EB-2013-0416

VECC CROSS EXAMINATION COMPENDIUM

PANEL #4

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TAB 1

Table 1: CDM Impact Analysis on Hydro One Retail Load (GWh)

Year	Non-Target Programs 2005-2010	Target programs 2011-2012	Other Organizations	Codes & Standards	Increased Conservation Effect	Total Annual Savings
	(A)	(B)	(C)	(D)	(E)	(F)
2005	4.1	-	-	-	-	4.1
2006	79.1	-	203.3	-	-	282.5
2007	224.8	-	384.0	8.6	-	617.4
2008	331.3	-	355.0	19.4	-	705.7
2009	399.9	-	432.4	32.3	-	864.6
2010	444.7	-	456.6	51.6	276.3	1,229.1
2011	432.2	43.6	531.7	139.6	341.0	1,487.9
2012	400.8	116.1	530.9	269.0	223.4	1,540.2
2013	388.2	187.1	558.1	298.6	160.5	1,592.5

Note: All savings are at end-use level.

Net Load Impact Reports submitted in all previous Hydro One Distribution rate proceedings (EB-2007-0168 and EB-2009-0096) only reported savings due to incremental (new) programs in a particular year. This report includes savings due to persistence of historical programs as well. For example, savings in 2006 includes savings from new programs launched in 2006 as well as savings due to persistence of the programs launched in 2005.

Additionally, the Non-Target and Target Program results have been adjusted using a “half year” rule as defined by the OEB in London Hydro’s 2013 Cost of Service Application (EB-2012-0146) to reflect the fact that most CDM programs do not have the full impact in the first year of implementation. This is consistent with the filing requirements set out in section 2.6.1.3 in the Board’s July 2013 Filing Requirements for Electricity Distribution Rate Applications.

TAB 2

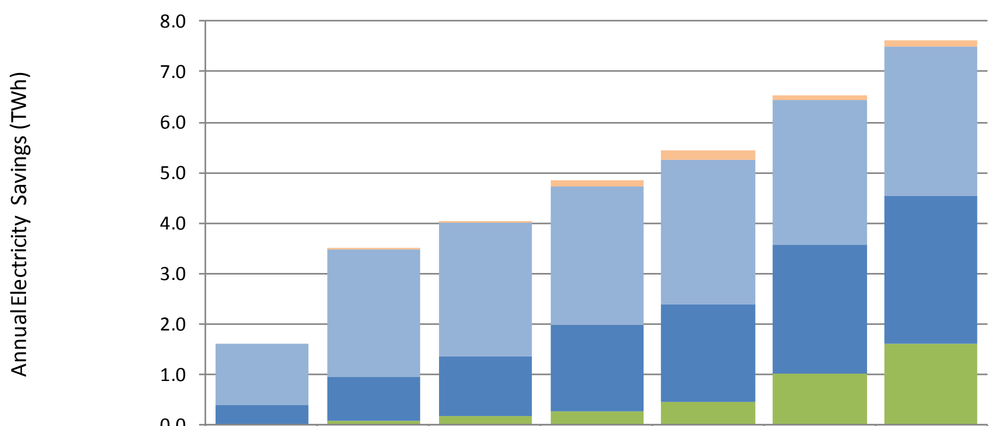
Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #15

Issue 1.2 Has Hydro One Distribution responded appropriately to all relevant Board directions from previous proceedings, including commitments from prior settlement agreements?

Interrogatory

Reference: A/T16/S3, pg. 3-4
2013 LTEP, Module 2, Slide 6

Preamble: The detail LTEP Information Breakdown provided by the OPA (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2 Conservation.pdf) includes the following data regarding historical conservation savings.



	2006	2007	2008	2009	2010	2011	2012
Demand Response and Pre-2008 Customer Based Generation	0.0	0.0	0.0	0.1	0.2	0.1	0.1
Other Influenced	1.2	2.5	2.6	2.7	2.9	2.9	3.0
Energy Efficiency Programs	0.4	0.9	1.2	1.7	1.9	2.6	2.9
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6
Total	1.6	3.5	4.0	4.9	5.4	6.5	7.6

a) Please provide a schedule that aligns the results reported for the five CDM categories used by Hydro One Networks (per Table 1) with the four categories used by the OPA (see Preamble and accompanying Figure).

Response

a) The requested information is provided below:

Hydro One Category	OPA Category
Non-Target Programs (2005-2010)	Energy Efficiency Programs
Target Programs (2011-2012)	
Other Organizations	Other Influenced
Codes & Standards	Codes & Standards
Increased Conservation Effect	N/A
N/A	Demand Response and Pre-2008 Customer Based Generation

TAB 3

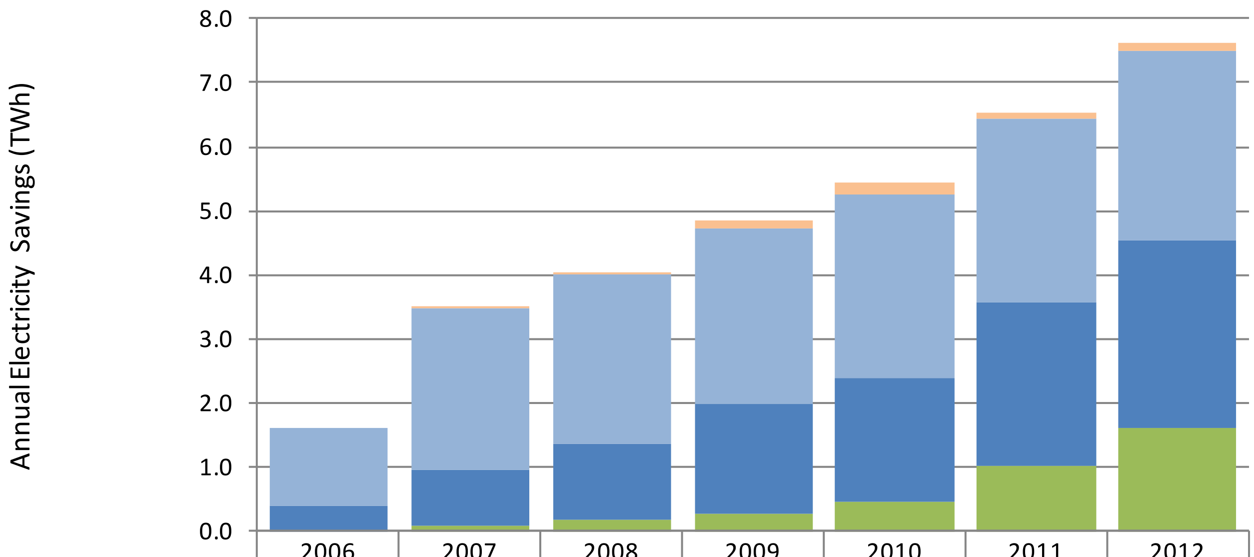
Conservation Targets and How They Reduce the Demand Forecast

2013 LTEP: Module 2

January 2014

Energy Efficiency Achieved to Date

- From 2006 to 2012, codes and standards, OPA conservation programs, and non-OPA programs and activities have contributed a total of 7.6 TWh of savings in 2012.



	2006	2007	2008	2009	2010	2011	2012
Demand Response and Pre-2008 Customer Based Generation	0.0	0.0	0.0	0.1	0.2	0.1	0.1
Other Influenced	1.2	2.5	2.6	2.7	2.9	2.9	3.0
Energy Efficiency Programs	0.4	0.9	1.2	1.7	1.9	2.6	2.9
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6
Total	1.6	3.5	4.0	4.9	5.4	6.5	7.6

Note: Other Influenced is the electricity savings from conservation activities by organizations and programs not funded by the OPA. Examples are federal government programs and gas utilities' programs.

TAB 4

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #21

Issue 1.2 Has Hydro One Distribution responded appropriately to all relevant Board directions from previous proceedings, including commitments from prior settlement agreements?

Interrogatory

Reference: A/T16/S3, pg. 15, Table 10

a) Please explain how the values set out in Table 10 were derived from the various studies and analyses described on the subsequent pages.

Response

a) The values in Table 10 are not derived directly from the various studies and analyses described in Section 6.1. These studies were conducted to provide evidence of the presence of Increased Conservation Effect. The values in Table 10 are calculated as the residual of the Total Annual CDM Savings after removing the savings due to Programs (Target and Non-Target), Other Organizations, and Codes & Standards.

TAB 5

Table ES 1: Hydro One Specific CDM Energy Savings (GWh) by Category

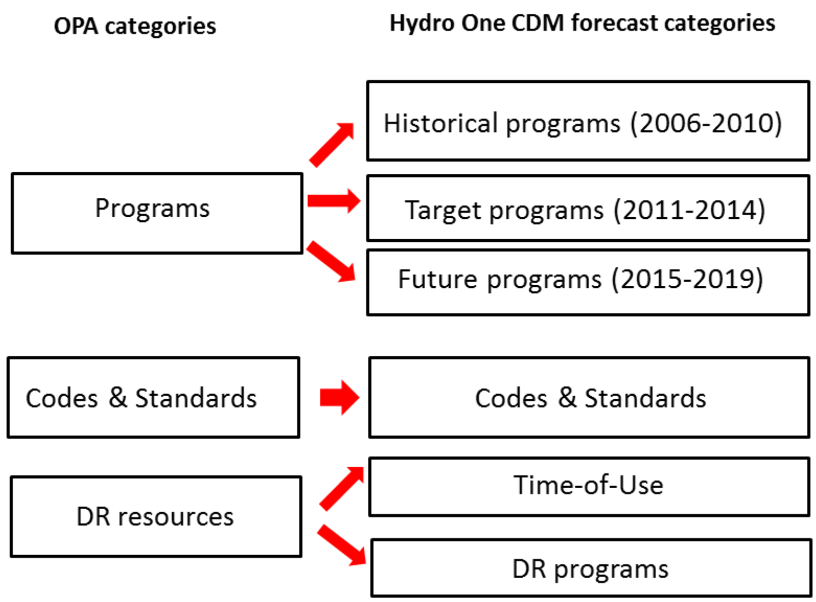
Category	2014	2015	2016	2017	2018	2019
Codes and Standards	328	358	387	417	527	637
Historical Program Persistence (2006-2010)	377	335	289	257	219	178
Target Program Persistence (2011-2014)	355	475	465	452	428	399
Forecasted Savings from Future Programs	585	514	582	588	784	1,073
Total	1,645	1,681	1,723	1,714	1,958	2,288

Note: All savings are at end-use level.

Note that the content of Appendices A, B and C in this report is similar to a report filed in Hydro One's last Transmission Rates Application (EB-2012-0031, Exhibit A-15-2, Attachment 1) which was approved by the Ontario Energy Board. For convenience, the information is re-submitted in this report and updated where appropriate.

TAB 6

Figure 2: Relationship between CDM Categories in Hydro One Load Forecast and the OPA's CDM Categories



A description of how Hydro One incorporates the OPA's savings assumptions into its load forecast is provided in detail below.

4.1 Steps to Incorporate the OPA Savings Assumptions

As previously discussed, Hydro One uses the assumptions provided by the OPA to forecast the CDM savings for each of its CDM categories. The OPA provides Hydro One with the province-wide annual energy and peak savings for energy efficiency, codes and standards, and Demand Response. Hydro One Distribution's share of provincial LDCs total peak demand and energy consumption are used to calculate the CDM forecast for 2014-2019 by category. To derive CDM savings by rate class, Hydro One needs information by sector which was not available in OPA's 2013 LTEP.

ICF Marbek conducted a "conservation achievable potential" study for the OPA to develop Ontario's updated Long-Term Energy Plan (LTEP). Hydro One requested ICF

TAB 7

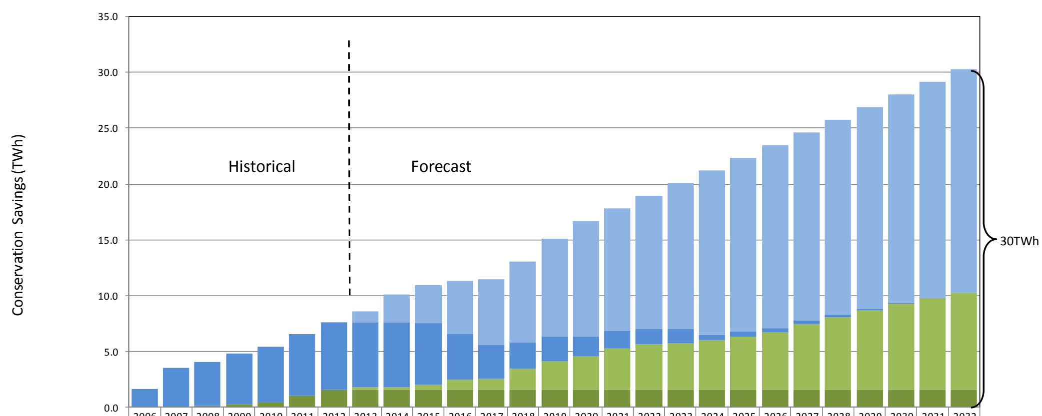
<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #87</u>

Issue 6.6 **Is the load forecast a reasonable reflection of the energy and demand requirements of the applicant? Is the forecast of other rates and charges appropriate? Is the forecast of other revenues appropriate?**

<u>Interrogatory</u>

Reference: **A/T16/S4, pg. 4-5**
2013 LTEP, Module 2, Slide 10

Preamble: The detail LTEP Information Breakdown provided by the OPA (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf) includes the following data regarding forecast conservation savings.



	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
Forecasted savings from future programs								1.0	2.5	3.3	4.8	5.9	7.2	8.7	10.4	10.9	12.0	13.1	14.7	15.5	16.4	16.8	17.5	18.0	18.7	19.3	20.0
Historical program persistence (2006-2012)	1.6	3.4	3.9	4.6	5.0	5.5	6.0	5.9	5.8	5.5	4.1	3.0	2.3	2.2	1.8	1.6	1.4	1.3	0.5	0.5	0.4	0.3	0.2	0.1	0.0	0.0	0.0
Codes and Standards (forecasted savings)								0.2	0.2	0.5	0.9	1.0	1.9	2.6	3.0	3.7	4.0	4.1	4.4	4.7	5.1	5.8	6.4	7.1	7.7	8.2	8.6
Codes and Standards (existing savings)	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
LTEP 2013 total energy savings	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0	20.1	21.2	22.3	23.5	24.6	25.7	26.9	28.0	29.1	30.2

a) How do the CDM categories used by Hydro One Networks in Table ES 1 relate to the OPA's CDM categories as used in the 2013 LTEP?
b) Please re-state Hydro One Networks' forecast 2014-2019 CDM savings using the OPA's CDM categories.
c) Please provide a schedule that sets out the savings expected in each of the years 2014-2019 from Target Programs offered in 2011-2014 showing the impact of each year's programs separately.
d) Using 2015 as an example, please detail how the Hydro One Networks' forecast

CDM savings due to Codes and Standards was derived and broken down by customer class.

e) Using 2015 as an example, please detail how Hydro One Networks' forecast CDM savings attributed to "Forecast Savings from Future Programs" was derived and broken down by customer class.

f) How did Hydro One Networks ensure there was no double counting as between its categories for "Target Program Persistence (2011-2014)" and "Forecast Savings from Future Programs" (per Table ES 1) given that the 2013 LTEP's definition of "future programs" includes savings for 2013 and 2014 programs?

Response

a) The relationship of CDM categories between OPA and HONI is as follows:

OPA's Categories		HONI's Categories
- Historical programs (2006-2012) - Future programs	**Program**	- Historical programs (2006-2010) - Target programs (2011-2014) - Future programs (2015-2019)
- Codes & Standards (existing savings) - Codes & Standards (forecasted savings)	**Codes & Standards**	- Codes & Standards (existing and forecasted savings)

b) Hydro One could not re-state the forecast 2014-2019 CDM savings using the OPA's CDM categories. Hydro one uses slightly different CDM categories from the OPA. For the historical programs, Hydro One has two categories: historical programs (2006-2010) and target programs (2011-2014). For the forecast period, Hydro One estimated CDM savings for the year of 2015-2019. OPA's historical programs savings cover the period of 2006-2012 and future program savings pertain to conservation after 2013.

c) The requested information is provided below:

Program Implementation Year	Annualized CDM Energy Savings (GWh)					
	2014	2015	2016	2017	2018	2019
2011	86	78	74	70	65	64
2012	59	58	53	50	48	44
2013	83	83	83	76	71	68
2014	252	250	250	249	227	212
Total	480	470	459	446	410	387

d) A step-by-step description of how Hydro One forecasts CDM savings due to Codes and Standards is provided in detail below.

Step 1: Estimate savings attributed to codes and standards by sector.

ICF Marbek conducted a "conservation achievable potential" study for the OPA to assist in the development of 2013 Long-Term Energy Plan (LTEP). Hydro One requested ICF Marbek to create a custom tailored dataset from the provincial study to estimate the conservation potential by sector and end use within Hydro One service territory. This analysis included details on the achievable potential in each of the residential, commercial and industrial sectors. The study covers a 20-year period with a base year of 2012 and milestone periods at five-year increments. The following table presents the Hydro One's savings attributed to codes and standards by sector.

Sector	2012	2017	2022	2027
Residential	3	113	546	745
Commercial	266	304	422	518
Industrial				
Total in GWh	269	417	968	1263

Step 2: Derive annual CDM saving by sector based on the average annual growth rate.

Sector	2012	2013	2014	2015	2016	2017	2018	2019
Residential	3	25	47	69	91	113	200	286
Commercial	266	274	281	289	296	304	328	351
Industrial								
Total	269	299	328	358	387	417	527	637

Step 3: Allocate monthly CDM savings by customer rate class.

Based on the customer billing data, Hydro One calculated the share of energy consumption within the residential and non-residential (commercial and industrial) sectors. The energy savings are then assigned to each rate class using the energy shares.

Sector	Rate class
Residential	R1 R2 UR Seasonal
Non-Residential (Commerical+Industrial)	GSE UGE GSD UGD ST

e) The table below provides the detailed calculation to determine the savings attributed to “forecasted savings from future programs” for Hydro One in 2015.

Formula	Items	2015(in GWh)		Note
(1)	LTEP 2013 Total energy saving		10,900	From OPA's LTEP 2013
(2)	Excluding saving from TX direct customers (at generation level)		953	assumption from OPA
(3)=((1)-(2))/distribution Loss factor	Total savings from all LDCs (at end use level)**		9,339	OPA's average loss factor for distribution customers is 0.065 in 2015
(4)=18%*(3)	HONI's Total energy savings (18% of all LDCs)		1,681	
(5)	HONI's saving from Non_Target Programs 2005-2010		335	based on the program evaluation
(6)	HONI's saving fromTarget programs 2011-2014		475	based on the program evaluation
(7)	HONI's saving from codes and standards		358	estimation of H1's share
(8)=(4)-)5)-(6)-(7)	HONI's saving from other programs/ future programs (OPFP)		514	
(9)	HONI's saving in GWh from OPFP by sector	Residenital	248	based on the saving % by sector from ICF study for HONI
		Commercial	219	
		Industrial	47	
(10)	HONI's saving in GWH from OPFP by rate class	Res- R1, R2, UR, Seasonal		allocate saving by rate class based on the energy % in 2012
		Com+Ind- GSE, UGE, GSD, UGD, ST		

*** The forecasted savings from future programs includes the persistence impacts from other influence during 2006-2014 and any other new programs starting in 2015*

f) Hydro One used different categories for CDM program savings from OPA’s LTEP 2013. Program categories include historical programs (2006-2010), target programs (2011-2014) and future programs (2015-2019). There is no double counting of savings for 2013 and 2014 using these categories.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #VECC 11

Interrogatory

6.6 Is the load forecast a reasonable reflection of the energy and demand requirements of the applicant? Is the forecast of other rates and charges appropriate? Is the forecast of other revenues appropriate?

Reference: 1/T6.06/S6-VECC-87

a) Please provide schedules similar to that in the response to VECC 87 e) for the years 2016-2019.

Response

a) The requested information is provided below. All assumptions pertaining to 2016-2019 are the same as 2015 as provided in VECC 87 (e)

Items	2015	2016	2017	2018	2019
LTEP 2013 Total energy saving	10,900	11,300	11,400	13,000	15,100
Excluding saving from TX direct customers (at generation level)	953	1,106	1,259	1,412	1,565
Total savings from all LDCs (at end use level)**	9,339	9,571	9,522	10,880	12,709
HONI's Total energy savings (18% of all LDCs)	1,681	1,723	1,714	1,958	2,288
HONI's saving from Non_Target Programs 2005-2010	335	289	257	219	178
HONI's saving fromTarget programs 2011-2014	475	465	452	428	399
HONI's saving from codes and standards	358	387	417	527	637
HONI's saving from other programs/ future programs (OPFP)	514	582	588	784	1,073

TAB 8

Draft LDC CDM Target and Budget Allocations

As of July 31, 2014

This table shows the target and budget each LDC has been allocated using the target and budget allocation methodologies outlined in Document 1.2 - LDC Target & Budget Allocation Methodology (Summary).

Local Distribution Company	Total 2015-2020 CDM Target (GWh)	Total 2015-2020 CDM Budget ($)
Algoma Power Inc.	12.5	$3,287,863
Atikokan Hydro Inc.	1.6	$410,589
Attawapiskat Power Corporation	0.8	$205,977
Bluewater Power Distribution Corporation	66.7	$16,779,653
Brant County Power Inc.	16.6	$4,263,045
Brantford Power Inc.	56.6	$14,550,122
Burlington Hydro Inc.	102.7	$26,653,845
Cambridge and North Dumfries Hydro Inc.	89.0	$22,637,097
Canadian Niagara Power Inc.	30.9	$7,938,653
Centre Wellington Hydro Ltd.	9.1	$2,334,868
Chapleau Public Utilities Corporation	1.6	$435,168
COLLUS PowerStream Corp.	14.3	$3,823,852
Cooperative Hydro Embrun Inc.	1.7	$504,036
E.L.K. Energy Inc.	16.9	$4,442,311
Enersource Hydro Mississauga Inc.	459.8	$116,567,138
Entegrus Powerlines Inc.	60.1	$15,429,587
EnWin Utilities Ltd.	161.7	$40,706,068
Erie Thames Powerlines Corporation	29.0	$7,405,021
Espanola Regional Hydro Distribution Corporation	3.8	$1,010,867
Essex Powerlines Corporation	32.2	$8,747,313
Festival Hydro Inc.	36.5	$9,165,833
Fort Frances Power Corporation	5.3	$1,412,501
Fort Albany Power Corporation	0.5	$137,223
Greater Sudbury Hydro Inc.	59.7	$15,553,786
Grimsby Power Incorporated	10.5	$2,822,537
Guelph Hydro Electric Systems Inc.	104.7	$26,113,677
Haldimand County Hydro Inc.	20.1	$5,482,351
Halton Hills Hydro Inc.	29.8	$8,159,017
Hearst Power Distribution Company Limited	6.4	$1,600,268
Horizon Utilities Corporation	339.3	$86,635,685
Hydro 2000 Inc.	1.3	$378,327
Hydro Hawkesbury Inc.	7.5	$2,047,276
Hydro One Brampton Networks Inc.	240.0	$63,275,972
Hydro One Networks Inc.	1,200.2	$333,701,727
Hydro Ottawa Limited	374.1	$100,695,213
Innisfil Hydro Distribution Systems Limited	10.9	$3,175,380
Kenora Hydro Electric Corporation Ltd.	7.5	$1,940,632

Local Distribution Company	Total 2015-2020 CDM Target (GWh)	Total 2015-2020 CDM Budget ($)
Kashechewan Power Corporation	0.7	$188,772
Kingston Hydro Corporation	40.7	$10,131,464
Kitchener-Wilmot Hydro Inc.	109.3	$28,536,169
Lakefront Utilities Inc.	14.3	$3,583,586
Lakeland Power Distribution Ltd.	9.5	$2,510,057
London Hydro Inc.	207.0	$53,571,188
Midland Power Utility Corporation	9.0	$2,290,161
Milton Hydro Distribution Inc.	46.8	$12,257,982
Newmarket-Tay Power Distribution Ltd.	30.4	$8,214,437
Niagara Peninsula Energy Inc.	73.0	$18,665,157
Niagara-on-the-Lake Hydro Inc.	11.4	$2,931,601
Norfolk Power Distribution Inc.	19.2	$5,157,676
North Bay Hydro Distribution Limited	37.0	$9,476,060
Northern Ontario Wires Inc.	8.0	$2,033,718
Oakville Hydro Electricity Distribution Inc.	92.6	$24,675,901
Orangeville Hydro Limited	14.6	$3,817,050
Orillia Power Distribution Corporation	13.8	$3,641,811
Oshawa PUC Networks Inc.	68.4	$18,976,631
Ottawa River Power Corporation	10.0	$2,606,069
Parry Sound Power Corporation	3.7	$991,000
Peterborough Distribution Incorporated	36.4	$9,635,651
PowerStream Inc.	492.8	$130,621,145
PUC Distribution Inc.	43.4	$11,448,810
Renfrew Hydro Inc.	4.9	$1,235,281
Rideau St. Lawrence Distribution Inc.	5.8	$1,495,592
Sioux Lookout Hydro Inc.	5.0	$1,322,775
St. Thomas Energy Inc.	18.2	$4,815,511
Thunder Bay Hydro Electricity Distribution Inc.	69.5	$17,862,254
Tillsonburg Hydro Inc.	12.1	$3,047,380
Toronto Hydro-Electric System Limited	1,487.3	$378,238,380
Veridian Connections Inc.	151.4	$40,223,679
Wasaga Distribution Inc.	5.3	$1,571,941
Waterloo North Hydro Inc.	86.0	$21,998,142
Welland Hydro-Electric System Corp.	24.9	$6,442,870
Wellington North Power Inc.	6.2	$1,559,658
West Coast Huron Energy Inc.	8.6	$2,118,038
Westario Power Inc.	21.6	$5,787,868
Whitby Hydro Electric Corporation	54.8	$15,067,277
Woodstock Hydro Services Inc.	24.4	$6,214,431
TOTAL	**7,000**	**$1,835,393,654**

TAB 9

3.4 Methodology for Hourly Load Profiles

This section discusses the methodology for generating the hourly load profiles by customer class and for specific customer delivery points.

Hourly Load Shape by Rate Class

The Electricity Power Research Institute ("EPRI")'s Hourly Electric Load Model ("HELM") was used to develop the hourly load shape for each rate class, taking out abnormal weather effects and load patterns. Actual 2012 hourly smart meter data from the IESO and interval meter data from our customer information system were used as a basis to develop the hourly load shapes. For rate classes that hourly data was not available for all customers, the hourly data was scaled to add up to the actual load for that rate class in 2012. Similarly, the hourly forecast for each rate class adds up to annual forecast for that rate class. Consequently, the forecast takes into account the share of each rate class in the total load and its dynamics over time. In particular, the load profiles for the years 2015-2019 take into account shifts between rate classes in accordance with the annual forecast. Appendix D provides more details for the methodology used by Hydro One to weather-normalize the total utility load and for each rate class.

Hourly Load Shape by Customer Delivery Point

Similarly, the HELM is used to normalize the hourly load for each of the customer delivery points, taking out abnormal weather effects and load patterns. The customer forecast is used to drive the customer delivery point forecast. Key information used in the analysis includes hourly load and weather data.

The most up to date customer totalization table is used to retrieve hourly electricity demand data for each of the customer delivery points connected to the Sub Transmission (ST) system.

TAB 10

7.0-VECC-56

Reference: E7/T1/Appendix 7-1
Cost Allocation Model, Tabs I9 and O5

a) With respect to Appendix 7-1, page 7, how many years of smart meter data does Horizon currently have and how many years' data are needed in order for the information to be used to establish load profiles for cost allocation?

b) With respect to Tabs I9 and O5, please confirm that the LU(2) class has been directly assigned assets in accounts 1840 and 1845 but has not been assigned or allocated any O&M costs associated with these assets.

c) If part (b) is confirmed, please revise the allocators for the O&M costs to include directly assigned assets and provide a revised Cost Allocation.

d) Tab I9 does not appear to attribute any depreciation to the assets directly assigned to the LU(2) class. Please indicate if this is done elsewhere in the cost allocation model and, if so where and what is the depreciation cost associated with these assets?

e) If not, please indicate what the associated depreciation cost would be and re-do the cost allocation with this cost also directly assigned to the LU(2) class.

Response:

a) Horizon Utilities believes that a minimum of four years of Smart Meter data after Smart Meters have been fully deployed is necessary in order to determine weather-sensitivity of load with weather normalization based on 30 years of historic weather data. As of June 2014, Horizon Utilities has 3 years of hourly Smart Meter data (beginning May 2011).

b) Horizon Utilities confirms that no O&M costs have been directly allocated to the LU(2) class. The LU (2) class is served with dedicated assets and essentially no O&M is required to maintain these dedicated assets (estimated at $7,000 every 3 years). Horizon Utilities plans to replace some of the dedicated assets and the capital costs associated with that project are directly allocated to the LU(2) class.

c) Per the answer in part b), no O&M costs are to be allocated to these assets.

d) Depreciation on the directly allocated assets is computed directly within cells J36 and J37 for each year's respective Cost Allocation model.

e) As stated in response to part d), the net fixed asset amounts are provided in the direct allocation tab and therefore include the impact of depreciation.

TAB 11

2.0 RURAL OR REMOTE RATE PROTECTION ("RRRP")

In accordance with the requirements of O.Reg. 442/01, Hydro One is provided rate protection funding of $127 million, of which $125.4 million is available to provide an RRRP credit to its R2 residential customers. The current RRRP credit is $28.50 per month. The number of R2 customers has dropped as a result of the rate class review, and Hydro One proposes to increase the RRRP credit to $30.50 per month over the five year Custom COS period.

3.0 RATE IMPACT MITIGATION

The annual total bill impacts across most rate classes resulting from the revenue requirement and regulatory asset disposition requested in this application are below the 10% value established by the Board in the *2006 Electricity Distribution Rate Handbook* for customers with typical consumption.

The total bill impact for a typical DGen customer is above 10% in 2015 to 2018. Hydro One has mitigated the impacts to DGen customers by spreading the increase in the R/C ratio for this class over the full five years of the Custom COS period. The impact on a typical customer in this class is less than $100 per month, which the Board established as a level below which special mitigation is not required for a General Service demand customer, as discussed below. As such, no rate mitigation is proposed for the DGen rate class.

There are some customers that may experience total bill impacts in excess of 10% in 2015 due to being moved to their appropriate rate class as a result of the rate class review. Specifically, residential customers moving from the UR rate class to the R2 rate class, and Urban General Service energy and demand-billed customers moving to the non-urban General Service energy and demand-billed rate classes will experience higher total impacts that Hydro One proposes to mitigate.

Hydro One proposes to adopt the special rate mitigation approach approved by the Board as part of its 2008 and 2010/11 cost-of-service applications, EB-2007-0681 and EB-2009-0096. The rate mitigation plan will limit total bill impacts as follows:

- UR residential customers moving to the R2 rate class will be limited to a maximum of 15% or $3 per month;
- Urban General Service energy-billed customers moving to the General Service energy-billed class will be limited to a maximum of 15% or $10 per month; and
- Urban General Service demand-billed customers moving to the General Service demand-billed class will be limited to a maximum of 15% or $100 per month.

The costs of this mitigation and related implementation will be tracked in a Bill Impact Mitigation variance account, as described in Exhibit F1, Tab 1, Schedule 2. The required mitigation will apply only in 2015, the year in which the move between rate classes due to the rate class review occurs. The mitigation amount for affected customers will be calculated based on the last 12 months of billing information available for affected customers at the time the credit is calculated. The mitigation will be applied via a credit to the affected customer's 2015 monthly bills.

TAB 12

CUSTOMER CLASSIFICATION

1.0 RATE CLASS REVIEW

In accordance with the Board Decision on Hydro One's IRM application EB-2012-0136 with respect to issue #13 of the settlement agreement, Hydro One has reviewed its customer rate classification to ensure that all customers are classified in accordance with the Company's currently approved density-based rate classes.

The rate class review leveraged the new functionality available through Hydro One's Geographic Information System ("GIS") to identify clusters of customers and the circuit-kilometers ("cct-km") of distribution line required to serve those customers to verify that the density zone criteria for Hydro One's density-based rate classes are being satisfied. Hydro One's residential and general service rate classes are tied to the identification of the following density zones:

- High (Urban) Density Zone: >= 3000 customers and >= 60 cust/cct-km
- Medium Density Zone: >=100 customers and >= 15 cust/cct-km
- Low Density Zone: Areas that are not Medium or High Density

The rate class review used the following methodology to define density zones:

1. GIS system used to identify core clusters of contiguous customers
2. Density zone boundary extended out from core cluster of contiguous customers in all directions to:
    - easily identifiable and communicated physical boundaries (e.g. highways/roads, railways, rivers, lakes)

- non-physical boundaries identifiable within the GIS system (e.g. property lines) where physical boundaries are remotely located from customer clusters

3. Combined customer clusters that are located close to each other into a larger, single density zone, where it helped to mitigate negative impacts to existing customer classifications
4. Determined the circuit-km of distribution line within a proposed density zone boundary and calculated the number of customers per cct-km of line
5. Confirmed the density zone definition applicable to the total number of customers and customers/cct-km for a proposed density zone boundary

In a few situations, a (-10%) deadband was applied to the density zone definition where a majority of customers within a proposed density zone boundary would be negatively impacted as a result of moving to a lower-density rate class.

While the density zone definition always applies to a core cluster of contiguous customers, extending the density zone boundary out from a core cluster per the criteria noted does result in a density zone value below the 10% deadband for a limited number of density zone boundaries.

As shown in Table 1, the rate class review results in 11% of Hydro One customers being reclassified, with the vast majority of those moving to a higher-density rate class with lower rates. The customer reclassifications identified by the rate class review have been incorporated into the customer load forecast included with this application for the 2015-2019 Custom COS period.

Table 1. Summary of Rate Class Review Results

	# of Customers	% of Total
Total	1,222,548	100.0%
No Change	1,087,980	89.0%
Total Changing	134,568	11.0%
Lower Rates	***112,019***	***9.2%***
R1 to UR	40,023	3.3%
R2 to UR	1,815	0.1%
R2 to R1	63,670	5.2%
GSe to UGe	5,733	0.5%
GSd to UGd	778	0.1%
Higher Rates	***22,549***	***1.8%***
UR to R1	5,704	0.5%
UR to R2	439	<0.1%
R1 to R2	16,028	1.3%
UGe to GSe	311	<0.1%
UGd to GSd	67	<0.1%

The net impact of the rate class review is a drop of about $40M in revenue at current rates. While many customers will see lower bills as a result of implementing the rate class review findings, customers will experience about a 3.4% increase on average across all rate classes to make up for the revenue deficiency resulting from the large number of customers moving to rate classes with lower rates.

The rate class review has resulted in a tool that has been incorporated into Hydro One's customer service processes to ensure that all new and existing customers are classified in their correct rate classes on a going forward basis.

Hydro One proposes to update the rate class review on a province-wide basis every 5 years to coincide with the resetting of rates as part of a rates application. Individual density zones will be updated in the interim period between rates applications if there are property developments within or adjacent to a density zone that result in a material change to the rate classification of affected customers.

2.0 NEW UNMETERED SCATTERED LOAD (USL) RATE CLASS

Per the direction of the Board in its report *Review of Electricity Distribution Cost Allocation Policy* issued March 31, 2011, Hydro One has created a separate USL rate class.

Hydro One proactively undertook a study to measure the hourly load profiles of cable boxes starting in late 2010 in anticipation of the need to create a separate USL rate class. Three cable companies (Rogers, Cogeco and East Link) provided site specific information of their equipment to Hydro One for sample selection purposes. A total of 35 interval meters were installed across Ontario to measure the hourly load. Cable equipment monitored included cable boxes with and without battery heating mats. Hourly load data was collected for a period of a year. Regression analysis was performed and weather normalized load profiles were generated. The results of this study, combined with profiles of other types of non-weather sensitive USL loads, were used to produce the USL hourly load profiles for this application.

USL customers were previously treated as General Service energy (“GSe”) customers, with a reduced monthly fixed charge to reflect that USL customers do not have any metering related costs. The number of USL customers and forecast kWh represented only a small portion of the GSe customers and load, and as such, the separation of this class has resulted in a negligible impact to the allocation of GSe costs. The creation of a separate USL rate class will have a small impact on other rate classes given that the USL class' R/C ratio, as discussed in Exhibit G1, Tab 3, Schedule 1, is above the Board approved range and Hydro One plans to bring the R/C ratios for all its rate classes to a range of 98% to 102%.

A new USL rate class has been created in the Board's Cost Allocation Model ("CAM") and populated with all required inputs. The CAM results for the USL rate class are included in the discussion of cost allocation in Exhibit G1, Tab 3, Schedule 1.

3.0 REVIEW OF SEASONAL RATE CLASS

In accordance with the Board Decision on Hydro One's IRM application EB-2012-0136 with respect to issue #17 of the settlement agreement, Hydro One has consulted with interested stakeholders to review the rates for Seasonal customers. The intent of the review was to ensure that Seasonal rates are fair and equitable, and in accordance with rate making principles.

Hydro One consulted with stakeholders on three occasions as part of the broader stakeholder sessions for the Custom COS period, described in Exhibit A, Tab 20, Schedule 1. Hydro One also engaged the consulting firm Citizen Optimum to conduct a series of focus groups with Seasonal customers. The report on the focus group findings is provided in Exhibit G1, Tab 2, Schedule 2. The focus groups were used to gather participant opinions on fair rate designs for Seasonal customers, and to solicit and present options for revising the existing Seasonal rate structure. The option preferred by focus group participants was to move Seasonal customers that have consumption characteristics similar to year-round residential customers to the residential customer classes. Hydro One had received similar feedback during the stakeholder sessions.

A review of Hydro One's historical consumption data indicates that there are a number of Seasonal customers that have annual consumption and monthly load profile characteristics very similar to that of year-round residential customers. To better align with cost causality and fairness rate principles, Hydro One proposes to treat as year-round residential customers those Seasonal customers that i) consume at least 9,600 kWh annually and ii) consume at least 600 kWh monthly for a minimum of 10 months of the year. The definition of Seasonal rate class included in the proposed rate schedules provided at Exhibit G2, Tab 2, Schedule 1 have been revised to reflect the proposed change.

Hydro One's proposal will result in moving approximately 11,000 Hydro One Seasonal customers, or 7%, of the total number of Seasonal customers to the medium density residential (R1) and low density residential (R2) rate classes. This change has been incorporated into the customer load forecast included with this application for the 2015-2019 Custom COS period.

The net impact of the proposed Seasonal customer change is a drop of about $7M in revenue at current rates. While those Seasonal customers moving to year-round residential classes will see lower bills as a result of implementing the proposed definition change, all customer classes will experience an average increase of about 0.5% to make up for the revenue deficiency resulting from this proposed change.

Hydro One believes that its consultation efforts and proposed changes to the definition of the Seasonal rate class, combined with the proposed changes to the fixed charges for the Seasonal class as discussed at Exhibit G1, Tab 4, Schedule 1, satisfies the requirement of issue #17 in the settlement agreement for the 2013 IRM application EB-2012-0136.

A number of potential options discussed with stakeholders were not evaluated further as they received very limited stakeholder support. Hydro One has not provided the results associated with eliminating the Seasonal class and moving all seasonal customers into year-round residential classes as the company believes this option is less consistent with the rate-making principle of cost causality and increases the cross-subsidization among customers in the amalgamated residential rate classes.

TAB 13

Summary of results: During the consultations, the following topics and trends were raised repeatedly, providing a broad picture of participant opinions.

The seasonal rate structure is not a prominent issue among rate payers.

The email invitation sent by FOCA (on behalf of Citizen Optimum and Hydro One) begins "Energy delivery rates are an important topic for seasonal property owners." While this was an assumption going into the consultations, participants feedback suggests that it may in fact be false. Many participants noted that without the email invitation, seasonal rates was otherwise not a topic of discussion.

Despite the concern that FOCA and other interveners have shown on this topic, consultations indicate concern is not widespread. To be clear, consultation participants were asked as part of their introduction whether electricity rates were discussed or stated as a priority for their association. Most associations answered no to this question. There was mention that many cottagers do speak about their electricity rates, but their associations had not made it a priority.

As noted below, the lack of prominence the issue of seasonal rates may be directly related to a general lack of understanding.

There was little knowledge of seasonal rates and rate-design principles.

The majority of participants understood they pay more than "urban" rate payers and in many cases their "full-time" residential neighbours. Further, most can cite relatively detailed comparisons of their own primary- and seasonal-residence energy bills. However, very few participants appeared to understand how the rates were determined and allocated.

There was general enthusiasm for greater clarity and transparency on this electricity invoicing and rate design. Overall, many, if not all, of the participants left the focus groups with a much better understanding of seasonal rates. While most appreciated this increased understanding, many said that being more informed made them more concerned and frustrated.

Opinions on seasonal energy rates often appeared motivated by personal interest.

Participants were invited to consultations on the basis of representing the interests of their association. The expectation was that they would speak on behalf of their members. While this request was respected and people frequently specified where their opinions would be regionally representative, participants frequently prefaced opinions with personal statements. For example, representatives of cottage associations where cottagers have higher personal energy use advocated for conditions that would benefit larger more heavily used properties (e.g. favouring higher fixed rates); participants with lower personal energy use advocated for the opposite (e.g. minimizing fixed rates or focusing on rewards for conservation).

To combat this inclination, participants were told to establish opinions on the basis of all seasonal rate payers. At times, this was a challenge. For example, in one session, all participants were asked whether customers should pay for electricity on the basis of what they use - i.e. with everyone paying their share. Six of seven participants disagreed. One group member summarized the sentiment by noting that higher users have been carrying lower users for a long time. And, "if it ain't broke, don't fix it."

In many sessions, participants seemed to clearly understand that the current rates do result in some cross-subsidization, but this was not a major point of concern.

The seasonal rate system is viewed as convoluted. The following quotes - both paraphrased and direct - illustrate different aspects of this point:

"If you set out to build this system from scratch, you wouldn't do it like this." This comment was offered during a comparison of how roads and other infrastructure systems are funded, and that associations would not apply the Hydro One model of charges to these scenarios.

"You're going to get the money. You just want to figure out how to explain it to me." This comment - and others like it - were offered in the context of the $100 million of recoverable charges, as established by the OEB cost allocation model.

"*The question is 'Why does it cost $342 more to deliver energy to me than it does to the guy 100 metres closer to the road than me?' and that's it."* Most participants fail to understand why seasonal rates are required. Density was a key theme in many of the focus groups - specifically the notion that there is only one set of poles and wires serving an area and that service shouldn't cost different people different amounts.

Many question the validity and fairness of the seasonal category.

One of the most common participant questions and objections related to the existence of the seasonal rate class itself. In some cases, objections hinged on the idea of a single province-wide rate class. More commonly, objections centered on the disparity of permanent and seasonal residents in the same area, around the same lake, along the same road, or on the same power lines.

The separate bucket of costs being allocated to the seasonal rate payers was a similar sticking point among the participants. Participants felt the infrastructure served all local residents equally and, as noted above, they were not satisfied with reasons for why neighbouring full-time residents would pay less for the same poles and wires.

TAB 14

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #93

Issue 7.2 Is the proposed definition of "seasonal" customer class appropriate? Particularly, is residency an appropriate criterion in defining a class? Has this criterion been applied consistently?

Interrogatory

Reference: G1/T2/S1, pg. 5-6
Technical Conference, April 30, 2013, pg. 26, lines 6-7; pg. 31, lines 2-6; pg. 35, lines 24-27 and pg. 64, lines 14-23

a) Please explain more fully the basis for the choice of i) 9,600 kWh per year and ii) at least 600 kWh monthly for a minimum of 10 months as the criteria for treating currently defined Seasonal customers as Residential customers. In particular, for the second criterion why were 600 kWh and 10 months chosen?

b) Please provide a schedule that sets out the average use per customer for 2013 for each of the following customer classes:
- UR
- R1
- R2
- Seasonal

  If possible please provide both the actual and weather normalized average use per customer.

c) What is the forecast total and average per customer 2015 total kWh usage for the roughly 11,000 Seasonal customers reclassified as Residential? If the 2015 forecast values are not available please indicate their current usage.

d) Please provide a schedule that indicates how many of the roughly 11,000 were reclassified to the R1 versus R2 classes and the 2015 forecast usage (or current usage if forecast is not available) in each case.

e) Based on the most recent 12 months of data available, please provide a frequency distribution for each of the UR, R1, R2 and Seasonal classes that indicates the number of customers that fall into each of the following usage categories:
- 0 to 100 kWh per month
- >100 to 250 kWh per month
- >250 to 500 kWh per month
- >500 to 800 kWh per month
- >800 to 1,000 kWh per month

- >1,000 to 1,500 kWh per month
- >1,500 to 2,000 kWh per month
- >2,000 kWh per month.

f) Based on the most recent 12 months of data available, please provide a frequency distribution for each of the UR, R1, R2 and Seasonal classes that indicates the number of customers that fall into each of the following usage categories for the ten months with the highest usage:

- 0 to 250 kWh per month for those ten months
- >250 to 450 kWh per month for those 10 month
- >450 to 600 kWh per month for those 10 months
- >600 to 1,000 kWh per month for those 10 months
- >1,000 to 1,500 kWh per month for those 10 months
- >1,500 to 2,000 kWh per month for those 10 months
- >2,000 kWh per month for those 10 months

Response

a) Hydro One has examined the year-round residential (R1, R2, UR) customer data by number of occupancy month, average monthly consumption and annual consumption. The majority (about 80%) of the year-round residential customers have annual consumption over 9,600 kWh, monthly consumption over 600 kWh and reside in the premise for at least 10 months. Based on this analysis, seasonal customers with these energy consumption characteristics should be classified as year-round customers.

b) The 2013 data is not available. The average actual and weather corrected use per customer using 2012 data by rate class is provided below.

Class	Average actual kwh per customer	Average WC kwh per customer
UR	9,322	9,536
R1	10,900	11,145
R2	14,865	15,202
Seasonal	4,334	4,432

c) The forecast of total annual energy consumption in 2015 for these 11,000 seasonal customers is 147 GWh and 13,000 kWh per customer on average.

d) The requested information is provided below.

Customers Reclassified	# of customers	2015 consumption in GWh
Seasonal to R1	4,734	55
Seasonal to R2	6,265	92

e) The requested information is provided below using 2012 data.

Average kWh per month	**R1**	**R2**	**UR**	**Seasonal**
0 to 100 kWh	1,890	2,412	698	41,706
>100 to 250 kWh	10,777	6,227	5,170	44,332
>250 to 500 kWh	61,256	30,335	31,644	25,508
>500 to 800 kWh	107,151	72,377	50,920	13,651
>800 to 1,000 kWh	56,867	51,374	23,848	5,377
>1,000 to 1,500 kWh	76,670	89,876	25,762	6,655
>1,500 to 2,000 kWh	28,721	42,904	6,931	2,625
>2,000	17,017	40,699	2,949	2,563

f) The requested information is provided below using 2012 data with 10 months of highest usage.

Average kWh per month	**R1**	**R2**	**UR**	**Seasonal**
0 to 100 kWh	1,612	2,152	615	33,852
>100 to 250 kWh	9,090	5,426	4,379	44,036
>250 to 500 kWh	54,472	26,379	28,176	27,641
>500 to 800 kWh	101,720	66,193	49,178	14,698
>800 to 1,000 kWh	57,292	49,304	24,531	5,999
>1,000 to 1,500 kWh	80,648	90,507	28,594	8,521
>1,500 to 2,000 kWh	32,583	46,965	8,294	3,654
>2,000	22,932	49,278	4,155	4,016

TAB 15

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #95

Issue 7.2 **Is the proposed definition of "seasonal" customer class appropriate? Particularly, is residency an appropriate criterion in defining a class? Has this criterion been applied consistently?**

Interrogatory

Reference: **G1/T2/S1, pg. 5-6**
G2/T2/S1, pg. 2
Technical Conference, April 30, 2014, pg. 35, lines 20-28

a) Please provide the eligibility requirements for Rural or Remote Electricity Rate Protection (RRRP) applicable to Hydro One Networks' customers per O. Reg. 442/01.
b) Please confirm that it is Hydro One Networks' proposal to provide RRRP to all R2 customers, including those customers that were formerly Seasonal customers.
c) Please explain how the definition of the year round residential customer (per G2/2/1) as used for purposes of the R2 class conforms to the definition of an eligible "residential premises" as set out in O. Reg. 442/01.
d) Please explain how the inclusion of Seasonal customers as being eligible for RRRP conforms to the definition of an eligible "residential premises" as set out in O. Reg. 442/01.
e) Please explain how the amount of RRRP each R2 customer receives is determined (i.e. is it based on divvying up a defined amount of dollars amongst the eligible customers?). Does changing the number of eligible customers change the amount of RRRP each customer receives monthly?

Response

a) The key eligibility requirements for Rural or Remote Electricity Rate Protection (RRRP) applicable to Hydro One Networks' customers per O. Reg. 442/01 are provided below:

> ***Eligibility for rate protection***
>
> ***2.*** *In addition to the persons described in subsection 79 (2) of the Act, the following classes of consumers in Ontario are eligible for rate protection:*
>
> *2. Consumers who occupy residential premises in a rural area and who, if section 108 of the* Power Corporation Act *had not been repealed by section 28 of Schedule E to the* Energy Competition Act, 1998 *and electricity had continued to be distributed by Ontario Hydro, would have been entitled, pursuant to section 108 of the* Power Corporation Act *as it read on March 31, 1999, to pay Ontario Hydro a discounted rate for the electricity they consumed.*

Where,

> *"residential premises" means a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter;*
>
> *"rural area" means those parts of Ontario connected to the IESO-controlled grid that, before March 31, 1999, received electricity from Ontario Hydro and, at the time subsection 26 (1) of the* Electricity Act, 1998 *comes into force, are receiving electricity from Hydro One Networks Inc.;*

b) Yes, that is Hydro One's proposal with respect to the portion of the 11,000 Seasonal customers that would move to the R2 rate class.

c) The definition of the R2 class customers conform to the definition of an eligible residential premise in that those customers reside in a rural area in a dwelling occupied as a residence on a year-round basis.

d) Hydro One proposes that the high consumption Seasonal customers to be moved to the R2 class be considered eligible for RRRP on the basis that their consumption is equivalent to the consumption of a residential customer that occupies their residence for at least eight months of the year.

e) Please see the response at Exhibit I, Tab 7.7, Schedule 6 VECC 110.

TAB 16

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ONTARIO ENERGY BOARD

FILE NO.: **EB-2013-0416**

VOLUME: **Technical Conference**

DATE: **July 22, 2014**

which is significant. We're not talking about consumption of 100 kilowatt-hours or 50 kilowatt-hours; we're talking about at least 600.

And that is the reason why we can assume -- you know, we can assume, infer from that it is being occupied.

MR. HARPER: So it was an inference, because when I read the response I thought you had some factual information that they resided there. I was wondering how you came up with that, but it was really using the 600 as an inference that they were using it as a permanent -– they were residing there permanently.

Okay. Fine. Thank you.

The next question I had in mind was about the qualification process. And I think that was already dealt with with -- earlier, in terms of customers only qualified basically when they request -- one, when they request an initial service and an account set up, they would be qualified. Then after that, their qualification, say, only changes if they actually take the initiative to contact Hydro One and say: Hey, this is now my permanent residence. Please reclassify me.

MR. ADAMS: Correct.

MR. HARPER: Okay. So you do no sort of asking for periodic sort of re-declarations from customers that it is still their permanent residence. Once they have done it at the time of the account set-up, even if they're there ten, 20 years, you're still assuming it is a residence in terms of the definition of the regulation?

MR. ADAMS: That's correct. And I think we would just also note that there would be a -- I don't know if I would use the word "significant", but large cost to be able to do that kind of qualification and records and things.

And I think it would also put, certainly, the customer, customers in a position where they would have to be providing that kind of declaration and things. And it is not something we have pursued.

MR. HARPER: No, I wasn't suggesting you should. I just wanted to understand what the current practice was.

Now, if we move to the proposal you have for people who don't do a declaration, in which you're reclassifying them as R2 or R1 as opposed to a seasonal customer based on their consumption pattern, you have your criteria now, which we're talking about moving 11,000 customers over.

Going forward, each year would you be reviewing the then-existing seasonal customers, to see whether any of them meet the sort of 600 kilowatt-hours for ten months, 9,600 in total, and doing a reclassification of those customers if additional customers met that threshold?

And if not each year, maybe how periodically might you do it going forward?

MR. ANDRE: Yeah, Bill. I think that would be the objective, to do that periodic review.

I mean, annually, to me, would seem to be the right approach to do it. I haven't talked with our customer service in terms of the implications from an administration and a cost perspective, but that would be the objective, is to do that review annually and see if there's any other seasonal customers that would qualify for that.

MR. HARPER: The flip side of that is for seasonal customers that, in this process, you have moved over, would you be -- and have not signed a declaration, would you periodically be reviewing their consumption now they're in the R2 class, to determine that they still have a consumption level high enough that they continue to qualify to be in the R2 as opposed to the seasonal class?

[Witness panel confers]

MR. ANDRE: Yes. So I think that moving both ways would be the appropriate way to go.

I mean, certainly that happens with the general service 50, above 50 and below 50. We do that annual check to see that they move.

If we move the seasonal to full-time residential on the assumption that they're there, you know, using that property like a full-time residential, if that changed, then there should be some mechanism to move them back.

So yes, I would agree we would check that.

MR. HARPER: Ms. Lea, before I go on I was looking at the clock and whether or not you want to break now for lunch. I know the panel has been up here for a while and...

I am in your hands, and Hydro One's hands.

MS. LEA: Do you have any idea yet, Bill, how much longer you might be? And I don't mind what the answer is; I'm just trying to -- oh, and Julie indicates she has five

TAB 17

Consumers Council of Canada (CCC) INTERROGATORY #30

Issue 7.2 **Is the proposed definition of "seasonal" customer class appropriate? Particularly, is residency an appropriate criterion in defining a class? Has this criterion been applied consistently**?

Interrogatory

Reference: Ex. G1/T2/S1/p. 5

Please provide a detailed explanation as to how Rural Rate Protection is funded allocated, and implemented. If Seasonal customers were moved to the other residential classes would they qualify for RRP?

Response

Details of the Rural or Remote Rate Protection (RRRP) are provided in Ontario Regulation 442/01 which fixes the rural rate protection amount available to Hydro One at $127M. This amount is used to fund the current $28.50 monthly RRRP credit that is applied to reduce the fixed charge of all customers in the low density (R2) residential rate class. Customers in the high density (UR) and medium density (R1) residential classes do not qualify for RRRP. This credit is included as part of the Delivery line on customers' electricity bill.

If all Seasonal customers were to move to the other residential classes they would not qualify for RRRP based on not meeting the eight month occupancy requirement per O.Reg 442/01.

TAB 18

School Energy Coalition (SEC) INTERROGATORY #60

Issue 7.4 Is moving revenue-to-cost ratios for all rate classes to within 98% to 102% over the 2015-2019 period appropriate?

Interrogatory

Reference: Exhibit G1/Tab 3/Schedule 1/p.15

Please provide details of the "improved cost allocations" that justify and support the Applicant seeking to move customers closer to unity over the test period, consistent with the Board's policy from the *Report of the Board: Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) at p.36:

As indicated in its September 2, 2010 letter, the Board expects that with the installation of smart meters and the availability of sufficient smart meter data, better cost allocators for the CA Model will become available and a more comprehensive review of the Board's cost allocation policies will become feasible. The Board anticipates that such a comprehensive review may provide an opportunity to further refine its target ranges. In the meantime, the Board's policy remains that distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations.

Response

Hydro One has made a number of changes to the inputs used by the cost allocation model that it believes result in an improvement to the allocation of costs by rate class. These include:

- 2012 smart meter data has been used to develop updated load profiles for all residential and general service energy rate classes, and the load profile for demand billed classes were updated based on currently available hourly data. Both of which result in an improvement to the 12CP and 4NCP allocators used in the model.
- The density factors used to allocate costs within the residential rate classes, the general service energy classes, and the general service demand classes have been incorporated into the model on a USofA basis and have been established based on the results of an independent Density Study that was approved by the Board as part of Hydro One's 2013 IRM application EB-2012-0136.
- The costs by USofA reflect an improvement in the allocation of project and program costs to USofA accounts, and the breakout of fixed asset costs between bulk, primary and secondary have been updated to reflect information available from the fixed asset and GIS systems, and to better delineate secondary assets.
- The creation of a USL rate class, whose customers were previously included as part of the General Service energy class for cost allocation purposes, and establishing a load profile for this class based on actual collected data, allows for an improved allocation of the costs required to serve both the USL and GSe classes.
- Hydro One has updated the PLCC calculations to provide a better alignment to the minimum system split used in the cost allocation model.
- The billing, collection and services weighting factors have been updated to reflect Hydro One's circumstances.
- Hydro One is using the updated cost allocation model issued by the Board which includes improvements to the allocation of Miscellaneous expenses and the allocation of Administrative costs.

TAB 19

3.0 IMPLEMENTATION OF COST ALLOCATION RESULTS

The Board's policy report *Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) established target ranges for the R/C for each customer class and states that utilities should endeavour to move their R/C ratios closer to 1 if this is supported by improved cost allocation. This view was reinforced in the Board's report *Review of Electricity Distribution Cost Allocation* (EB-2010-0219) and in their Decision in rate applications for Toronto Hydro (EB-2010-0142) and Brant County Power (EB-2010-0125). Hydro One has made numerous improvements to its cost allocation, including:

- using updated customer load profiles based on 2012 smart meter data;
- creation of a USL rate class;
- improvements to the assignment of OM&A costs by USofA;
- improvements to the breakout of fixed asset costs by USofA;
- updated density factors tied to approved Density Study results; and
- updated billing, collection and services weighting factors.

Hydro One proposes to adjust class revenue recoveries as necessary to move the R/C ratios for all rate classes to within a range of 98% to 102% over the five year Custom COS period. The proposed range provides some flexibility in establishing rates and mitigates the undesirable result of having customer rates fluctuate up or down as a result of even minor movements around an absolute target of 1.

The approach in this application to moving the R/C ratios as determined by the CAM is to ensure that all rate classes with R/C ratios outside the upper limit of the Board range are brought within the Board approved ranges in 2015. In subsequent years, the class with the highest R/C ratio will be phased-in over the remaining years of the Custom COS period to achieve the end state target of 1.02. All other classes with ratios above the

TAB 20

MANITOBA	Board Order 116/08
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	July 29, 2008
Edited for format and typographical errors only August 25, 2008	

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair
Susan Proven, P.H.Ec., Member

AN ORDER SETTING OUT FURTHER DIRECTIONS, RATIONALE AND BACKGROUND FOR OR RELATED TO THE DECISIONS IN BOARD ORDER 90/08 WITH RESPECT TO AN APPLICATION BY MANITOBA HYDRO FOR INCREASED RATES AND FOR RELATED MATTERS

13.0 Cost of Service

13.1 Background

Currently, MH's Cost of Service Study is a prospective study of average (embedded) historically-based costs classified, functionalized, and allocated to each customer class and sub-class on the basis of system usage. The costs reflect invested funds in Generation, Transmission, and Distribution, updated to use in forecasting costs for the next upcoming fiscal year.

Costs related to finance (interest, etc.), depreciation, and OM&A are shared by domestic customer classes and one export class on the basis of energy consumption, peak load demand, and customer numbers. Currently, surplus export revenues (above assigned and allocated costs, i.e. notional profit) are credited to the various domestic classes proportional to their share of total allocated costs.

COSS is a tool to assess the extent to which each customer class' revenues recover/compare to allocated and historic costs. The revenue to cost coverages derived from PCOSS-08 illustrate a degree of disparity in embedded cost sharing by the various classes. Yet, the results should not be viewed as being representative of a degree of unfairness, but rather as an indication of possible rate increase differentiations, if only historic costs are to be taken into account and the current method of allocating costs and revenue (including net export results) is maintained.

MH employs a Zone of Reasonableness (ZOR) from 95% to 105% to assess the need for differentiated rate increases. In this GRA, MH chose to seek an across-the-Board rate increase for all classes other than Area and Roadway Lighting (a

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

2007 RATE DESIGN APPLICATION
PHASE -1

DECISION

October 26, 2007

Before:

Anthony J. Pullman, Panel Chair & Commissioner
Robert J. Milbourne, Commissioner
L.A. O'Hara, Commissioner

Commission Determination

The Commission Panel notes the wide spread practice of setting the range of reasonableness at 95 percent - 105 percent in other jurisdictions. Furthermore, the Commission Panel is persuaded by the JIESC position that once the key allocation methodologies have been properly established, the variation in cost of service and R/C results would be expected to be less than five percent and notes the evidence that there has been no systematic bias in allocation. The Commission Panel also agrees that in conjunction with the known system demand and demand metering of large commercial and industrial customers, the accuracy of the relatively sophisticated load research analysis should be acceptable within the overall range of reasonableness of 95 percent - 105 percent.

Accordingly, the Commission Panel finds that the range of reasonableness of 95 percent - 105 percent is the correct range for the purpose of future rebalancing in the circumstances of BC Hydro. **BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied.**

The Commission Panel is further persuaded by the Intervenors' argument that under BC Hydro's approach of not making adjustments within its 90 percent - 110 percent band, those classes that start high will remain high and vice versa. Accordingly, the Commission Panel finds that the appropriate target for R/C ratios in each class is unity or one in this RDA, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness.

BC Hydro is directed to adjust its rates in equal percentage amounts over the next three years so as to achieve R/C ratios of unity for each class after adjustments to the FACOS as described elsewhere in this Section and to file Rate Schedules for all classes for the first phase of the three year phase-in with rates effective April 1, 2008 with the Commission, together with supporting documentation, within 60 days of the date of Order No. G-111-07.

BC Hydro is directed to undertake FACOS studies on an annual basis within 90 days of its fiscal year end in order to calculate actual R/C ratios and determine the need for future rate rebalancing applications in regard to the 95 percent to 105 percent range of reasonableness and submit the findings to the Commission.

Decision 2014-018

Alberta Utilities Commission

FortisAlberta Inc.

2012-2014 Phase II Distribution Tariff

January 27, 2014

a directional change, but not sufficiently precise to allow for the proposed adjustments to achieve a 100 per cent revenue-to-cost ratio for all rate classes.

143. Accordingly, although the Commission considers that revenue-to-cost ratios should be adjusted toward 100 per cent, the Commission must also consider possible rate shock as a result of adjusting revenue-to-cost ratios. The Commission directs Fortis to adjust the revenue-to-cost ratios for all rate groups as close as possible to the generally accepted 95 per cent to 105 per cent revenue-to-cost ratio range, such that the average total bill impact for each rate class does not exceed a ten per cent increase.

9 Transmission rate design

144. Fortis proposed to continue to set the total revenue-to-cost ratios for the transmission component of each rate class to 100 per cent. Fortis proposed to retain its transmission rate design to recover all AESO transmission tariff demand charges through a single ratcheted demand charge, for those rate classes that are billed based on demand. Fortis indicated that designing rates in such a manner recognizes the intended flow-through nature of transmission costs, "as well as the ongoing increases to the AESO transmission tariff and the corresponding proposed increase to the Transmission Component of FortisAlberta's rates in FortisAlberta's PBR Compliance Filing (Proceeding ID. 2130)."[77]

145. In response to CWSAA evidence, Fortis proposed an alternative rate design for Rate classes 44, 45, 61 and 63 to recover bulk transmission charges. The Commission discusses this proposal in the following section.

9.1 Recovery of bulk transmission charges

146. CWSAA considered that Fortis' bulk transmission cost of service study accurately reflected the current AESO tariff structure. These costs are allocated to rate classes based on each rate class' average MW/month of billing capacity. As this allocation is consistent with the AESO tariff, changes are neither necessary nor appropriate. Notwithstanding, Fortis' current tariff applies a twelve month ratchet to all demand charges, including bulk transmission charges and as a result, customers with seasonal load variation pay considerably more than their actual bulk transmission cost of service.

147. Customers without demand meters pay bulk transmission costs through an energy charge. Using an energy charge to recover bulk transmission costs from all customers would provide consistency across rate classes and would not require a new billing determinant. However, transferring this cost recovery to an energy charge would create significant rate dislocations across a large number of customers. This approach would also not be consistent with the principle of cost recovery based upon cost causation, since energy is not the basis on which these costs are charged to Fortis by the AESO.

148. CWSAA pointed out that the 'highest metered demand in the billing period' is a billing determinant which is already available, used in billing processes, and more closely matches the way in which bulk transmission demand charges flow to Fortis. Since this demand-based billing determinant is quite consistent with the existing ratcheted billing determinant, its application creates less rate dislocation than an energy-based billing determinant.

[77] Exhibit 1, application, paragraph 155, PDF page 47.

TAB 21

Table 4

Current and 2015 Proposed Monthly Fixed Charges

Rate Class	Current (2014) Monthly Fixed Charge ($/month)*	Proposed 2015 Monthly Fixed Charge ($/month)*	CAM Scenario1: Customer Unit Cost per Month - Avoided Cost	CAM Scenario2: Customer Unit Cost per Month - Directly Related	CAM Scenario3: Customer Unit Cost per Month - Min System with PLCC Adjustment
UR	12.72	20.29	7.94	10.07	20.29
R1	20.15	27.92	7.71	9.88	27.92
R2	29.11	37.99	8.51	11.01	50.59
Seasonal	19.71	26.78	7.56	9.42	51.54
GSe	35.92	28.96	16.65	20.94	28.96
UGe	10.2	22.48	19.73	24.35	22.48
GSd	52.27	82.14	58.73	75.59	82.14
UGd	28.71	84.4	66.40	83.03	84.40
St Lgt	1.47	4.01	3.00	4.01	23.39
Sen Lgt	1.5	2.42	1.78	2.42	18.10
USL	29.69	39.14	7.07	9.33	39.14
DGen	38.13	166.48	89.45	147.99	166.48
ST	294.97	453.27	324.30	431.43	618.24

* Fixed Charge shown for R2 class is net of RRRP Credit.

The R2 fixed charge has been set based on the currently approved 2014 charge escalated to reflect the proposed 2015 average increase in rates revenue requirement, as per the factor used to increase revenue at existing rates shown on Sheet O1 of the Board's CAM. The proposed fixed charge set using this approach results in the collection of 56% from fixed charges for the R2 class, which is equal to the currently approved fixed/variable split, but below the 71.3% fixed revenue share that existed in 2008. The proposed R2 fixed charge is within the range of values calculated by the CAM when the RRRP credit applicable to R2 customers is taken into consideration. The fixed charge for the Seasonal customer class is set to collect a fixed revenue share equivalent to the average of the R2 and R1 fixed revenue share, in recognition that Seasonal customers are located in both medium and low density zones. Hydro One does not propose adopting the minimum

TAB22

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0317

COST ALLOCATION REVIEW

Board Directions on Cost Allocation Methodology For Electricity Distributors

September 29, 2006

Customer Unit Cost Adjustment

Another output of the filing model is customer and demand unit costs by rate classification. These unit costs can be used to help set future distribution rates; however, to reflect the results of the PLCC adjustment, an appropriate amount of customer-related costs should be moved into the demand-related costs before rates are determined. This unit cost adjustment will be incorporated into the cost allocation model. Note the adjustment will not change the total cost allocated to the rate classification.

Distributor-specific PLCC Adjustment

If, and only if, a distributor files its own minimum system study, it must also file and explain its own PLCC adjustment.

7.5.3 Filing Question

If any distributor suspects its generic minimum system result and/or the generic PLCC adjustment has contributed to an anomalous filing result for a rate classification, an explanation should be included in the Filing Summary.

7.6 Distributor-Specific Minimum System Study

7.6.1 Background

One distributor undertook a new minimum system study at the time of unbundling and has asked whether these results may be used in the present filings. A similar issue would arise if a distributor completed a new minimum system study before its scheduled filing date. The Board cautions, however, that the use of the approved generic minimum system results is encouraged to make the overall filing and review process more efficient. As the generic results are considered reasonably reliable, delays in filing based on non-mandatory further minimum system analyses are undesirable.

7.6.2 Direction – Use of Distributor-Specific Minimum System Study

While use of the generic minimum system results is encouraged for these filings, if a distributor does undertake a new minimum system study before its filing date, then the distributor may use such minimum system results in Run 3 of the cost allocation model to be filed.

If a distributor has an existing minimum system study that was completed during or after its distribution rates were unbundled, then it may use these results in Run 3 of the cost allocation model to be filed.

TAB 23

HON Dx - 2015 Cost Allocation Model – Sheet O2 Extract (rows 138-241)

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge						
			1	2	3	4
USoA Account #	**Accounts**	**Total**	**UR**	**R1**	**R2**	**Seasonal**
	Distribution Plant					
1565	Conservation and Demand Management Expenditures and Recoveries	$1,713,669	$116,659	$370,085	$646,872	$123,132
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$840,713,882	$48,615,603	$193,202,650	$373,121,049	$119,995,665
1830-5	Poles, Towers and Fixtures - Secondary	$210,178,470	$12,247,916	$48,674,286	$94,001,819	$30,230,969
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$606,582,405	$35,076,582	$139,397,398	$269,210,094	$86,577,920
1835-5	Overhead Conductors and Devices - Secondary	$57,520,745	$3,351,957	$13,320,970	$25,726,016	$8,273,482
1840	Underground Conduit	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$194,401,597	$11,253,958	$44,724,210	$86,373,267	$27,777,628
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0
1850	Line Transformers	$1,214,259,463	$70,293,787	$279,353,645	$539,499,460	$173,502,934
1855	Services	$618,415,106	$60,008,159	$188,271,839	$287,848,781	$82,286,328

HON Dx - 2015 Cost Allocation Model – Sheet O2 Extract (rows 138-241)

1860	Meters	$546,913,581	$71,242,192	$149,011,943	$132,897,528	$56,986,429
9999	blank row					
	Sub-total	$4,290,698,918	$312,206,811	$1,056,327,025	$1,809,324,886	$585,754,488
	Accumulated Amortization					
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($1,802,466,416)	($132,690,264)	($447,043,845)	($758,217,107)	($241,414,175)
	Customer Related Net Fixed Assets	$2,488,232,502	$179,516,547	$609,283,180	$1,051,107,780	$344,340,312
	Allocated General Plant Net Fixed Assets	$210,114,108	$14,627,227	$49,839,272	$85,971,907	$28,444,344
	Customer Related NFA Including General Plant	$2,698,346,609	$194,143,774	$659,122,452	$1,137,079,687	$372,784,656
	Misc Revenue					
4082	Retail Services Revenues	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0
4225	Late Payment Charges	($17,700,000)	($1,886,173)	($5,496,085)	($6,213,378)	($1,011,780)
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0
4235-1	Account Set Up Charges	($3,754,657)	($579,197)	($1,211,464)	($926,103)	($132,371)
4235-2	Sentinel Lights Pole Rental Charges	($3,042,020)	$0	$0	$0	$0
4235-90	Miscellaneous Service Revenues - Residual	($10,966,719)	($750,663)	($2,386,965)	($4,185,333)	($795,443)
	Sub-total	($35,463,396)	($3,216,034)	($9,094,514)	($11,324,814)	($1,939,594)
	Operating and Maintenance					
5005	Operation Supervision and Engineering	$1,851,279	$120,218	$446,989	$815,759	$254,810

HON Dx - 2015 Cost Allocation Model – Sheet O2 Extract (rows 138-241)

5010	Load Dispatching	$471,083	$30,591	$113,742	$207,581	$64,840
5020	Overhead Distribution Lines and Feeders - Operation Labour	$9,467,167	$548,115	$2,178,256	$4,206,740	$1,352,887
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$556,547	$32,222	$128,053	$247,302	$79,532
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$3,010	$174	$692	$1,337	$430
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$2,596	$150	$597	$1,154	$371
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0
5065	Meter Expense	$17,391,651	$2,027,674	$4,241,133	$3,782,490	$1,621,931
5070	Customer Premises - Operation Labour	$25,650,347	$4,170,984	$8,724,135	$6,669,164	$2,859,736
5075	Customer Premises - Materials and Expenses	$3,283,262	$533,889	$1,116,695	$853,658	$366,048
5085	Miscellaneous Distribution Expense	$13,026,481	$845,914	$3,145,225	$5,740,073	$1,792,962
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$6,399,765	$415,588	$1,545,214	$2,820,034	$880,862
5120	Maintenance of Poles, Towers and Fixtures	$11,318,898	$655,546	$2,605,196	$5,031,263	$1,618,053
5125	Maintenance of Overhead Conductors and Devices	$25,279,694	$1,462,818	$5,813,365	$11,227,013	$3,610,605
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$75,939,875	$4,396,645	$17,472,651	$33,743,916	$10,852,038
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$645,237	$37,353	$148,444	$286,681	$92,196

HON Dx - 2015 Cost Allocation Model – Sheet O2 Extract (rows 138-241)

5155	Maintenance of Underground Services	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$1,632,502	$94,506	$375,575	$725,326	$233,265
5175	Maintenance of Meters	$0	$0	$0	$0	$0
	Sub-total	$192,919,394	$15,372,387	$48,055,962	$76,359,490	$25,680,567
	Billing and Collection					
5305	Supervision	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$6,643,624	$138,318	$614,749	$2,904,687	$942,701
5315	Customer Billing	$33,954,515	$5,237,860	$10,955,638	$8,375,036	$1,197,071
5320	Collecting	$8,466,268	$1,306,016	$2,731,695	$2,088,244	$298,479
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$15,474,000	$1,884,026	$5,179,717	$4,606,203	$428,076
5340	Miscellaneous Customer Accounts Expenses	$4,683,978	$722,555	$1,511,315	$1,155,325	$165,134
	Sub-total	$69,222,385	$9,288,775	$20,993,113	$19,129,495	$3,031,462
	Sub Total Operating, Maintenance and Biling	*$262,141,779*	*$24,661,163*	*$69,049,075*	*$95,488,985*	*$28,712,029*
	Amortization Expense - Customer Related	$135,235,807	$11,236,948	$33,700,022	$51,586,839	$16,969,808
	Amortization Expense - General Plant assigned to Meters	$40,078,591	$2,855,269	$9,728,743	$16,781,918	$5,552,403
	Admin and General	$86,646,866	$7,939,548	$22,444,201	$31,437,179	$9,393,563
	Allocated PILs	$24,643,837	$1,777,959	$6,034,434	$10,410,333	$3,410,399
	Allocated Debt Return	$82,527,646	$5,954,057	$20,208,203	$34,862,277	$11,420,796
	Allocated Equity Return	$111,508,655	$8,044,927	$27,304,662	$47,104,768	$15,431,406

HON Dx - 2015 Cost Allocation Model – Sheet O2 Extract (rows 138-241)

		Total	UR	R1	R2	Seaonal
	PLCC Adjustment for Line Transformer	$30,997,082	$0	$0	$10,391,968	$0
	PLCC Adjustment for Primary Costs	$96,188,891	$6,471,339	$25,700,107	$49,617,734	$0
	PLCC Adjustment for Secondary Costs	$24,584,931	$1,721,697	$6,693,621	$12,726,121	$0
	Total	$555,548,880	**$51,060,802**	**$146,981,097**	**$203,611,662**	**$88,950,811**

TAB 24

Item #	Issue	Summary of Directive	Reference Exhibit
(iv)	Conservation and Demand Management (CDM)	Hydro One to: 1. Consult with stakeholders to devise terms of reference for this study. 2. Develop a robust methodology to forecast the CDM impacts. 3. Work with the OPA to derive expected CDM impacts in Hydro One territory. 4. Propose a methodology to incorporate the forecasted CDM impacts (both those attributable to Hydro One's actions and those that are not) into the load forecast.	A-16-4
(iv)	Line Losses	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.	G1-8-1 G1-8-2

Table 2
Directives from Proceeding EB-2010-0228 (Joint Use Charges)

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	Generator Power Space Factor	The Board finds that the issue of space allocation, and therefore the resulting specific charges, should be revisited in Hydro One's next rebasing application.	G2-5-1
(ii)	Appropriate Charge Adjustor	Joint use charges should be revisited at the next Hydro One rebasing application, at which time the issue of indexing can be considered in the context of all joint users.	G2-5-1
(iii)	Joint Use Variance Account	Hydro One to address the methodology and level for all its joint use charges at the next rebasing application, the Board does not expect that this account would be needed beyond that time.	F1-1-2