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BY COURIER

July 11, 2018

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

Dear Ms. Walli,

EB-2017-0049 Hydro One Networks Inc. 2018-2022 Distribution Custom IR Application – Undertakings

Please find enclosed responses to undertakings J 3.06, J 3.11, J 9.03, J 9.06, J 10.01, J 10.05-Q1 to 33, J 11.01, J 11.02, and J 11.03 from the Oral Hearing in regards to the above noted proceeding.

This filing has been submitted electronically using the Board's Regulatory Electronic Submission System and two (2) hard copies will be sent via courier.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Enc.

UNDERTAKING – J 3.6

Reference

I-40-AMPCO-047-01

Undertaking

To make best efforts to advise, of the 438 positions, how many were filled and how many were vacant.

Response

Hydro One does not have a position management system that tracks staffing numbers (people in seats) against FTE's (complement) that updates when positions are changed. It is difficult to match the headcount allocation from positions when they become vacant.

Hydro One has attempted to present the vacant positions as shown in Exhibit I-40-AMPCO – 47 Attachment 1 page 2 "Turnover" with backfilled vacancies in Attachment 1 of this Undertaking. Please note that the HR metrics reflected in Attachment 1 to Exhibit I-40-AMPCO-47 are enterprise-level metrics.

For positions that had an incumbent terminate in 2017, headcount figures between December 31, 2016 and January 31, 2018[1] have been presented with the headcount difference between these two dates and the number of terminations for each position. Positions have been grouped by common function/role.

Hydro One management will assess resourcing needs prior to filling a vacancy. As such, caution needs to be exercised when interpreting this data. Where there is a positive headcount delta, it is a reasonable assumption that the particular role was backfilled. The converse is not necessarily true; a negative headcount delta may not necessarily mean that all terminations were not backfilled. The vacant role could have been reviewed and replaced with another rated position, possibly within a different jurisdiction (e.g. a higher rated position could have been replaced with a lower rated position) or a new role (e.g. 102 positions were created in new roles in 2017). In addition, Hydro One may have incurred costs (i.e. overtime, temporary assignments or utilized the PWU hiring hall) while positions remain unfilled with a regular incumbent.

[1] January 31, 2018 was selected to capture any vacancy backfilling resulting from a termination late in 2017.

UNDERTAKING – J 3.11

Reference

Updated Compensation Study

Undertaking

To provide the analysis that led to the derivation of the number as well as the underlying calculations.

Response

Upon further review by Mercer, the calculation of the aggregate total remuneration difference to the market median as shown in Exhibit I-40-SEC-83 (updated on June 7, 2018) remains unchanged.

Below are the steps taken by Mercer in calculating Hydro One's aggregate total remuneration difference to the market median.

1. **Determine Benchmark Incumbent Level Total Remuneration Difference:**

   Determine the difference in total remuneration for each Hydro One incumbent, within the survey benchmark jobs, relative to the market total remuneration median.

2. **Determine Average Total Remuneration Difference For Each Employee Group:**

   Using the incumbent level total remuneration difference data generated in step 1, determine the average total remuneration difference for each employee group (Non- Represented, Energy Professionals and Trades and Technical).

3. **Determine the Aggregate Total Remuneration Difference For Each Employee Group:**

   Using the average total remuneration difference data for each employee group generated in step 2, determine the aggregate total remuneration difference for each employee group by multiplying the employee group average by the total number of full-time incumbents, across Hydro One, in that employee group.

4. **Determine the Aggregate Total Remuneration Difference For Hydro One:**

   Using the aggregate total remuneration difference data for each employee group generated in step 3, determine the aggregate Hydro One total remuneration difference by adding the dollar difference for each employee group as determined in step 3.

Conducting this analysis as indicated above resulted in an aggregate total remuneration difference of approximately $70,915,000. This number reflects full-time employees across Hydro One. Please refer to Exhibit I-40-SEC-83 for the allocation methodology.

UNDERTAKING – J 9.3

Reference

C1-03-01-02

Undertaking

To submit the revised forecast.

Response

The costs below represent the updated cost of operating the Fleet Services organization. These costs are allocated to work programs based on utilization of equipment via standard fleet rates. Please see the cost allocation table below.

The 2018 forecast is an update to Table 2: Fleet Management Services budget expenditures ($ Millions). Also included in the forecast are helicopters as per Exhibit I-24-CCC-27.

Description	**Test 2018 Forecast**
Operations & Repairs	72.2
Fuel Costs	24.1
Depreciation	40
Subtotal	**136.3**
External Fleet Rentals	1
Total	**137.3**
Helicopters	10.1
Grand Total	**147.4**

Cost Allocation Table

	DX	**TX**	**Total**
Capital	36%	26%	62%
OM&A	29%	9%	38%
Total	**65%**	**35%**	**100%**

Hydro One notes that its cost estimates continue to evolve over time as new information or circumstances change, but does not propose to adjust its request in this Application as described by Mr. D'Andrea on Day 1 of the oral hearing in this proceeding. For example, Hydro One's internally updated productivity forecast for "fault indicator deployment" for the rate term is presently $0 and is shown as $800,000 annually in Exhibit I-25-Staff-123.

UNDERTAKING – J 9.6

Reference

B1-01-01 Section 3.8

Undertaking

To advise, first, whether Hydro One will be replacing the meters at the acquired local distribution companies; and, second, whether Hydro One customers will be bearing those costs.

Response

Hydro One confirms that the proposed meter programs have integrated the Acquired Utilities planned meter replacement requirements in 2021 and 2022. For meters being replaced in 2021 and 2022 the meter costs are part of Hydro one's total meter programs costs, and the acquired utility customers will share in Hydro One's total costs per the cost allocation methodology described in Exhibit G1, Tab 3, Schedule 1.

UNDERTAKING – J 10.1

Reference
J7.1

Undertaking
To provide the FTE analysis that fed into the labour strategy

Response
Hydro One was asked about the check mark under "FTE benchmarking" in the Corporate Functions row on slide 58 of 78 of attachment 1 to undertaking J 7.1.

Hydro One has confirmed that the basis for the check mark under "FTE benchmarking" is the material that was redacted in red in the attachments to J 7.1, and was ruled on by the Board at Transcript, Day 9, June 25, page 141, line 15 to page 142, line 16.

UNDERTAKING – J 10.5-Q1

Reference
I-43-VECC-071

Undertaking
In response to 43-VECC-71 your provided an excel spreadsheet setting out the derivation of the customer counts for the different Residential classes – including Seasonal.

a) Can you confirm that the forecast for the overall annual increase in the total number of Residential customer in your existing Retail class for 2018-2022 was determined by calculating the ratio of the 2017 increase in HON's residential customer count versus the total increase in Ontario households for 2017 and applying the result to the annual forecasted increase in Ontario household for 2018 through 2022?
b) For each of the acquired utilities, can you confirm that the forecast annual change in Residential customers is based on a fraction of the annual change in provincial households – approximately 0.003 in the case of Norfolk and Woodstock and 0.0015 for Haldimand?
c) How were the fractions for the acquired utilities derived?

Response
a) Please see Volume 10 of the transcript for the oral hearing, pages 95 and 96.
b) Please see the transcript noted above at the beginning of page 97.
c) The fractions were based on historical ratios (i.e., change in acquired number of customers to change in Ontario number of customers).

UNDERTAKING – J 10.5-Q2

Reference

I-46-Staff-219

Undertaking

In response to 46-Staff-219 you have revised your overall Residential customer count forecast and it is now somewhat lower. For example, in 2022 the initial application called for a total of 1,183,932 customer in your four "Residential" classes (this can be seen from the VECC-71 attachment, Cell G42 and from totaling the values in Table E.4 of the original application) whereas in the updated forecast provided in Staff-219 – Table E.4 the total for these same four Residential classes is 1,179,997. However, the total number of starts in the revised forecast is 433,200 over the period 2017-2022 where as in the initial application the total number of forecast housing starts for the same period was 423,000.

a) Why is the updated Residential customer count forecast lower when the forecast for the underlying driver – housing starts – has increased in your update?
b) Can H1 provide an updated version of the attachment to 43-VECC-71 – based on your updated customer count forecast?

Response

a) Please see Volume 10 of the oral transcript, page 98.
b) Please see live MS Excel attachment to this response.

UNDERTAKING – J 10.5-Q3

Reference
G1-02-01

Undertaking
According to Exhibit G1/Tab 2/Schedule 1, page 2 (Table 1) the results of customer classification review were to:

a) Increase UR by 8,296 (i.e., 8,250+46)
b) Decrease R1 by 4,363 (net impact of 8,250-3,887)
c) Decrease R2 by 3,887
d) Shift 227 from GSe to UGe, and
e) Shift 22 from GSd to UGd.

However, in the attachment provided by H1 in your response to JT3.18-6, I see:

a) UR increasing 9,296 not 8,296
b) R1 decreasing by 5,343 not 4,363
c) R2 decreasing by 3,933 not 3,887
d) A shift between GSe and UGe of 317 not 227 and
e) A shift between GSd and UGd of 29 not 22

Can you explain these differences?

Response
The differences account for changes in the number of customers to be reclassified between the time when customer reclassification review was performed and the forecast of reclassifications for the period 2018 to 2022. For example, there are some medium density R1 communities with density very close to the threshold for moving them to the higher-density UR rate class, which are expected to occur over the application period.

UNDERTAKING – J 10.5-Q4

Reference

JT3.18-6

Undertaking

With reference to the attachment to JT3.18-6, can you explain why the number of customers shifted between classes increase throughout the forecast period for all classes except R2?

Response

As R2 is the lowest density rate class, no customers are expected to be reclassified into the R2 class from the higher density rate classes (R1 and UR).

UNDERTAKING – J 10.5-Q5

Reference

I-43-VECC-071

Undertaking

Looking at the text provided in the Attachment to 43-VECC-71, would I be correct that the economic outlook (e.g. forecast growth in GDP) is one of the factors you look at in developing the aggregate forecast for the number of Retail General Service Customers?

Response

Confirmed.

Witness: ALAGHEBAND Bijan

UNDERTAKING – J 10.5-Q6

Reference

I-46-Staff-219

Undertaking

In response to 46-Staff-219 you have revised your overall General Service customer count forecast and it is now somewhat lower. For example, in 2022 the initial application called for a total of 114,411 customers in your four "General" classes (this can be seen from the VECC-71 attachment, Cell G88 and from totaling the values in Table E.4 of the original application) whereas in the updated forecast provided in Staff-219 – Table E.4 the total for these same four Residential classes is 113,025. However, if I look at the revised GDP forecast provided in Staff-219 (Table E.3) – I see that the GDP increases to $780,618 M (2007$) for 2022 where as in the initial application the GDP forecast for 2022 was $770,631 M (2017$) (per the original Table E.3).

a) Can you explain why the General Service customer count forecast is lower when the forecast for the underlying driver – GDP- has increased in your update?

Response

a) Please see pages 100 and 101 of Volume 10 of the oral hearing transcript for Hydro One's response.

UNDERTAKING – J 10.5-Q7

Reference

JT3.18-1

Undertaking

At JT3.18-1 c), VECC asked for a reconciliation of the 2,765 GWh of end-use CDM savings for 2016 reported in Table E.9 of the Application with the 1,866.7 GWh shown in the Attachment 1to 43-VECC-75. Your explanation was that the 1,866.7 GWh was for Hydro One Retail customers. Now if you turn to your response to 43-VECC-73 – here you provide a break out for the Retail customers contribution to the 2,765 GWh and the value is 1,678 GWh – not 1,8667.7 GWh. Can you explain the difference?

Response

The value of 1,866.7 GWh in Attachment 1 to Exhibit I, Tab 43, Schedule VECC-75 is at the purchases level including line losses, and the value of 1,678 GWh is at the metered kWh (sales level) and does not include losses.

UNDERTAKING – J 10.5-Q8

Reference

I-43-VECC-075

Undertaking

At 43-VECC-75 a). We'd asked you to provide a breakdown of Hydro One's CDM results reported by the IESO for purposes of its 2016 Ontario Planning Outlook and you indicated that the information was not available in the 2016 OPO or other available information.

a) Did Hydro One approach the IESO to determine whether they had Hydro One's CDM results for the purposes of its 2016 Ontario Planning Outlook (as distinct from the outlook itself) and could provide it to you? If not, why not?
b) Can you confirm that historical values for the impact of energy efficiency programs that you used in your load forecast methodology are estimated based as a percentage of the total province wide energy efficiency programs savings reported by the IESO for the period 2006 to 2016 rather than based on actual values – as set out in 43-VECC-75, Attachment 1 (Cells A34 – N56)?

Response

a) Hydro One did approach the IESO and were told that the IESO (OPA) only provided the conservation results report for each LDC for the saveON energy 2011-2014 programs and Conservation First Framework 2015-2020 programs funded through the IESO (OPA). The historical (2006-2020) EE programs' persistent impact is not available for each LDC.
b) Confirmed.

UNDERTAKING – J 10.5-Q9

Reference

JT3.18-2

Undertaking

In JT 3.18-2, Hydro One indicates that the definition of the EE programs savings reported by Hydro One is same as the historical EE savings reported in the OPO.

Response

Hydro One notes that this undertaking poses no question. Hydro One confirms the statement is correct.

UNDERTAKING – J 10.5-Q10

Reference

I-43-VECC-075-01

Undertaking

At Tab VECC has set out the historical annual values for the impact of CDM programs on HON's retail load as calculated in 43-VECC-75, Attachment 1 and used in your load forecast modelling. We have also set out the impact of HON's 2011-2016 CDM programs as verified by the IESO per JT 3.18.2 b) and calculated the residual.

a) Since you've confirmed that both references use the same definition for EE programs - is it fair to consider this "residual" as representing the persisting impact of the 2006-2010 CDM programs on HON's load?
b) There are slight anomalies in 2011 and 2012 values. However, in 2013 we see a more material increase – which is more than one would expect to see from rounding. Would you agree that these anomalies, particularly in for 2013, suggest that there are "problems" with your approach to estimating the impact of Hydro One's historic CDM programs?
c) In preparing the Application, did you perform any similar reasonableness checks regarding the results of your calculated impacts of historical CDM on HON's Retail load? If so, can you provide the results?

Response

a) Yes.
b) No, this does not suggest a problem with Hydro One's approach. The comparison of EE program impact (GWh) assumptions and the verified 2011-2014 program impact, as shown in Tab 17 of the VECC Compendium for Panel 7, is as follows:

   Hydro One applied the average ratio of HONI achieved 2011-2014 cumulative savings to the cumulative savings for all LDCs for 2010-2014 since Hydro One does not have the verified results for the 2006-2010 program. The residual in 2013 is 1% (634-628=6GWh) higher than it in 2012 based on this method because the share of Hydro One's verified result is 12.4% of all LDCs and is lower than the average of 13.7%. The average of 2013 and 2014 is 598 GWh ((634+562)/2=598) which is 5% lower than that in 2012.

c) Hydro One analyzed the changes in average electricity consumption per customer for the residential and energy billed general service customers from 2003 to 2016 based on the monthly billing information. The analysis shows that these customers' consumption dropped by approximately 15% from 2006-2016 which is consistent with the CDM savings assumption used in the load forecast.

As discussed in the evidence at Exhibit E1, Tab 2, Schedule 1, Hydro One uses an explicit model of incorporating CDM in the load forecast by adding CDM savings (EE and C&S) back to the actual load and then deducting all past and future savings from the forecast. The C&S and the historical 2006-2010 program verified results are not available from the IESO (the OPA), therefore Hydro One uses its share of the Ontario total savings to estimate the savings for the historical programs. Hydro One previously assessed different methods of incorporating CDM in load forecasting (EB-2013-0416, Exhibit A, Tab 16, schedule 4, page 80-90) and demonstrated that its approach is technically sound and efficient.

UNDERTAKING – J 10.5-Q11

Reference

I-43-VECC-076

Undertaking

Confirm that Hydro One used three different models to forecast retail customer load and then averaged the resulting growth rates to develop a preliminary forecast and the calculations for this are set out in response to 43-VECC-76 c).

Response

Confirmed.

UNDERTAKING – J 10.5-Q12

Reference

E1-02-01

Undertaking

Confirm that these models use forecast of various economic indicators such as GDP, population and housing starts (See Exhibit E1, Tab 2, Schedule 1, page 6)

Response

Confirmed.

UNDERTAKING – J 10.5-Q13

Reference

JT3.18-7

Undertaking

Confirm that for purposes of the Application this preliminary forecast was adjusted upwards as, at the time the forecast was being finalized, the economic outlook seemed to be improving. (JT 3.18-7, a)

Response

Confirmed.

UNDERTAKING – J 10.5-Q14

Reference

I-46-Staff-219

Undertaking

In response to 46-Staff-219 you updated your economic forecast, updated your models and provided an updated Retail customer load forecast which is set out in the updated Table 7 in that response.

a) Confirm that this updated Retail load forecast was lower than the forecast in the original Application? (Exhibit E1, Tab 2, Schedule1, Table 7).
b) Confirm that this updated Retail load forecast was also lower than the preliminary forecast you made at the time the original Application was being prepared.
c) Table E.3 in Staff-219 sets out the updated forecast for the various economic variables. Confirm that the updated GDP forecast for all years 2018-2022 is higher than in the initial Application? (Exhibit E1, Tab 2, Schedule 1, page 38 – Table E.3)
d) Confirm that the updated population forecast for all years 2018-2022 is higher than in the initial Application?
e) Confirm that the total forecast housing starts are higher in the update than in the original Application?
f) Why is the updated load forecast is lower when the forecast values for the various economic indicators in the used in the forecast models have all increased?

Response

a) Confirmed.
b) Confirmed.
c) Confirmed.
d) Confirmed.
e) Confirmed.
f) The 2017 actual load, which is the base-year for the updated forecast in Exhibit I, Tab 46, Schedule Staff-219, was lower compared to 2017 forecast in the original pre-filed evidence. Moreover, although the updated economic variables were higher in terms of level, it is the impact of growth rate pattern of these variables on load that matters. The combination of a lower 2017 base-year load and new pattern of growth rates yielded the lower forecast in the updated forecast that was provided in the response at Exhibit I, Tab 46, Schedule Staff-219.

UNDERTAKING – J 10.5-Q15

Reference

I-46-Staff-219

Undertaking

Going back to the updated version of Table 7 in your response to 46-Staff-219 and comparing it with the Table 7 in the original Application we see that the – before CDM deduction – forecast for embedded customers is also now lower that than in the original Application's Table 7. For example in the original Application the forecast for 2020 was 17,484 GWh whereas in the update it is now 17,370 GWh. Can you explain why this is the case when the updated forecasts for provincial GDP and housing starts are both higher?

Response

The same answer provided in response to undertaking J10.05-Q14, f) also applies to the embedded customers forecast.

UNDERTAKING – J 10.5-Q16

Reference

I-43-VECC-075

Undertaking

In VECC-75, in response to part (j) you provided the derivation of the CDM forecast for 2017-2022 that was incorporated in your initial load forecast submitted with the Application.

a) Confirm that the forecast consists of two parts: One is the forecast contribution of codes and standards implemented since 2006 and the second is the forecast impact in the years 2017-2022 of the energy efficiency programs implemented since 2006 – correct.
b) Confirm that with respect to energy efficiency programs – what you've done is taken the IESO's forecast of the total impact of energy efficiency programs adopted since 2006, determined the amount attributable to all Distributors by removing an amount for the impact of energy efficiency programs on transmission connected retail customers and then assumed that 13.71% of the distributors' portion was attributable to HON.
c) So Hydro One's CDM forecast for 2017-2022 in not based on a specific forecast of HON's CDM activity but rather based on a percentage of the forecast CDM activity for all of the province's LDCs?

Response

a) Confirmed.
b) Confirmed.
c) That is correct. Hydro One uses an EE forecast for 2017-2020 based on the percentage of the total Ontario EE savings for the forecast period so that the persistence of earlier programs would also be captured.

UNDERTAKING – J 10.5-Q17

Reference

I-43-VECC-075-05

Undertaking

Refer to the forecast of CDM activity for LDCs overall that you used to derived the HON forecast – which is found at 43-VECC-75 – Attachment 5 (Cells A33-I39). The forecast EE program savings for 2018 are: 9,044,428 kWh.

a) Confirm that this represents the persisting savings in 2018 from EE programs implemented over the years 2006-2018.
b) What assumptions did the IESO make in its forecast per the 2016 Ontario Planning Outlook with respect to the contribution to this 9,044,428 kW from EE programs implemented in 2017 and 2018? Please provide these figures for 2017, 2018, 2019, and 2020, i.e. for each year the impact of EE programs implemented in 2017 and after.

Response

a) Confirmed.
b) Hydro One does not have the assumptions that the IESO made in its forecast per the 2016 OPO. Hydro One understands that there are two EE categories in the OPO and they include the savings from all the LDCs and transmission direct connected customers. The 7 TWh saving target of the 2015- 2020 framework for all LDCs is reflected in the 2016 OPO and included in the total of 12.8TWh in 2020.

   As shown in the response to Exhibit I, Tab 43, Schedule VECC-75, Attachment 5, Hydro One's 2015-2020 target share of savings for all LDCs (1159/7000=16.6%) is applied to the total Ontario EE savings from 2015 onward. The EE savings include historical programs' persistence and 2015-2020 target framework.

UNDERTAKING – J 10.5-Q18

Reference

I-43-VECC-075

Undertaking

In 43-VECC-75 i) you provide a table that you claim indicates the impact of EE programs by program year for 2015 and onward implicitly included in your load forecast.

a) If your forecast of HON savings is based on a percentage of the EE program savings by all LDCs and, as we just discussed, how can you separate out the contribution of EE programs by implementation year for the provincial total? How were the values shown here established in a way that is consistent with your overall EE program impact forecast for HON and, as you state in the response, implicit in your total CDM forecast?

Response

a) Hydro One does not have the EE savings for all LDCs by implementation year, therefore what was provided in I-43-VECC-75 i) is based on the OEB's template (straight line method) to forecast savings for each year to meet 2015-2020 target.

UNDERTAKING – J 10.5-Q19

Reference
I-46-Staff-219

Undertaking
46-Staff-219 contains your updated load forecast and, more specifically the updated version of Table 4 which sets out the CDM forecast used in the updated Load Forecast.

a) The updated CDM forecast for the Retail class has changed marginally in some years from that in the original Table 4. Is this just rounding or have your changed the basis for your CDM forecast for the Retail customers for purposes of the update? If there is a change, please describe how the new forcast was developed.

Response
a) Please see page 102 of Volume 10 of the oral hearing transcript for Hydro One's response to this question.

UNDERTAKING – J 10.5-Q20

Reference
None

Undertaking
The forecast for the Direct customers in your ST class has increased in every year of the update. Is there a particular reason for this?

Response
The reason for increase is primarily the higher 2017 base-year actual load for direct customers.

UNDERTAKING – J 10.5-Q21

Reference

None

Undertaking

There appears to be a material reduction in the updated CDM forecast for the LDCs included in your ST class. What is the reason for this?

Response

Please see page 102 of Volume 10 of the oral hearing transcript for Hydro One's response to this question.

UNDERTAKING – J 10.5-Q22

Reference

EB-2017-0049 Transcript Volume 3, Page 122

Undertaking

In response to earlier cross examination (Volume 3, page 122), HON stated that they are only seeking recovery of lost revenue due to CDM from:

a) The impact in 2018 of 2017 & 2018 energy efficiency programs
b) The impact in 2019 from 2017 – 2019 energy efficiency programs and
c) The impact in 2020 from 2017 – 2020 energy efficiency programs.

In JT 3.18-4 c) we asked you to confirm that Table provided in response to 55-CCC-75 included the LRAM baselines values against which you proposed any true-up of lost revenue would be made and you confirmed that "yes" they were. Looking at the Table the total CDM for 2018 is 842,605,433 kWh which appears to be more than the totals for the years 2017-2018 and indeed more than the total for the years 2015-2018.

a) What are the total savings for the year 2018 (in kWh) that you're proposing will be used for purposes of lost revenue due to EE programs given that you will only be seeking recovery of lost revenue from the impact of 2017 and 2018 programs?
b) Could you similarly, given me the baseline values for 2019 and 2020 that will be used for true-up purposes?

Response

The total row in the table provided to the response to Exhibit I, Tab 55, Schedule CCC-75 was not correctly summing the values in the rows above, as discussed by Mr. Alagheband during the oral hearing (see Transcript Volume 10, page 103).

However, Hydro One would like to clarify that the LRAM threshold for the purpose of determining lost revenue due to EE programs in the 2015-2020 CDM framework is actually derived from Table 1 provided in the response to Exhibit I, Tab 46, Schedule Staff-233, which is reproduced below:

	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			160,064,036	160,064,036	160,064,036	160,064,036
2018 CDM Programs				160,064,036	160,064,036	160,064,036
2019 CDM Programs					160,064,036	160,064,036
2020 CDM Programs						160,064,036
Total in Year	**335,528,398**	**528,017,133**	**683,208,870**	**842,605,433**	**1,001,184,662**	**1,159,020,000**

Table 1 in Exhibit I, Tab 46, Schedule Staff-233 appropriately reflects Hydro One's verified 2015 and 2016 CDM program results and the 2017-2020 forecast CDM program amounts required to achieve the 2020 Hydro One CDM target of 1,159,020,000 kWh which is incorporated into Hydro One's proposed load forecast.

a) The proposed threshold for the LRAMVA in 2018 is:

	2016	2018	Threshold in 2018 (2018 vs 2016)
Cumulative savings (kWh)	528,017,133	842,605,433	314,588,300

b) The thresholds for the LRAMVA in 2019 and 2020 are:

	2016	2019	Threshold in 2019 (2019 vs 2016)
Cumulative savings (kWh)	528,017,133	1,001,184,662	473,167,529

	2016	2020	Threshold in 2020 (2020 vs 2016)
Cumulative savings (kWh)	528,017,133	1,159,020,000	631,002,867

UNDERTAKING – J 10.5-Q23

Reference
JT3.18-4

Undertaking
In JT3.18-4 g), VECC asked you to provide a breakdown of the LRAMVA threshold by customer class and explain how the values were derived. In your explanation – you state that: “The threshold is the incremental savings in 2018-2020 compared to the savings in 2016. For the energy billed customers, the share of CDM savings by rate class was applied to the incremental six year target program CDM savings in 2018-2020 vs 2016. For the demand billed customers, the share of six year target program savings of total EE savings was applied to peak savings.

a) Can you undertake to provide the detailed calculations in the form of an functional excel spreadsheet?
b) Since some of the classes are demand billed and some are energy billed can you, as part of the undertaking, also provide the energy values for those classes that are demand billed and show how the total across all customer classes links back to your total CDM for each year 2018-2020.
c) Is the table provided in response to JT 3.18-4 g) is based on your original CDM forecast or the updated forecast provide in response to 46-Staff-219?

    i. If the table is based on the original CDM forecast: Refer to Exhibit E1, Tab 2, Schedule 1 – page 42 – Table E.9. Here you have set out a breakdown of your CDM forecast by rate class.

        1. Confirm that these values capture the impact of codes and standards as well as energy efficiency programs and
        2. Confirm that these values represent for each year the persisting CDM savings for codes and standards and EE programs in that year and prior years going back to 2006.
        3. For, the Residential Low Density savings and we can see that in 2018 the value is 300 GWh and in 2016 it is 256.7 GWh – with a difference of 43.3 GWh. Now if I look at your response to JT3.18-4 g). – we see an LRAMVA values for this class for 2018 of 53.2 GWh – which is meant to represent the impact on the Residential Low Density class of energy efficiency programs implemented in 2017 and 2018. We’ll get

similar results for the years 2019 and 2020 – where the values in JT 3.18-4 g) are greater that the increase in CDM between 2016 and those respective years set out in Table E.9. Can you tell me why, in each of the three years, the values in JT 3.18-4 are so much higher than the total impact you ascribed to the class in each of those years from all codes and standards and energy efficiency programs adopted since 2006?

ii. If the table is based on the original CDM forecast: Refer to 46-Staff-219 – Updated Table E.9. Here you have set out a breakdown of your CDM forecast by rate class.

1. Confirm that these values capture the impact of codes and standards as well as energy efficiency programs and
2. Confirm that these values represent for each year the persisting CDM savings for codes and standards and EE programs in that year and prior years going back to 2006.
3. If I look at your response to JT3.18-4 g). – we see an LRAMVA value for this class for 2018 of 53.2 GWh – which is meant to represent the impact on the Residential Low Density class of energy efficiency programs implemented in 2017 and 2018. We'll get similar results for the years 2019 and 2020 – where the values in JT 3.18-4 g) are greater that the increase in CDM between 2016 and those respective years. Can you tell me why, in each of the three years, the values in JT 3.18-4 are so much higher than the total impact you ascribed to the class in each of those years from all codes and standards and energy efficiency programs adopted since 2006?

Response

Parts a) and b). The detailed calculation and information requested is provided in the live MS Excel attachment to this response.

The proposed 2018-2020 LRAMVA threshold by rate class provided to the response to JT3.18-4 g) is updated as shown below to be consistent with an LRAMVA threshold that is based on the incremental CDM program savings in 2018-2020 relative to 2016:

Implementation Year	GSD	GSE	R1	R2	SR	ST	UGD	UGE	UR
	General Service - Demand Billed	General Service - Energy Billed	Residential - Medium Density	Residential - Low Density	Seasonal	Sub-transmission	Urban General Service -	Urban General Service - Energy	Urban Residential
	kW	KWH	KWH	KWH	KWH	KW	KW	KWH	KWH
2018	173,583	70,896,614	45,717,090	43,347,730	5,793,913	220,255	59,596	18,969,468	18,151,449
2019	247,061	106,149,598	69,237,990	64,761,584	8,604,120	315,705	84,161	28,497,734	27,373,220
2020	320,144	140,897,655	92,965,972	85,783,466	11,327,539	410,462	108,208	37,956,633	36,599,441

Part c, i.

a) N/A.
b) N/A.
c) N/A.

Part c, ii.

a) Confirmed for Updated Table E.9.
b) Confirmed for Updated Table E.9.
c) This is addressed by the updated table provided in the response to parts a) and b).

UNDERTAKING – J 10.5-Q24

Reference

I-49-Staff-242-01

Undertaking

Refer to 49-Staff-242 – Attachment 1 – Tab 1 where you set out the gross book values by year for the acquired utilities as used in determining the Gross Fixed Asset Adjustment Factor. Here we see that as of 2020 year-end – just before integration – the Gross Book value for Norfolk is $86.7 M. Refer now to 53-CCC-71 where HON was asked for details on the costs being added to the revenue requirement as a result of integration. Looking at the response dealing with Norfolk we see a total Gross Book value of $67.8 M as of 2020 year-end – substantially less than what you used in the cost allocation for accounts 1815 to 1860 – a subset of Norfolk's total assets. Furthermore, if you look at the other two acquired utilities there are similar discrepancies between the value reported in the two IRs. Can you explain the discrepancies?

Response

The response to I-53-CCC-71 reflects the fixed asset values used to determine revenue requirement. For accounting purposes, fixed assets are purchased at market value, which is deemed equivalent to their net book value at the date of acquisition. The values shown in I-49-Staff-242 Tab 1 are the gross book values of these assets prior to acquisition plus the in-service additions since acquisition. The gross book values are appropriate for cost allocation purposes, as they reflect the value of assets used to serve the acquired customers on a comparable basis with the gross book values used for allocating costs to Hydro One's other rate classes.

UNDERTAKING – J 10.5-Q25

Reference

I-46-VECC-092

Undertaking

Refer to 46-VECC-92 Here you provide a comparison of the net plant allocated to the acquired customer classes versus that attributed to the acquired utilities for purposes of the revenue requirement adjustment in 2021.

a) Confirm that the amount identified in the response as being allocated "per the CAM" is not all of the net plant that the CAM allocates to all the acquired customers since some of the acquired customers – such as street lights and USL- are included in HON's existing customer classes.
b) Can you explain why – even after the application of your "adjustment factors" the CAM allocates significantly more costs to the acquired utility customers (over 30% in the one case and almost 20% in the other) than is actually associated with the acquired utilities?

Response

a) Confirmed.
b) The Net Plant allocated per the 2021 CAM represents the total assets required to serve the acquired customers.

   The adjustment factors were used to align the "local assets", which include USofA 1815 to 1860 fixed assets only. As discussed in Exhibit G1, Tab 3, Schedule 1, page 6, line 9-19, bulk distribution assets and assets in all other USofA fixed assets accounts are considered to be commonly shared among all classes served by Hydro One. These shared assets are allocated to all rate classes using the cost allocation principles underlying the CAM, and are not affected by the adjustment factors.

   The Net Plant values per Exhibit B1, Tab 1, Schedule 1, Appendix A are a forecast of fixed assets (net plant) added to Hydro One from the three acquired utilities for the purpose of calculating Hydro One's total revenue requirement. They only represent a portion of the total assets actually required to serve these acquired customers.

Witness: ANDRE Henry

UNDERTAKING – J 10.5-Q26

Reference

I-46-VECC-095

Undertaking

Refer to 46-VECC-95. Here in part (b) you identify the OM&A costs allocated to your acquired classes in the 2021 cost allocation and in part (c) you identify the OM&A costs as added to the 2021 revenue requirement as a result of integrating the acquired utilities into HON's 2021 business.

a) Confirm that the amounts identified in part (b) being allocated to the acquired classes totals roughly $16.4 M and that this is not all of the OM&A that the CAM allocates to the acquired customers since some of the acquired customers – such as street lights and USL- are included in HON's existing customer classes.
b) Can you explain the discrepancy between the $16.4 M of allocated costs and the $10.7 M of additional costs added due to the integration of the acquired utilities and why adjustment factors weren't also developed and applied to the OM&A costs as was done for the capital-related costs?

Response

a) Confirmed.
b) The difference between the $16.4M of allocated costs and the $10.7M of additional costs added due to the integration of the acquired utilities is explained in Hydro One's response to Exhibit I, Tab 56, Schedule SEC-90, part (e).

   As mentioned in Exhibit G1, Tab 3, Schedule 1, page 7, the Board's cost allocation methodology uses fixed assets as the main driver to allocate majority of the distribution O&M costs which, in turn, is the key driver in allocating most administration and general costs. Thus, the adjustment factors are implicitly applied to the OM&A costs as well.

UNDERTAKING – J 10.5-Q27

Reference

JT3.18-19

Undertaking

Refer to Undertaking JT 3.18-19. Here you have a table here that compares the increase in HON's revenue requirement as a result of the integration of the 3 acquired utilities with you estimate of the status quo revenue requirement for the three utilities. Confirm that the $36.9 M you show here is your estimate of what the combined 2021 revenue requirement for the three utilities would be if they continued as stand-alone utilities.

Response

Please refer to pages 121 and 122 of Volume 10 of the oral hearing transcript for Hydro One's response to this question.

UNDERTAKING – J 10.5-Q28

Reference

I-56-SEC-096

Undertaking

Refer to 56-SEC-96.

a) Confirm that in the response to part b) – "combined classes" refers to those acquired customers who are not segmented into a separate acquired customer class but rather included with one of Hydro One's existing customer classes – such as street lighting.

    i. If yes, confirm the total allocated to these customers is $1.5 M

Response

a) Both requested confirmations can be found on page 122 of Volume 10 of the oral hearing transcript.

UNDERTAKING – J 10.5-Q29

Reference

None

Undertaking

If I go through this response and sum up the costs allocated to the 6 new acquired customer classes in 2021 I get:

a) From Part a) - $16.4 M for OM&A. and
b) From Part d) - $11.5 M for Depreciation, $4.9 M for Interest, $6.9 M for Return on Equity, and $1.6 M for payments in lieu of taxes – for a total of $41.3 M which is roughly equivalent to the $41.2 M total you given in response to SEC 96 – part e) iii)

Response

Hydro One notes that this undertaking poses no question but notes that this was discussed at the oral hearing. Please refer to page 122 of Volume 10 of the oral hearing transcript for the discussion.

UNDERTAKING – J 10.5-Q30

Reference
I-49-VECC-098

Undertaking
Please turn up the 49-VECC-98, where we asked that you provide a schedule that for each year of transition demonstrates whether the change in the fixed charge meets the Board's $4 criterion. As we can see, the table provided shows the total change in fixed charges for the UR, R1, R2 and Seasonal classes. However, in our Technical Conference question JT 3.18-16 we noted that the Board's $4 criterion is based on the change in the fixed charge net of the annual rate increases and so we requested a revised schedule consistent with the Board's approach and you referred us to your response to 49-Staff-245, which provided the calculation based on the Board's approach but – as you note in the undertaking response – the resulting fixed charges are not the ones that HON is actually proposing. Can you provide a response to JT 3.18-16 based on your proposal that shows the change in these class' fixed charges for each year – net of impact of the annual rate increase?

Response
The table below is a summary of the proposed year-over-year change in fixed charges as a result of moving to all fixed rates for all residential classes, excluding the impact of the revenue requirement increases.

	Change in Fixed Rate due to Move to All Fixed				
	2018	2019	2020	2021	2022
UR	$ 1.92	$ 2.55	$ 3.64	$ -	$ -
R1	$ 2.71	$ 3.15	$ 3.55	$ 4.37	$ 4.79
R2	$ 5.15	$ 6.38	$ 7.24	$ 8.52	$ 9.97
Seasonal	$ 2.66	$ 3.53	$ 3.75	$ 4.54	$ 4.78

Witness: ANDRE Henry

UNDERTAKING – J 10.5-Q31

Reference

I-51-VECC-110

Undertaking

Refer to 51-VECC-110. Here we asked why the time required for an after-hours reconnection was more that for a regular hours reconnection and your response was: "The time required for an after regular hours reconnect (Table 13) is higher than the time required for a regular hours reconnect (Table 12), because after hours, the employee requires time to travel to and from the site, whereas during regular hours, the employee will already be in the vicinity of the work."

a) Now, since I assume crews are not always in vicinity of each and every customer, one interpretation that could be taken from this response is that, when a reconnection is requested, if the customer wants to pay the regular hours charge then Hydro One waits to perform the work until there is work crew scheduled to be in the vicinity and that customers would have to wait accordingly for a reconnection. Is that a correct interpretation?

    i. If yes, how long do customers have typically wait for a regular hours reconnection?
    ii. If no, and a crew is dispatched specifically in response to the request – please explain the difference in time requirements.

Response

a) Yes.

    i. Hydro One aims to connect a customer within 2 business days. Generally, a reconnection is completed on the same day, after the customer has made payment. When the payment is made, and the Scheduling Department receives the order to reconnect the service, the crew is scheduled according to its availability and proximity.

       If the Scheduling Department receives the order to reconnect at the end of the day, the customer is notified that if they want to be reconnected after hours, a higher charge will apply. Otherwise, the connection order will be scheduled during regular hours.
    ii. N/A

UNDERTAKING – J 10.5-Q32

Reference
I-51-VECC-116

Undertaking
Please turn to 49-VECC-116. Here the response indicates that there is set fee for a standard micro net-metered connection of 10 kW or under. However, in going over your listing of specific service charges (Exhibit H1, Tab 2, Schedule 3, Table 1) I could not see a charge for this service. Is it set out in your listing of specific service charges and, if so, where?

a) If not why not?
b) If not, are there any other services for which you charge "standard" fees that are not set out in the application for approval?

Response
No.

a) This charge was not studied in our current Time Study, filed as Exhibit H1, Tab 2, Schedule 3, Attachment 1. The current fee is $800 based on a time study, and is not in our current tariff. Hydro One believes this adequately reflects the cost of connecting these customers and wishes to include it as a standard charge on its tariff. The $800 fee is treated as a capital contribution.

b) No.

UNDERTAKING – J 10.5-Q33

Reference

EB- 2017-0049 Transcript Volume 2, Page 132

Undertaking

Starting at about page 132 of the transcript for the second day of the Technical Conference Mr. Merali explained that in those instances where changing the charges would involve material costs in terms of system changes and staff training the decision was made to keep the charges constant over the period. He also noted that keeping the charges constant was more “customer friendly”. However, in looking more closely we noted that in some cases (for example Rate Code 6 a) the charge for an Easement Letter) the constant charge is based on the average cost over the period whereas in others (for example Rate Code 2 – the charge for a Statement of Account) the charge is set at less than the average cost. Can you explain the basis on which you decided which charges would be set based on average cost and which would be set below cost?

Response

Please refer to I-54-CME-93 (a) for an explanation of the rates that are not smoothed.

The charges that were set below costs (particular the ones that were set at $13) were set based on the lowest average of the combined group of charges that were previously set at $15 in the 2006 OEB Rate Handbook. As explained in I-51-VECC-103, these charges were smoothed in order to avoid customer confusion and avoid costly updates that would have to be made to Hydro One’s Customer Information System (CIS) on an annual basis.

Furthermore, as stated during the Oral Hearing on Thursday, June 28th, Transcript Volume 11, pages 5 (line 28) – 7 (line 6), Hydro One proposes to no longer charge these $13 charges.

UNDERTAKING – J 11.1

Reference

N/A

Undertaking

To clarify the "other revenues", whether it includes more than external revenues

Response

As indicated in Exhibit J1.4, "Other Revenue Impacts" presented in Exhibit I-03-SEC-004 Attachment 2, on page 8 of the attachment refers solely to changes in external revenue. More specifically, the difference between 2017 OEB approved amount and the 2018 forecast. The submission to the Board of Directors from November 11, 2016 was based on best information available at that time which included a lower figure for external revenue forecast for 2018 of $41.7M.

When the current application was updated as part of the blue page submission (June 7, 2017) the external revenue forecast was further refined to the referenced number of $53.6M which is presented in the updated Exhibit E1-1-2, on page 2. The impact on the 2018 revenue requirement as a result of the updated figures for external revenue submitted as part of the blue page submission is a -0.1% as presented in Exhibit E1-1-1 on table 7.

Witness: JODOIN Joel

UNDERTAKING – J 11.2

Reference

E1-01-02

Undertaking

To provide an update to table 2.

Response

Table 2: Forecast of Total Distribution External Revenues ($ Millions)

Description	Test				
	2018* Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Regulated Revenues**	39.3	40.2	40.4	41.3	41.6
Unregulated Revenues ***	3.8	3.8	3.8	3.8	3.9
Sub-Total External Revenue	**43.1**	**44.0**	**44.3**	**45.1**	**45.4**
Standard Supply Service Charge	3.9	3.9	4.0	4.0	4.0
Total External Revenue and Other	**47.0***	**47.9**	**48.2**	**49.1**	**49.4**

*2018 External Revenues are based on forecast volumes and charges. 2018 External Revenue will be updated when the Draft Rate Order is filed to reflect the forecast External Revenue based on applying the 2017 approved Specific Service Charges until the effective date that new charges are approved.

**Regulated Joint Use Revenues have been updated to reflect Hydro One no longer introducing some specific service charges (Rate Code 1, 2, 3, 4, 5, 7, 8, 9, 10, 12, 13, 31(a), 31 (b)), maintaining the current OEB-approved rates for disconnections and reconnections at the meter (Rate Code 18, 19, 20, 21), updating Late Payment Charges (Rate Code 52) and reducing forestry line clearing costs by $0.08 for 10 feet of power space (Rate Code 47, 48).

***Unregulated Joint Use Revenues have been updated to reflect new vegetation management practices where clearing no longer occurs around the telecom attachment space and is defect-based around energized equipment as described in Exhibit Q-01-01.

UNDERTAKING – J 11.3

Reference
Exhibit J4.5

Undertaking
Exhibit J4.5 asserts the following:

Based on an analysis of overdue receivables for residential customers at 2016 year-end, R1 and R2 residential customers accounted for 84% of the corresponding overdue receivables (approximately $74 million of $88 million), whereas seasonal customers only accounted for approximately 5% of the overdue receivables (approximately $4 million of $88 million).

a) Please confirm that HONI performed the "analysis of overdue receivables" referred to in Exhibit J4.5 in January, 2017 and specifically relied upon that analysis when developing the proposal to the provincial government at Exhibit I-5-BLC-4 Attachment 1. If confirmed, please provide any documentation developed in January, 2017 with respect to the "analysis of overdue receivables" summarized in Exhibit J4.5.

b) Please confirm that the analysis at Exhibit J4.5 would capture overdue receivables at 2016 year-end resulting from customers inadvertently missing their payment due date.

c) Please provide the total amount of overdue receivables in 2016 that were ultimately written off as bad debt and never collected.

d) Please confirm that "overdue receivables for residential customers at 2016 year-end" encompasses overdue amounts relating to a customers' total bill, not just distribution related charges. If not confirmed, please explain what components of a customers' bill are included in "overdue receivables for residential customers at 2016 year-end".

e) For each residential rate class (UR, R1, R2 and Seasonal) please confirm the date of the last bill issued in 2016 that could result in "overdue receivables for residential customers at 2016 year-end"; i.e. for the UR, R1 and R2 class the date of the last monthly bill that could have resulted in overdue amounts at 2016 year-end, and for the Seasonal class the last quarterly bill that could have resulted in overdue amounts at 2016 year-end. To the extent the bills for a particular class of customers are not all issued at the same time of the month or, for the Seasonal class, the same quarterly schedule, please explain how the billing for those classes are staggered within the month or the year as appropriate.

f) Please confirm that the “overdue receivables for residential customers at 2016 year-end” includes amounts that became overdue not only as a result of the last bill issued to a customer, but also amounts that remained overdue from previous bills. By way of example, an R1 customer that had not paid any amounts to HONI resulting from their September, October, November and December 2016 bills would result in an overdue receivable at 2016 yearend reflecting several months of overdue charges. If not confirmed please explain what billing period of overdue charges would be reflected in the overdue receivable for a residential customer at 2016 year-end.

g) Please provide:

i. the number of customers in each of the UR, R1, R2 and Seasonal Classes at 2016 year-end,

ii. the number of customers in each of the UR, R1, R2 and Seasonal Classes with an overdue receivable at 2016 year-end,

iii. the exact amount of overdue receivables at 2016 year-end for each of the UR, R1, R2 and Seasonal Classes (i.e. the full disaggregation of the $84 million referred to in Exhibit J4.5) and

iv. the total amount billed to each of the UR, R1, R2 and Seasonal Classes in 2016.

In answering this question please separately report the amounts for each class in the following table format:

Class	2016 Year-End Customer Count	# of Customers at 2016 Year-end with an Overdue Receivable	Overdue Receivables at 2016 Year-End	Total Amount Billed to Class in 2016
UR				
R1				
R2				
Seasonal				

Response

a) Confirmed. The associated analysis is provided in part g).

Hydro One monitors accounts receivable balances on a monthly basis. Although 2016 year-end data was provided in this undertaking, this trend existed throughout 2016. Hydro One also identified similar trends through its customer engagement approaches (as outlined in Section 1.3 of the Distribution System Plan at Exhibit B, Tab 1, Schedule 1), including call centre contacts and direct personal contact.

b) Confirmed.

c) $35M of Hydro One's total overdue receivables were written off in 2016.

d) Confirmed.

e) Hydro One customers are divided across multiple bill groups. As such, bills are issued every day and outstanding balances are always in-flux. Any outstanding balance as of December 31, 2016 was included in the "overdue receivables for residential customers at 2016 year-end", regardless of the customer's billing frequency. More specifically, a bill issued on December 31, 2016 that included an overdue balance would be included.

f) Confirmed.

g) Table completed below:

Residential Class	2016 Year-End Customer Count (K)	# of Customers at 2016 Year-end with an Overdue Receivable (K)	% of Customers Overdue	Overdue Receivables at 2016 Year-End ($M)	% of Total Overdue Receivables	Estimated Total Billed Revenue in 2016 ($B)
Urban (UR)	216	34	16%	$9	11%	$0.4
Medium (R1)	493	114	23%	$45	51%	$1.1
Low Density (R2)	329	52	16%	$29	33%	$1.1
Seasonal	148	12	8%	$4	5%	$0.2
Total Residential	**1,185**	**212**		**$88**		**$2.8**

Note: For the purpose of the accounts receivable analysis, the acquired residential customers were included in the totals shown above within the R1 rate class.