hydro One Networks' proposed forecast.

Response:
a) Please see below the requested table.

Total Transmission System Load Prior to Embedded Generation and CDM (12-Month Average Peak in MW)

	Ontario Demand	Network	Line Connection	Transformation Connection
2012	21,803	21,522	20,677	17,834
2013	22,000	21,848	20,878	17,943
2014	22,481	22,532	21,466	18,396

b) Please see below the requested schedule.

Total Transmission System Forecasts Prior to Embedded Generation and CDM
(12-Month Average Peak in MW)

	Ontario Demand	Network	Line Connection	Transformation Connection
End-Use Model Forecast				
2016	22,288	22,324	21,559	18,425
2017	22,300	22,336	21,570	18,435
2018	22,221	22,256	21,494	18,370
Annual Econometric Model Forecast				
2016	22,328	22,363	21,597	18,458
2017	22,674	22,710	21,932	18,744
2018	22,919	22,956	22,169	18,947
Monthly Econometric Model Forecast *				
2016	21,500	21,535	20,797	17,774
2017	20,914	20,947	20,229	17,289
2018	20,396	20,429	19,729	16,862
Hydro One Networks Proposed Forecast				
2016	22,606	22,642	21,862	18,685
2017	22,784	22,820	22,034	18,832
2018	23,105	23,142	22,344	19,096

* Due to its short-term nature, forecasts beyond 2017 should be ignored.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #033

Reference:

Exhibit E1/Tab 3/Schedule 1, pages 29-39

Interrogatory:

a) Please provide Hydro One Networks forecast of electricity prices in the residential, commercial and industrial sectors as used in the Annual Econometric Model and describe how they were established.

b) For context please also include the actual prices for 2012-2015 used in the models' estimations.

Response:

a) The forecast of electricity prices in the residential, commercial and industrial sectors as used in the Annual Econometric Model are provided in Exhibit E2, Tab 2, Schedule 1. They were established on the basis of the 2013 LTEP electricity price forecasts for residential and commercial sectors and the NEB electricity price forecast for the industrial sector. (LTEP did not have a forecast for the industrial sector.) The figures are expressed in constant $/eGWh.

b) Actual electricity prices for the years 2012-2015 are also provided in Exhibit E2, Tab 2, Schedule 1.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #034

Reference:

Exhibit E1/Tab 3/Schedule 1, pages 50-51

Preamble: The Application states that "no incremental demand response was assumed over the forecast 18-month horizon".

Interrogatory:

a) Please clarify what is meant by "incremental demand response".

b) Did Hydro One Networks subtract from its pre-CDM load forecast for 2016-2018 any impact due to demand response programs?

c) If yes, please explain why this wouldn't contribute to the variance between the IESO's and Hydro One Networks' load forecasts.

Response:

a) "Incremental demand response" over the forecast period refers to change in demand response in any forecast year compared to its 2015 value.

b) No, in the current application, Hydro One did not add demand response to its 2015 base-year actual and part of 2016 for which actual data was available. Hydro One also did not deduct demand response from its forecast prior to CDM and embedded generation because incremental demand response was zero.

c) See Exhibit I, Tab 1, Schedule 144 for clarification on this point.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #035

Reference:

Exhibit F1/T1/S1, page 3
Exhibit F2/T1/S3

Interrogatory:

a) For each of the regulatory accounts for which Hydro One Networks is seeking disposition, please provide a schedule that details the annual debits and credits associated with the annual transactions (per F2/T1/S3) for each of the years 2014- 2016.

b) For those accounts that were included in the EB-2014-0140 Application and for which there forecast balances for December 2014 (Exhibit F1/T1/S1, page 1) please explain the variance between the forecast balance per EB-2014-0140 and the actual December 2014 balance.

Response:

a) Please see attached schedule.

b) The variance between forecast balance per EB-2014-0140 and the actual December 2014 balance represents the transactions that occurred in 2014 (other than any board approved dispositions) as such amounts are not forecasted.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity Schedules - Regulatory Accounts

Year ending December 31, 2014

Account Description	Account Number	Opening Principal	Transactions during the year Debit /Credit	Board-Approved Disposition during 2014	Closing Principal	Opening Interest	Interest during the year	Board-Approved Disposition during 2014	Closing Interest	Total Principal plus Interest
Excess Export Service Revenue	2405	(40.9)	(5.0)	18.5	(27.5)	(1.0)	(0.5)	0.5	(1.1)	(28.5)
External Secondary Land Use Revenue	2405	(31.8)	(5.9)	14.2	(23.6)	(0.9)	(0.4)	0.5	(0.9)	(24.5)
External Stations Maintenance, E&CS & Other External Revenue	2405	(6.2)	0.1	5.1	(1.0)	(0.3)	0.0	0.2	(0.0)	(1.1)
Tax Rate Changes	1592	(3.0)	0.2	3.8	1.0	(0.6)	(0.0)	0.5	(0.1)	0.9
Rights Payments	2405	(3.5)	(1.5)	1.7	(3.3)	(0.1)	(0.1)	0.0	(0.1)	(3.4)
Pension Costs Differential	2405	20.1	3.1	(12.4)	10.8	0.7	0.2	(0.4)	0.5	11.3
Long-Term Transmission Future Corridor Acquisition and Development	1508	0.1	0.3	0.0	0.4	0.0	0.0	0.0	0.0	0.4
LDC CDM and Demand Response Variance Account	1508	0.0	(24.7)	0.0	(24.7)	0.0	(0.4)	0.0	(0.4)	(25.1)
External Revenue – Partnership Transmission Projects Account	2405	0.0	(0.9)	0.0	(0.9)	0.0	0.0	0.0	0.0	(0.9)
North West Bulk	1508		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		**(65.2)**	**(34.4)**	**30.8**	**(68.8)**	**(2.2)**	**(1.1)**	**1.2**	**(2.1)**	**(70.9)**

Year ending December 31, 2015

Account Description	Account Number	Opening Principal	Transactions during the year Debit /Credit	Board-Approved Disposition during 2015	Closing Principal	Opening Interest	Interest during the year	Board-Approved Disposition during 2015	Closing Interest	Total Principal plus Interest
Excess Export Service Revenue	2405	(27.5)	(12.7)	0.0	(40.1)	(1.1)	(0.4)	0.0	(1.5)	(41.6)
External Secondary Land Use Revenue	2405	(23.6)	(20.0)	0.0	(43.6)	(0.9)	(0.4)	0.0	(1.3)	(44.9)
External Stations Maintenance, E&CS & Other External Revenue	2405	(1.0)	0.5	0.0	(0.5)	(0.0)	(0.0)	0.0	(0.1)	(0.6)
Tax Rate Changes	1592	1.0	0.0	0.0	1.0	(0.1)	0.0	0.0	(0.0)	0.9
Rights Payments	2405	(3.3)	(1.4)	0.0	(4.7)	(0.1)	(0.0)	0.0	(0.2)	(4.9)
Pension Costs Differential	2405	10.8	2.7	0.0	13.4	0.5	0.1	0.0	0.6	14.1
Long-Term Transmission Future Corridor Acquisition and Development	1508	0.4	0.3	0.0	0.7	0.0	0.0	0.0	0.0	0.7
LDC CDM and Demand Response Variance Account	1508	(24.7)	(27.8)	0.0	(52.5)	(0.4)	(0.6)	0.0	(1.0)	(53.5)
External Revenue – Partnership Transmission Projects Account	2405	(0.9)	0.0	0.0	(0.9)	0.0	(0.0)	0.0	(0.0)	(0.9)
North West Bulk	1508	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		**(68.8)**	**(58.4)**	**0.0**	**(127.3)**	**(2.1)**	**(1.3)**	**0.0**	**(3.4)**	**(130.7)**

Year ending December 31, 2016

Account Description	Account Number	Opening Principal	Transactions during the year Debit /Credit	Board-Approved Disposition during 2016	Closing Principal	Opening Interest	Interest during the year	Board-Approved Disposition during 2016	Closing Interest	Total Principal plus Interest
Excess Export Service Revenue	2405	(40.1)	0.0	22.4	(17.7)	(1.5)	(0.3)	1.0	(0.7)	(18.4)
External Secondary Land Use Revenue	2405	(43.6)	0.0	17.7	(25.9)	(1.3)	(0.3)	0.8	(0.8)	(26.7)
External Stations Maintenance, E&CS & Other External Revenue	2405	(0.5)	0.0	1.1	0.6	(0.1)	0.0	0.1	0.1	0.7
Tax Rate Changes	1592	1.0	0.0	(0.8)	0.2	(0.0)	0.0	0.0	(0.0)	0.1
Rights Payments	2405	(4.7)	0.0	1.8	(3.0)	(0.2)	0.0	0.1	(0.1)	(3.0)
Pension Costs Differential	2405	13.4	0.0	(7.7)	5.7	0.6	0.1	(0.5)	0.2	6.0
Long-Term Transmission Future Corridor Acquisition and Development	1508	0.7	0.0	(0.1)	0.6	0.0	0.0	(0.0)	0.0	0.6
LDC CDM and Demand Response Variance Account	1508	(52.5)	0.0	0.0	(52.5)	(1.0)	(0.5)	0.0	(1.5)	(54.0)
External Revenue – Partnership Transmission Projects Account	2405	(0.9)	0.0	0.0	(0.9)	(0.0)	(0.0)	0.0	(0.0)	(0.9)
North West Bulk Transmission Def	1508	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		**(127.3)**	**0.0**	**34.4**	**(92.8)**	**(3.4)**	**(1.0)**	**1.6**	**(2.8)**	**(95.6)**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #036

Reference:

Exhibit F1/T1/S1, pages 3 and 9

Interrogatory:

a) Please provide the detailed calculations supporting the annual additions to the LDC CDM and Demand Response Variance Account including:
   - The annual forecast and actual CDM savings and Demand Response amounts (separately) used in the calculation, with supporting sources for the values used.
   - How the actual reported CDM and Demand Response results were translated into impact on the transmission billing determinants.
   - The rates used and resulting calculation of the dollar impacts due to difference between forecast and actual CDM and Demand Response results.

Response:

The detailed calculations supporting the annual additions to the Hydro One CDM and Demand Reponse variance account for 2013 and 2014 are provided in the attached PDF files.

2013 Variance Account on CDM and Demand Response

Economic and Load Forecasting

September 2014

OPA 2013 Verified Results

	2011	2012	2013	Verified Demand Saving (KW) in 2013
Energy Efficiency Total	136,610	109,191	117,536	363,337
Demand Response Total	79,733	142,670	280,099	280,099
Adjustments to Previous Years' Verified Results Total	-	1,406	6,901	8,307
OPA-Contracted LDC Portfolio Total (inc. Adjustments)	216,343	253,267	404,536	

	Demand Saving (MW) in 2013
Energy Efficiency Total	372
Demand Response Total	280

Comparison of Actual Vs Forecasted CDM demand saving for the Variance Account

Forecast for 2013

Target EE program

Target DR program

Non-Target DR program

DR

2013 Result

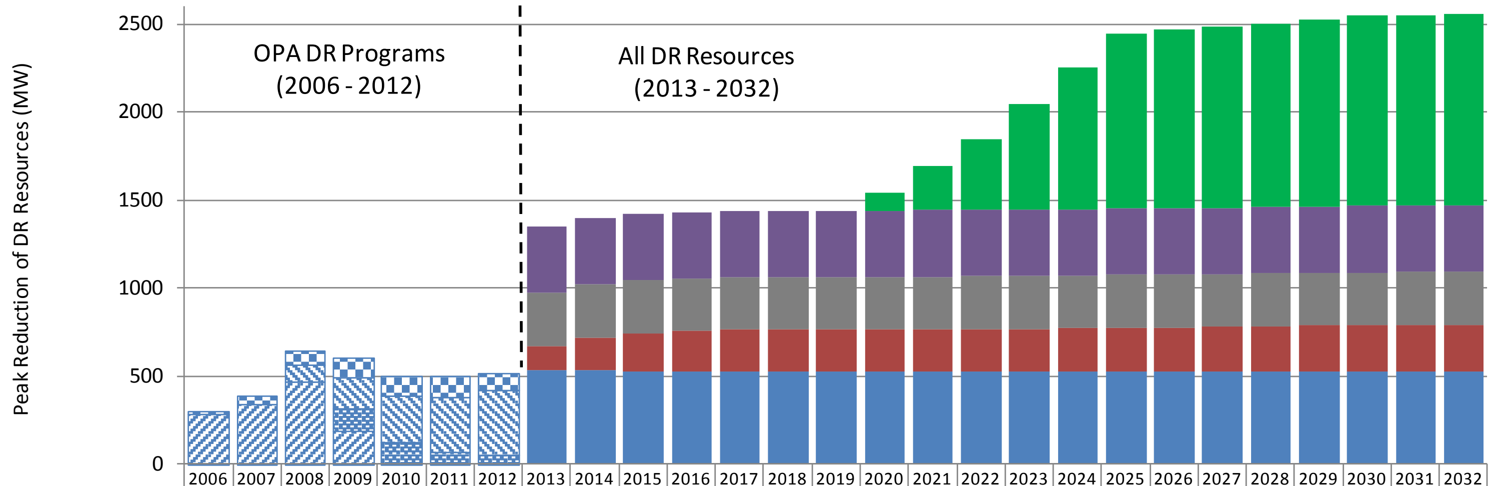
OPA Verified result
EE program

DR

- Demand response
- **Dispatchable Load ****
- **Industrial conservation initiative****

*** Included as Demand Response Resources in the OPA 2013 LTEP*

Peak Reduction from Existing and Future Demand Response Resources



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
New dispatchable DR															100	250	400	600	800	990	1010	1030	1040	1060	1080	1080	1090
Dispatchable load								377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377
Industrial Conservation Initiative								300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Time of Use rates								137	184	221	232	239	239	239	239	241	243	245	248	250	253	256	259	262	265	268	268
Existing DR programs (capacity maintained)								539	539	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528
peaksaver and other direct load control	20	48	84	112	117	115	96																				
DR3	0	0	91	182	264	315	367																				
DR2	0	0	0	128	122	69	56																				
DR1	285	340	471	188	0	0	0																				
Total	305	388	646	609	504	498	519	1352	1399	1425	1437	1444	1444	1444	1544	1696	1848	2050	2253	2445	2468	2491	2504	2527	2550	2553	2563

- DR resources will contribute 2,445 MW by 2025, which is about 10% of the forecast net peak demand.
- DR program performance from 2006 to 2012 shown above is from OPA DR programs only, which are verified.
- Current capacity and resources are to be maintained. This would be subject to future programs and choices on DR. New DR resources start to ramp up in 2020.
- The breakdown of future demand response resources will depend on future program and policy decisions and are illustrative in this diagram.

2013 CDM Variance_Target EE

Month	(1) Forecast	(2) Actual	(3)=(1)-(2) Diff
1	295	251	44
2	286	243	43
3	266	226	40
4	272	231	41
5	291	248	43
6	403	342	61
7	**438**	**372**	**66**
8	399	339	60
9	358	304	54
10	264	224	40
11	274	233	41
12	290	247	44
12 month average	**320**	**272**	**48**

Note:

- Target EE peak saving in July based on OPA's Final verified annual 2013 CDM report
- Peak saving for other months is estimated based on OPA's saving profile.

2013 CDM Target Viarance_ Other DR Resources

Month	Dispatchable Load	Industrial Conservation Initiative (ICI)
1	3	-
2	3	-
3	2	-
4	7	-
5	6	-
6	15	300
7	94	900
8	0	-
9	24	-
10	-	-
11	-	-
12	21	-
12 Month Average	15	100

Note:

- Peak savings due to dispatchable load and ICI are included to be consistent with the OPA 2013 LTEP DR defination
- Dispatchable load monthly saving is provided by IESO
- ICI saving of 916MW in July is based on IESO 18 month outlook (June 2014), 300MW saving in June is estimated based on H1's detail analysis

2013 CDM Target Viarance_ DR

Month	(1) Forecast	(2) Actual	(3)=(1)-(2) DR Diff
1	712	47	665
2	144	47	97
3	144	46	99
4	144	46	99
5	144	46	99
6	1,083	156	927
7	1,083	509	574
8	1,083	65	1,018
9	473	46	428
10	144	46	99
11	417	46	372
12	722	47	675
12 Month Average	524	95	429

Note:

- DR saving provided by the OPA, including DR2, DR3 and peaksaver

Variance in MW and $

Month	(1) Target EE	(2) DR	(3) Dispatchable Load	(4) Industrial Conservation Initiative (ICI)	(5)=(1)+(2)-(3)-(4) Total Variance
1	44	665	3		706
2	43	97	3	-	137
3	40	99	2	-	137
4	41	99	7	-	132
5	44	99	6	-	136
6	61	927	15	300	673
7	66	574	94	916	(370)
8	60	1,018	0	-	1,078
9	54	428	24	-	457
10	40	99	-	-	138
11	41	372	-	-	413
12	44	675	21	-	697
12 Month Average	48	429	15	101	361

Month	(1) Target EE	(2) DR	(3) Dispatchable Load	(4) Industrial Conservation Initiative (ICI)	(5)=(1)+(2)-(3)-(4) Total Variance
Variance in MW	48	429	15	101	361
Variance in Million $					
Network	2.05	18.22	0.62	4.30	15.34
Line Connection	0.40	3.59	0.12	0.85	3.02
Transformation Connectio	0.85	7.55	0.26	1.78	6.36
Total Million $	3.30	29.37	1.01	6.94	24.72

UTR and Ratio of CD used for the $ calculation

Uniform Transmission Rates ($/KW)

Charge Determinants	2013
Network	3.63
Line Connection	0.75
Transformation Connection	1.85

Ratio of Charge Determinants to Ontario Peak (12-month Average)

TX Charge Determinant	2013
Network	0.9749
Line Connection	0.9299
Transformation Connection	0.7930

Data Sources Summary

EE: OPA LDC target program result for 2013
OPA EE saving load shape

DR:
DR3 and PeakSaver saving by month and sector from OPA
DR2 based on OPA report

Dispatchable load:
Saving by month from IESO

ICI:
Saving of 900 MW in July based on IESO 18 month outlook
Saving of 300 MW in June based on OPA 2013 LTEP

2014 Variance Account on CDM and Demand Response

Economic and Load Forecasting

September 2015

Overview

As part of the Settlement Agreement in EB-2012-0031 Hydro One agreed to

Set up a variance account to track the difference between the forecast of 755 MW for 2013 and 1158 MW for 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs. […] Time-of-use savings will not be included in this variance account because they are currently not included in the annual province-wide CDM program results reported by the OPA.

Hydro One also agreed to

Track the actual Demand Response results against the forecast as set out in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix A, Table 8 of 836 MW in 2013 and 880 MW 2014 (net of 317 MW and 410 MW respectfully for 2013 and 2014 already included in CDM program results delivered by LDCs) in this variance account.

Please note that Demand Response (DR) savings of 836 MW in 2013 and 880 MW in 2014 in the agreement should be corrected as 766 MW and 801 MW respectively in order to bring the numbers to the end-use level.

Comparison of Actual Vs Forecasted CDM demand saving for the Variance Account

Forecast for 2014			2014 Result
Target EE program			OPA Verified result EE program
Target DR program Non-Target DR program	DR	DR	- Demand response **- Dispatchable Load **** **- Industrial conservation initiative****

*** Included as Demand Response Resources in the OPA 2013 LTEP*

Methodology

CDM and DR

Target CDM programs (748 MW)

Target DR programs (410MW)

Non-Target DR programs (801 MW)

Sources for Estimates

OPA 2014 final verified results

- DR results provided by the IESO
- Dispatchable load and industrial Conservation Initiative (ICI) results provided by the IESO

LDC target savings (1158MW)=target CDM programs (748 MW)+Target DR programs (410MW)
Total DR savings (1211 MW)= Target DR programs (410 MW)+ Non-Target DR programs (801 MW)

CDM Saving in the LF

OPA IPSP 1.0 used in HONI TX LF

	2013	2014	Formula
DR_GS LEVEL	1,153	1,290	(1)
EE_GS LEVEL	2,126	2,884	(2)
DR_END USE LEVEL	1,083	1,211	(3)=(1)/(5)
EE_END USE LEVEL	1,996	2,708	(4)=(2)/(5)
Loss Factor	1.065	1.065	(5)

Breakdown of LDC CDM target

	2013	2014	Formula	
EE	438	748	(6)	FROM OPA
DR	317	410	(7)	FROM OPA
TOU	128	172	(8)	FROM OPA
TOTAL	883	1330	(9)=(6)+(7)+(8)	
Non CDM target	1,113	1,378	(10)=(4)-(9)	
DR target_GS level	1,153	1,290	(11)=(1)	
DR target_End use level	1,083	1,211	(12)=(3)	
DR component already in LDC target	317	410	(13)=(7)	
subtotal	766	801	(14)=(12)-(13)	
Total under variance AC	1,521	1,959	(15)=(6)+(7)+(14)	

755

1158

DR for the variance account	2013	2014	Formula
number in the settlement	836	880	(16)=(11)-(7)
corrected number	766	801	(17)=(12)-(7)

IESO 2014 Verified Results

Initiative	2014 Net Annual Peak Demand Savings (kW)
Energy Efficiency	575,650
Demand Response	309,091
Adjustments to Previous Years' Verified Results	43,005
OPA-Contracted LDC Portfolio Total (inc. Adjustments)	927,746

619 MW

Time-of-use savings (KW)	54,795

564 MW

Month	(1) Forecast	(2) Actual	(3)=(1)-(2) Diff
1	484	364	119
2	480	362	118
3	447	337	110
4	464	350	114
5	506	381	124
6	690	520	170
7	748	564	184
8	680	513	167
9	609	459	150
10	450	339	111
11	459	346	113
12	487	367	120
12 Month Average	547	412	135

2014 CDM Variance - EE

Month	(1) Forecast	(2) Actual	(3)=(1)-(2) Variance
1	484	364	119
2	480	362	118
3	447	337	110
4	464	350	114
5	506	381	124
6	690	520	170
7	748	564	184
8	680	513	167
9	609	459	150
10	450	339	111
11	459	346	113
12	487	367	120
12 Month Average	542	409	133

Note:

- Target EE peak saving in July based on IESO's Final verified 2011-2014 CDM report
- Peak saving for other months is estimated based on IESO's saving profile

2014 CDM Variance - DR

Month	(1) Forecast	(2) Actual (IESO verified result)	(3) DR2	(4)=(1)-(2)-(3) Variance
1	766	195	47.2	523
2	146	37	47.2	62
3	146	37	45.5	63
4	832	212	45.5	574
5	832	212	45.5	574
6	1,211	309	56.7	845
7	1,211	309	56.7	845
8	1,211	309	56.7	845
9	508	130	45.5	333
10	146	37	45.5	63
11	775	198	45.5	532
12	775	198	47.2	530
12 Month Average	708	181	49	478

Note:
- DR peak saving in July based on IESO’s Final verified 2011-2014 CDM report
- Peak saving for other months is estimated based on IESO’s saving profile
- DR2 saving is from the “2012 Impact Evaluation of OPA commercial and industrial Demand Response Programs” Report

2014 CDM Variance- Other DR Resources

Month	Dispatchable Load	Industrial conservation Initiative (ICI)
1	4	-
2	77	-
3	60	-
4	15	-
5	7	-
6	17	300
7	48	300
8	9	900
9	10	1,050
10	27	-
11	2	-
12	34	-
12 Month Average	26	213

Note:

- Peak savings due to dispatchable load and ICI are included to be consistent with the OPA 2013 LTEP DR defination
- Dispatchable load monthly saving is provided by IESO

2014 Variance in MW and $

Demand Saving Variance in MW

Month	(1) Target EE	(2) DR	(3) Dispatchable Load	(4) Industrial Conservation Initiative (ICI)	(5)=(1)+(2)-(3)-(4) Total Variance
1	119	523	4	-	638
2	118	62	77	-	103
3	110	63	60	-	114
4	114	574	15	-	674
5	124	574	7	-	692
6	170	845	17	300	698
7	184	845	48	300	681
8	167	845	9	900	104
9	150	333	10	1,050	(577)
10	111	63	27	-	147
11	113	532	2	-	642
12	120	530	34	-	616
12 Month Average	133	483	26	213	378

Month	(1) Target EE	(2) DR	(3) Dispatchable Load	(4) Industrial Conservation Initiative (ICI)	(5)=(1)+(2)-(3)-(4) Total Variance
Variance in MW	133	483	26	213	378
Variance in Million $					
Network	6.03	21.80	1.17	9.60	17.06
Line Connection	1.24	4.49	0.24	1.98	3.51
Transformation Conne	2.55	9.21	0.49	4.05	7.20
Total Million $	9.82	35.50	1.91	15.63	27.77

UTR and Ratio of CD used for the $ calculation

Uniform Transmission Rates ($/kW)		
Charge Determinants	2014	2013
Network	3.82	3.63
Line Connection	0.82	0.75
Transformation Conne	1.98	1.85

Ratio of Charge Determinants to Ontario Peak (12-month avereag		
TX Charge Determinant	2014	2013
Network Connection	0.9856	0.9749
Line Connection	0.9452	0.9299
Transformation Connection	0.8029	0.7930

Data Sources Summary

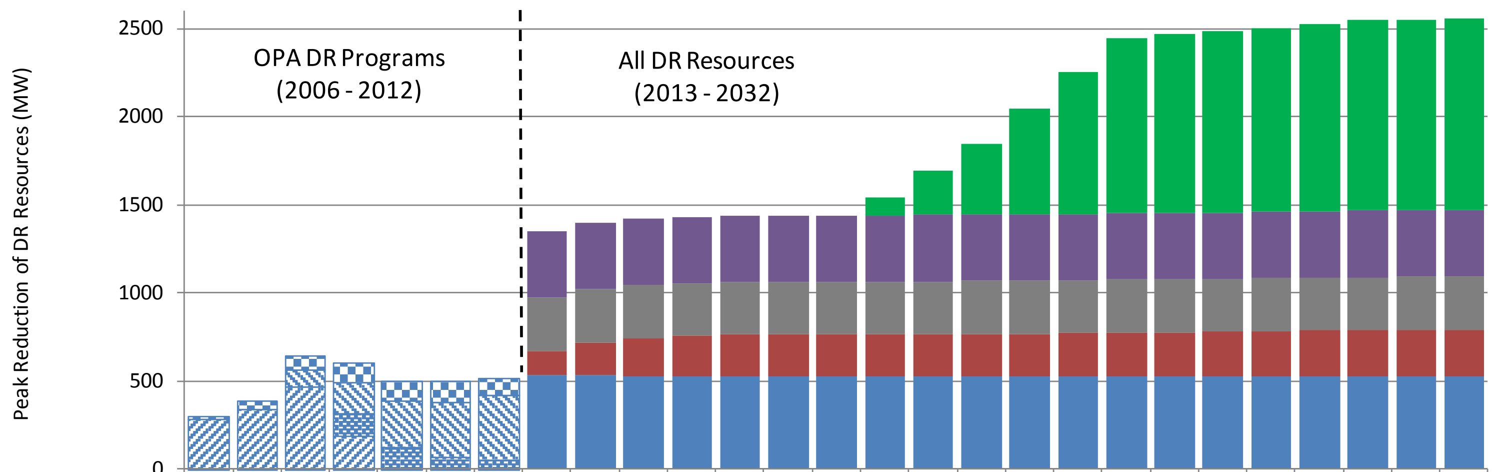
<u>EE:</u> IESO LDC target program 2011-2014 result
OPA EE saving load shape

<u>DR:</u>
IESO LDC target program 2011-2014 result

<u>Dispatchable load:</u>
Saving by month from IESO

<u>ICI:</u>
Saving estimate from IESO

Peak Reduction from Existing and Future Demand Response Resources



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
New dispatchable DR															100	250	400	600	800	990	1010	1030	1040	1060	1080	1080	1090
Dispatchable load								377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377
Industrial Conservation Initiative								300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Time of Use rates								137	184	221	232	239	239	239	239	241	243	245	248	250	253	256	259	262	265	268	268
Existing DR programs (capacity maintained)								539	539	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528
peaksaver and other direct load control	20	48	84	112	117	115	96																				
DR3	0	0	91	182	264	315	367																				
DR2	0	0	0	128	122	69	56																				
DR1	285	340	471	188	0	0	0																				
Total	305	388	646	609	504	498	519	1352	1399	1425	1437	1444	1444	1444	1544	1696	1848	2050	2253	2445	2468	2491	2504	2527	2550	2553	2563

- DR resources will contribute 2,445 MW by 2025, which is about 10% of the forecast net peak demand.
- DR program performance from 2006 to 2012 shown above is from OPA DR programs only, which are verified.
- Current capacity and resources are to be maintained. This would be subject to future programs and choices on DR. New DR resources start to ramp up in 2020.
- The breakdown of future demand response resources will depend on future program and policy decisions and are illustrative in this diagram.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #037

Reference:

Exhibit G1/T1/S1, pages 1-2 /Exhibit G1/T2/S1, pages 9-10

Interrogatory:

a) As of the end of 2015 how many customers used the Transformation Connection function and, of these, for how many did Hydro One Networks own and service a WRM installation?

b) Out of the $437.1 M Revenue Requirement in 2017 (per Table 1) for the Transformation Connection function how much is attributable to Wholesale Meters?

Response:

a) As of the end of 2015, there are 260 Hydro One transmission connected customers comprising of 308 delivery points that use the Transformation Connection function. Hydro One owned and serviced 52 WRM installations, all connected to the same customer.

b) Out of the $437.1 million Revenue Requirement in 2017 for the Transformation Connection function (per Table 1 in Exhibit G1, Tab 1, Schedule 1), the cost attributable to Wholesale Meters is estimated to be $0.3 million, as described in Exhibit G1, Tab 3, Schedule 1.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #038

Reference:

Exhibit G1/T2/S1, page 2

Preamble: At lines 9-16 Hydro One Networks states that assets are functionalized based on the normal system operating conditions as of the end of 2015.

Interrogatory:

a) Please explain how transmission assets that are in-service for the 2017 and/or 2018 test years but come into service on or after January 1, 2016 are functionalized.

Response:

a) Based on Hydro One's Transmission System Plan, transmission assets planned for in-service in the test years (2017 or 2018) but come into service on or after January 1, 2016 are identified and are then grouped into functional categories in accordance with the functional category descriptions in Exhibit G1, Tab 2, Schedule 1.

Witness: Henry Andre

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #039

Reference:

Exhibit G2/T1/S1

Interrogatory:

a) Please provide a schedule that lists the new Transmission Lines that were not included in EB-2014-0140. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Lines whose functional categorization has changed from that in EB-2014-0140 and provide an explanation as to the reason for the change.

Response:

a) A list of new transmission line assets that were not included in proceeding EB-2014-0140 is provided in Table 1 below.

b) A list of the transmission line assets whose functional category has changed from that in EB-2014-0140 is provided in Table 2 below.

Table 1 – List of New Transmission Lines

Operation Designation	Section	From	To	Functional Category (EB-2016-0160)	Explanation
A565L	1	Ashfield SS	Longwood TS	N	EB-2012-0031 Project D24: K2 Wind Generator Connection
A592K	1	Ashfield SS	K2 Wind 500 CGS	N	EB-2012-0031 Project D24: K2 Wind Generator Connection
B20P	5	Bruce HW Plant D JCT	B20P_B24P T#2 JCT	LC	Reconfiguration of normal operating system
B20P	6	B20P_B24P T#2 JCT	Bruce A TS	OTHER	Reconfiguration of normal operating system
B20P	7	B20P_B24P T#2 JCT	Bruce HW Plant B TS	LC	Reconfiguration of normal operating system
B22D	11	Armow JCT	Wingham JCT	DFL	EB-2012-0031 Project D23: Armow Wind Generation Connection
B22D	12	Armow JCT	Armow CSS	LC	EB-2012-0031 Project D23: Armow Wind Generation Connection
B23D	11	Zurich JCT	Festival MTS #1 JCT	DFL	Generation Connection: Zurich Wind Generation Connection
B23D	12	Zurich JCT	Zurich CSS	LC	Generation Connection: Zurich Wind Generation Connection
B24P	5	Bruce HW Plant D JCT	B20P_B24P T#2 JCT	LC	Reconfiguration of normal operating system
B24P	6	B20P_B24P T#2 JCT	Bruce A TS	OTHER	Reconfiguration of normal operating system
B24P	7	B20P_B24P T#2 JCT	Bruce HW Plant B TS	LC	Reconfiguration of normal operating system
B4V	7	GV3 WF JCT	Amaranth JCT	DFL	Generation Connection: Grand Valley 3 Windfarm
B4V	8	GV3 WF JCT	GV3 WF CGS	LC	Generation Connection: Grand Valley 3 Windfarm
B562E	1	Bruce A TS	Bruce JCT	N	EB-2012-0031 Project D25: Adelaide/Bornish/Jericho WEC
B562E	2	Bruce JCT	Willow Creek JCT	N	EB-2012-0031 Project D25: Adelaide/Bornish/Jericho WEC
B562E	3	Willow Creek JCT	Evergreen SS	N	EB-2012-0031 Project D25: Adelaide/Bornish/Jericho WEC
B563A	1	Bruce B SS	Bruce JCT	N	EB-2012-0031 Project D24: K2 Wind Generator Connection
B563A	2	Bruce JCT	Willow Creek JCT	N	EB-2012-0031 Project D24: K2 Wind Generator Connection
B563A	3	Willow Creek JCT	Ashfield SS	N	EB-2012-0031 Project D24: K2 Wind Generator Connection
B563A	4	Bruce JCT	Bruce JCT	N	EB-2012-0031 Project D24: K2 Wind Generator Connection
C21J	6	Leamington JCT	Leamington TS	LC	EB-2016-0160 Project D14: Supply to Essex County Transmission Reinforcement
C22J	6	Leamington JCT	Leamington TS	LC	EB-2016-0160 Project D14: Supply to Essex County Transmission Reinforcement

Operation Designation	Section	From	To	Functional Category (EB-2016-0160)	Explanation
D2H	1	Pinard TS	Pinard JCT #2	LC	Reconfiguration of normal operating system
D2H	2	Pinard JCT #2	Hwy 634 JCT	LC	Reconfiguration of normal operating system
D2H	3	Pinard JCT #2	Hwy 634 JCT	LC	Reconfiguration of normal operating system
D2H	4	Hwy 634 JCT	Island Falls JCT	LC	Reconfiguration of normal operating system
D2H	5	Hwy 634 JCT	Island Falls JCT	LC	Reconfiguration of normal operating system
D2H	6	Island Falls JCT	Greenwater Pr Pk JCT	LC	Reconfiguration of normal operating system
D2H	7	Island Falls JCT	Greenwater Pr Pk JCT	LC	Reconfiguration of normal operating system
D2H	8	Greenwater Pr Pk JCT	Calder JCT	LC	Reconfiguration of normal operating system
D2H	9	Greenwater Pr Pk JCT	Calder JCT	LC	Reconfiguration of normal operating system
D2H	10	Hunta JCT	Hunta SS	LC	Reconfiguration of normal operating system
D2H	11	Hunta JCT	Hunta JCT	LC	Reconfiguration of normal operating system
D2H	12	Hwy 634 JCT	Hwy 634 JCT	LC	Reconfiguration of normal operating system
D2H	13	Island Falls JCT	Island Falls JCT	LC	Reconfiguration of normal operating system
D2H	14	Greenwater Pr Pk JCT	Greenwater Pr Pk JCT	LC	Reconfiguration of normal operating system
D2H	15	Pinard JCT #2	Pinard JCT #2	LC	Reconfiguration of normal operating system
D2H	18	Calder JCT	Calder JCT	LC	Reconfiguration of normal operating system
D2H	19	Calder JCT	Hunta JCT	LC	Reconfiguration of normal operating system
D2H	20	Calder JCT	Hunta JCT	LC	Reconfiguration of normal operating system
D2H	21	Calder JCT	Calder CSS	LC	Reconfiguration of normal operating system
D2L	18	New Liskeard JCT	Upper Notch JCT	DFL	Generation Connection: New Liskeard CGS
D2L	19	New Liskeard JCT	New Liskeard JCT #2	LC	Generation Connection: New Liskeard CGS
D3H	15	Pinard JCT #2	Pinard JCT #2	LC	Reconfiguration of normal operating system
D3H	16	Calder JCT	Hunta JCT	LC	Reconfiguration of normal operating system
D3H	17	Calder JCT	Hunta JCT	LC	Reconfiguration of normal operating system
D3H	18	Calder JCT	Calder JCT	LC	Reconfiguration of normal operating system

Operation Designation	Section	From	To	Functional Category (EB-2016-0160)	Explanation
D5A	7	Orleans JCT #2	Orleans TS	LC	EB-2012-0031 Project D16: New Orleans TS
D5A	10	Cumberland JCT	Orleans JCT #2	DFL	EB-2012-0031 Project D16: New Orleans TS
D6V	10	Campbell TS	C.G.E. JCT	N	EB-2012-0031 Project D12: GATR
D6V	11	Cedar TS	C.G.E. JCT	DFL	EB-2012-0031 Project D12: GATR
D7F	10	D7F_D9F T#162 PH JCT	D7F_D9F T#157 PH JCT	DFL	EB-2012-0031 Project D12: GATR
D7F	11	D7F_D9F T#157 PH JCT	Kitchener MTS #7	DFL	EB-2012-0031 Project D12: GATR
D7V	10	Campbell TS	C.G.E. JCT	N	EB-2012-0031 Project D12: GATR
D7V	11	Cedar TS	C.G.E. JCT	DFL	EB-2012-0031 Project D12: GATR
D9F	10	D7F_D9F T#162 PH JCT	D7F_D9F T#157 PH JCT	DFL	EB-2012-0031 Project D12: GATR
D9F	11	D7F_D9F T#157 PH JCT	Kitchener MTS #7	DFL	EB-2012-0031 Project D12: GATR
E29C	1	Almonte TS	Almonte TS	LC	Customer Connection: Terry Fox MTS
E29C	2	Almonte TS	Wilson JCT	DFL	Customer Connection: Terry Fox MTS
E29C	3	Wilson JCT	Whitby JCT	DFL	Customer Connection: Terry Fox MTS
E29C	4	Whitby JCT	Cherrywood TS	DFL	Customer Connection: Terry Fox MTS
E29C	5	Wilson JCT	Wilson TS	LC	Customer Connection: Terry Fox MTS
E29C	6	Whitby JCT	Whitby TS	LC	Customer Connection: Terry Fox MTS
E29C	7	Almonte TS	Almonte TS	DFL	Customer Connection: Terry Fox MTS
E34M	1	Merivale TS	Terry Fox JCT	DFL	Customer Connection: Terry Fox MTS
E34M	2	Terry Fox JCT	Terry Fox JCT	DFL	Customer Connection: Terry Fox MTS
E34M	3	Terry Fox JCT	Didsbury Road JCT	DFL	Customer Connection: Terry Fox MTS
E34M	4	Didsbury Road JCT	Almonte TS	DFL	Customer Connection: Terry Fox MTS
E34M	5	Almonte TS	Almonte TS	LC	Customer Connection: Terry Fox MTS
E34M	6	Almonte TS	Almonte TS	DFL	Customer Connection: Terry Fox MTS
E34M	7	Terry Fox JCT	Terry Fox MTS	LC	Customer Connection: Terry Fox MTS
E34M	8	Terry Fox JCT	Terry Fox MTS	LC	Customer Connection: Terry Fox MTS

Witness: Henry Andre

Operation Designation	Section	From	To	Functional Category (EB-2016-0160)	Explanation
E564L	1	Evergreen SS	Longwood TS	N	EB-2012-0031 Project D25: Adelaide/Bornish/Jericho WEC
E578P	1	Evergreen SS	Parkhill CTS	N	EB-2012-0031 Project D25: Adelaide/Bornish/Jericho WEC
H BUS	1	Rabbit Lake SS	Kenora DS	LC	Change to update connectivity model
H10EJ	4	Hearn SS	Hearn SS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
H12P	3	Hearn SS	Hearn SS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
H13P	3	Hearn SS	Hearn SS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
H14P	3	Hearn SS	Hearn SS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
H22D	5	Harmon JCT	Kipling JCT	LC	EB-2012-0031 Project D21: Lower Mattagami River
H22D	6	Smoky Falls JCT	Little Long JCT	LC	EB-2012-0031 Project D21: Lower Mattagami River
H22D	7	Kipling JCT	Kipling GS	LC	EB-2012-0031 Project D21: Lower Mattagami River
H22D	9	Smoky Falls JCT	Smoky Falls 2 JCT	LC	EB-2012-0031 Project D21: Lower Mattagami River
H2JK	16	Hearn SS	Hearn SS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
H2JK	17	Strachan TS	Strachan TS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
H2JK	18	Strachan TS	Strachan TS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
H9A	25	Orleans JCT #2	Borromee JCT	LC	EB-2012-0031 Project D16: New Orleans TS
H9A	26	Orleans JCT #2	Orleans TS	LC	EB-2012-0031 Project D16: New Orleans TS
H9EJ	4	Hearn SS	Hearn SS	LC	EB-2012-0031 Project D09: Rebuild Hearn SS
IDLE24	1	Leong JCT	Nafziger Road JCT	OTHER	Change to update connectivity model
IDLE25	1	Major Ln Str 16 JCT	MacPherson Road JCT	OTHER	Change to update connectivity model
IDLE25	2	Major Ln Str 16 JCT	MacPherson Road JCT	OTHER	Change to update connectivity model
IDLE26	1	Buchanan JCT	Buchanan East JCT	OTHER	Change to update connectivity model
IDLE27	1	Centre JCT	Station Street JCT	OTHER	Change to update connectivity model
K6F	15	Barwick JCT	Ainsworth Str #4 JCT	LC	EB-2012-0031 Project D14: New Barwick TS
K6F	16	Barwick JCT	Barwick TS	LC	EB-2012-0031 Project D14: New Barwick TS
K6F	17	Barwick JCT	Barwick TS	LC	EB-2012-0031 Project D14: New Barwick TS
K6J	7	Strachan TS	Strachan TS	LC	Change to update connectivity model

Witness: Henry Andre

Operation Designation	Section	From	To	Functional Category (EB-2016-0160)	Explanation
K6J	8	Strachan TS	Strachan TS	LC	Change to update connectivity model
L20D	5	Smoky Falls JCT	Harmon JCT	LC	EB-2012-0031 Project D21: Lower Mattagami River
L20D	6	Harmon JCT	Kipling JCT	LC	EB-2012-0031 Project D21: Lower Mattagami River
L20D	7	Kipling JCT	Kipling 2 GS	LC	EB-2012-0031 Project D21: Lower Mattagami River
L20D	8	Harmon JCT	Harmon 2 GS	LC	EB-2012-0031 Project D21: Lower Mattagami River
L20D	10	Smoky Falls JCT	Smoky Falls 2 JCT	LC	EB-2012-0031 Project D21: Lower Mattagami River
L2M	25	Limebank JCT	Merivale TS	LC	Customer Connection: Limebank MTS
L2M	26	Limebank JCT	Limebank MTS	LC	Customer Connection: Limebank MTS
L7S	16	Goshen JCT	Kirkton JCT	LC	Generation Connection: Goshen WEC
L7S	17	Goshen JCT	Goshen CSS	LC	Generation Connection: Goshen WEC
M31	1	Espanola TS	Eddy Tap A JCT	LC	Change to update connectivity model
M31	2	Eddy Tap A JCT	Domtar Espanola CGS	LC	Change to update connectivity model
N5M	4	Grand JCT	Caledonia JCT	DFL	Generation Connection: Samsung Grand Renewable Energy Park Connection
N5M	5	Grand JCT	Grand CSS	LC	Generation Connection: Samsung Grand Renewable Energy Park Connection
Q11S	7	Warner Road JCT	Warner Road JCT	OTHER	Customer Connection: Niagara-on-the-Lake MTS #1 and #2
Q11S	8	NOTL York MTS #1 JCT	McKinnon's JCT	LC	Customer Connection: Niagara-on-the-Lake MTS #1 and #2
Q12S	6	Warner Road JCT	NOTL York MTS #1 JCT	LC	Customer Connection: Niagara-on-the-Lake MTS #1 and #2
Q12S	7	NOTL York MTS #1 JCT	NOTL York MTS #1 JCT	OTHER	Customer Connection: Niagara-on-the-Lake MTS #1 and #2
Q1N	3	Niagara JCT	Niagara TS	OTHER	Reconfiguration of normal operating system
Q2AH	5	St.Anns JCT	Dunnville TS	LC	Reconfiguration of normal operating system
Q3N	1	Beck #1 SS	Portal JCT	LC	Reconfiguration of normal operating system
Q3N	2	Portal JCT	Dresser JCT	LC	Reconfiguration of normal operating system
Q3N	3	Dresser JCT	Niagara JCT	LC	Reconfiguration of normal operating system
Q3N	4	Niagara JCT	Murray TS	LC	Reconfiguration of normal operating system
Q3N	5	Portal JCT	Stanley TS	LC	Reconfiguration of normal operating system

Witness: Henry Andre

Operation Designation	**Section**	**From**	**To**	**Functional Category (EB-2016-0160)**	**Explanation**
Q3N	6	Dresser JCT	Trei-bacher JCT	OTHER	Reconfiguration of normal operating system
Q6S	7	Invista JCT	Q6S STR M60 JCT	OTHER	Reconfiguration of normal operating system
R13K	2	Manby TS	Manby TS	LC	Reconfiguration of normal operating system
R13K	3	Manby TS	Vansco JCT	LC	Reconfiguration of normal operating system
R13K	4	Vansco JCT	Horner TS	LC	Reconfiguration of normal operating system
S2N	13	Landon JCT	Enbrg Keyser CTS	LC	Generation Connections: Landon CGS
S2N	14	Landon JCT	Landon CGS	LC	Generation Connections: Landon CGS
T8M	1	Otter Rapids SS	Moosonee SS	LC	Reconfiguration of normal operating system
W6CS	8	Marchwood JCT	South March SS	DFL	Customer Connection: Marchwood MTS
W6CS	9	Marchwood JCT	Marchwood MTS	LC	Customer Connection: Marchwood MTS
WT1A	2	Silvercreek JCT	Aylmer TS	LC	Generation Connections: Silvercreek Solar Park
WT1A	3	Silvercreek JCT	Silvercreek CGS	LC	Generation Connections: Silvercreek Solar Park
X3H	3	Kingston Solar JCT	Cataraqui TS	DFL	Generation Connections: Kingston Solar
X3H	4	Kingston Solar JCT	Kingston Solar CGS	LC	Generation Connections: Kingston Solar

Table 2 – List of Transmission Lines with Functional Category Changes

Operation Designation	Section	From	To	Functional Category (EB-2014-0140)	Functional Category (EB-2016-0160)	Explanation
56M1	3	Red Rock JCT	Red Rock Mill CTS	LC	OTHER	Disconnection of Customer
A6C	3	Hurricane JCT	BF Goodrich JCT	LC	OTHER	Database cleanup
A6C	6	BF Goodrich JCT	Cytec Welland CTS	LC	OTHER	Database cleanup
B1S	6	Northbrook JCT	Northbrook DS	LC	DFL	Change to update connectivity model
B5G	1	Burlington TS	Harper's JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B5G	2	Harper's JCT	Puslinch JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B5G	6	ASEA Brown Bovri JCT	ASEA Brown Bovri CTS	LC	OTHER	EB-2012-0031 Project D12: GATR
B5G	16	Puslinch JCT	Arlen MTS JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B5G	17	Hanlon JCT	Cedar TS	LC	DFL	EB-2012-0031 Project D12: GATR
B5G	20	Arlen MTS JCT	Hanlon JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B6G	1	Burlington TS	Harper's JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B6G	2	Harper's JCT	Puslinch JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B6G	6	ASEA Brown Bovri JCT	ASEA Brown Bovri CTS	LC	OTHER	EB-2012-0031 Project D12: GATR
B6G	9	Hanlon JCT	Cedar TS	LC	DFL	EB-2012-0031 Project D12: GATR
B6G	11	Puslinch JCT	Arlen MTS JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B6G	13	Arlen MTS JCT	Hanlon JCT	LC	DFL	EB-2012-0031 Project D12: GATR
B8W	9	Commerce Way JCT	Commerce Way TS	LC	OTHER	Database cleanup
D5A	2	Orleans JCT #2	Hawthorne TS	N	DFL	EB-2012-0031 Project D16: New Orleans TS
D6V	6	Guelph North JCT	Campbell TS	LC	DFL	EB-2012-0031 Project D12: GATR
D7F	1	Detweiler TS	Detweiler JCT	LC	DFL	EB-2012-0031 Project D12: GATR
D7F	2	Detweiler JCT	Kitchener #6 JCT	LC	DFL	EB-2012-0031 Project D12: GATR
D7F	3	Kitchener #6 JCT	Siebert JCT	LC	DFL	EB-2012-0031 Project D12: GATR
D7F	4	Siebert JCT	D7F_D9F T#162 PH JCT	LC	DFL	EB-2012-0031 Project D12: GATR

Operation Designation	Section	From	To	Functional Category (EB-2014-0140)	Functional Category (EB-2016-0160)	Explanation
D7V	6	Guelph North JCT	Campbell TS	LC	DFL	EB-2012-0031 Project D12: GATR
D9F	1	Detweiler TS	Detweiler JCT	LC	DFL	EB-2012-0031 Project D12: GATR
D9F	2	Detweiler JCT	Kitchener #6 JCT	LC	DFL	EB-2012-0031 Project D12: GATR
D9F	3	Kitchener #6 JCT	Siebert JCT	LC	DFL	EB-2012-0031 Project D12: GATR
D9F	4	Siebert JCT	D7F_D9F T#162 PH JCT	LC	DFL	EB-2012-0031 Project D12: GATR
F11C	1	Freeport SS	Speedsville JCT	LC	DFL	EB-2012-0031 Project D12: GATR
F11C	2	Speedsville JCT	Preston TS	OTHER	DFL	EB-2012-0031 Project D12: GATR
F11C	3	Speedsville JCT	C.G.E. JCT	LC	DFL	EB-2012-0031 Project D12: GATR
F11C	4	C.G.E. JCT	Cedar TS	LC	DFL	EB-2012-0031 Project D12: GATR
F12C	1	Freeport SS	Speedsville JCT	LC	DFL	EB-2012-0031 Project D12: GATR
F12C	2	Speedsville JCT	Preston TS	LC	DFL	EB-2012-0031 Project D12: GATR
F12C	3	Speedsville JCT	C.G.E. JCT	LC	DFL	EB-2012-0031 Project D12: GATR
F12C	4	C.G.E. JCT	Cedar TS	LC	DFL	EB-2012-0031 Project D12: GATR
H10EJ	3	Esplanade TS	John TS	LC	OTHER	Database cleanup
H9EJ	3	Esplanade TS	John TS	LC	OTHER	Database cleanup
K25BUS	1	Sandusk SS	Sandusk CGS	OTHER	LC	Database cleanup
K3	1	Kapuskasing TS	Kapuskasing R Jct	LC	OTHER	Database cleanup
M20D	6	Galt JCT	Preston JCT	LC	DFL	EB-2012-0031 Project D12: GATR
M20D	9	Preston JCT	Cambridge #1 JCT	LC	DFL	EB-2012-0031 Project D12: GATR
M20D	10	Cambridge #1 JCT	Preston TS	LC	DFL	EB-2012-0031 Project D12: GATR
M20D	16	Preston TS	Preston TS	OTHER	DFL	EB-2012-0031 Project D12: GATR
M21D	6	Galt JCT	Ameristeel Cambr JCT	LC	DFL	EB-2012-0031 Project D12: GATR
M21D	7	Ameristeel Cambr JCT	Preston JCT	LC	DFL	EB-2012-0031 Project D12: GATR
M21D	11	Preston JCT	Cambridge #1 JCT	LC	DFL	EB-2012-0031 Project D12: GATR
M21D	12	Cambridge #1 JCT	Preston TS	LC	DFL	EB-2012-0031 Project D12: GATR

Witness: Henry Andre

Operation Designation	Section	From	To	Functional Category (EB-2014-0140)	Functional Category (EB-2016-0160)	Explanation
M21D	16	Preston TS	Preston TS	LC	DFL	EB-2012-0031 Project D12: GATR
Q5B	8	James Street JCT	ResFP Thundr Bay CTS	LC	OTHER	Disconnection of Customer
S24V	1	Orangeville TS	Shannon CSS	OTHER	LC	Database cleanup
S3S	1	Smoky Falls SS	KAP LMRP JCT	LC	OTHER	EB-2012-0031 Project D21: Lower Mattagami River
S3S	3	KAP LMRP JCT	Kapuskasing R Jct	LC	OTHER	EB-2012-0031 Project D21: Lower Mattagami River
S4S	1	Smoky Falls SS	Kapuskasing R Jct	LC	OTHER	EB-2012-0031 Project D21: Lower Mattagami River
S4S	2	Kapuskasing R Jct	Tembec Kapuskas CTS	LC	OTHER	EB-2012-0031 Project D21: Lower Mattagami River
W3T	3	Kettle Creek JCT	Ford Talbotville CTS	LC	OTHER	Disconnection of Customer
W4T	3	Kettle Creek JCT	Ford Talbotville CTS	LC	OTHER	Disconnection of Customer
X3H	1	Lennox TS	Kingston Solar JCT	N	DFL	Generation Connections: Kingston Solar

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #040

Reference:

Exhibit G2/T1/S2

Interrogatory:

a) Please provide a schedule that lists the new Transmission Stations that were not included in EB-2014-0140. In each case, please indicate the relevant project reference number (from this Application or a previous Application if applicable) that describes the investment, note the functional category it has been assigned to and indicate why.

b) Please provide a schedule that lists those Transmission Stations whose functional categorization has changed from that in EB-2014-0140 and provide an explanation as to the reason for the change.

Response:

a) A list of new transmission station assets that were not included in proceeding EB-2014-0140 is provided in the table below.

Station Number	Station Name	Functional Category (EB-2016-0160)	Explanation
2145	Orleans TS	TC	EB-2012-0031 Project D16: New Orleans TS
3026	Ashfield SS	N	EB-2012-0031 Project D24: K2 Wind Generator Connection
4043	Guelph North JCT	N	EB-2012-0031 Project D12: GATR
4181	D7F_D9F T#157 PH JCT	LC	EB-2012-0031 Project D12: GATR
4182	D7F_D9F T#162 PH JCT	LC	EB-2012-0031 Project D12: GATR
4258	Winona JCT	LC	Change to update connectivity model
6099	Barwick TS	TC	EB-2012-0031 Project D14: New Barwick TS
7106	Evergreen SS	N	EB-2012-0031 Project D25: Adelaide/Bornish/Jericho WEC

b) A list of the transmission station assets whose functional category has changed from that in EB-2014-0140 is provided in the table below.

Station Number	Station Name	Functional Category (EB-2014-0140)	Functional Category (EB-2016-0160)	Explanation
4035	Freeport SS	LC	N	EB-2012-0031 Project D12: GATR
4045	Cedar TS	TC	N,TC	EB-2012-0031 Project D12: GATR
4091	Preston TS	LC,TC	N,TC	EB-2012-0031 Project D12: GATR
5306	Moosonee SS	LC,UN-L	LC	Reconfiguration of normal operating system
6020	Fort Frances TS	N,TC	N	Reconfiguration of normal operating system

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #041

Reference:

Exhibit H1/T4/S1

Interrogatory:

a) Please provide a schedule that sets out the annual volumes of electricity exported from, or wheeled through, Ontario over the period 2013-2015.

b) Please provide volume of electricity exported from, or wheeled through, Ontario for the first six months of 2016 along with the volumes for the first six months of 2014 and 2015.

Response:

a) Please refer to part (a) in Exhibit I, Tab 11, Schedule 39.

b) The volume of electricity exported from, or wheeled through, Ontario for the first 6 months (January to June) of 2014, 2015 and 2016 is provided in the table below.

Year	**Export Volumes (TWh)** ***January to June***
2014	8.9
2015	13.0
2016	11.2

Witness: Henry Andre

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #042

Reference:

Exhibit H1/T5/S1, page 2

Interrogatory:

a) With respect to Table 2, please provide the derivation of the "% Impact of load forecast change" for 2017 (i.e., 2.1%).

Response:

a) The 2.1% impact of the load forecast change is determined based on looking at the revenue deficiency in the 2017 test year as a percentage of 2017 revenue requirement, taking into account Hydro One's revenue share of those amounts based on approved allocation factors.

The revenue deficiency is calculated as the change in 2016 to 2017 Uniform Transmission Rate ("UTR") charge determinants multiplied by the currently approved UTR rates. The calculations are provided below.

			Approved HONI Rates Rev Req 2016 ($M)		1,480.47	A
			HONI N Allocation Factor		0.93219	B1
			HONI LC & TC Allocation Factor		0.96648	B2
Transmission Service	UTR Charge Determinants (MW)			2016 UTR Rates	2017 Revenue Defficiency	
	2016 Approved	2017 Proposed	Difference 2017-2016		($M)	(%)
	b	c	e=c-b	f	g=e*f	h=g*B /(A+g*B)
Network	253760	249074	-4686	3.66	-17.2	
Line Connection	245453	240388	-5065	0.87	-4.4	
Transformation Connection	209197	203722	-5475	2.02	-11.1	
				Total =	-32.6	**-2.1%**

Notes:
1. 2016 HONI rates revenue requirement, UTR charge determinants, UTR rates and revenue allocation factors are as approved in OEB Order EB-2015-0311.
2. Proposed 2017 UTR charge determinants are per Exhibit H2-1-2

Witness: Henry Andre