Arbourbrook Estates Interrogatory # 2

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
Ref.: Email Exchange between Hydro One and Phil Sweetnam

Interrogatory:
a) Please identify the total number of residences in the area referred to in the Email exchange between Hydro One and Mr. Phil Sweetnam, both on July 10, 2013 and the present.

b) Please confirm the density classification for residences referred to in the email exchange between Hydro One and Mr. Phil Sweetnam and located on William Mooney Rd, Covered Bridge Way, Sentinel Pine Way, Wilbert Cox Drive, Cavanmore Rd, and Huntley Manor Drive:
   i) on July 10, 2013, and
   ii) the present.

Please note that Arbourbrook is not seeking information about specific addresses.

c) Each time the density classification for any of the residences referred to in part a) was changed from one classification to another between July 10, 2013 to the present please describe the nature and cause of the reclassification. Arbourbrook notes that it is not seeking information about specific addresses; Arbourbrook is seeking information about the numbers of residences that experienced density reclassification over the noted time period and the causes for the reclassification.

d) How often does Hydro One review density classifications on its own initiative? How often did Hydro One review, on its own initiative, the density classifications in the area referred to in the Email exchange between Hydro One and Mr. Phil Sweetnam between July 10, 2013 and the present? Please provide the details of any such review of that area.

e) When one customer seeks a density classification review and the result of that review is a reclassification, does Hydro One go on to change the classification for the customers in proximity to the initial customer? If not why not? Does Hydro One notify the customers in proximity to the initial customer that they are entitled to a reclassification? If so, how is that notice given? If not why not?

Response:

a) Hydro One does not have information on the number of residences in the referenced areas "A", "B" and "C" on July 10, 2013. Currently there are about 108 residences in the referenced areas.

b) Hydro One cannot readily identify the density classification for the subject residences on July 10, 2013. However, based on information collected as part of the density classification review completed in mid-2013 as input to Hydro One's 2015 Distribution Application EB-2013-0416, it appears that the majority of residences in the subject area were classified as low density R2 customers at the time. Presently all residential customers on the referenced streets are classified as medium density R1 customers, consistent with the fact that a new medium density zone was defined as part of the 2013 density review that included all of the referenced streets.

c) Hydro One cannot readily provide the detailed information requested as it involves manually pulling the information from our billing system for each individual customer in the subject area. However, Hydro One can advise that all customers in the subject area would have been reclassified to medium density R1 (if not already in that class) in May of 2015, after Board approval of Hydro One's density review as part of its Decision in EB-2013-0416. The only other changes in density classifications that could appear on a customer's account would be in response to an individual customer's request to have their rate classification checked, which could have occurred if for some reason they were not captured as part of the May 2015 implementation of the density review results.

d) Hydro One carried out a province wide review of its density classifications in mid-2013 and again in mid-2016 as part of its preparations for its 5 year custom IR applications. Hydro One will update its rate classifications based on a province wide density review every 5 years going forward to coincide with the rebasing of rates as part of a future application. Hydro One will also update rate classifications on its own initiative if there are developments within or adjacent to a density zone that results in a change to the existing density classifications. The area referred to in question was reviewed in mid-2013 and a medium density zone was created that encompassed the referenced area, resulting in a change to the density classification of customers that was implemented in May 2015, after approval of the density review process and results by the Board as part of EB-2013-0416.

e) Since the Board's 2015 approval of Hydro One's density review process, Hydro One will change all customers impacted by the establishment of a new density zone created in response to an individual customer density review request. All customers within the new density zone whose density classification is changing are advised of the rate classification change via a letter mailed directly to each customer.

Canadian Manufacturers & Exporters Interrogatory # 70

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01

Interrogatory:

The evidence states (page 15) that Hydro One uses three different forecasting models for the 19 rate classes shown.

a) Is there a different model within each of the three different methods used by Hydro One (monthly econometric, annual econometric, end use) for each of the 19 rate classes or is there one model (as shown in Appendices A, B and C) for each of the methods for the total of the 19 rate classes?

b) If this is a model for each of the 19 rate classes, please provide a table for each of the rate classes and a table for the sum of the forecasts for the 19 rate classes that shows the annual forecast for each of 2018 through 2022 from each of the three methods (monthly econometric, annual econometric, end use) and the forecast ultimately used by Hydro One in this application.

c) Please explain fully how Hydro One determined its forecast used in this application based on the three forecasting methodologies set out in its evidence. For example, did Hydro One do a weighted average of the three methods (as adjusted for CDM) and/or did it make some other adjustments to arrive at the final forecast?

d) If there is only one model used for each of the methods (as implied by the Appendices A, B & C), please explain fully how Hydro One takes the overall forecast and breaks it down into forecasts for each of the 19 rate classes. Please provide all assumptions and calculations used.

Response:

a) None of the models described in Appendix A to Appendix C is for forecasting by rate class. There is one model for each of the three methods. For example, monthly econometric model is for modeling weather corrected load for retail customers at the aggregate level for up to and including year 2018.

b) Not applicable.

c) Hydro One uses a simple average of forecasts produced by the three forecasting methodologies after adjusting for CDM.

d) For Hydro One retail, the aggregate level forecast is allocated to different rate classes in accordance with their historical share of the aggregate. Next, the forecast is adjusted for rate re-classification that is expected to occur after 2017. For Acquired Utilities, a forecast for each rate class is developed in relation to Ontario number of household / customers, Ontario GDP, or historical average change. In cases were the forecast was low compared to economic outlook and retail growth, the forecast was adjusted upward accordingly. Please see Attachment 1 for the assumptions and calculations used to develop the forecast by rate class.

City of Hamilton Interrogatory # 1

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

None

Interrogatory:

a) Did the calculation of the load forecast for the determination of the COH street lighting rate class reflect the effect of the COH's LED street light conversion program?

b) If so, what is the effect on the rates to be charged for the COH street lighting rate class?

c) If not, why not?

d) What data and assumptions were used to generate this load forecast, and how is LED technology adoption accounted for?

Response:

a) Yes, the load forecast for the street lighting reflects the effects the COH's LED street light conversion program, as well as the LED conversion program in all other municipalities served by Hydro One. Hydro One has implemented municipality street lighting programs since 2012 and the total cumulative energy savings is about 22 GWh. The actual street lighting load in 2016, which is the base for forecasting, should already reflect the conservation impact of the street lighting conversion program.

b) Distribution rates are determined for each rate class as a whole, rather than specific customers. A decrease in the forecast will increase the rates for the street light class as a whole. However, with a reduction in street lighting load, COH would benefit from a proportional reduction in its volumetric distribution charges in addition to savings on commodity charges.

c) Not applicable.

d) The allocation of aggregate sales forecast amongst different rate classes takes into account historical shares of each rate class in total sales. Consequently, if electricity usage for the street lighting class reduces, it would be reflected in the forecast because its share of the total reduces. Thus actual conservation impact, including LED technology adaptation, is implicitly reflected in the actual load and the forecast.

City of Hamilton Interrogatory # 2

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

None

Interrogatory:

a) In the calculation of the load forecast for the street lighting rate classes in any of the other urban municipalities within HONI's service area, has HONI included the effect of LED conversion programs?

b) If so, what is the effect of doing so on the rates for the street lighting rate class in those urban municipalities?

c) If not, why not?

d) What data and assumptions were used to generate the load forecast for the street lighting class in other urban municipalities within HONI's service area, and how was LED technology adoption accounted for?

Response:

(a) Please see Exhibit I-46-COFH-1.

(b) Please see Exhibit I-46-COFH-1.

(c) Please see Exhibit I-46-COFH-1.

(d) Please see Exhibit I-46-COFH-1.

Witness: ALAGHEBAND Bijan

City of Hamilton Interrogatory # 3

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
H1-01-01 Page: 3
HONI states that it applies the Bonbright principles in its rate design process. Included in those principles is the principle that "customers should, in general, pay rates for distribution services that reflect the costs they "cause" as determined by a board-approved cost allocation study".

Interrogatory:
a) Does HONI believe that the application of that principle requires it to include, in the calculation of the rates for the street lighting rate class for the COH, the effect of the COH's LED conversion program?

b) If not, why not?

Response:
a) Yes.

b) Not applicable.

Witness: ANDRE Henry

City of Hamilton Interrogatory # 4

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

None

Interrogatory:

a) Does HONI believe that the application of the conservation and demand management directives of the province require that, in the calculation of rates for the street lighting rate class for COH, it include the effect of COH's LED conversion program?

b) If not, why not?

c) What were the load impacts of the CDM applications for 2015, 2016 and 2017 related to street lighting?

Response:

a) Yes.

b) Not Applicable

c) Based on the HONI's municipality street lighting approval list, the estimated energy savings related to municipality street lighting programs for 2015-2017 is as follows:

Approval Year	Sum of Estimated Energy Savings in LDC's Territory (kWh)
2015	3,494,089.0
2016	6,839,966.6
2017	2,935,103.0

Witness: ANDRE Henry

City of Hamilton Interrogatory # 5

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
None

Interrogatory:
a) How many municipal LED conversions in HONI's service territory have received pre-approval for IESO SaveOnEnergy incentives via HONI's CDM group? Please provide the accompanying load reduction values.

b) How are the pre-approved IESO SaveOnEnergy incentive LED conversion projects represented in the street lighting load profile?

Response:
a) 139 LED conversions have been pre-approved by Hydro One for IESO SaveOnEnergy incentives, with estimated energy savings of 35 GWh. Furthermore, 92 LED conversions have been completed since 2012, with estimated energy savings of 22 GWh.

b) The street lighting load profile implicitly includes any saving through the LED conversion projects noted above.

City of Hamilton Interrogatory # 6

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

None

Interrogatory:

a) Is HONI proposing to include, in its five-year IR plan, a mechanism whereby rates can be adjusted, annually or otherwise, to take account of developments like LED conversion programs?

b) If not, why not?

Response:

Hydro One's proposed Custom IR index does not specifically include a mechanism for annually adjusting rates to account for developments like LED conversion programs. That said, Hydro One has proposed a mid-term update to its load forecast for 2021 and 2022. As discussed in Hydro One's responses to Exhibit I-46-COFH-1 and Exhibit I-46-COFH-5, the methodology used to derive the updated load forecast will implicitly reflect the savings associated with CDM programs such as LED conversion programs.

Energy Probe Research Foundation Interrogatory # 65

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
H1-05-01 Page: 3

Interrogatory:
Will Hydro One's capital spending program – and the updating of many of its assets – have any impact on its Total Loss Factors? Please provide any documents, memos or evidence that discuss the impact that the utility's capital spending program will have on Total Loss Factors.

Response:
The potential for reducing losses is a consideration in assessing capital spending programs, where appropriate, while the replacement and reconfiguration of distribution assets can have an impact on system losses. However, there are no documents, memos or evidence that quantifies the impact of the capital spending programs on Total Loss Factors.

OEB Staff Interrogatory # 219

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 7

Interrogatory:

The load forecast was last updated June 7, 2017 using data available in January 2017. Since then, Hydro One prepared a partial update of the application in December 2017.

Please file an update of the load forecast using 2017 actual consumption information, or as much of 2017 as possible. Please also update for updates to explanatory variables including actual and normal weather, as well as historic and forecast economic data.

Response:

The following material is provided based on an update to the load forecast using 2017 actual information:

- Updated Forecast and CDM Tables 3, 4, 7, and 8 originally provided in Exhibit E1, Tab 2, Schedule 1;
- Updated Tables E2, E3, E4, E5, E6, E7, E8a, E8b, and E9 originally provided in Appendix E to that Exhibit; and
- Updated regression results for models in Appendix A and Appendix B to that Exhibit.

Updated explanatory variables including actual and normal weather, as well as historic and forecast economic data are provided in the MS Excel attachment to this response.

Table 3 (Updated) - Hydro One Distribution Load and Number of Customers

Year	GWh Delivery Forecast	Distribution Customer Count
2018	35,055	1,297,878
2019	34,619	1,305,398
2020	34,543	1,312,936
2021	35,381	1,380,394
2022	35,357	1,388,694

Table 4 (Updated) - CDM Impact on Hydro One Distribution Load (GWh)

Year	Retail Customers	ST Customers Direct	ST Customers LDC	Total
2015	1,619	169	856	2,644
2016	1,810	195	929	2,935
2017	1,982	209	957	3,149
2018	2,171	229	1,056	3,456
2019	2,377	252	1,153	3,782
2020	2,504	267	1,219	3,990
2021*	2,639	283	1,208	4,130
2022*	2,695	289	1,225	4,210

Note. All figures are weather-normal.
* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

Table 7 (Updated) - Hydro One Distribution Load Forecast Before and After Deducting CDM Impact (GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2015	21,822	17,241	39,063
2016	21,896	17,178	39,074
2017	21,646	17,322	38,969
2018	21,552	17,342	38,894
2019	21,483	17,296	38,779
2020	21,510	17,370	38,880
2021*	22,573	16,937	39,511
2022*	22,646	16,921	39,567
Load Impact of CDM			
2015	1,619	1,025	2,644
2016	1,810	1,124	2,935
2017	1,982	1,166	3,149
2018	2,171	1,286	3,456
2019	2,377	1,406	3,782
2020	2,504	1,486	3,990
2021*	2,639	1,491	4,130
2022*	2,695	1,514	4,210
Load Forecast After Deducting Impact of CDM			
2015	20,203	16,216	36,419
2016	20,085	16,054	36,139
2017	19,664	16,156	35,426
2018	19,382	16,056	35,055
2019	19,106	15,890	34,619
2020	19,006	15,885	34,543
2021*	19,934	15,446	35,381
2022*	19,951	15,406	35,357

Note. All figures are weather-normal.
* Includes Acquired Utilities.

Table 8 (Updated) - One Standard Deviation Uncertainty Bands for Hydro One Distribution Load (GWh)

Year	Lower Bound	Forecast	Upper Bound
2016	36,139	36,139	36,139
2017	35,426	35,426	35,426
2018	34,447	35,055	35,646
2019	33,801	34,619	35,450
2020	33,578	34,543	35,512
2021*	34,149	35,381	36,600
2022*	33,892	35,357	36,874

* Includes the impact of integrating Acquired Utilities into Hydro One Distribution.

APPENDIX E

Table E.2 (Updated) - Consensus Forecast for Ontario GDP and Housing Starts

Survey of Ontario GDP Forecast (annual growth rate in %)

	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2017)	3.0	2.3	2.3	2.1	2.0	2.0
Conference Board (Nov 2017)	3.0	1.9	1.7	1.9	1.9	1.9
U of T (Oct 2017)	2.8	2.2	2.2	2.3	2.3	2.3
C4SE (Aug 2017)	2.8	2.0	2.5	2.2	1.7	2.0
CIBC (Dec 2017)	3.0	2.3	1.7			
BMO (Jan 2018)	2.8	2.4	2.0			
RBC (Sep 2017)	2.9	2.1	1.8			
Scotia (Jan 2018)	2.9	2.3	1.8			
TD (Dec 2017)	2.9	2.3	1.9			
Desjardins (Dec 2017)	3.0	2.3	1.8			
Central 1 (Dec 2017)	2.8	2.5	2.3			
National Bank (Jan 2018)	3.0	2.6	1.5			
Laurentian Bank (Aug 2017)	2.2	2.0				
Average	**2.9**	**2.2**	**2.0**	**2.1**	**2.0**	**2.1**

Survey of Ontario Housing Starts Forecast (in 000's)

	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2017)	81.0	71.2	63.5	62.9	61.3	59.8
Conference Board (Nov 2017)	81.7	74.7	69.3	70.4	71.3	70.8
U of T (Aug 2017)	80.6	68.1	69.3	71.2	72.4	73.3
C4SE (Jan 2017)	72.8	81.0	79.8	78.9	78.7	75.8
CIBC (Dec 2017)	78.0	70.0	63.0			
BMO (Jan 2018)	80.2	76.0	70.0			
RBC (Sep 2017)	80.1	68.8	70.0			
Scotia (Jan 2018)	79.0	75.0	71.0			
TD (Dec 2017)	81.1	73.1	69.4			
Desjardins (Dec 2017)	82.6	68.9	67.7			
Central 1 (Dec 2017)	80.7	76.6	78.4			
National Bank (Jan 2018)	80.4	69.0	65.0			
Laurentian Bank (Aug 2017)	72.0	71.0				
Average	**79.2**	**72.6**	**69.7**	**70.9**	**70.9**	**69.9**

Forecast updated on January 20, 2018

Table E.3 (Updated) - Economic Variables for Ontario

Year	GDP (2007 M$)	% change	Population (1,000's)	% change	Housing (1,000's)	% change
2005	586,000	3.2	12,528	1.1	77.8	-7.9
2006	596,942	1.9	12,662	1.1	74.4	-4.4
2007	601,735	0.8	12,764	0.8	68.0	-8.6
2008	601,717	0.0	12,883	0.9	75.6	11.2
2009	582,941	-3.1	12,998	0.9	49.5	-34.5
2010	600,135	2.9	13,135	1.1	61.2	23.7
2011	614,590	2.4	13,264	1.0	68.5	11.9
2012	622,725	1.3	13,414	1.1	63.2	-7.8
2013	631,882	1.5	13,556	1.1	59.3	-6.3
2014	648,763	2.7	13,680	0.9	58.3	-1.7
2015	667,659	2.9	13,790	0.8	69.9	20.0
2016	685,008	2.6	13,976	1.4	75.3	7.7
2017	704,570	2.9	14,193	1.6	79.2	5.2
2018	720,361	2.2	14,375	1.3	72.6	-8.4
2019	734,437	2.0	14,553	1.2	69.7	-4.0
2020	750,103	2.1	14,720	1.1	70.9	1.6
2021	764,857	2.0	14,879	1.1	70.9	0.1
2022	780,618	2.1	15,034	1.0	69.9	-1.4

Table E.4 (Updated) - Number of Customers History and Forecast

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	106	248	477	633	893	907	1,004	1,119	1,236	1,356	1,465	1,562
General Service - Demand Billed	7,183	6,550	6,669	6,504	6,098	5,323	5,231	5,239	5,276	5,320	5,365	5,412
General Service - Energy Billed	98,095	98,513	98,568	95,503	87,686	88,878	88,523	87,902	87,625	87,464	87,424	87,505
Residential - Medium Density	402,173	403,304	409,901	416,493	432,519	441,836	447,647	447,029	450,545	454,013	457,450	460,812
Residential - Low Density	368,479	370,995	373,980	373,551	328,170	328,766	330,514	328,159	329,568	330,939	332,412	333,941
Seasonal	157,017	153,653	153,253	153,957	153,498	148,991	147,253	147,537	147,748	147,946	148,130	148,287
Sub-transmission *	794	795	800	882	838	804	805	807	810	813	824	827
Urban General Service - Demand Billed	1,272	1,185	1,184	1,167	1,893	1,715	1,711	1,735	1,739	1,746	1,755	1,766
Urban General Service - Energy Billed	11,650	12,308	12,307	10,807	17,703	17,780	17,747	18,000	18,050	18,123	18,220	18,342
Urban Residential	159,086	167,672	169,795	170,796	208,639	213,199	215,844	226,816	229,377	231,914	234,449	236,957
Street Light *	4,771	4,724	4,804	5,104	5,118	5,251	5,428	5,462	5,495	5,528	5,568	5,602
Sentinel Light *	31,447	30,504	30,380	26,670	25,689	24,364	22,761	22,582	22,407	22,220	22,270	22,150
Unmetered Scattered Load *	5,504	5,512	5,562	5,104	5,624	5,537	5,455	5,490	5,522	5,555	5,799	5,830
Acquired Residential	35,434	35,562	35,892	36,212	36,382	36,487	36,664	37,000	37,257	37,509	37,763	38,015
Acquired General Service - Energy Billed	4,361	4,357	4,340	4,349	4,350	4,348	4,282	4,280	4,278	4,276	4,274	4,272
Acquired General Service - Demand Billed	307	309	322	321	330	336	292	298	303	309	315	321
Acquired Urban Residential	13,709	13,862	14,020	14,175	14,353	14,515	14,703	14,887	15,058	15,227	15,397	15,565
Acquired Urban General Service - Energy Billed	1,180	1,207	1,222	1,243	1,246	1,263	1,257	1,271	1,284	1,297	1,310	1,323
Acquired Urban General Service - Demand Billed	193	185	182	189	193	193	201	205	205	205	205	205
Sum: Includes Newly Acquired for 2021-2022 only	1,247,577	1,255,963	1,267,680	1,267,171	1,274,369	1,283,351	1,289,922	1,297,878	1,305,398	1,312,936	1,380,394	1,388,694

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.5 (Updated) - Hydro One Distribution Load History and Forecast in GWh

Year	Actual/Forecast GWh	Growth	Normalized Weather GWh	Growth
2011	37,641	-0.8	38,062	3.2
2012	37,627	0.0	37,419	-1.7
2013	37,621	0.0	37,418	0.0
2014	37,798	0.5	37,091	-0.9
2015	36,686	-2.9	36,419	-1.8
2016	35,856	-2.3	36,139	-0.8
2017	35,101	-2.1	35,426	-2.0
2018	35,055	-0.1	35,055	-1.0
2019	34,619	-1.2	34,619	-1.2
2020	34,543	-0.2	34,543	-0.2
2021*	35,381	2.4	35,381	2.4
2022*	35,357	-0.1	35,357	-0.1

Table E.6 (Updated) - Actual Sales and Forecast in GWh

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	26	27	28	29	30	31
General Service - Demand Billed	3,100	2,888	2,825	2,928	2,394	2,343	2,482	2,458	2,418	2,401	2,392	2,391
General Service - Energy Billed	2,306	2,518	2,398	2,358	2,189	2,132	2,239	2,207	2,154	2,120	2,096	2,081
Residential - Medium Density	4,402	4,396	4,553	4,499	4,930	4,851	4,596	4,592	4,560	4,569	4,589	4,620
Residential - Low Density	5,491	5,515	5,563	5,541	4,767	4,614	4,418	4,331	4,249	4,207	4,181	4,171
Seasonal	701	666	699	682	671	641	594	585	571	562	555	551
Sub-transmission *	16,787	17,082	16,395	16,599	15,806	15,468	15,143	15,158	15,003	15,026	14,918	14,878
Urban General Service - Demand Billed	686	677	607	628	1,064	1,036	1,020	1,037	1,022	1,016	1,014	1,016
Urban General Service - Energy Billed	397	415	400	382	600	589	597	604	595	591	589	589
Urban Residential	1,541	1,563	1,564	1,528	1,983	1,947	1,833	1,910	1,900	1,908	1,920	1,937
Street Light *	125	127	125	122	122	122	100	99	99	99	109	109
Sentinel Light *	19	19	20	20	21	21	14	14	13	13	14	14
Unmetered Scattered Load *	23	23	23	23	24	24	29	29	29	30	31	31
Acquired Residential	308	302	305	303	301	300	297	298	295	293	290	287
Acquired General Service - Energy Billed	114	111	110	111	110	109	111	111	109	108	107	106
Acquired General Service - Demand Billed	270	233	232	241	235	237	237	239	237	236	236	236
Acquired Urban Residential	105	106	107	106	102	100	100	99	98	97	95	94
Acquired Urban General Service - Energy Billed	41	43	44	43	43	43	41	42	41	41	41	42
Acquired Urban General Service - Demand Billed	164	128	129	136	136	138	111	147	145	145	146	146
Sum: Includes Acquired Utilities for 2021-2022 only	35,587	35,901	35,186	35,327	34,586	33,804	33,093	33,051	32,641	32,572	33,354	33,330

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.7 (Updated) - Weather Corrected Sales and Forecast in GWh

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	26	27	28	29	30	31
General Service - Demand Billed	3,150	2,959	2,803	2,769	2,373	2,368	2,515	2,480	2,445	2,432	2,428	2,431
General Service - Energy Billed	2,343	2,580	2,380	2,229	2,169	2,155	2,269	2,218	2,167	2,136	2,114	2,101
Residential - Medium Density	4,466	4,495	4,528	4,453	4,901	4,907	4,645	4,619	4,595	4,612	4,640	4,679
Residential - Low Density	5,571	5,640	5,532	5,485	4,738	4,668	4,464	4,379	4,298	4,256	4,230	4,220
Seasonal	711	681	695	675	667	648	600	585	571	562	555	551
Sub-transmission *	16,901	16,427	16,421	16,271	15,683	15,526	15,243	15,158	15,003	15,026	14,918	14,878
Urban General Service - Demand Billed	697	694	602	594	1,054	1,047	1,034	1,015	995	985	979	976
Urban General Service - Energy Billed	404	425	397	362	595	595	605	593	582	575	571	569
Urban Residential	1,563	1,599	1,555	1,513	1,971	1,969	1,852	1,834	1,817	1,816	1,820	1,829
Street Light *	125	127	125	122	122	122	100	99	99	99	109	109
Sentinel Light *	19	19	20	20	21	21	14	14	13	13	14	14
Unmetered Scattered Load *	23	23	23	23	24	24	29	29	29	30	31	31
Acquired Residential	312	309	303	300	299	300	300	298	295	293	290	287
Acquired General Service - Energy Billed	115	114	109	105	109	109	112	111	109	108	107	106
Acquired General Service - Demand Billed	274	239	230	228	233	237	240	239	237	236	236	236
Acquired Urban Residential	107	108	107	105	101	100	101	99	98	97	95	94
Acquired Urban General Service - Energy Billed	42	44	43	40	42	43	42	42	41	41	41	42
Acquired Urban General Service - Demand Billed	167	132	128	128	135	138	145	147	145	145	146	146
Sum: Includes Acquired Utilities for 2021-2022 only	35,982	35,680	35,094	34,531	34,334	34,068	33,397	33,051	32,641	32,572	33,354	33,330

* Includes Acquired Utilities corresponding figures in 2021 and 2022 only.

Table E.8a (Updated) - Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2011	66,297	10,331,311	1,964,583	35,730,299	671,097	458,532	48,092,490
2012	80,371	10,060,780	1,914,575	36,409,471	587,036	374,718	48,465,197
2013	127,613	9,893,511	1,878,538	35,537,470	669,854	390,595	47,437,132
2014	161,733	9,883,885	1,872,751	35,781,683	675,645	395,502	47,700,052
2015	165,405	8,536,187	3,076,837	35,473,518	662,107	393,100	47,251,947
2016	171,973	8,118,010	2,846,792	33,699,203	665,454	397,953	44,835,978
2017	188,672	7,848,256	2,745,769	30,285,554	663,744	403,987	41,068,251
2018	197,039	7,860,142	2,698,633	30,587,100	670,226	415,528	41,342,914
2019	202,720	7,748,892	2,639,651	30,273,707	664,657	411,015	40,864,970
2020	209,833	7,709,334	2,605,735	30,321,166	662,985	410,313	40,846,068
2021	216,001	7,694,461	2,581,634	30,540,679	662,217	412,725	42,107,717
2022	222,751	7,704,261	2,567,244	30,461,169	662,705	414,543	42,032,673

* The total and ST include corresponding Acquired Utilities figures and for only 2021 and 2022.

Table E.8b (Updated) - Weather Corrected Actual and Forecast for Billing Peak in kW

Rate Class	DGEN	GSd	UGd	ST *	Acquired GSd	Acquired UGD	Total *
2011	66,297	10,030,850	1,907,448	34,691,170	651,580	445,197	46,695,764
2012	80,371	9,909,510	1,885,788	35,862,030	578,209	369,084	47,737,698
2013	127,613	9,807,861	1,862,275	35,229,815	664,055	387,214	47,027,563
2014	161,733	9,849,440	1,866,224	35,656,983	673,290	394,123	47,534,380
2015	165,405	8,484,670	3,058,267	35,259,430	658,111	390,728	46,967,772
2016	171,973	8,116,669	2,846,321	33,693,637	665,344	397,887	44,828,600
2017	191,621	7,970,925	2,788,685	30,758,917	674,118	410,301	41,710,148
2018	197,039	7,860,142	2,698,633	30,587,100	670,226	415,528	41,342,914
2019	202,720	7,748,892	2,639,651	30,273,707	664,657	411,015	40,864,970
2020	209,833	7,709,334	2,605,735	30,321,166	662,985	410,313	40,846,068
2021	216,001	7,694,461	2,581,634	30,540,679	662,217	412,725	42,107,717
2022	222,751	7,704,261	2,567,244	30,461,169	662,705	414,543	42,032,673

* The total and ST include corresponding Acquired Utilities figures and for only 2021 and 2022.

Table E.9 (Updated): Hydro One Distribution CDM Impacts (GWh) by Rate Class

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
General Service - Demand Billed	191.0	225.3	271.8	329.5	295.3	328.5	368.1	405.4	445.9	472.0	479.3	491.1
General Service - Energy Billed	193.8	270.1	317.3	367.1	373.6	418.1	461.6	503.4	549.0	575.9	582.3	592.1
Residential - Medium Density	116.6	115.2	114.2	176.6	238.6	269.9	294.3	324.6	358.1	380.0	388.2	398.3
Residential - Low Density	145.4	144.5	139.6	217.5	230.7	256.7	282.9	307.8	334.9	350.6	353.9	359.2
Seasonal	18.6	17.5	17.5	26.8	32.5	35.7	38.0	41.1	44.5	46.3	46.5	46.9
Sub-transmission *	551.2	667.1	731.7	922.0	991.8	1,087.5	1,128.1	1,243.5	1,359.4	1,436.9	1,442.0	1,464.6
Urban General Service - Demand Billed	42.2	52.8	58.3	70.6	131.2	145.2	151.3	165.9	181.6	191.2	193.3	197.3
Urban General Service - Energy Billed	33.4	44.5	52.9	59.5	102.4	115.5	123.1	134.7	147.4	155.1	157.4	160.4
Urban Residential	40.8	41.0	39.2	60.0	96.0	108.3	117.4	128.9	141.6	149.6	152.2	155.7
Acquired Residential	0.9	1.6	2.5	4.2	5.7	6.5	9.1	12.0	14.2	16.6	19.5	20.4
Acquired General Service - Energy Billed	0.7	1.7	2.6	3.9	4.8	5.9	8.5	11.2	13.2	15.6	18.2	19.2
Acquired General Service - Demand Billed	1.0	2.1	3.7	4.8	5.6	7.6	10.6	13.9	16.5	19.3	22.7	23.8
Acquired Urban Residential	0.4	0.7	1.0	1.6	2.1	1.8	2.3	2.8	3.3	3.7	4.2	4.4
Acquired Urban General Service - Energy Billed	0.5	1.0	1.4	2.3	2.9	2.5	3.0	3.6	4.2	4.7	5.4	5.6
Acquired Urban General Service - Demand Billed	4.0	4.3	5.8	7.6	10.9	10.8	10.7	17.0	19.4	22.1	25.2	26.2
Sum: Includes Acquired Utilities for 2021-2022 only	1,333	1,578	1,743	2,230	2,492	2,765	2,965	3,255	3,562	3,758	3,890	3,965

* Includes Acquired Utilities corresponding figure in 2021 and 2022 only.

APPENDIX A
MONTHLY ECONOMETRIC MODEL

The monthly econometric model uses the State-Space approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that could affect the energy estimates because these events would likely cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LRTLT = f (LGDPONT, LBPONT, D98Jan)

where:
LRTLT = logarithm of retail load,
LGDPONT = logarithm of Ontario GDP in constant 1997 dollars,
- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance
- Forecast is based on annual consensus forecast for Ontario GDP as presented in Appendix E

LBPONT = logarithm of Ontario residential building permits in constant dollar,
- History is based on monthly value of Ontario residential building permits from Statistics Canada
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

D98Jan = dummy variable to account for the load impact of 1998 Ice Storm, equals 1 in January 1998 and zero elsewhere,

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

Seasonal Factors	State-Space (SS) parameters:
A[1]	-0.110997
K[1]	-0.522702

<u>Non-Seasonal</u>	
<u>Factors</u>	<u>SS parameters:</u>
A[1]	0.480758
K[1]	-0.39066
GDPONT[-4]	0.0570301
BPONT[-8]	0.0064509
D98JAN	-0.0152325

R-squared = 0.987, R-squared corrected for mean = 0.987, Durbin-Watson Statistics = 2.24.

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain for the variations in load. In fact, the results show that in this case the fit is very good, and therefore there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the above parameters are used in the monthly regression equation described on the previous page to generate the forecast for Hydro One Distribution load.

APPENDIX B
ANNUAL ECONOMETRIC MODELS

Retail Load

Annual econometric model for retail load uses personal disposable income per household, relative energy price, and heating degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-4)-LPGASRES(-4))+C(4)
*LHDD+C(5)*LRTLT(-1)-C(4)*C(5)*LHDD(-1)+C(6)*D99A+C(7)*TR
+C(8)*TR2+C(9)*D08ON

where:
LRTLT = logarithm of retail load,
LYPDPHH = logarithm of Ontario personal disposable income per household / house in constant dollar,

- History is based on disposable income in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistics Canada and divided by the number of households / houses based on IHS Global Insight housing starts
- Forecast is based on forecasts of disposable income from C4SE, University of Toronto (PEAP) and Conference Board of Canada deflated by CPI from IHS Global Insight and divided by the number of household / houses based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016 Outlook
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,
D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,
TR2 = TR to power 2,
D08ON = a dummy variable to account for economic changes, equals zero prior to 2008 and 1 elsewhere.
C(1) – C(9) = variable coefficients.

The estimated coefficients and associated statistics are presented below:

	Estimated Coefficient	Standard Error	t-ratio
C(1)	5.455606	1.417433	3.848934
C(2)	0.501070	0.117024	4.281767
C(3)	-0.018521	0.011507	-1.609597
C(4)	0.059849	0.039567	1.512599
C(5)	0.286743	0.125373	2.287128
C(6)	-0.024341	0.009153	-2.659188
C(7)	-0.095632	0.030017	-3.185970
C(8)	0.002488	0.000682	3.649962
C(9)	-0.013932	0.008698	-1.601852

R-squared = 0.989, Adjusted R-squared = 0.976, Durbin-Watson Statistic = 1.56.

Similar to the regression analysis in the case of the Monthly Econometric model above, the goodness of fit, measured by (Adjusted) R-square for the Annual Econometric Model for retail load, is also found to be close to 1. Therefore the assessment on an annual basis also leads to a forecast outcome which provides consistent results, thus giving confidence to the econometric method.

The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for personal disposable income per household / house, energy prices, and heating degree days and dummy variables, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Distribution load.

<u>Embedded LDC Load</u>

Annual econometric model for embedded LDC load uses number of houses / households, relative energy price, and heating and cooling degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LEMBLDCS=C(1)+C(2)*D(LHHOLD)+C(3)*(LPELRES(-1)-LPGASRES(-1))
+C(4)*LCDD+C(5)*LHDD+C(6)*LEMBLDCS(-1)-C(4)*C(6)
*LCDD(-1)-C(5)*C(6)*LHDD(-1)+C(7)*TR

where:
LEMBLDCS = logarithm of Embedded LDC load,
LHHOLD = logarithm of Ontario number of households / houses,
- History from IHS Global Insight housing starts
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector
- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016 Outlook
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,
- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,
D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,
TR = a dummy variable to account for a shift in growth pattern of distribution load, increases by 1 per year prior to 1989 and no increase afterwards,
C(1) – C(7) = variable coefficients.

The estimated coefficients and associated statistics are presented below:

	Estimated Coefficient	Standard Error	t-ratio
C(1)	1.688480	0.599547	2.816260
C(2)	1.658200	0.898035	1.846476
C(3)	-0.049467	0.016226	-3.048694

C(4)	0.008636	0.009463	0.912634
C(5)	0.013980	0.057537	0.242965
C(6)	0.790897	0.073593	10.74685
C(7)	0.010313	0.004125	2.499980

R-squared = 0.981, Adjusted R-squared = 0.977, Durbin-Watson Statistic = 1.85.

Similar to the regression analysis in the case of the other econometric models noted above, the goodness of fit, measured by (Adjusted) R-square for the Embedded LDC Model, is also found to be close to 1 leading to a forecast outcome which provides consistent results, thus giving confidence to the econometric method. The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for Ontario number of households / houses, energy prices, and cooling and heating degree days and dummy variable, the above parameters are used in the annual regression equation described above to generate the forecast for Hydro One Embedded LDC load.

OEB Staff Interrogatory # 220

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 1 and 13

Interrogatory:

Hydro One assumes typical weather conditions based on the average of the last 31 years.

a) Please confirm that the comparisons in Table 5 on page 13 of the Load Forecast evidence are based on averages of the last 20 and 10 years.

b) If part a) cannot be confirmed, please explain.

c) Please prepare a forecast run using a 20 year trend definition of normal weather.

Response:

a) Confirmed.

b) Not applicable in view of response to part a).

c) Provided below is Hydro One's Retail GWh forecast based on a 20-year trend definition of normal weather.

	2018	2019	2020	2021*	2022*
20-year trend	19,938	19,771	19,775	20,695	20,692

* Includes the load impact of integrating Acquired Utilities into Hydro One Distribution.

OEB Staff Interrogatory # 221

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 11 – Load Forecasting Methodology

Interrogatory:

On page 11, Hydro One provides the following:

> *"Hydro One Distribution's load forecast is developed using both econometric and end-use approaches. The load impacts of CDM are added back to the historical values during the modeling process (see Figure 2 below)."*

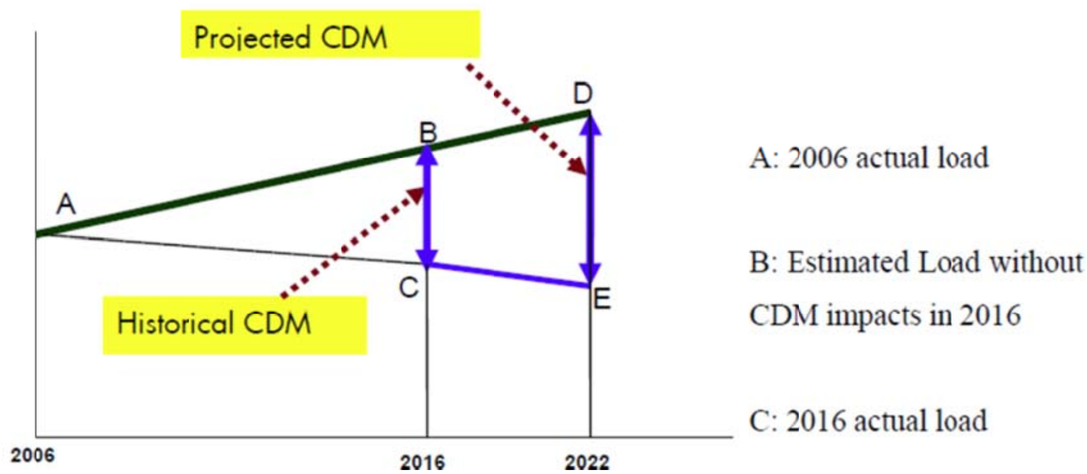

Figure 2: Incorporation of CDM in the Load Forecast

The forecast base-year is corrected for abnormal weather conditions and the forecast growth rates are applied to the normalized base-year value. The forecast is weather-normal in the sense that it predicts the future load under normal weather conditions.

a) What are the points "D" and "E" in Figure 2?

b) Please provide a more precise explanation of Hydro One's methodology for incorporating or otherwise adjusting for historical actual and forecasted CDM in its load forecast.

Response:

a) Point D represents the forecasted gross load (i.e., load without CDM impact) in 2022 based on economic theory. Point E represents the load forecast net of CDM in 2022.

b) A detailed description of the various methodologies used to incorporate conservation and demand management impacts in the load forecast was provided in a study on this subject, which in support of Hydro One's last distribution application (EB-2013-0416, see Exhibit A/Tab 16/Schedule 4, pages 80-90).

Hydro One's methodology employs the following steps, as illustrated in Figure 1 below, which is reproduced from the above-mentioned study.

- The load impact of CDM is added back to the actual load yielding a consistent data set (gross of CDM) over time for modeling;
- The adjusted (gross) load data is then used to model and forecast the load using appropriate explanatory variables (e.g., gross domestic product, income, population, number of households, etc.) as well as prices in a manner consistent with economic theory. Having used consistent data and having accounted for all influential factors affecting the load, the model does not suffer from structural change due to CDM. As a result, both estimated model coefficients (elasticity) and forecasts are unbiased and efficient; and
- Finally, the historical CDM impacts and CDM impacts during the forecast period are deducted from the gross load forecast to arrive at the load forecast net of CDM.

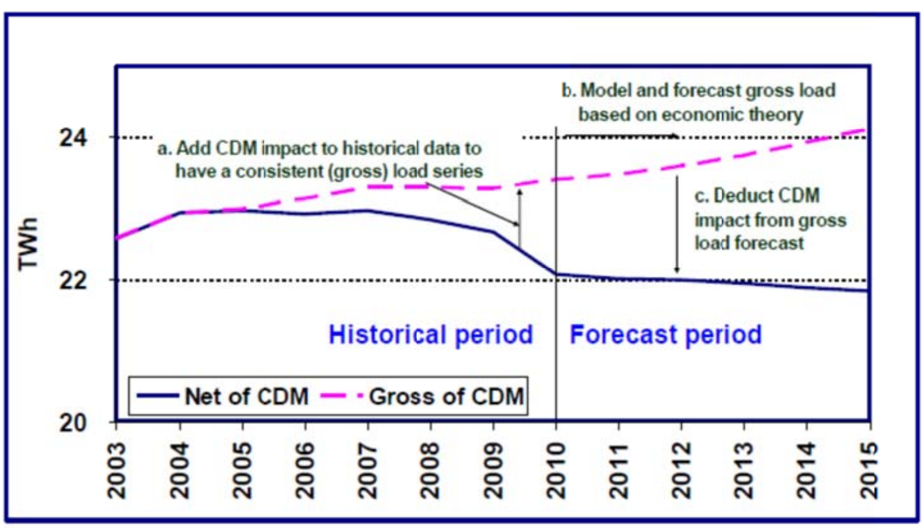

Figure 1

OEB Staff Interrogatory # 222

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 17

Interrogatory:

In producing 2015 load profiles, 2015 actual hourly smart meter and interval meter data was used. Where hourly data was not available for all customers, the available hourly data was scaled up to the 2015 actual load for the rate class.

Has Hydro One considered other methods, such as calculating an hourly residual net of known hourly customers, and estimated losses in developing the hourly load profile for each rate class? Please describe.

Response:

The method that Hydro One uses to generate the load profile by rate class is in line with the industry best practice.

Hydro One did not consider the method mentioned above "as calculating an hourly residual net of known hourly customers, and estimated losses in developing the hourly load profile for each rate class" because the hourly load data for each rate class is not available at the aggregate level.

OEB Staff Interrogatory # 223

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 22-23

Interrogatory:

Appendix A provides a description of the monthly model. Page 2 provides the coefficient estimates. Please explain the following:

a) A[1]

b) K[1]

c) GDPONT[-4]. Does the [-4] mean that the variable is lagged by four months? What is the rationale for this lag, and why is the current month's value not relevant?

d) BPONT[-8]. Does the [-8] mean that the variable is lagged by eight months? What is the rationale for this lag? Further, on page 1, Hydro One defines the variable LBPONT as "logarithm of Ontario residential building permits in constant dollar". How is this variable expressed in dollars?

e) How were the appropriate lags for Ontario GDP and Ontario building permits determined?

Response:

a) Parameters A[1] and K[1] are not defined by the user of algorithm. They are internally defined and calculated to handle the following tasks. (1) Account for seasonality in data through seasonal differencing (which is associated with one set of parameters A[1] and K[1]). (2) Account for rate of change in data through first-differencing (which is associated with another set of parameters A[1] and K[1]).

b) Please see answer to question a).

c) Yes, [-4] means that the variable is lagged by four months. It would reflect the fact that it takes time to measure the actual GDP and to disseminate GDP information to the public. For example, the current month value is not known to customers to respond to.

d) Yes, [-8] means that the variable is lagged by eight months. It would reflect the fact that, after obtaining a building permit, it takes time to build the house, find a buyer for it, and finally for the buyer to move in and start using electricity. The value of residential building permit is measured in nominal dollar by Statistic Canada. (In this Application, the nominal dollar series is divided by the implicit price index for residential construction from Ministry of Finance to arrive at the constant dollar value.)

e) The number of lags for GDPONT and for BPONT was selected using standard regression analysis including consistency of results with the underlying economic theory.

OEB Staff Interrogatory # 224

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 24-26 – Annual Retail Load Model

Interrogatory:

Hydro One specifies the following equation format for the annual Retail Load Model:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-4)-LPGASRES(-4))+C(4)*LHDD+C(5)*LRTLT(-1)-C(4)*C(5)*LHDD+C(6)*D99A+C(7)*TR+C(8)*TR2+C(9)*D08ON

and defines the terms following:

LRTLT = logarithm of retail load,

LYPDPHH = logarithm of Ontario personal disposable income per household / house in constant dollar,

- History is based on disposable income in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistics Canada and divided by the number of households / houses based on IHS Global Insight housing starts

- Forecast is based on forecasts of disposable income from C4SE, University of Toronto (PEAP) and Conference Board of Canada deflated by CPI from IHS Global Insight and divided by the number of household / houses based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016

- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016 Outlook

- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

TR2 = TR to power 2,

D08ON = a dummy variable to account for economic changes, equals zero prior to 2008 and 1 elsewhere.

C(1) – C(9) = variable coefficients.

OEB staff notes that, since the model is specified in double-log (double-logarithmic) form, the coefficients of variables such as income and price can be interpreted as the elasticities of demand. For example, C(2) is the income elasticity of demand.

OEB staff notes that the regression equation could be written as follows, after rearranging terms:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*LPELRES(-4)-C(3)*LPGASRES(-4)
+C(4)*(1+C(5))*LHDD+C(5)*LRTLT(-
1)+C(6)*D99A+C(7)*TR+C(8)*TR2+C(9)*D08ON

a) Do LPELRES(-4) and LPGASRES(-4) mean that these variables are lagged by 4 years? If so, why does demand depend of such prices that are lagged so long, and not on current prices?

b) Are PELRES (residential electricity price) and PGASRES (residential natural gas price) specified in real (adjusted for inflation) or nominal terms?

c) As OEB staff has written it, C(3) is the price elasticity of demand and –C(3) is the cross-price elasticity of demand with respect to natural gas prices. The estimated coefficient is -0.013723, but is statistically insignificant (t-statistic of -1.04), as shown on page 26. This means that, all else being equal, a 1% increase in the price of electricity results in a 0.013723% decline in electricity consumption.

   i. Hydro One's specification assumes that the price elasticity of demand and the cross-price elasticity of demand with respect to natural gas prices are equal in magnitude. What is the basis for Hydro One's assumption?

   ii. While electricity demand is basically assumed to be price inelastic (i.e. price elasticity between 0 and -1), does Hydro One believe that the price elasticity of electricity demand is so small? Please explain your response.

d) What is the purpose of specifying the coefficient of LHDD as C(4)+C(4)*C(5) = C(4)*(1+C(5))?

e) Please confirm that LRTLT(-1) means that annual demand lagged one year is used as a regressor variable.

f) Why is HDD at Pearson Airport considered to be a suitable explanatory variable for weather impacts for Hydro One's expansive service territory?

g) Why is there no variable for CDD (Cooling Degree Days)?

Response:

a) Yes, LPELRES(-4) and LPGASRES(-4) mean that these variables are lagged by 4 years. These variables measure economic incentive for fuel-switching. However, switching from electricity to natural gas and vice-versa requires changing the heating and probably the cooking systems, which involves an initial costly process. In such situations, it would take time for customers to opt for such a change in view of changes energy prices noted above.

For example, one needs to make sure that changes in energy prices are stable over time through a wait-and-see strategy. From a practical point of view, the requisite number of lags was selected using standard regression analysis, in particular, in relation to the size and sign for related price elasticity of demand for electricity. The reason for not using the current price is that, when it was tried, its estimated coefficient turned out to be positive (and statistically insignificant), which is counterintuitive from both economic theory and a practical point of view as the load impact of price is expected to be negative.

b) Both PELRES and PGASRES are measured in real terms.

c)

i. The elasticity of demand with respect to electricity price is assumed to have the same magnitude but opposite sign compared to cross-price elasticity of demand with respect to natural gas price. The basis for this assumption is economic theory asserting that demand for a commodity depends on the ratio of its price to the price of its substitute (see, e.g., Hal R. Varian (2014) "Intermediate Microeconomics, ninth edition, W. W. Norton, & Co., New York, London, chapters 7-8). In this connection, due to the properties of logarithms, the price terms LPELRES –LPGASRES can also be written as Log (PELRES/PGASRES) reflecting the ratio of prices in log form consistent with the economic theory.

ii. There is limited availability of natural gas in Hydro One Distribution service area. In this connection, one would expect a low price elasticity of demand over the year compared to metropolitan areas. However, Hydro One believes price elasticity is stronger in response to price differential across time-of-use periods as customers have the chance to shift part of their electricity usage away from peak period when the price is highest. Clearly, assuming no conservation effect in this regard, i.e., if same amount of load is shifted across hours within a year, the annual consumption would not be affected.

d) The lag operator (-1) is missing from the expression -C(4)*C(5)*LHDD. The correct expression is: -C(4)*C(5)*LHDD(-1). It measures impact of weather on the lagged value of electricity demand [LRTLT(-1)], which is also on the right-hand-side of the equation.

e) Confirmed.

f) Hydro One Distribution Service territory is scattered across Ontario, with more concentration in the southern Ontario. In this connection, weather conditions at Pearson Airport, which is located in south-central Ontario, would be the most appropriate weather station to be used is a multivariate regression model for retail load. Moreover, weather conditions in different locations across Ontario are similar subject to a few hours difference in timing and, normally, a constant differential in temperature / degree days. Consequently, the Pearson Airport can stand for a close proxy of weather conditions across Ontario.

g) Inclusion of logarithm of CDD (LCDD) in the model was also considered, but the estimated coefficient of LCDD was close to zero and was not statistically significant. This counterintuitive result is basically due to the impact of multicollinearity (i.e., correlation between explanatory variables). However, a higher (lower) HDD normally implies a lower (higher) CDD in a given year so that the coefficient of HDD implicitly would measure the net impact of both CDD and HDD on the annual load.

OEB Staff Interrogatory # 225

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 24-26

Interrogatory:

In the Retail Load forecast, several coefficients have a t-ratio between -2.0 and 2.0 indicating a lack of certainty in the statistical significance of the variables, including C(3), C(4), and C(9) relating to LPELRES(-4)-LPGASRES(-4), LHDD, and D08ON.

a) Has Hydro One tested other variables related to differences in fuel costs, heating degree days, and the economic changes of 2008?

b) Has Hydro One considered forecasting using explanatory variables rather than logarithms of explanatory variables?

Response:

a) Yes, each equation presented in the evidence has been arrived at after examining various other specifications/variables when available. However, there are limitations in finding an alternative variable for energy prices. Such prices should be related to electricity demand and its close substitute (natural gas) and, as such, there is a unique measure for each of these prices available. The dummy variable D08ON picks up the impact of structural change in economy after financial crisis. It is customary to pick up the impact of such broad changes by a dummy variable rather than a great number of variables reflecting the different aspects of the new structure, which may lead to a prohibitive number of variables for performing the regression.

b) Yes, other specifications have been tried in the past. However, the log-linear specification of explanatory variables proved to be stable over time. From a practical point of view, growth rate of most economic variable normally move in tandem so that log-linear specification is the suitable way of linking variables involved in modeling a specific commodity (here, electricity usage). Another advantage of such specification is that the estimated coefficient of each explanatory variable in the model directly measure elasticity related to that variable.

OEB Staff Interrogatory # 226

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 24-26

Interrogatory:

The prior year retail load forecast, LRTLT(-1) is used in generating the current year forecast.

Please prepare a sensitivity of a 5% change in the 2018 forecast on the results of 2019, 2020, 2021, and 2022.

Response:

The impact of 5% change in the 2018 retail load forecast on the results of 2019-2022 is presented in the following table.

Year	Impact
2019	1.52%
2020	0.46%
2021	0.14%
2022	0.04%

Witness: ALAGHEBAND Bijan

OEB Staff Interrogatory # 227

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
E1-02-01 Page: 27-28 - Annual Embedded LDC Load Model

Interrogatory:
Hydro One specifies the following equation format for the annual Embedded LDC Load Model:

LEMBLDCS=C(1)+C(2)*D(LHHOLD)+C(3)*(LPELRES(-1)-LPGASRES(-1)) +C(4)*LCDD+C(5)*LHDD+C(6)*LEMBLDCS(-1)-C(4)*C(6)*LCDD(-1)-C(5)*C(6)*LHDD(-1)+C(7)*TR

and defines the terms as:

LEMBLDCS = logarithm of Embedded LDC load,
LHHOLD = logarithm of Ontario number of households / houses,
- History from IHS Global Insight housing starts
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector
- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016 Outlook
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,
- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

C(1) – C(7) = variable coefficients.

a) Please provide the definition of the variable LCDD. If this is the logarithm for Cooling Degree Days as measured by Environment Canada at Pearson Airport, please explain how CDD at Pearson Airport is considered appropriate for the demand of all of the embedded distributors served by Hydro One Networks distribution throughout Ontario.

b) Why is HDD at Pearson Airport considered to be a suitable explanatory variable for weather impacts for Hydro One's expansive service territory with respect to the energy demand/consumption of embedded distributors served by One Networks distribution throughout Ontario?

c) Hydro One provides the following estimates and associated statistics for the model coefficients:

	Estimated Coefficient	Standard Error	*t*-Statistic
C(1)	1.763528	0.621723	2.836516
C(2)	1.586283	0.916446	1.730908
C(3)	-0.046937	0.016798	-2.794270
C(4)	0.007978	0.009718	0.820939
C(5)	0.012515	0.058312	0.214612
C(6)	0.781907	0.076054	10.28089
C(7)	0.010703	0.004228	2.531607

C(4) is the coefficient for LHDD and C(5) is the coefficient for LCDD. Both coefficients have low t-statistics and are statistically insignificant at even a 90% confidence level. Why has Hydro One retained these variables given their insignificant estimated coefficients?

d) C(3) is the price elasticity of demand, and has an estimated value of -0.46937. In the Retail Load Model for Hydro One's directly served end customers, the estimated price elasticity of demand is estimated at -0.013723. Notwithstanding that the two estimates may not be statistically significantly different, please provide Hydro One's views on whether these estimated price elasticities for the two segments are reasonable from a conceptual economic basis.

Response:

a) Yes, LCDD represents "logarithm of Cooling Degree Days" as measured by Environment Canada at Pearson Airport. As in the case of retail load, embedded LDC load is scattered across Ontario, with concentration in southern Ontario. In this connection, weather conditions at Pearson Airport (located in south-central Ontario) would be the most appropriate weather station to be used is a multivariate regression model for embedded LDC load. Other justifications are also similar to those mentioned in part f) of Exhibit I-46-Staff-224.

b) HDD at Pearson Airport is considered to be a suitable explanatory variable for the same reasons mentioned in part a) above.

c) Hydro One retains the identified variables because embedded LDC load is sensitive to temperature as measured by LHDD and LCDD, so the impact of LCDD and LHHD on load cannot be expected to be zero. Also, from a practical point of view, the coefficients have correct sign and reasonable magnitude. Another reason is that statistical significance may be misleading in the presence of multicollinearity (i.e., correlation amongst explanatory variables), which is normally the case amongst economic variables. Multicollinearity reduces statistical significance of explanatory variable, undermining their theoretical importance.

d) The price elasticity of demand in the equation noted above is 0.046937 (rather than 0.46937 stated in the question). This estimated elasticity is higher compared to the price elasticity of demand in the retail equation. This is consistent with the fact that natural gas is more available in embedded LDCs areas compared to retail areas so that it is more feasible to switch between using electricity and natural gas as the price changes. In other words, embedded LDC load can be more responsive to price changes, leading to a higher price elasticity of demand, compared to retail load. Consequently, Hydro One believes that the estimated price elasticity of demand for retail and embedded LDC customers are reasonable from a conceptual economic basis.

OEB Staff Interrogatory # 228

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 27-28

Interrogatory:

In the Embedded LDC load forecast, three coefficients have a t-ratio between -2.0 and 2.0 indicating a lack of certainty in the statistical significance of the variables, including C(2), C(4), and C(5) relating to LHHOLD, LCDD, and LHDD. C(5) in particular has a t-stat of only 0.214612 indicating very little certainty of statistical significance at all.

a) Has Hydro One tested other variables related to differences in fuel costs, heating degree days, and the economic changes of 2008?

b) Has Hydro One considered forecasting using explanatory variables rather than logarithms of explanatory variables?

Response:

a) Please see response to part a) of Exhibit I-46-Staff-225.

b) Please see response to part b) of Exhibit I-46-Staff-225.

OEB Staff Interrogatory # 229

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 27-28

Interrogatory:

The prior year forecast, LEMBLDCS(-1) is used in generating the current year forecast.

Please prepare a sensitivity of a 5% change in the 2018 forecast on the results of 2019, 2020, 2021, and 2022.

Response:

The impact of 5% change in the 2018 embedded LDC forecast on the results of 2019-2022 is presented in the following table.

Year	Impact
2019	3.91%
2020	3.06%
2021	2.39%
2022	1.87%

Witness: ALAGHEBAND Bijan

OEB Staff Interrogatory # 230

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
E1-02-01 Page: 39 and 41

Interrogatory:
Table E.5 normalized energy use for Hydro One Distribution and Table E.7 weather corrected sales and forecast do not match.

Please reconcile the apparent discrepancy between Tables E.5 and E.7 for all years.

Response:
Table E.5 presents Hydro One Distribution load at purchase level so that it includes distribution losses. In contrast, Table E.7 presents Hydro One Distribution load at sales level so that it excludes distribution losses. Thus, the difference between the two sets of figures is distribution losses.

OEB Staff Interrogatory # 231

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01 Page: 39-41

Interrogatory:

The tables supplied include the effect of Acquired Utilities in 2021 and 2022.

a) Please provide versions of E.4, E.6, and E.7 which exclude the acquired utilities.

b) Please provide versions of E.4, E.6, and E.7 which include only the acquired utilities for all 2011 – 2022, or all available years.

Response:

a) Please see below versions of E.4, E.6, and E.7 for Hydro One excluding Acquired Utilities.

Table E.4a: Number of Customers History and Forecast, Excluding Acquired Utilities

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
		142	229	156	260	14	127	119	120	124	111	101
Generator	106	248	477	633	893	907	1,034	1,152	1,272	1,396	1,508	1,608
General Service - Demand Billed	7,183	6,550	6,669	6,504	6,098	5,323	5,379	5,406	5,457	5,511	5,563	5,612
General Service - Energy Billed	98,095	98,513	98,568	95,503	87,686	88,878	88,817	88,484	88,423	88,405	88,435	88,515
Residential - Medium Density	402,173	403,304	409,901	416,493	432,519	441,836	446,636	446,102	449,958	453,821	457,608	461,272
Residential - Low Density	368,479	370,995	373,980	373,551	328,170	328,766	330,695	328,410	330,076	331,741	333,473	335,223
Seasonal	157,017	153,653	153,253	153,957	153,498	148,991	149,166	149,485	149,813	150,145	150,445	150,701
Sub-transmission	794	795	800	882	838	804	806	808	811	814	817	819
Urban General Service - Demand Billed	1,272	1,185	1,184	1,167	1,893	1,715	1,715	1,744	1,753	1,762	1,772	1,783
Urban General Service - Energy Billed	11,650	12,308	12,307	10,807	17,703	17,780	17,763	18,074	18,166	18,268	18,380	18,501
Urban Residential	159,086	167,672	169,795	170,796	208,639	213,199	214,934	225,944	228,666	231,390	234,088	236,737
Street Light	4,771	4,724	4,804	5,104	5,118	5,251	5,286	5,323	5,364	5,401	5,438	5,474
Sentinel Light	31,447	30,504	30,380	26,670	25,689	24,364	24,166	23,987	23,822	23,645	23,501	23,388
Unmetered Scattered Load	5,504	5,512	5,562	5,104	5,624	5,537	5,567	5,597	5,633	5,667	5,701	5,735
Total	1,247,577	1,255,963	1,267,680	1,267,171	1,274,369	1,283,351	1,291,963	1,300,516	1,309,216	1,317,967	1,326,728	1,335,368

Table E.6a: Actual Sales and Forecast in GWh, Excluding Acquired Utilities

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	18	18	19	20	20	21
General Service - Demand Billed	3,100	2,888	2,825	2,928	2,394	2,343	2,378	2,342	2,317	2,312	2,302	2,297
General Service - Energy Billed	2,306	2,518	2,398	2,358	2,189	2,132	2,146	2,104	2,064	2,043	2,018	1,999
Residential - Medium Density	4,402	4,396	4,553	4,499	4,930	4,851	4,939	4,924	4,917	4,953	4,971	4,998
Residential - Low Density	5,491	5,515	5,563	5,541	4,767	4,614	4,640	4,539	4,478	4,457	4,426	4,408
Seasonal	701	666	699	682	671	641	643	632	620	613	605	600
Sub-transmission	16,787	17,082	16,395	16,599	15,806	15,468	15,625	15,528	15,368	15,362	15,323	15,336
Urban General Service - Demand Billed	686	677	607	628	1,064	1,036	1,046	1,058	1,048	1,047	1,044	1,044
Urban General Service - Energy Billed	397	415	400	382	600	589	594	598	592	591	589	589
Urban Residential	1,541	1,563	1,564	1,528	1,983	1,947	1,975	2,047	2,047	2,064	2,075	2,090
Street Light	125	127	125	122	122	122	121	121	122	123	123	124
Sentinel Light	19	19	20	20	21	21	21	20	20	20	20	20
Unmetered Scattered Load	23	23	23	23	24	24	24	24	25	25	25	25
Total	35,587	35,901	35,186	35,327	34,586	33,804	34,170	33,957	33,637	33,631	33,542	33,551

Table E.7a: Weather Corrected Sales and Forecast in GWh, Excluding Acquired Utilities

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generator	8	11	14	16	16	17	18	18	19	20	20	21
General Service - Demand Billed	3,150	2,959	2,803	2,769	2,373	2,368	2,378	2,342	2,317	2,312	2,302	2,297
General Service - Energy Billed	2,343	2,580	2,380	2,229	2,169	2,155	2,146	2,104	2,064	2,043	2,018	1,999
Residential - Medium Density	4,466	4,495	4,528	4,453	4,901	4,907	4,939	4,924	4,917	4,953	4,971	4,998
Residential - Low Density	5,571	5,640	5,532	5,485	4,738	4,668	4,640	4,539	4,478	4,457	4,426	4,408
Seasonal	711	681	695	675	667	648	643	632	620	613	605	600
Sub-transmission	16,901	16,427	16,421	16,271	15,683	15,526	15,625	15,528	15,368	15,362	15,323	15,336
Urban General Service - Demand Billed	697	694	602	594	1,054	1,047	1,046	1,058	1,048	1,047	1,044	1,044
Urban General Service - Energy Billed	404	425	397	362	595	595	594	598	592	591	589	589
Urban Residential	1,563	1,599	1,555	1,513	1,971	1,969	1,975	2,047	2,047	2,064	2,075	2,090
Street Light	125	127	125	122	122	122	121	121	122	123	123	124
Sentinel Light	19	19	20	20	21	21	21	20	20	20	20	20
Unmetered Scattered Load	23	23	23	23	24	24	24	24	25	25	25	25
Total	35,982	35,680	35,094	34,531	34,334	34,068	34,170	33,957	33,637	33,631	33,542	33,551

b) Please see below versions of E.4, E.6, and E.7 for only the Acquired Utilities.

Table E.4b: Number of Customers History and Forecast for Acquired Utilities

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sub-transmission	7	6	6	7	7	8	8	9	9	10	10	11
Street Light	8	8	8	7	7	7	7	7	7	7	7	7
Sentinel Light	401	373	355	299	251	230	227	225	223	220	218	217
Unmetered Scattered Load	252	275	269	265	264	261	257	254	250	247	244	240
Acquired Residential	35,434	35,562	35,892	36,212	36,382	36,487	36,745	37,000	37,257	37,514	37,769	38,018
Acquired General Service - Energy Billed	4,361	4,357	4,340	4,349	4,350	4,348	4,347	4,345	4,343	4,341	4,339	4,337
Acquired General Service - Demand Billed	307	309	322	321	330	336	342	348	353	359	365	371
Acquired Urban Residential	13,709	13,862	14,020	14,175	14,353	14,515	14,676	14,834	14,994	15,153	15,312	15,467
Acquired Urban General Service - Energy Billed	1,180	1,207	1,222	1,243	1,246	1,263	1,280	1,295	1,310	1,324	1,339	1,352
Acquired Urban General Service - Demand Billed	193	185	182	189	193	193	193	193	193	194	194	194
Sum: Includes Acquired Utilities for 2021-2022 only	55,852	56,144	56,616	57,067	57,383	57,648	58,082	58,510	58,939	59,369	59,796	60,212

Table E.6b: Actual Sales and Forecast in GWh for Acquired Utilities

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sub-transmission	45	83	88	90	91	92	96	97	98	99	102	105
Street Light	9	9	9	9	10	10	10	10	10	10	10	10
Sentinel Light	1	1	1	1	1	1	1	1	1	1	1	1
Unmetered Scattered Load	1	1	1	1	1	1	1	1	1	1	1	1
Acquired Residential	308	302	305	303	301	300	298	295	292	290	287	284
Acquired General Service - Energy Billed	114	111	110	111	110	109	110	108	107	105	104	102
Acquired General Service - Demand Billed	270	233	232	241	235	237	241	239	237	236	236	236
Acquired Urban Residential	105	106	107	106	102	100	98	96	95	94	93	92
Acquired Urban General Service - Energy Billed	41	43	44	43	43	43	44	44	43	43	43	44
Acquired Urban General Service - Demand Billed	164	128	129	136	136	138	142	143	142	141	142	143
Sum: Includes Acquired Utilities for 2021-2022 only	1,058	1,017	1,026	1,041	1,030	1,029	1,039	1,035	1,026	1,020	1,019	1,017

Table E.7b: Weather Corrected Sales and Forecast in GWh for Acquired Utilities

Rate Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sub-transmission	46	85	88	85	90	92	96	97	98	99	102	105
Street Light	9	9	9	9	10	10	10	10	10	10	10	10
Sentinel Light	1	1	1	1	1	1	1	1	1	1	1	1
Unmetered Scattered Load	1	1	1	1	1	1	1	1	1	1	1	1
Acquired Residential	312	309	303	300	299	300	298	295	292	290	287	284
Acquired General Service - Energy Billed	115	114	109	105	109	109	110	108	107	105	104	102
Acquired General Service - Demand Billed	274	239	230	228	233	237	241	239	237	236	236	236
Acquired Urban Residential	107	108	107	105	101	100	98	96	95	94	93	92
Acquired Urban General Service - Energy Billed	42	44	43	40	42	43	44	44	43	43	43	44
Acquired Urban General Service - Demand Billed	167	132	128	128	135	138	142	143	142	141	142	143
Sum: Includes Acquired Utilities for 2021-2022 only	1,074	1,041	1,019	1,003	1,022	1,029	1,039	1,035	1,026	1,020	1,019	1,017

It should be clarified that, in the tables provided in responses to a) and b), the sum of the figures for the year 2021 and 2022 would add up to more than the sum presented in Tables E.4, E.6, and E.7 in the evidence noted above for those years. The reason is that the portion of Haldimand and Norfolk load that is considered to be embedded is no longer treated as embedded load after 2020 so that it is deducted from ST class load.

OEB Staff Interrogatory # 232

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01

Interrogatory:

The Fair Hydro Plan (FHP) will have an impact on retail electricity prices which will vary by customer class, over the 4 year scope of the FHP. All else being equal, the Fair Hydro Plan should have a stimulative impact on kW and kWh.

a) Has Hydro One considered the impact of the FHP on its load forecast?

b) If the answer to part a) is no, why not?

c) If the answer to part a) is yes, what are the impacts?

d) If the impacts are not significant, why not?

e) If the impacts are significant, please explain how the FHP was taken into account or how the load forecast will be amended.

Response:

a) Yes, Hydro One considered the impact of the FHP on the price of energy as stated in Appendix B to the referenced Exhibit, lines 27-28.

b) Not applicable.

c) A reduction in the price of electricity relative to natural gas contributes to increasing the load forecast, but the impact is not expected to be significant in the short-run. A moderate impact is expected in long run.

d) Not applicable.

e) The price impact mentioned in part c) is through the energy prices as an explanatory variable. The negative elasticity of demand with respect to electricity price implies that a lower price leads to a higher demand for electricity. Please see Appendix B to the referenced Exhibit for the equations linking electricity demand to electricity price.

OEB Staff Interrogatory # 233

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-02-01-02 Page: 15-16

Interrogatory:

Appendix 2-I was filed prior to the release of the 2018 Chapter 2 Appendices. The default weighting factor for the most recent historic year is 0.5 reflecting that half of the CDM savings are already reflected in the historic load. The default weighting factor for the test year is 0.5 reflecting that on average, CDM programs are delivered half way through the year, and therefore only realize savings for half a year.

a) Why has Hydro One chosen a weighting factor of 1.0 for both 2016 and 2018 reflecting that all CDM delivery in those years would serve to reduce the 2018 load forecast?

b) Please provide an updated Appendix 2-I based on the current Chapter 2 Appendices. Recognizing the update to include 2017 historic actual usage in ExE-Staff-03, please weight 2016 CDM savings at 0, 2017 CDM savings at 0.5, and 2018 CDM savings at 0.5, or explain why this would not be appropriate.

Response:

a) The calculation of the CDM adjustment to the load forecast in the tab of "App_2_I LF_CDM" in the OEB's filling requirement Chapter 2 Appendices is suitable for the LDCs who use an implicit model (data used to generate the forecast has past conservation impacts embedded, subtract future incremental efficiency program savings from the forecast). Hydro One uses an explicit model of incorporating CDM in the load forecast (adding historical efficiency program savings back to actual load and then deducting all past and future efficiency savings from the forecast). Please see response in part b) to Exhibit I-46-Staff-221. Hydro One chose a weighting factor of 1.0 for both 2016 and 2018 in the tab because the default formula of calculating manual CDM adjustment for 2018 (row 79-85) could not reflect the CDM adjustment that Hydro One used in the load forecast.

b) The requested information is provided below.

Table 1- 2015-2020 CDM Program - 2017, Third Year of the Current CDM Plan

6 Year (2015-2020) kWh Target:							
1,159,020,000							
	2015	2016	2017	2018	2019	2020	Total
%							
2015 CDM Programs						26.78%	26.78%
2016 CDM Programs						17.98%	17.98%
2017 CDM Programs						13.81%	13.81%
2018 CDM Programs						13.81%	13.81%
2019 CDM Programs						13.81%	13.81%
2020 CDM Programs						13.81%	13.81%
Total in Year	0.00%	0.00%	0.00%	0.00%	0.00%	**100.00%**	**100.00%**
kWh							
2015 CDM Programs	335,528,398.00	316,400,314.00	313,131,371.00	312,901,775.00	311,747,625.00	310,389,781.00	310,389,781.00
2016 CDM Programs		211,616,819.00	210,013,463.00	209,575,586.00	209,244,930.00	208,374,076.00	208,374,076.00
2017 CDM Programs			160,064,035.75	160,064,035.75	160,064,035.75	160,064,035.75	160,064,035.75
2018 CDM Programs				160,064,035.75	160,064,035.75	160,064,035.75	160,064,035.75
2019 CDM Programs					160,064,035.75	160,064,035.75	160,064,035.75
2020 CDM Programs						160,064,035.75	160,064,035.75
Total in Year	**335,528,398.00**	**528,017,133.00**	**683,208,869.75**	**842,605,432.50**	**1,001,184,662.25**	**1,159,020,000.00**	**1,159,020,000.00**

Note: 2015 and 2016 CDM saving and persistence are based on the Tab “LDC Savings Persistence”, Final verified HONI 2016 annual LDC CDM program results report.

Table 2- Weight Factors for Inclusion in CDM Adjustment to 2017-2020 Load Forecast

	2015	2016	2017	2018	2019	2020
2015 CDM Programs	Acutal savings					
2016 CDM Programs						
2017 CDM Programs			0.5	1	1	1
2018 CDM Programs				0.5	1	1
2019 CDM Programs					0.5	1
2020 CDM Programs						0.5

Table 3- 2015-2020 LRAMVA and 2015-2020 CDM Adjustment to Load Forecast

	2015	2016	2017	2018	2019	2020
2015 CDM Programs	335,528,398	316,400,314	313,131,371	312,901,775	311,747,625	310,389,781
2016 CDM Programs		211,616,819	210,013,463	209,575,586	209,244,930	208,374,076
2017 CDM Programs			80,032,018	160,064,036	160,064,036	160,064,036
2018 CDM Programs				80,032,018	160,064,036	160,064,036
2019 CDM Programs					80,032,018	160,064,036
2020 CDM Programs						80,032,018
Total in Year	335,528,398	528,017,133	603,176,852	762,573,415	921,152,644	1,078,987,982

Please see the MS Excel file attached to this response.

OEB Staff Interrogatory # 234

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

E1-01-02 Page: 5-8
H1-02-03 Pages 4-8
Decision, March 12, 2015 (EB-2013-0416) Page 51

Interrogatory:

In the decision referenced above, Hydro One was directed to file "a study assessing whether its service charges reflect Hydro One's underlying costs and to propose changes accordingly." This was in response to a concern of Sustainable Infrastructure Alliance (SIA) that "Hydro One's charges for miscellaneous services significantly under-recover the true cost of the services." The results of that study are included in Exhibit H1/Tab 2/ Schedule 3, and the impact on revenue is seen in Exhibit E1/Tab1/Schedule 2.

a) Several charges in the reference at Exhibit H1, e.g. rate code 26 have current approved and updated 2018 proposed charges, while at the same time do not appear in Exhibit E1.
   i. Are these charges being applied to existing customers?
   ii. If so, why are they not included in the reference in Exhibit E1?
   iii. If not, how was the appropriate charge calculated in the reference in Exhibit H1?

b) The Miscellaneous Service Revenue is expected to increase from $18.7 million to $21.2 million. Is Hydro One expecting that this will address the significant under-recovery concern of SIA?

Response:

a) i) Yes.

   ii) They were omitted and should be included in Exhibit E1. Historical and projected volumes, with corresponding revenues are shown below.

Specific Service Charges - Revenue

		Historical Years				Bridge Year		Test Years									
Rate Code	Description	2013	2014	2015	2016	2017		2018		2019		2020		2021		2022	
		Volume	Volume	Volume	Volume	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast	Volume Forecast	Revenue Forecast
25	Service Call - Customer Owned Equipment - During Regular Hours	179	121	205	173	170	$5,085	170	$35,039	170	$35,503	170	$35,971	170	$36,458	170	$36,927
26	Service Call - Customer Owned Equipment - After Regular Hours	120	80	136	116	113	$18,645	113	$86,756	113	$88,022	113	$89,296	113	$90,620	113	$91,898

iii) N/A

b) Yes. Hydro One was directed and completed a time study to determine the cost of Specific Service Charges. These costs were directly used to calculate these revenues, which address the under-recovery issue.

Vulnerable Energy Consumers Coalition Interrogatory # 81

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-02-01 Page: 1-2

Interrogatory:

a) Please provide a table similar to Table 1 that sets out number of customers that have been "reclassified" during the period between the EB-2013-0416 Decision and the referenced rate class review.

Response:

a) During the period between EB-2013-0416 and the referenced rate class review Hydro One updated customer rate class densities based on verified requests initiated by individual customers, which may also have resulted in changes to the density boundary for a community of customers.

   The number of individual customer density reclassifications is not readily available, but Hydro One can confirm that as a result of changes to the density boundary for various communities approximately 3,500 customers were reclassified from medium density to urban density, and approximately 400 customers were reclassified from low density to medium density.

Vulnerable Energy Consumers Coalition Interrogatory # 82

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
G1-02-01 Page: 3

Interrogatory:
a) Since December 1, 2016 has Hydro One Networks received any communications from the Board regarding the status or next steps with respect to the elimination of the seasonal rate class?
b) If yes, please provide copies of any written communications and/or summarize any oral communications received.

Response:
a) Hydro One Networks has not received any communications from the Board regarding the status or the next steps with respect to the elimination of the Seasonal rate class since December 1, 2016.

b) N/A

Vulnerable Energy Consumers Coalition Interrogatory # 83

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-02-01 Page: 8

Interrogatory:

a) What were the average customer densities for the former Norfolk Power and Haldimand Hydro?

Response:

a) Table below provides the requested information:

	Number of Customers per square km of service area	Number of Customers per km of Line	Data Source
Former Norfolk Power Distribution Inc.	28.22	24.66	2014 Yearbook of Electricity Distributors
Former Haldimand County Hydro Inc.	17.10	12.35	2015 Yearbook of Electricity Distributors

Vulnerable Energy Consumers Coalition Interrogatory # 84

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-02-01 Page: 8

Interrogatory:

a) At lines 4-13 the Application states: i) that the Hydro One bills its Sentinel Light and Street Lighting customers on kWh and ii) it proposes that the Sentinel and Street Lighting customers of the acquired utilities will adopt the Hydro One charge determinants in 2021. The Application then states the existing kWh consumption from these acquired Street Lighting and Sentinel customers will be used as the billing determinant. Please clarify what is meant by "existing kWh consumption" (e.g. is it the current 2016 consumption, their consumption as it will exist in 2021 and 2022 or some other value?).

Response:

a) The term "existing" was intended to reflect that the existing kWh information available for these customers would be used as the basis for developing the forecast billing determinant. "Existing kWh consumption" should be written as "forecast kWh consumption".

Witness: ANDRE Henry

Vulnerable Energy Consumers Coalition Interrogatory # 85

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
G1-03-01 Page: 3 Lines 1-8

Interrogatory:
a) For purposes of the 2021 CAM, did Hydro One review what the impact would be of adding the acquired utilities assets on the previously established minimum system splits?
   i. If yes, please provide the results of the assessment.
   ii. If not, why not?

Response:
a) Hydro One did not review the impact of adding the acquired utilities assets on previously established minimum system splits.
   i. N/A
   ii. The acquired utilities assets represent a small portion of Hydro One's total distribution assets (e.g. about 2% of distribution line km) and less than 5% of its customer base. As such, Hydro One does not believe that adding the acquired utilities assets will have a material impact on the minimum system splits.

Vulnerable Energy Consumers Coalition Interrogatory # 86

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: 3 Lines 16-20
2021 CAM, Tab I3 (TB Data)

Interrogatory:

a) With respect to rows 20-442 of Tab I3, please provide a excel spreadsheet the breaks out the values for each account associated with the acquired utilities for both the direct allocation column (Column G) and the reclassified balance column (Column H).

b) With respect to rows 490-533, please provide an excel spreadsheet that breaks out the values for each account associated with the acquired utilities for the reclassified balance column (Column E).

Response:

a) Hydro One only has the information by USofA as provided in Tab I3 of the 2021 CAM based on the total amounts for Hydro One including the acquired utilities. For the purpose of developing the adjustment factors to allocate costs to the new acquired rate classes, Hydro One has established acquired utility values for USofA accounts 1815 to 1860 equivalent to those shown in Tab I3. These are are provided in Worksheet 1 of the spreadsheet provided as an attachment to Exhibit I-49-Staff-242. There are no other amounts specific to the acquired utilities by USofA.

   The only costs directly allocated to the demand-billed acquired classes are associated with USofA's 5310, 5315, 5610, 5615, 5630, and 5665, which are also directly allocated to Hydro One's existing demand billed classes. The directly allocated costs for the affected acquired rate classes (AGSd and AUGd) are shown in Tab I9 Direct Allocations of the 2021 CAM.

b) See response to part a).

Witness: ANDRE Henry

Vulnerable Energy Consumers Coalition Interrogatory # 87

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: 3 Lines 20-23 and Page 4, Table 1
EB-2009-0265 (Haldimand), Cost Allocation Model
EB-2010-0145 (Woodstock), Cost Allocation Model
EB-2011-0272 (Norfolk), Cost Allocation Model

Interrogatory:

a) Please provide a copy of the reviews (referenced at page 3, lines 21-22) that confirm the continued appropriateness for the 2018 CAM of the Billing & Collecting and Services weighting factors previously used.

b) A review of the CAM filed by each of the three acquired utilities in their last cost of service application indicates that all three utilities assigned Services weights greater than zero to their GS<50 and GS>50 customer classes. Some of these utilities also attributed Services' assets to their Street Lighting and USL classes. Given these facts, why has Hydro One Networks assumed (per Table 1) that there are no Services assets associated with the acquired customers in these customer classes?

Response:

a) See response to Exhibit I-49-Staff-241.

b) Hydro One's policy, as stated in its Conditions of Service, requires non-residential customers to pay for the full costs of secondary services. Since acquisition (2014 for Norfolk, 2015 for Haldimand and Woodstock), Hydro One has adopted this policy for any new connections in the acquired utilities. As such, no services assets have been added to the non-residential classes since 2014/2015 and none will be added in the foreseeable future. The proposed services factors are therefore consistent with Hydro One's treatment of Services.

With regards to historical Services assets, Hydro One has developed GFA adjustment factors[1] to align the amount of local assets (which include Services assets) used to serve these

[1] As discussed in Exhibit G1-03-01 section 2.2.3 and further detailed in the response to Exhibit I-46-VECC-90 c).

utilities to the amount of assets assigned by the CAM to the acquired rate classes. Since Services assets (USofA 1855) are included in the GFA adjustment factor calculations, the *total* amount of local assets (i.e. USofA 1815 to 1860) allocated in the CAM by rate class appropriately account for the acquired utilities' allocation of services assets to its rate classes.

Vulnerable Energy Consumers Coalition Interrogatory # 88

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: 3 Lines 20-23 and Page 4, Table 2 and Page 5, Table 3

Interrogatory:

a) Table 2 does not provide the weighted average cost (i.e., $/meter) for each class as suggested by the table's title. Please provide a revised table setting out weighted average cost by customer class as used in the 2018 and 2021 CAMs.

b) Please include in the preceding table the weighted average cost per meter as used in the EB-2013-0416 CAM.

c) Table 3 does not provide the weighted average cost for each class as suggested by the table's title. Please provide a revised table setting out average meter reading cost (relative to UR) as used in the 2018 and 2021 CAMs.

d) Please include in the preceding table the weights for meter reading for each customer class as used in the EB-2013-0416 CAM.

Response:

a)

Updated Table 2: Weighted Average Meter Cost by Rate Class

2018 CAM		**From I7.1**																
UR	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**UGe**	**UGd**	**St Lgt**	**Sen Lgt**	**USL**	**DGen**	**ST**						
$338	$338	$338	$338	$606	$1,590	$606	$1,590	$0	$0	$0	$1,888	$41,249						
2021 CAM		**From I7.1**																
UR	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**UGe**	**UGd**	**St Lgt**	**Sen Lgt**	**USL**	**DGen**	**ST**	**Acq_UR**	**Acq_UGe**	**Acq_UGd**	**Acq_Res**	**Acq_GSe**	**Acq_GSd**
$338	$338	$338	$338	$606	$1,590	$606	$1,590	$0	$0	$0	$1,888	$41,000	$279	$1,152	$1,152	$320	$888	$971

b) The table below provides the requested information from EB-2013-0416.

Weighted Average Meter Cost by Rate Class from 2015 CAM

2015 CAM		From I7.1										
UR	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**UGe**	**UGd**	**St Lgt**	**Sen Lgt**	**USL**	**DGen**	**ST**
$150	$150	$175	$175	$360	$1,450	$475	$1,450	$0	$0	$0	$1,700	$41,000

Hydro One has corrected the average meter cost by rate class for 2018 and 2021 to reflect the most current available information, which has resulted in a better alignment with the total meter assets in USofA 1860 as compared to 2015 CAM.

c) Hydro One has corrected the title of the table to reflect that it is based on the weighted number of meter reads, which is used to allocate meter reading costs.

Updated Table 3: Number of Manual Meter Reads and Weighting Factors by Rate Class

	2018 CAM		From I7.2																	
	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST							Total
Number of Manual Meter Reads	1,946	10,955	93,956	18,769	36,859	33,965	4,821	11,040												212,311
Meter Reading Weighting Factor	1.00	1.25	2.00	2.50	1.25	1.25	1.00	1.00												
	2021 CAM		From I7.2																	
	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd	Total
Number of Manual Meter Reads	1,656	9,324	79,969	15,975	31,372	28,908	4,103	9,396								36	1,224	320	36	182,319
Meter Reading Weighting Factor	1.00	1.25	2.00	2.50	1.25	1.25	1.00	1.00								1.00	1.25	1.25	1.25	

d) The table below provides the requested information from EB-2013-0416.

Number of Manual Meter Reads and Weighting Factors by Rate Class from 2015 CAM

	2015 CAM		From I7.2											
	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Total
Number of Manual Meter Reads	4,822	17,145	50,632	13,146	31,572	18,306	3,244	5,694						144,562
Meter Reading Weighting Factor	1.00	1.25	2.00	2.50	1.25	1.25	1.00	1.00						

The forecast number of manual meter reads in 2018 and 2021 have been updated from those used in EB-2013-0416 based on the latest information available regarding the feasibility of connecting certain hard to reach smart meters to the smart meter network.

Vulnerable Energy Consumers Coalition Interrogatory # 89

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: Page 5, Lines 6-9

Interrogatory:

a) If a density value of other than 1 was used in the 2021 CAM for the six acquired rate classes, would the resulting revenue to cost ratios in Tab O1 change?

b) What is the basis of Hydro One Networks' assumption that the density factors for the existing rate classes do not need to be updated/revised? Please provide any analysis undertaken to support this assumption.

Response:

a) No. The results of the CAM, including the revenue to cost ratios in Tab O1, are not impacted by the density values for any classes other than Hydro One's existing residential (UR, R1, R2, Seasonal) and general service (GSe/UGe and GSd/UGd) classes which have density factors as approved by the Board in their Decision in EB-2013-0416.

b) The derivation of the density factors for Hydro One's density-based rate classes was detailed in Exhibit G1-3-1 of Hydro One's last distribution application EB-2013-0416. The density study that underpinned the derivation of the density factors was based on consideration of the *relative* cost to serve high, medium and low density areas in Hydro One's service territory. Hydro One has no information to indicate that the relative cost of serving these different density areas has changed. However, the manner in which the density factors are applied within the CAM, as detailed in rows 152-363 of Tab E2 of the 2018 CAM, does update the allocation of costs to take into account the relative change in the forecast number of customers for the various density based classes.

Vulnerable Energy Consumers Coalition Interrogatory # 90

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: Page 6, Lines 3-14 and Page 7, Table 5
EB-2009-0265 (Haldimand), Cost Allocation Model
EB-2011-0272 (Norfolk), Cost Allocation Model
EB-2010-0145 (Woodstock) Cost Allocation Model

Interrogatory:

a) Please confirm that, prior to acquisition by Hydro One, Norfolk and Haldimand were ST customers of Hydro One.
   i. If not confirmed, please explain the basis for the LV charges currently included in the approved 2017 tariff sheets for the former customers of these utilities.

b) Are the bulk distribution assets discussed at lines 9-14 of page 6 the assets used to serve these two utilities as ST customers? If not, please explain what assets are being referred to at these lines.

c) Please provide the detailed derivation of the GFA Adjustment Factors set out in Table 5. As part of the response, please indicate for each of the three acquired utilities:
   i. The value of the assets in each of the 1830-1860 accounts based on the assets of the utility at time of acquisition plus the in-service additions up to 2021.
   ii. The assets in each of the 1830-1860 accounts that have been allocated to each of the new acquired rate classes (per lines 6-8) and how the allocation was done.
   iii. The values for bulk distribution assets (and their associated USoA numbers) that have been allocated to the acquired rate classes (per lines 9-12) and how they were determined.
   iv. How these bulk distribution assets were attributed to the acquired utilities (per lines 12-14).
   v. What adjustments were made, if any, to account for the fact that Street Lighting, Sentinel Light, USL and MicroFIT customers from the acquired utilities have been incorporated into Hydro One Networks' existing customer classes?

d) Please provide schedules that for each of Haldimand, Woodstock and Norfolk sets out:

i. The percentage of USoA 1830-1860 GFA attributed to their Residential, GS<50 and GS>50 customer classes for purposes of the 2021 CAM (i.e., response to c(i) versus c(ii)).
ii. The percentage of USoA 1830-1860 GFA attributed their Residential GS<50 and GS>50 customer classes in the last Cost Allocation used for rate setting prior to acquisition.

e) Please explain why a separate GFA Adjustment Factor was not determined for each of the 1830-1860 USoA accounts or, for that matter, for each of the sub-accounts used in the CAM.

f) What would the GFA Adjustment Factors for Accounts #1830 and #1860 be, if calculated separately?

g) Were the bulk distribution assets attributable to the acquired utilities and removed from the assets allocated to customer classes in the 2018 CAM?
i. If not, why not since the customers in the former utilities of Haldimand and Norfolk continue to pay LV charges?
ii. If not, please re-state the revenue requirement for 2018 with the costs attributable to these assets removed, using the same approach to identify in the assets as was used for the 2021 CAM.
iii. If not, please re-do the 2018 CAM with these assets removed.
iv. If yes, please indicate how this was done with reference to the 2018 CAM.

Response:

a) Prior to the acquisition by Hydro One, Norfolk and Haldimand were ST customers and for the purpose of cost allocation and rate design they continue to be treated as ST customers until rates are harmonized in 2021.

b) Lines 9-14 on page 6 describe the approach used to allocate a portion of bulk distribution assets to the new acquired rate classes for the purposes of cost allocation. It does not refer to the specific assets used to serve these utilities as ST customers.

c) The derivation of the GFA Adjustment Factors shown in Table 5, updated to reflect the cost allocation model as described in Section 2 of Exhibit Q-1-1, is provided in Excel format as I-49-Staff-242-01.xlsx.

d) The following is a description of the worksheets provided in the GFA Adjustment Factor spreadsheet (I-49-Staff-242-01):

Worksheet 1: Provides the derivation of the total 2021 GFA associated with USofA accounts 1815-1860 for each acquired utility

Worksheet 2: Provides information from each utility's last CAM used to determine how much of each USofA account 1815-1860 was allocated to the various rate classes for each acquired utility.

Worksheet 3: Provides the proportion of the total 2021 GFA for accounts 1815-1860 that is associated with the each of the new acquired residential and general service rate classes.

Worksheet 4: Provides information on the 2021 GFA associated with USofA accounts 1815-1860 that is allocated to each new acquired rate class by the CAM, and also distinguishes the bulk assets included in those account, from those that specifically serve the new acquired rate classes

Worksheet 5: Provides the derivation of the GFA Adjustment Factor for each new acquired rate class based on comparing the GFA that should be allocated to each new acquired rate class aginst the GFA allocated to those classes by the CAM prior to any adjustments.

Worksheet 6: Provides the derivation of the NFA Adjustment Factors for each new acquired rate class based on the ratio of NFA to GFA as determined in the CAM.

Worksheet 7: Provides the derivation of the adjusted annual depreciation costs for the new acquired rate classes.

i. The acquired GFA adjustment factors are based on the gross value of each utility's fixed assets at the time of acquisition plus in-service additions to 2021 as shown in Worksheet 1.

ii. Allocation of the assets in each account is provided in Worksheets 2 to 5, as described above.

iii. The amounts of bulk distribution fixed assets in each account that are allocated to the new acquired classes are shown in Worksheet 5.

iv. The derivation of the allocated bulk asset amounts are shown in rows 8-16 of Worksheet 5.

v. The development of the adjustments factors proposed for the new acquired classes takes into account that a portion of the acquired utilities' assets were used to serve the Street Lighting, Sentinel Light and USL classes as shown in Worksheets 2 and 3.

e)

i. The percentage of c(i) versus c(ii), which is the portion of the total forecast GFA amount that is allocated to each acquired rate class in the CAM is provided in Worksheet 3, and reproduced below for each acquired utilitiy:

1

Woodstock Hydro Services Inc.			Portion of Total GFA associated with only RES and GS rate classes			
USofA		Total 2021 GBV	Residential	GS <50	GS 50 to 999 kW	Total
1815	Transformer station equip - above 50kV	$ 72,191	48%	17%	34%	99%
1820	Distribution station equip - below 50kV	$ 2,261,523	31%	17%	29%	77%
1830	Poles, towers and fixtures	$ 12,536,584	57%	11%	15%	83%
1835	Overhead conductors and devices	$ 9,034,527	64%	9%	12%	85%
1840	Underground conduit	$ 5,794,906	67%	8%	11%	86%
1845	Underground conductors and devices	$ 9,339,664	67%	8%	11%	86%
1850	Line transformers	$ 10,444,380	58%	18%	19%	94%
1855	Services	$	84%	0%	0%	84%
1860	Meters (existing)	$ 7,853,698	32%	43%	22%	97%
	TOTAL	$ 57,337,473				

Haldimand County Hydro Inc.			Portion of Total GFA associated with only RES and GS rate classes			
USofA		Total 2021 GBV	Residential	GS <50	GS 50 to 999 kW	Total
1815	Transformer station equip - above 50kV	$ 203,939	48%	17%	34%	99%
1820	Distribution station equip - below 50kV	$ 1,781,670	47%	19%	33%	100%
1830	Poles, towers and fixtures	$ 31,488,152	68%	14%	13%	95%
1835	Overhead conductors and devices	$ 23,674,849	69%	14%	12%	95%
1840	Underground conduit	$ 1,723,786	69%	14%	12%	95%
1845	Underground conductors and devices	$ 9,449,373	69%	14%	12%	95%
1850	Line transformers	$ 19,524,211	69%	14%	12%	95%
1855	Services	$ 3,564,629	85%	7%	0%	92%
1860	Meters (existing)	$ 3,716,861	68%	19%	10%	97%
	TOTAL	$ 95,127,471				

Norfolk Power Distribution Inc.			Portion of Total GFA associated with only RES and GS rate classes			
USofA		Total 2021 GBV	Residential	GS <50	GS 50 to 999 kW	Total
1815	Transformer station equip - above 50kV	$ 9,039,336	48%	17%	34%	99%
1820	Distribution station equip - below 50kV	$ 4,730,854	41%	23%	35%	99%
1830	Poles, towers and fixtures	$ 23,083,469	58%	18%	21%	96%
1835	Overhead conductors and devices	$ 14,774,218	58%	18%	21%	96%
1840	Underground conduit	$ 5,142,242	58%	18%	21%	96%

1845	Underground conductors and devices	$ 8,263,873	58%	18%	21%	96%
1850	Line transformers	$ 18,823,725	59%	18%	19%	96%
1855	Services	$ 2,781,477	70%	24%	6%	100%
1860	Meters (existing)	$ 2,977,474	80%	16%	4%	100%
	TOTAL	$ 89,616,667				

ii. The amounts of GFA allocated to the acquired residential and general service rate classes are the same as shown above and are provided in Worksheet 2.

f) In developing the GFA adjustment factors to reflect the actual assets used to serve the new acquired utility rate classes, Hydro One adopted an approach that would be relatively simple to implement within the CAM and readily understandable to the Board and intervenors. Given that determining the costs to serve a specific rate class is an allocation process and recognizing that the Board has established a relatively wide range of acceptable revenue-to-cost ratios, Hydro One believes its proposed approach is reasonable. With respect to the question's reference to using specific adjustment factors for all sub-accounts used in the CAM, Hydro One notes that the proposed GFA adjustment factors apply only to USofA accounts 1815-1860, which are the local assets used to serve the new acquired rate classes. For all other USofA accounts, it is proposed that the new acquired rate classes attract a share of those accounts in the same manner as all other Hydro One rate classes consistent with the cost allocation principles underlying the CAM.

g) The following table shows the GFA adjustment factors for accounts 1830 and 1860, if calculated separately.

USofA	**AUR**	**AUGe**	**AUGd**	**AR**	**AGSe**	**AGSd**	**Total**
1830	35.7%	20.5%	14.5%	63.6%	61.8%	43.9%	49.0%
1860	50.0%	187.5%	186.3%	37.9%	28.4%	34.7%	53.1%

h) No, none of Hydro One's assets, including bulk distribution assets, associated with serving the acquired utilities were removed from the 2018 CAM.

i. The Board in each of the MAAD applications for the three acquired utilities approved a 5-year rate rebasing deferral period, which means that their previous Board-approved rates are effective for that period. Hydro One's ST rates calculation for 2018, within this deferral period, includes both the cost of all ST assets <u>and</u> the embedded load forecast for Norfolk and Haldimand. As such, the ST rates proposed for Hydro One Network's customers in 2018 appropriately reflect their cost to serve.

ii. It is not possible to determine the revenue requirement specifically associated with the assets used to serve the acquired utilities. In any case, as stated in the response to part i, it would not be appropriate to exclude any assets in the determination of Hydro One's rates in 2018 given that Norfolk and Haldimand continue to be treated as embedded loads for the purpose of cost allocation and rate setting.

iii. Per the response to parts i and ii, it is not possible to re-do the 2018 CAM with these assets and associated costs removed.

iv. N/A

Vulnerable Energy Consumers Coalition Interrogatory # 91

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
G1-03-01 Page: 6 Lines 16-19

Interrogatory:
a) What USoA accounts are the assets discussed at line 16-19 recorded in?

b) Please provide a schedule setting out the value of these assets (by USoA) allocated to each of the acquired rate classes in the 2021 CAM.

c) What portion of the total assets allocated to each of the acquired rate classes do the assets discussed at lines 16-19 represent?

d) Were the any of these assets attributable to the acquired rate classes and removed from the assets included in the 2018 revenue requirement and allocated to customer classes in the 2018 CAM?
   i. If not, why not?
   ii. If yes, please indicate how this was done with reference to the 2018 revenue requirement and 2018 CAM.

Response:
a) The common assets discussed at lines 16-19 refer to all assets that are not included in USofAs 1830-1860. As a part of the updates filed in Exhibit Q-01-01, the fixed assets were re-examined and USofAs 1815 and 1820 were moved from the common asset group and treated as ‘local’ assets that are subject to the acquired allocation factors.

b) The value of these common assets by USofA allocated to each of the acquired rate classes are shown in Tab O4 of the 2021 CAM filed with Exhibit Q-01-01.

c) The following table shows the portion of the total fixed assets that are considered common and discussed at lines 16-19:

Rate Class	Common Assets
AUR	8.6%
AUGe	7.7%
AUGd	7.7%
AR	10.2%
AGSe	10.9%
AGSd	9.0%

d) No
  i. Please see the response to Exhibit I-46-VECC-90 part g).
  ii. N/A

Vulnerable Energy Consumers Coalition Interrogatory # 92

Issue:
Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:
G1-03-01 Page: 6-7
A-07-01 Page 11 Lines 5-14
2021 CAM
B1-01-01 Appendix A Pages 6-11

Interrogatory:
a) Please provide a schedule that sets out the gross fixed assets, accumulated depreciation and net fixed assets for each acquired utility as of January 1, 2021 that was added to the opening balances per page 11?

b) Please reconcile the values reported in part (a) with the Net Plant for each acquired utility reported in Appendix A.

c) Please provide a schedule that sets out the Net Plant allocated to each of the six acquired utility rate classes per the 2021 CAM.

d) Please provide schedules that contrast:
   i. The Net Plant allocated to the Acq. UR, Acq. UGSe, and Acq. UGSd classes per the 2021 CAM with the total Net Plant attributable to Woodstock in 2021 (per Appendix A)
   ii. The Net Plant allocated to the Acq. Res, Acq. GSe, and Acq. GSd classes per the 2021 CAM with the total Net Plant attributable to Haldimand and Norfolk in 2021 (per Appendix A)

Response:
a) Please see Exhibit I-53-CCC-71

b) Please see Exhibit I-53-CCC-71

c) The Table below provides the Net Plant allocated to each of the six acquired rate classes in 2021:

	AUR	AUGe	AUGd	AR	AGSe	AGSd
Net Plant Allocated to Acquired Rate Classes in 2021 ($M)	$26.5	$7.1	$8.3	$95.1	$24.0	$26.6

d) i. & ii. The Table below compares the total Net Plant allocated to the acquired customers in the 2021 CAM and that provided in B1-01-01 Appendix A:

	Net Plant Allocated per CAM 2021 ($M)	Average Net Plant per B1-01-01, Appendix A
Woodstock	$41.9	$31.7
Norfolk+Haldimand	$145.7	$121.7

Vulnerable Energy Consumers Coalition Interrogatory # 93

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: 7-8
2018 and 2021 CAM Models (Tab 06-Lines 111-107)

Interrogatory:

a) Please provide a schedule showing the derivation of the NFA and NFA ECC adjustment factor for each acquired customer class.

b) Was the GFA to NFA relationship used based on all distribution assets for just those for accounts 1830-1860?

c) If based on all distribution assets, please explain why and recalculate Table 6 using just the relationship for assets in accounts 1830-1860.

d) With respect to Tab O6, please explain why the values for NFA Excluding Credit for Capital Contribution (NFA ECC – row 117) and NFA (row 116) both use the value for GFA - Distribution plant (exclude credit for contributed capital) in row 112 as the starting point before subtracting the relevant accumulated depreciation value. In particular, why isn't GFA - Distribution plant (credit to contributed capital) from row 111 used in one of the calculations?

e) Was the NFA for the bulk distribution assets attributable to the acquired utilities removed from the assets allocated to customer classes in the 2018 CAM?
   i. If not, why not since the customers in the former utilities of Haldimand and Norfolk continue to pay LV charges?
   ii. If not, please re-do the 2018 CAM with these assets removed. Using the same approach to identify in the assets as was used for the 2021 CAM.
   iii. If yes, please indicate how this was done with reference to the 2018 CAM.

Response:

a) The derivation of the NFA and NFA ECC adjustment factors, as modified in Exhibit Q-01-01 filed December 21, 2017, is provided in Worksheet 6 of the spreadsheet provided as an attachment to Exhibit I-49-Staff-242.

b) The GFA to NFA relationship used is based on all distribution plant assets, not just accounts 1815-1860 [updated from 1830-1860 as proposed in Exhibit Q-01-01].

c) Hydro One used the data available from Tab O6 of the 2021 CAM to calculate the total distribution plant GFA to NFA relationship. Data on NFA by USofA is not available in the CAM, and as such, Hydro One cannot calculate the relationship for just the assets in accounts 1815-1860. However, Hydro One notes that per the information provided in Tab O6, accounts 1815-1860 make up 96% of the total distribution plant GFA and so the GFA to NFA relationship is not expected to be materially different from what is calculated using total distribution plant GFA.

d) In Tab 06 of its 2021 CAM, Hydro One inadvertently used GFA - Distribution plant from row 112 to derive Net Fixed Assets in row 116. GFA - Distribution plant from row 111 should have been used to derive Net Fixed Assets in row 116. This resulted in an erroneous calculation of Net Fixed Assets, which affects the NFA allocators and the acquired classes' NFA Adjustment Factors used in the 2021 CAM. After assessing the impact of correcting this error, Hydro One has determined that it results in less than a 1.0% change to the revenue-to-cost ratios for the proposed 2021 rate classes. However, Hydro One will make the required correction to Sheet O6 of the cost allocation model in the draft rate order phase of this application.

e) i, ii, iii. Please see the response to Hydro One's response to Exhibit I-46-VECC-90 part g).

Vulnerable Energy Consumers Coalition Interrogatory # 94

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

G1-03-01 Page: 8

Interrogatory:

a) Was the depreciation expense for the bulk distribution assets attributable to the acquired utilities removed from the costs included in the 2018 revenue requirement and allocated to customer classes in the 2018 CAM?
   i. If not, why not since the customers in the former utilities of Haldimand and Norfolk continue to pay LV charges?
   ii. If not, please restate the 2018 revenue requirement with this depreciation expense removed and re-do the 2018 CAM with these depreciation costs removed. Using the same approach to identify in the assets as was used for the 2021 CAM.
   iii. If yes, please indicate how this was done with reference to the 2018 revenue requirement and 2018 CAM.

Response:

a) i, ii, iii. Please see the response to Exhibit I-46-VECC-90 part g).

Witness: ANDRE Henry

Vulnerable Energy Consumers Coalition Interrogatory # 95

Issue:

Issue 46: Is the load forecast methodology including the forecast of CDM savings appropriate?

Reference:

Previous Proceeding
EB-2009-0265 (Haldimand), Cost Allocation Model
EB-2011-0272 (Norfolk), Cost Allocation Model
EB-2010-0145 (Woodstock) Cost Allocation Model
EB-2016-0276, Hydro One Networks Final Argument, page 4

Interrogatory:

a) Please provide schedules that for each of Haldimand, Woodstock and Norfolk sets out the values and the percentage of total OM&A attributed their Residential GS<50 and GS>50 customer classes in the last Cost Allocation used for rate setting prior to acquisition.

b) Please provide a schedule setting out the total OM&A attributed to each of the acquired customer classes per the 2021 CAM.

c) Please provide a schedule that sets out, for each of the three acquired utilities, the total OM&A added to the Hydro One Networks' 2021 revenue requirement/2021 CAM.

Response:

a) Table below provides the requested information:

	OM&A	Residential	GS < 50 kW	GS 50-4,999 kW*	Total OM&A for all Rate Classes
Woodstock (EB-2010-0145)	**($)**	$2,627,287	$560,751	$572,009	$4,169,207
	(%)	63.0%	13.4%	13.7%	
Norfolk (EB-2011-0272)	**($)**	$3,817,789	$865,723	$821,213	$5,651,555
	(%)	67.6%	15.3%	14.5%	
Haldimand (EB-2013-0134)	**($)**	$5,758,497	$1,032,520	$747,013	$8,217,075
	(%)	70.1%	12.6%	9.1%	

* For Woodstock, this columns shows data for the GS 50-999kW.

b) The Table below provides the requested information:

HONI - 2021 OMA ($)	**AUR**	**AUGe**	**AUGd**	**AR**	**AGSe**	**AGSd**
	$2,871,657	$512,840	$935,312	$8,811,860	$1,847,606	$1,428,178

c) The schedule below shows incremental OM&A for each of the acquired utilities that will be added to Hydro One's revenue requirement in 2021. See part a) above the the OM&A allocated to each acquired utility.

Acquired Utilities OM&A	**2021**
Haldimand	5.3
Norfolk	3.2
Woodstock	2.2
Total	**10.7**

Building Owners and Managers Association Toronto Interrogatory # 23

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

A-03-01 Page: 24 Table 8

Interrogatory:

Please explain more fully the footnote to this table.

Response:

The footnote clarifies that, until 2021, the Acquired Utilities (Haldimand, Norfolk and Woodstock) are treated separately for rate-setting purposes. As such, the forecast data from 2018 to 2020 excludes the Acquired Utilities' incremental load, and the load forecast data for 2021 and 2022 includes the Acquired Utilities' incremental load. For the purposes of assessing the load forecast trend over the five-year application period, the footnote goes on to provide what the 2021 and 2022 change in load forecast would be if the Acquired Utilities were not included.

Canadian Manufacturers & Exporters Interrogatory # 71

Issue:
Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:
E1-02-01

Interrogatory:
The evidence indicates that the annual econometric model uses relative energy price.

a) Please confirm that the relative energy price is electricity as compared to natural gas. If this cannot be confirmed, please explain fully what the relative energy price is.

b) Please confirm that the Hydro One forecast takes into account the increase in natural gas prices due to the addition of cap & trade related charges effective January 1, 2017? If this cannot be confirmed, please explain.

c) Please confirm that the Hydro One forecast takes into account the reduction in electricity prices that have resulted from the Fair Hydro Act, including changes to the commodity cost and the introduction of distribution rate protected residential customers and the delivery credit for on-reserve customers? If this cannot be confirmed, please explain.

Response:
a) Confirmed.

b) Confirmed.

c) Confirmed.

Canadian Manufacturers & Exporters Interrogatory # 72

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01

Interrogatory:

a) The evidence indicates (page 16) that the annual econometric model used for embedded distribution utility customers uses energy prices. Please confirm that the forecast for natural gas prices and electricity prices reflect the adjustments noted in the previous interrogatory. If they do not, please explain fully.

Response:

a) Confirmed.

Canadian Manufacturers & Exporters Interrogatory # 73

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01, and Appendix 2-IB

Interrogatory:

a) Please confirm that the difference in the Hydro One Distribution load for 2018 shown in Table 3 of 36,019 GWh and the figure of 33,957 GWh shown in Appendix 2-IB is related only to the loss factor. If this cannot be confirmed, please explain the difference between the two figures.

Response:

a) Confirmed.

Canadian Manufacturers & Exporters Interrogatory # 74

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01

Interrogatory:

a) Are the number of customers shown in Table E.4 based on monthly averages, average of beginning of the year and end of the year, mid-point, or some other methodology?

b) Based on the latest month of actual data available, please provide the actual number of customers for this month in 2017 and the figures for the corresponding month in 2016, in the same level of detail as shown in Table E.4.

c) Please explain why Hydro One is forecasting a decrease of more than 500 R1 customers in 2018, despite this class growing by nearly 8,000 per year between 2012 and 2016.

d) Please explain why Hydro One is forecasting a decrease of more than 2,200 R2 customers in 2018, despite this class growing by more than 500 customers per year since 2015.

e) Please explain why Hydro One is forecasting an increase of more than 11,000 UR customers in 2018 when growth in the number of customers has only been about 3,000 per year since 2015.

f) What is the approximate distribution revenue impact of the Hydro One forecast of customers in the R1, R2 and UR rate classes as compared to the result if the 2018 forecast increase in these three rate classes was in the same proportion as the increases forecast between 2016 and 2017?

g) Please explain the reduction in General Service – Energy Billed customers in 2018, 2019 and 2020.

Response:

a) The number of customers shown in Table E.4 is based on year mid-point.

b) The latest month for which data for all rate classes mentioned in Table E.4 are available is July 2017. Since July is very close to mid-year, please see Table E.4 for 2016 actual figures. For 2017 actual mid-year figures, please see Exhibit I-46-Staff-219, Table E.4.

c) Please see the statement made in this regard in the Exhibit E1, Tab 2, Schedule 1, page 20, lines 1-5 which describes the impact of customer reclassifications and in particular the customer reclassifications that will be completed in 2018 as shown on page 2 of Exhibit G1, Tab 2, Schedule 1.

d) Please see response to (c).

e) Please see response to (c).

f) Assuming a 2018 customer forecast based on the same increase in customers as observed between 2016 and 2017 is not appropriate in view of the customer reclassifications noted in response to (c), and given the detailed methodology used to forecast number of customers as detailed on pages 9 and 10 of Exhibit E1, Tab 2, Schedule 1, which describes the influence of provincial housing demand, population and household forecast, vacancy rates and specific growth patterns of various customers groups in coming up with the forecast number of customers..

g) The decline is consistent with customer reclassification noted in response to part (c) as well as historical relationship between economic growth and the number of general service energy-billed customers.

Canadian Manufacturers & Exporters Interrogatory # 75

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01

Interrogatory:

a) Please explain why the number of customers was not used as an explanatory variable in the monthly econometric equation shown in Appendix A.

b) Please explain why heating and cooling degree days were not used as explanatory variables in the monthly econometric equation shown in Appendix A.

c) Please explain why the number of customers was not used as an explanatory variable in the annual econometric equation shown in Appendix B.

d) Please provide the expected annual growth rate for each of the commercial, industrial and agricultural sectors that were used in the end use models described in Appendix C and provide the GDP growth rates that were used to estimate these expected annual growth rates. Please also show how these GDP figures tie into the forecast values shown at page 5 of Attachment 1.

Response:

a) Monthly econometric model was designed to have a strong predictive power in the short run. For this purpose, building permits are a better leading indicator that provides an early estimate of future changes in the number of houses or customers. As such, they have better predictive power compared to number of customers.

b) The monthly econometric model uses weather-corrected retail load as the dependent variable, so that there is no need to use CDD and HDD to pick up variations in weather.

c) Different explanatory variables were tried in developing the annual econometric model for retail load. Hydro One found that personal disposable income per household was the strongest explanatory variable compared to alternative variables accounting for economic/

demographic trend over time. Moreover, when the number of households / customers was added to the model, both its estimated coefficient and the associated t statistics were close to zero.

d) The growth rates for end-use forecast for residential, commercial, and agricultural sectors are provided below. Related economic indicators are also provided. The indicators are expected to contribute to GDP growth either directly or through demand they create.

Comparision of End-Use Growth with Economic Indicators

	Growth of Sales Net of CDM (%)			Econometric Indicators (%)		
				Number of	Commercial	Agriculture &
Year	Residential	Commercial	Agricultural	Housholds	Floor Space	Fishing GDP
2017	-1.2	-1.6	-1.7	1.1	1.0	2.4
2018	-1.7	-1.2	-1.7	1.1	1.2	2.1
2019	-0.6	-0.7	-1.1	1.1	0.8	2.2
2020	-0.7	-0.6	-0.8	1.1	0.8	2.5
2021	0.1	0.2	-0.7	1.1	1.2	2.6
2022	-0.8	-0.2	-1.1	1.0	0.8	2.6

Canadian Manufacturers & Exporters Interrogatory # 76

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01, Appendix E

Interrogatory:

a) Please provide a version of Table E.1 that shows the comparison of the forecasts for previous rate submissions with actual consumption based on each of the three methodologies used by Hydro One: monthly econometric model, annual econometric model, and end use model.

Response:

a) Please see below for versions of Table 1 with different forecasting models.

Table 1.a

Comparison of End-Use Forecasts Used in Previous Rate Submissions with Actual
(GWh)

Year	2005 Forecast (EB-2005-0378) End-Use	2007 Forecast (EB-2007-0681)	2009 Forecast (EB-2009-0096)	2013 Forecast EB-2013-0416	Weather Corrected Actual	Actual	% Difference from Weather Corrected Actual 2005 Forecast	2007 Forecast	2009 Forecast	2014 Forecast
2005	22,908				22,969	23,182	-0.26			
2006	22,823				22,921	22,485	-0.43			
2007		22,911			22,966	22,909		-0.24		
2008		23,055			22,845	22,624		0.92		
2009		23,081	22,183		22,660	22,299		1.85	-2.11	
2010			21,755		22,062	21,977			-1.39	
2011			21,770		22,023	21,718			-1.15	
2012					20,434	19,964				
2013					20,439	20,668				
2014				20,123	20,267	20,639				-0.71
2015				20,106	20,203	20,343				-0.48
2016				20,140	20,085	19,862				0.27
3-Year Average							-0.35	0.84	-1.55	-0.31

Table 1.b

Year	2005 Forecast (EB-2005-0378)	2007 Forecast (EB-2007-0681)	2009 Forecast (EB-2009-0096)	2013 Forecast EB-2013-0416	Weather Corrected Actual	Actual	% Difference from Weather Corrected Actual 2005 Forecast	2007 Forecast	2009 Forecast	2014 Forecast
2005	22,907				22,969	23,182	-0.27			
2006	22,948				22,921	22,485	0.11			
2007		23,017			22,966	22,909		0.22		
2008		23,120			22,845	22,624		1.20		
2009		n.a.	22,626		22,660	22,299		n.a	-0.15	
2010			22,005		22,062	21,977			-0.26	
2011			n.a.		22,023	21,718			n.	
2012					20,434	19,964				
2013					20,439	20,668				
2014				20,401	20,267	20,639				0.66
2015				20,421	20,203	20,343				1.08
2016				n.a.	20,085	19,862				n.a.
3-Year Average							-0.08	0.71	-0.21	0.87

Comparison of Annual Econometric Forecasts Used in Previous Rate Submissions with Actual

Table 1.c

Year	2005 Forecast (EB-2005-0378)	2007 Forecast (EB-2007-0681)	2009 Forecast (EB-2009-0096)	2013 Forecast EB-2013-0416	Weather Corrected Actual	Actual	% Difference from Weather Corrected Actual 2005 Forecast	2007 Forecast	2009 Forecast	2014 Forecast
2005	23,134				22,969	23,182	0.72			
2006	23,229				22,921	22,485	1.34			
2007		22,871			22,966	22,909		-0.41		
2008		22,938			22,845	22,624		0.40		
2009		22,723	22,750		22,660	22,299		0.28	0.39	
2010			21,889		22,062	21,977			-0.79	
2011			21,785		22,023	21,718			-1.08	
2012					20,434	19,964				
2013					20,439	20,668				
2014				20,448	20,267	20,639				0.89
2015				20,493	20,203	20,343				1.44
2016				20,535	20,085	19,862				2.24
3-Year Average							1.03	0.09	-0.49	1.52

Canadian Manufacturers & Exporters Interrogatory # 77

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01

Interrogatory:

a) Please update Tables E.2 and E.3 to reflect the most recent forecasts available for each of the sources shown in Table E.2.

Response:

a) Please see response to Exhibit I-46-Staff-219, Tables E.2 and E3.

Canadian Manufacturers & Exporters Interrogatory # 78

Issue:
Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:
E1-02-01

Interrogatory:
a) Please explain fully, with all assumptions and calculations shown, how Hydro One has divided the total forecast sales into the amounts shown for each rate class in Table E.6. Please provide a live Excel spreadsheet if possible that shows the calculations and data used.

Response:
a) Please see response to part (d) of Exhibit I-46-CME-70.

Canadian Manufacturers & Exporters Interrogatory # 79

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01

Interrogatory:

a) Please provide all the assumptions and calculation used to determine the kW forecast figures for 2017 through 2022 for each of the rate classes shown in Table E.8a. Please provide a live Excel spreadsheet if possible that shows the calculations and data used.

Response:

a) Peak forecast is derived from sales forecast so that the peak-to-energy ratio remains constant. The exception is GSd rate class for which the ratio is assumed to continue falling in a manner consistent with historical pattern. A MS Excel file is also prepared as Attachment 1 to this response.

	2017	2018	2019	2020	2021	2022	
Sales (GWh)							
DGEN	18	18	19	20	20	21	
GSd	2,378	2,342	2,317	2,312	2,302	2,297	
UGd	1,046	1,058	1,048	1,047	1,044	1,044	
ST *	15,625	15,528	15,368	15,362	15,132	15,149	
Acquired GSd	241	239	237	236	236	236	
Acquired UGD	142	143	142	141	142	143	
Billing Peak (12-month sum in MW)							
DGEN	178,213	184,739	191,107	198,809	204,487	210,569	
GSd	8,149,966	8,025,918	7,940,259	7,924,744	7,887,971	7,871,666	
UGd	2,842,412	2,832,322	2,797,926	2,787,731	2,771,740	2,764,065	
ST *	33,699,242	33,491,228	33,144,837	33,133,111	33,111,381	33,152,081	
Acquired GSd	677,233	672,386	667,563	664,084	663,644	662,981	
Acquired UGD	409,686	414,168	410,184	408,125	410,749	411,710	
Peak to Energy Ratio							
DGEN	10,058	10,058	10,058	10,058	10,058	10,058	
GSd	3,427	3,427	3,427	3,427	3,427	3,427	
UGd	2,716	2,678	2,670	2,663	2,655	2,648	UGD peak is expcted to grow slower than energy.
ST *	2,157	2,157	2,157	2,157	2,188	2,188	Due to integrating Acquired Utilities into Hydro One in 2020, the ratio goes to a new level.
Acquired GSd	2,813	2,813	2,813	2,813	2,813	2,813	
Acquired UGD	2,887	2,887	2,887	2,887	2,887	2,887	

* Includes the impact of intergrating Acquired Utilities for the years 2021 and 2022 only.

Canadian Manufacturers & Exporters Interrogatory # 80

Issue:

Issue 47: Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Reference:

E1-02-01-01

Interrogatory:

a) For each of the following variables shown on page 2 of Attachment 1, please explain how the forecasted figures have been derived:
   i. Ontario Disposable Income
   ii. Ontario Commercial GDP
   iii. Ontario Industrial GDP
   iv. Ontario Number of Households

b) Please explain the relationship between the commercial and industrial GDP figures shown on page 2 with the figures shown on page 5. For example, do the industrial GDP figures shown on page 2 include the manufacturing and mining figures shown on page 5, while the commercial GDP figures shown on page 2 include services, construction and utilities?

c) What is the source(s) of the GDP forecast figures by industry shown on page 5. If the forecasts are derived from external sources, please update the figures on page 5 to reflect the most recent forecasts now available.

d) How has the residential building permit index (page 3) been calculated and specifically how has the forecast for 2017 and 2018 been determined. Please provide all external information used to calculate this index and to forecast it

e) Why is there no forecast for the residential building permit index for 2019 through 2022? What values has Hydro One used for this variable in 2019 through 2022

f) Please explain why the monthly Ontario GDP figures shown on page 4 do not match the annual Ontario GDP figures shown on page 2.

g) Why is there no monthly Ontario GDP forecast beyond 2018? What figures have Hydro One used for 2019 through 2022 for the monthly econometric model?

h) Does the monthly retail load used in the monthly econometric model (Appendix A) equal the annual retail load used in the annual econometric model (Appendix B)? Please confirm that the figures used in the annual econometric model for the retail load are those found on page 6 of Attachment 1. If both of these cannot be confirmed, please provide a live Excel spreadsheet that includes the monthly retail load and the annual retail load used in the models shown in Appendix A and B.

i) Where is the data shown on page 7 (weather-corrected gross retail load, including losses, in Av MW) used in the econometric models?

j) Please show how each of the electricity and natural gas prices shown on pages 8 and 9 of Attachment 1 have been calculated.

k) Please show how the impact of the Fair Hydro plan and the cap & trade plan have been factored into the forecast for 2017 through 2022.

l) Please explain why the electricity price remains flat for 2018 through 2022, while the natural gas price continues to rise over the same period.

Response:

a)

i. Please see Exhibit E1, Tab 2, Schedule 01, Appendix B lines 16-22.
ii. The source is IHS Global Insight adjusted to be consistent with consensus forecast for Ontario GDP presented in Appendix E, Table E2.
iii. Please see response to ii.
iv. This is based on consensus forecast for housing starts presented in Appendix E, Table E2.

b) Yes, industrial GDP includes manufacturing and mining. Commercial GDP include services, construction and utilities.

c) Please see part (a) ii. For an updated forecast, please see Exhibit I-46-Staff-219.

d) The value of residential building permit is measured in nominal dollar by Statistic Canada. In this Application, the nominal dollar series is divided by the implicit price index for residential construction from Ministry of Finance to arrive at the constant dollar value. The forecast is based on the consensus forecast for housing starts presented in Appendix E, Table E2.

e) The monthly residential building permit was used as an explanatory variable only in monthly econometric model. Due to its short-term nature, the forecast horizon for this model ends in 2018 so that there was no need to have a forecast for monthly building permit after 2018.

f) Monthly Ontario GDP figures are measured at annual rate. Thus the 12-month average of these figures for each year equals the annual GDP for that year.

g) For the same reason indicated for monthly building permits in response to question (e).

h) For the purposes of the monthly econometric model, the monthly retail load is weather corrected and, as such, is not equal to annual retail load which is not weather corrected as required for input to the annual econometric model. It is confirmed that the monthly and annual retail load used in models presented in Appendices A and B are in the Exhibit E1, Tab 2 Schedule 1, Attachment 1 in pages 6 and 5, respectively.

i) Please see response to question (h).

j) Please see Exhibit E1, Tab 2 Schedule 1, lines 24 to 28.

k) As noted on page 7 of Exhibit E1, Tab 2 Schedule 1, lines 2-5 and Appendix B lines 24-28 of the same Exhibit, the impact of the Fair Hydro plan and the cap and trade plan has been factored into the forecast for 2017 through 2022 in relation to the impact of these plans on electricity and natural gas prices. Thus lower electricity price and higher natural gas price (due to the cap and trade plan) reduces electricity price relative to natural gas price and, thereby, increases demand for electricity.

l) The electricity and natural gas prices presented in Attachment 1 noted above are measured in constant dollar. The electricity price remains flat for 2018 through 2022 in a manner consistent with the Fair Hydro plan as the Province plans to keep the rate of increase in electricity bill in tandem with rate of inflation. Thus, the nominal price of electricity corrected for inflation is expected to remain flat. The natural gas price continues to rise over the same period as the cap and carbon trade contributes to the natural gas price growth.

Vulnerable Energy Consumers Coalition Interrogatory # 96

Issue:
Issue 48: Has the load forecast appropriately accounted for the addition of the Acquired Utilities' customers in 2021?

Reference:
H1-01-01 Page: 3 and 7
H1-01-02

Interrogatory:
a) Does Hydro One plan on updating the 2021 CAM in order to reflect the 2021 revenue requirement? If not, why not?

Response:
a) Yes. Hydro One has updated the 2021 CAM to reflect the 2021 revenue requirement proposed in Exhibit Q1-01-01 as part of the response to Exhibit I-52-SEC-088.

Vulnerable Energy Consumers Coalition Interrogatory # 97

Issue:

Issue 48: Has the load forecast appropriately accounted for the addition of the Acquired Utilities' customers in 2021?

Reference:

H1-01-01 Page: 9-10
H1-01-02

Interrogatory:

a) Please confirm that in Schedule 2 for the years 2019, 2020 and 2022, the Allocated Costs (i.e., Column B) for each customer class were determined by increasing the previous year's allocated costs by a common factor based on the overall percentage increase in the total revenue requirement from the previous year. If not, please explain how the values were determined.

b) Please explain why this approach is reasonable when the load forecasts for the various customer classes are not changing by a common factor?

c) With respect to tables in Schedule 2 for the years 2019, 2020 and 2022, please clarify whether Column Y (Revenues with Previous Year's Rates and Current Year's Charge Determinants) includes or excludes Miscellaneous Revenues.
   i. If included, please provide a breakout by class for each of the three years of the revenue attributable to Miscellaneous Revenues and indicate how the value for each class was determined.

d) Please provide a schedule that for each of years 2019-2022 compares the revenues at the proposed distribution rates versus the revenues using the previous year's rates and the current year's billing determinants and calculates the percentage change for each customer class for each year.
   i. If for any given year, the year over year increases (per part (e)) are not the same for all customer classes where the R/C ratio is not proposed to change from the previous year (per Exhibit H1, Tab 1, Schedule 1, pages 9-10), please explain why.

e) Please re-calculate the 2019 and 2020 revenues from distribution rates for each class using the following approach:

i. Re-calculate the 2018 allocated revenue requirement for each customer class using the proposed R/C ratios for 2019/2020.

ii. In each case, recalculate the 2018 Base Revenue Requirement for each customer class using the results from part (i) and the miscellaneous revenues allocated to the class by the 2018 CAM.

iii. Determine the 2019/2020 Base Revenue Requirements for each customer class by based on the percentage increase from 2018 to 2019/2020 in the overall Base Revenue Requirement.

f) Please compare the results from part e) (iii) with Hydro One Networks' proposed base revenue requirements by customer class for the same years.

Response:

a) Confirmed.

b) Hydro One is proposing a method of calculating distribution rates in 2019, 2020 and 2022 that uniformly increases the revenues and costs associated with each rate class. This is consistent with the approach used by the Board for IRM applications that uniformly increases the rates for all classes even though customer load forecasts may be changing for each class. Hydro One is unclear as to how the allocated costs for each class could be adjusted to take into account the load forecast by rate class, but notes that changing the costs allocated to the rate classes would not impact rates unless the R/C ratio of the affected rate class departs from the OEB approved range. As shown in the response to part f) of this interrogatory there is virtually no difference for most classes between the approach suggested by VECC and the approach proposed by Hydro One.

c) Revenue in Column Y in H1-1-2 for the years 2019, 2020 and 2022 include Miscellaneous Revenues.

i. Column C in Exhibit H1-1-2 for the years 2019, 2020 and 2022 provides Miscellaneous revenues. The Miscellaneous revenues were allocated among rate classes using the percentage increase in Miscellaneous revenues in each year compared to the previous year.

d) Tables 1, 2 and 3 below provide the comparison between revenues at proposed rates versus revenues at previous year's rates and current year's billing determinants for 2019, 2020 and 2022.

Table 1 - Comparison of 2019 Revenues at Proposed 2019 Rates and Proposed 2018 Rates

Rate Class	2019 Forecast Charge Determinants			Proposed 2018 Rates			2019 Revenue at Proposed 2018 Rates	Proposed 2019 Rates			2019 Revenue at Proposed 2019 Rates	Change in 2019 Revenue at Proposed 2018 and 2019 Rates
	Number of Customers	kWh	kW	Fixed Charge ($/Month)	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)		Fixed Charge ($/Month)	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)		
UR	228,666	2,047,339,001	-	$27.71	$0.0078		$91,951,777	$31.23	$0.0047		$95,379,475	3.7%
R1	449,958	4,917,201,793	-	$37.79	$0.0218		$311,395,873	$42.19	$0.0193		$322,820,755	3.7%
R2	330,076	4,478,345,990	-	$88.61	$0.0359		$511,962,767	$97.68	$0.0321		$530,634,194	3.6%
Seasonal	149,813	619,771,621	-	$40.52	$0.0601		$110,110,094	$45.07	$0.0528		$113,720,446	3.3%
GSe	88,423	2,064,247,047	-	$29.56	$0.0589		$152,943,832	$30.20	$0.0613		$158,524,312	3.6%
GSd	5,457	2,316,983,638	7,940,259	$102.52		$16.6975	$139,295,973	$104.19		$17.3153	$144,310,713	3.6%
UGe	18,166	592,270,624	-	$23.88	$0.0278		$21,698,104	$24.47	$0.0290		$22,495,371	3.7%
UGd	1,753	1,047,731,808	2,797,926	$100.72		$9.5589	$28,863,371	$102.72		$9.9159	$29,904,298	3.6%
St Lgt	5,364	121,925,376	-	$4.07	$0.0976		$12,157,413	$4.20	$0.1011		$12,600,715	3.6%
Sen Lgt	23,822	20,235,185	-	$3.15	$0.1199		$3,326,653	$3.37	$0.1281		$3,555,266	6.9%
USL	5,633	24,560,309	-	$34.76	$0.0284		$3,047,668	$35.49	$0.0291		$3,113,025	2.1%
DGen	1,272	19,001,248	191,107	$196.16		$6.3673	$4,211,837	$196.16		$9.7580	$4,859,832	15.4%
ST	811	15,367,777,027	29,637,492	$1,022.07		$1.4367	$52,527,943	$1,046.24		$1.4928	$54,426,454	3.6%

Table 2 - Comparison of 2020 Revenues at Proposed 2020 Rates and Proposed 2019 Rates

Rate Class	2020 Forecast Charge Determinants			Proposed 2019 Rates			2020 Revenue at Proposed 2019 Rates	Proposed 2020 Rates			2020 Revenue at Proposed 2020 Rates	Change in 2020 Revenue at Proposed 2019 and 2020 Rates
	Number of Customers	kWh	kW	Fixed Charge ($/Month)	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)		Fixed Charge ($/Month)	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)		
UR	231,390	2,064,454,439	-	$31.23	$0.0047		$96,468,234	$35.85	$0.0000		$99,543,656	3.2%
R1	453,821	4,953,183,920	-	$42.19	$0.0193		$325,474,964	$47.06	$0.0160		$335,742,988	3.2%
R2	331,741	4,456,998,731	-	$97.68	$0.0321		$531,894,144	$107.71	$0.0269		$548,503,431	3.1%
Seasonal	150,145	613,086,833	-	$45.07	$0.0528		$113,551,663	$50.05	$0.0439		$117,085,947	3.1%
GSe	88,405	2,042,548,312	-	$30.20	$0.0613		$157,192,890	$30.88	$0.0633		$162,105,409	3.1%
GSd	5,511	2,312,456,387	7,924,744	$104.19		$17.3153	$144,110,290	$106.19		$17.8594	$148,554,571	3.1%
UGe	18,268	591,211,185	-	$24.47	$0.0290		$22,495,021	$25.10	$0.0299		$23,202,627	3.1%
UGd	1,762	1,046,863,808	2,787,731	$102.72		$9.9159	$29,814,749	$105.02		$10.2289	$30,735,823	3.1%
St Lgt	5,401	122,674,116	-	$4.20	$0.1011		$12,678,053	$4.33	$0.1043		$13,073,829	3.1%
Sen Lgt	23,645	20,117,348	-	$3.37	$0.1281		$3,533,660	$3.57	$0.1354		$3,736,431	5.7%
USL	5,667	24,848,190	-	$35.49	$0.0291		$3,135,514	$36.66	$0.0298		$3,234,318	3.2%
DGen	1,396	19,766,983	198,809	$196.16		$9.7580	$5,226,579	$196.16		$10.5803	$5,390,057	3.1%
ST	814	15,362,340,281	29,567,094	$1,046.24		$1.4928	$54,356,278	$1,073.56		$1.5407	$56,039,031	3.1%

Table 3 - Comparison of 2022 Revenues at Proposed 2022 Rates and Proposed 2021 Rates

Rate Class	2022 Forecast Charge Determinants			Proposed 2021 Rates			2022 Revenue at Proposed 2021 Rates	Proposed 2022 Rates			2022 Revenue at Proposed 2022 Rates	Change in 2022 Revenue at Proposed 2011 and 2022 Rates
	Number of Customers	kWh	kW	Fixed Charge ($/Month)	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)		Fixed Charge ($/Month)	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)		
UR	236,737	2,090,411,223	-	$36.67	$0.0000		$104,173,536	$37.37	$0.0000		$106,164,240	1.9%
R1	461,272	4,997,679,120	-	$52.31	$0.0116		$347,530,953	$58.26	$0.0066		$355,379,977	2.3%
R2	335,223	4,408,437,098	-	$118.85	$0.0201		$566,920,848	$131.71	$0.0117		$581,580,779	2.6%
Seasonal	150,701	600,089,302	-	$55.37	$0.0317		$119,151,837	$61.48	$0.0184		$122,224,045	2.6%
GSe	88,515	1,999,481,405	-	$31.38	$0.0652		$163,624,960	$31.94	$0.0670		$167,860,402	2.6%
GSd	5,612	2,296,967,927	7,871,666	$107.59		$18.3492	$151,684,036	$109.21		$18.8280	$155,562,622	2.6%
UGe	18,501	588,566,373	-	$25.55	$0.0308		$23,790,066	$26.07	$0.0316		$24,409,527	2.6%
UGd	1,783	1,043,919,652	2,764,065	$106.68		$10.5113	$31,336,747	$108.50		$10.7876	$32,139,402	2.6%
St Lgt	5,481	133,429,997	-	$4.77	$0.1069		$14,581,352	$4.88	$0.1097		$14,958,149	2.6%
Sen Lgt	23,605	20,494,533	-	$3.72	$0.1383		$3,888,333	$3.87	$0.1440		$4,047,929	4.1%
USL	5,975	26,397,633	-	$37.37	$0.0303		$3,478,414	$38.30	$0.0309		$3,563,169	2.4%
DGen	1,608	20,936,266	210,569	$196.16		$11.3274	$6,171,386	$196.16		$12.0863	$6,331,186	2.6%
ST	828	15,149,405,058	29,499,182	$1,085.90		$1.5849	$57,542,709	$1,111.42		$1.6264	$59,019,994	2.6%
AUR	15,467	91,767,419	-	$30.78	$0.0000		$5,712,795	$31.59	$0.0000		$5,863,141	2.6%
AUGe	1,352	43,685,012	-	$30.26	$0.0174		$1,251,830	$36.37	$0.0210		$1,505,529	20.3%
AUGd	194	142,604,414	411,710	$207.78		$3.8268	$2,058,475	$283.62		$5.2141	$2,805,951	36.3%
AR	38,018	284,062,949	-	$40.43	$0.0000		$18,444,766	$41.49	$0.0000		$18,926,985	2.6%
AGSe	4,337	102,300,056	-	$40.92	$0.0188		$4,049,313	$43.26	$0.0201		$4,303,802	6.3%
AGSd	371	235,706,494	662,981	$206.23		$5.0842	$4,287,733	$252.41		$6.3268	$5,316,920	24.0%

In Tables 1, 2 and 3, other than the rate classes with R/C ratio changes (DGen, USL, R1 and Seasonal in 2019; AGSd, AGSe, AUGd, AUGe, USL, UR and R1 in 2022), most classes' year over year increases are very similar. The only exception is the Sentinel lights rate class, where the year over year increases are typically higher than for the other rate classes. This is because this class' year-over-year load forecast is decreasing slightly compared to other classes.

e) Tables 4 and 5 below provide the 2019 and 2020 revenues from distribution rates re-calculated using the methodology described in sub-parts i), ii) and iii) of part e) of this interrogatory.

Table 4 - Recalculated 2019 Revenue from Distribution Rates

Overall increase in 2019 base revenue requirement (A)	3.46%

Rate Class	2018 Allocated Costs from CAM (Revenue Requirement)	2019 Calculated Revenue to Cost Ratios	2018 Revenue using 2019 R/C Ratios	2018 Miscellaneous Revenues from CAM	2018 Revenue from Rates (Base Revenue Reuirement)	2019 Revenue from Rates (Base Revenue Requirement)
	B	C	D=B*C	E	F=D-E	G=F*A
UR	$91,807,608	1.06	$97,275,133	$5,113,873	$92,161,260	$95,353,424
R1	$301,376,300	1.08	$325,743,914	$13,762,853	$311,981,061	$322,787,064
R2	$557,706,225	0.95	$529,879,138	$16,978,792	$512,900,345	$530,665,535
Seasonal	$104,711,041	1.08	$113,177,395	$3,251,750	$109,925,644	$113,733,109
GSe	$158,109,324	1.00	$158,369,260	$5,143,910	$153,225,350	$158,532,575
GSd	$148,142,418	0.96	$142,314,046	$2,799,207	$139,514,839	$144,347,176
UGe	$22,272,612	1.02	$22,625,773	$884,648	$21,741,125	$22,494,167
UGd	$31,348,758	0.94	$29,540,619	$630,884	$28,909,735	$29,911,073
St Lgt	$13,405,033	0.94	$12,580,542	$400,910	$12,179,632	$12,601,495
Sen Lgt	$6,258,629	1.04	$6,487,853	$3,095,690	$3,392,164	$3,509,657
USL	$2,902,765	1.08	$3,137,467	$128,914	$3,008,553	$3,112,759
DGen	$6,445,207	0.76	$4,872,667	$175,550	$4,697,118	$4,859,811
ST	$55,396,005	0.97	$53,878,120	$1,263,504	$52,614,615	$54,437,014
Total	**$1,499,881,927**		**$1,499,881,927**	**$53,630,485**	**$1,446,251,442**	**$1,496,344,858**

Table 5 - Recalculated 2020 Revenue from Distribution Rates

Overall increase in 2019 base revenue requirement (A)	**3.46%**
Overall increase in 2020 base revenue requirement (B)	**3.38%**

Rate Class	2018 Allocated Costs from CAM (Revenue Requirement)	2020 Calculated Revenue to Cost Ratios	2018 Revenue using 2020 R/C Ratios	2018 Miscellaneous Revenues from CAM	2018 Revenue from Rates (Base Revenue Reuirement)	2019 Revenue from Rates (Base Revenue Requirement)	2020 Revenue from Rates (Base Revenue Requirement)
	C	D	E=C*D	F	G=E-F	H=G*A	I=H*B
UR	$91,807,608	1.07	$98,110,462	$5,113,873	$92,996,589	$96,217,686	$99,471,568
R1	$301,376,300	1.09	$327,565,015	$13,762,853	$313,802,161	$324,671,241	$335,650,945
R2	$557,706,225	0.95	$529,860,633	$16,978,792	$512,881,840	$530,646,389	$548,591,742
Seasonal	$104,711,041	1.08	$112,748,859	$3,251,750	$109,497,109	$113,289,730	$117,120,952
GSe	$158,109,324	0.99	$156,716,562	$5,143,910	$151,572,653	$156,822,633	$162,126,047
GSd	$148,142,418	0.96	$141,779,088	$2,799,207	$138,979,881	$143,793,689	$148,656,492
UGe	$22,272,612	1.01	$22,573,676	$884,648	$21,689,028	$22,440,265	$23,199,148
UGd	$31,348,758	0.94	$29,383,614	$630,884	$28,752,730	$29,748,631	$30,754,667
St Lgt	$13,405,033	0.94	$12,625,836	$400,910	$12,224,926	$12,648,357	$13,076,098
Sen Lgt	$6,258,629	1.03	$6,468,682	$3,095,690	$3,372,992	$3,489,822	$3,607,840
USL	$2,902,765	1.09	$3,152,018	$128,914	$3,023,104	$3,127,815	$3,233,591
DGen	$6,445,207	0.81	$5,215,206	$175,550	$5,039,657	$5,214,214	$5,390,548
ST	$55,396,005	0.97	$53,682,275	$1,263,504	$52,418,771	$54,234,386	$56,068,480
Total	**$1,499,881,927**		**$1,499,881,927**	**$53,630,485**	**$1,446,251,442**	**$1,496,344,858**	**$1,546,948,119**

f) Tables 6 and 7 below compare the 2019 and 2020 revenue from rates calculated in response to part e) and those proposed by Hydro One in Exhibit H1, Tab 1, Schedule 2.

Table 6 - 2019 Base Revenue Requirement Comparison

Rate Class	2019 Base Revenue Requirement per response to part e)	2019 Base Revenue Requirement Proposed by Hydro One	Difference ($)	Difference (%)
UR	$95,353,424	95,379,475	26,050	0.0%
R1	$322,787,064	322,820,755	33,691	0.0%
R2	$530,665,535	530,634,194	(31,341)	0.0%
Seasonal	$113,733,109	113,720,446	(12,663)	0.0%
GSe	$158,532,575	158,524,312	(8,263)	0.0%
GSd	$144,347,176	144,310,713	(36,463)	0.0%
UGe	$22,494,167	22,495,371	1,205	0.0%
UGd	$29,911,073	29,904,298	(6,775)	0.0%
St Lgt	$12,601,495	12,600,715	(779)	0.0%
Sen Lgt	$3,509,657	3,555,266	45,609	1.3%
USL	$3,112,759	3,113,025	266	0.0%
DGen	$4,859,811	4,859,832	21	0.0%
ST	$54,437,014	54,426,454	(10,559)	0.0%
Total	**$1,496,344,858**	**1,496,344,858**	**(0)**	

Table 7 - 2020 Base Revenue Requirement Comparison

Rate Class	2020 Base Revenue Requirement per response to part e)	2020 Base Revenue Requirement Proposed by Hydro One	Difference ($)	Difference (%)
UR	$99,471,568	99,543,656	72,088	0.1%
R1	$335,650,945	335,742,988	92,043	0.0%
R2	$548,591,742	548,503,431	(88,311)	0.0%
Seasonal	$117,120,952	117,085,947	(35,005)	0.0%
GSe	$162,126,047	162,105,409	(20,638)	0.0%
GSd	$148,656,492	148,554,571	(101,921)	-0.1%
UGe	$23,199,148	23,202,627	3,479	0.0%
UGd	$30,754,667	30,735,823	(18,845)	-0.1%
St Lgt	$13,076,098	13,073,829	(2,269)	0.0%
Sen Lgt	$3,607,840	3,736,431	128,591	3.6%
USL	$3,233,591	3,234,318	728	0.0%
DGen	$5,390,548	5,390,057	(491)	0.0%
ST	$56,068,480	56,039,031	(29,449)	-0.1%
Total	**$1,546,948,119**	**1,546,948,119**	**(0)**	