TECHNICAL CONFERENCE UNDERTAKING - JT 1.14

JT 1.14

To advise the factors behind the increase in overall net earnings.

RESPONSE:

Hydro Ottawa wishes to clarify that the scope of this undertaking is to explain the higher earnings achieved in 2017, as shown in Table 8 (as revised) and Table A in the response to interrogatory CCC-78.

Table A below shows applicable elements of the Earnings Sharing Mechanism ("ESM") calculation, as well as the year-over-year changes for 2017 as compared to 2016 and 2018 as compared to 2017.

Table A – Elements of ESM Calculation[1] ($'000s)

	2016	2017	2018	2017-2016 Change	2018-2017 Change
Net Income (per RRR)	$33,483	$36,114	$34,605	8%	(4%)
Deemed Equity (per RRR)	$341,540	$357,578	$378,652	5%	6%

2017 as compared to 2016:

As per the OEB's Reporting and Record Keeping Requirements ("RRRs"), net income increased by 8% or $2.6M in 2017. The growth in revenue was larger than the growth in expenses. The lower growth in expenses was due to a one-time cost included in 2016 of $1.5M for non-vested sick leave. (Please see UPDATED Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and Program Variance Analysis for further details). The growth in net income excluding this one-time cost was 4%.

[1] Please refer to Table 8 (as revised) and Table A in the response to interrogatory CCC-78 for further details and elements in relation to the ESM calculation.

Deemed Equity increased by 5% from 2016 to 2017, which was a slower pace than the growth in net income. The 5% increase is attributable to a 5% increase in rate base. Tables 1 and 2 in UPDATED Exhibit 2-1-1: Rate Base Overview identify all of the elements included in rate base, including the working capital allowance. The working capital allowance decreased by 9% in 2017, whereas the average Net Book Value increased by 6%. The decrease in working capital allowance was due to a 9% decrease in cost of power.

2018 as compared to 2017:

Net income (as per the RRRs) decreased by 4% or $1.5M in 2018, relative to 2017. The lower net income in 2018 is largely explained by higher OM&A on account of three major storms in that year. For further details, please see UPDATED Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and Program Variance Analysis.

Deemed Equity increased by 6% from 2017 to 2018. The 6% increase is attributable to a 6% increase in rate base. Net Book Value likewise increased by 7% and was partially offset by a 2% decrease in cost of power. The reduction in cost of power was at a slower pace than in 2017.

TECHNICAL CONFERENCE UNDERTAKING - JT 2.1

JT 2.1

To explain the percentage distribution increase in General Service less than 50 kilowatts.

RESPONSE:

The main factors that have resulted in an increase in the General Service <50 kW rate class are the increase in the revenue requirement proposed and the change in the distribution-related rate riders.

The increase in the proposed revenue requirement was allocated based on the same allocation factors as the original revenue requirement submitted and therefore impacted rate classes in a similar manner. Please refer to UPDATED Exhibit: 7-1-1 Cost Allocation for further details on cost allocation, UPDATED Exhibit 8-1-1: Fixed/Variable Proportion for rate design, and UPDATED Exhibit 1-1-5: Application Summary for a summary of the proposed changes to revenue requirement and related exhibits.

The distribution-related rate riders had a less uniform impact on the rate classes and resulted in less uniform distribution bill impact results. To help demonstrate the impact, Table A below presents the bill impacts for the General Service <50 kW rate class as follows:

- Application as Originally Submitted (February 10, 2020);
- Application as Updated for 2019 Actuals (May 5, 2020);
- Application as Originally Submitted (February 10, 2020), excluding the Group 2 proposed rate rider and the Lost Revenue Adjustment Mechanism ("LRAM") proposed rate rider; and
- Application as Updated for 2019 Actuals (May 5, 2020), excluding the Group 2 proposed rate rider and the LRAM proposed rate rider.

Table A – General Service <50 kW (2000 kWh) Distribution Bill Impacts

Bill Impact Version		2020	2021	2022	2023	2024	2025
Original Application (Feb. 10, 2020)	Distribution Charge	$71.32	$73.06	$78.13	$83.28	$86.33	$88.58
	$ Change		$1.74	$5.07	$5.15	$3.05	$2.25
	% Change		2.44%	6.94%	6.59%	3.66%	2.61%
Updated Application (May 5, 2020)	Distribution Charge	$71.32	$74.21	$79.23	$83.71	$86.76	$89.02
	$ Change		$2.89	$5.02	$4.48	$3.05	$2.26
	% Change		4.05%	6.76%	5.65%	3.64%	2.60%
Original Application (Feb 10, 2020), without rate riders	Distribution Charge	$71.32	$73.26	$79.13	$83.28	$86.33	$88.58
	$ Change		$1.94	$5.87	$4.15	$3.05	$2.25
	% Change		2.72%	8.01%	5.24%	3.66%	2.61%
Updated Application (May 5, 2020), without rate riders	Distribution Charge	$71.32	$74.01	$79.03	$83.71	$86.76	$89.02
	$ Change		$2.69	$5.02	$4.68	$3.05	$2.26
	% Change		3.77%	6.78%	5.92%	3.64%	2.60%

TECHNICAL CONFERENCE UNDERTAKING - JT 2.13

JT 2.13

To provide information showing quantified productivity savings as it relates to capital embedded in the plan or the capital budget over the 2021-2025 period.

RESPONSE:

As discussed in several Exhibits included in the pre-filed evidence for this Application (e.g. UPDATED Exhibit 2-4-1: Capital Expenditure Summary and Exhibit 2-4-3: Distribution System Plan), productivity and continuous improvement remain firmly embedded in Hydro Ottawa's capital expenditure program. The utility has now fully aligned itself to the ISO 55001 Asset Management Standard, evidenced by successful completion of the audit process and subsequent recommendation for certification by Lloyds Register. This asset management framework strengthens the strategic asset decision-making processes by striving to balance the weighting of cost, risk, and asset performance that meet or exceed service level expectations of customers; comply with the terms of applicable acts, licences, and codes; improve asset value and resource efficiency; and minimize health, safety, and environmental impacts.

Hydro Ottawa developed its forecasted capital expenditures for the years 2021-2025 based upon an identification and analysis of system and asset needs, customer growth and expectations, and requirements for capital. The total capital expenditure forecast then underwent a number of iterations and refinements, using the following criteria:

- asset needs;
- issues of priority;
- customer preference;
- rate and bill impacts;
- resource capacity; and
- financing constraints.

This review resulted in a reduction in the capital expenditure forecast of approximately $50M per year (or $250M over the five-year period). The expenditure levels presented in this Application represent the end product of this assessment and rationalization process, and are consistent with OEB-approved levels from the 2016-2020 period. The resulting "average run rate" of approximately $100.8M per year represents the expenditure levels required to ensure the safety and reliability of the system and to address challenges associated with aging infrastructure and customer growth.

In addition, inflationary rates were not applied to the System Service ("SS") and System Renewal ("SR") areas of the capital budget for the 2021-2025 period. Although there will be inflationary increases in labour and outside services, the goal will be to offset these increases by savings in productivity and continuous improvement initiatives. Embedded capital productivity savings were calculated by taking the difference between the in-year Capital Budget and the 2021 Base Capital Budget of $65M after applying an inflation factor. The embedded capital productivity savings for the System Service and System Renewal areas are just over $13M for the 2021-2025 period, as summarized in Table A.

Table A – Overall System Service and System Renewal Capital Efficiency ($'000,000s)

	2021	2022	2023	2024	2025	2021-2025 Total
SS/SR Target at 2% inflation (Excluding Cambrian MTS)	$65.0	$66.3	$67.6	$69.0	$70.4	$338.3
SS/SR Application Budget (Excluding Cambrian MTS)	$62.4	$69.2	$64.5	$64.6	$64.4	$325.1
Embedded Capital Productivity Savings						**$13.2**

In the distribution System Renewal category, the scope of the programs included are generally predictable, controllable by Hydro Ottawa, and have a significant component of internal labour, making the programs an ideal area of focus for capital productivity. Although it is recognized that there will be variability within the types of projects undertaken within the renewal programs, it is expected that with the development of additional capital tracking tools, Hydro Ottawa will be in a position to ascertain and track the improvements.

As outlined in the responses to interrogatories EPRF-47, EPRF-48, EPRF-49, and EPRF-55, inflation was not built into several of the budget programs under the System Renewal category. The associated savings comprise just over $4M of the $13M embedded capital productivity savings shown in Table A above. These specific program savings were calculated by taking the difference between the in-year unit cost and the 2021 unit cost after applying an inflation factor, multiplied by the forecasted units to be replaced in each year. A summary of the expected savings by budget program is provided in Table B.

Table B – Overhead and Underground Distribution Renewal Capital Efficiency ($'000s)

Budget Program	2021[1]	2022	2023	2024	2025	2021-2025 Total
Pole Renewal	$0.0	$115.8	$279.8	$447.1	$617.7	$1,460.4
Overhead Switch/Recloser Renewal	$0.0	$0.0	$15.1	$32.5	$0.0	$47.6
Vault Renewal	$0.0	$10.0	$20.1	$30.5	$41.1	$101.7
Cable Replacement	$0.0	$698.4	$282.5	$554.8	$748.3	$2,284.0
Underground Switchgear Renewal	$0.0	$12.2	$24.6	$37.2	$50.1	$124.1
Embedded Capital Productivity Savings	**$0.0**	**$836.4**	**$622.1**	**$1,102.1**	**$1,457.2**	**$4,017.8**

Two specific initiatives that will be undertaken by Hydro Ottawa to help achieve capital savings are described in detail in Exhibit 1-1-13: Productivity and Continuous Improvement Initiatives (Section 3.2.2 Crew Wrench Time Analysis and Productivity Improvements, and Section 3.2.3 Seasonal Construction Shifts). As noted in this Exhibit, the objective for the wrench time initiative is to increase wrench time by 4%, or approximately 15 minutes per day per crew member. This represents more than $520k of additional value annually for a staff of 110 Power Line Technicians and Power Cable Technicians, or $2.6M over the 2021-2025 rate term. As for the Seasonal Construction shift initiative, its primary focus is overtime reduction. It is anticipated that this initiative will result in a targeted 5% reduction in overtime costs for those crews working

[1] Dollars are shown as zero because of the inflationary calculation from the base cost per unit in 2021.

seasonal shifts, while also enhancing the customer and contractor experience. This translates into an expected savings of approximately $532k over the 2022-2025 period. Other areas of focus for capital productivity will include seeking savings through contract negotiations with external contractors and through material procurement opportunities.

The remainder of the budget programs within the System Service and System Renewal envelope do not lend themselves well to capital productivity target development, and for this reason have not been explicitly stated in the same manner as those distribution System Renewal budget programs included in Table B above. Hydro Ottawa recognizes that in order to accurately track and target capital productivity savings, specific tools and metrics will need to be developed. As such, the development of capital productivity tracking and analytics will be a key focus area for the utility for the 2021-2025 period.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.9

JT 3.9

To calculate whether there would have been earnings sharing if the dead band of 150 basis points had been in place during the last term.

RESPONSE:

As an initial note, Hydro Ottawa has identified an error in the calculation of the Earnings Sharing Mechanism ("ESM"). Hydro Ottawa records any ESM in the year after the period being considered for over earnings, in order to align with the adjustments related to the Lost Revenue Adjustment Mechanism ("LRAM"). In reviewing the calculation, it was realized that the customer portion was not being added back to the Distribution Net Income submitted as part of the Reporting and Record Keeping Requirements ("RRRs") filing in determining the current year's sharing. Table 8 in UPDATED Exhibit 9-1-3: Group 2 Accounts has been revised below accordingly.

Excess earnings during the individual years of 2016 and 2018, from both RRR filings and as adjusted for LRAM and previous years' earnings sharing, were below 1% or 100 basis points. For 2017, they were below 1.5% or 150 basis points. Therefore, for the finalized 2016-2018 years, Hydro Ottawa would not have had earnings sharing if a dead band of 150 basis points had been in place. As indicated during the Technical Conference held in this proceeding, the 2019 excess earnings have not been adjusted and the LRAM calculation has not been completed for 2019. In addition, at this time it cannot be determined if earnings would be above the 150 basis points for 2020. As such, Hydro Ottawa is only proposing to clear balances as calculated in the revised version of Table 8 below. Please refer to the responses to interrogatories CCC-26 and CCC-78 for further information on the ESM.

Table 8 from UPDATED Exhibit 9-1-3 (Filed May 5, 2020) – ESM Calculation ($'000s)[1]

	2016	2017	2018
Net Income (per RRR)	$33,483	$36,114	$34,605
Deduct Previous Years' LRAM[2]	$(1,042)	$(1,081)	($1,081)
Add Current Year LRAM[3]	$773	$935	$935
PILS Grossed-up on CDM Adjustments[4]	$(172)	$222	($45)
Net Income after Adjustments	**$33,311**	**$36,336**	**$34,559**
Deemed Equity (per RRR)	$341,540	$357,578	$378,652
ESM Achieved ROE	9.75%	10.16%	9.13%
Deemed ROE	9.19%	9.19%	9.19%
% Return Above Deemed	**0.56%**	**0.97%**	**(0.06)%**
Earnings Above Regulated Return	$1,924	$3,475	($239)
50% of Earnings above Regulated Return	$962	$1,737	$0
PILS Grossed-up[5]	$347	$626	$0
RATEPAYERS' SHARE OF OVEREARNING[6]	**$1,309**	**$2,364**	**$0**

[1] "Current year" means 2016 for the purposes of the column with information for 2016, and 2017 for the purposes of the column with information for 2017.
[2] Previous years' LRAM includes adjustment to any year not related to the current year.
[3] Current year LRAM includes adjustments in reporting years subsequent to the current year.
[4] Tax rate = 26.5%.
[5] Tax rate = 26.5%.
[6] Totals may not sum due to rounding.

Table 8 from UPDATED Exhibit 9-1-3 – AS REVISED AUGUST 2020 – ESM Calculation ($'000s)[7]

	2016	2017	2018
Net Income (per RRR)	$33,483	$36,114	$34,605
Deduct Previous Years' LRAM[8]	$(1,042)	$(1,081)	($482)
Add Current Year LRAM[9]	$804	$1,429	$411
Add ESM recorded	$0	$1,385	$1,976
Deduct PILS Grossed-up on CDM Adjustments[10]	$(86)	$625	$687
Net Income after Adjustments	**$33,311**	**$37,222**	**$35,823**
Deemed Equity (per RRR)	$341,540	$357,578	$378,652
ESM Achieved ROE	9.76%	10.41%	9.46%
Deemed ROE	9.19%	9.19%	9.19%
% Return Above Deemed	**0.57%**	**1.22%**	**0.27%**
Earnings Above Regulated Return	$1,944	$4,360	$1,025
50% of Earnings above Regulated Return	$972	$2,180	$513
PILS Grossed-up[11]	$350	$786	$185
RATEPAYERS' SHARE OF OVEREARNING[12]	**$1,322**	**$2,966**	**$697**

[7] "Current year" means 2016 for the purposes of the column with information for 2016, and 2017 for the purposes of the column with information for 2017, and so on.
[8] Previous years' LRAM includes adjustment to any year not related to the current year.
[9] Current year LRAM includes adjustments in reporting years subsequent to the current year.
[10] Tax rate = 26.5%.
[11] Tax rate = 26.5%.
[12] Totals may not sum due to rounding.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.18

JT 3.18

To provide an explanation of how the numbers were set historically with respect to each of the Commercial and Industrial rate classes.

RESPONSE:

On May 11, 2005, the OEB issued the *2006 Electricity Distribution Rate Handbook* ("Handbook") which set out filing requirements and guidelines for distribution rates effective May 1, 2006. The Handbook's guidelines for 2006 required Local Distribution Company ("LDC") applications to contain, at a minimum, a summary of the application; the completed 2006 Electricity Distribution Rate ("EDR") model; and supporting schedules. Hydro Ottawa filed its 2006 rate application on August 2, 2005. The 2006 rates were set based on using a forward Test Year in the 2006 EDR model without any changes to the fixed/variable splits as calculated by the model. On April 12, 2006, the OEB approved Hydro Ottawa's 2006 Revenue Requirement.[1] These amounts were put through the 2006 EDR Model to generate the approved fixed and variable rates for all customer classes.

In 2007, the OEB set rates using the 2007 Incentive Rate Mechanism ("IRM") Model to adjust utilities' 2006 approved fixed and variable rates by the price escalator and X factor as per the 2007 IRM Model. On April 12, 2007, the OEB approved Hydro Ottawa's fixed and variable rates for all customer classes as updated using the IRM Model.

For 2008 rates, the OEB adopted its multi-year rate setting plan for distributors. At this time, Hydro Ottawa self-nominated to prepare a Cost of Service application for 2008-2010 distribution rates. For purposes of that application, Hydro Ottawa filed its Cost Allocation Study for 2006, following the OEB's methodology as set out in the policy document entitled *Board Directions on*

[1] Ontario Energy Board, *Decision with Reasons*, EB-2005-0381 (April 12, 2006), page 15.

Cost Allocation Methodology for Electricity Distributors.[2] When completing the Cost Allocation, Hydro Ottawa noted in the Manager's Summary that for the General Service 50-1,499 kW, General Service 1,500-4,999 kW, and Large User classes, the monthly fixed charge calculated using the minimum system with Peak Load Carrying Capability ("PLCC") adjustment was significantly lower than the Monthly Fixed Service Charges in use at that time.

Ultimately, Hydro Ottawa did not use the Cost Allocation model as a basis to establish the fixed portion of any of the commercial rates. The mandate of an LDC to connect everyone in the service area to the network, and serve their load requirements, creates a largely fixed cost environment. Although the variable distribution charge is in place to recover the costs for building and maintaining the distribution system to supply load, once the system has been built to supply the load of commercial customers it must be maintained at all times whether or not the expected electricity is consumed. A low monthly service charge can leave the LDC open to increased risks if the load does not materialize, since the costs of the distribution system are largely fixed in anything other than the very long term. Converting any portion of a fixed monthly service charge to a variable rate based on consumption or demand puts the LDC at an increased risk of revenue shortfall, particularly in the environment of falling demand that would be encouraged by that conversion. The OEB recognized the value of the connection and required system assets to support that connection in its decision to convert Residential delivery rates to a 100% fixed monthly service rate.

On November 28, 2007, the OEB issued its report on *Application of Cost Allocation for Electricity Distributors*.[3] In this report, it stated that the OEB did not expect LDCs to make changes to their Monthly Service Charge that resulted in a charge higher than the ceiling. LDCs which were then above the ceiling value were not required to make changes to their Monthly Service Charge bringing it to, or below, the ceiling level. This expectation has continued to date.

[2] Ontario Energy Board, *Board Directions on Cost Allocation Methodology For Electricity Distributors*, EB-2005-0317 (September 29, 2006).
[3] Ontario Energy Board, *Application of Cost Allocation for Electricity Distributors - Report of the Board*, EB-2007-0667 (November 28, 2007).

For reference, Hydro Ottawa has provided the historical approved fixed and variable rates for commercial classes from 2007-2020 in its response to undertaking JT 3.20.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.22 - QUESTION 2

JT 3.22 - WRITTEN QUESTION #2

REFERENCE: 3-VECC-69 a) & d) and Attachment VECC-69(A)

Exhibit 3, Attachment C, Table 4

QUESTION:

a) Please confirm that the CDM savings set out in Table 4 of Attachment C and the values provided in response to VECC-69 a) are all “annualized” CDM savings values. If not, please explain what they represent.

b) Please confirm that, apart from the application of a ½ year adjustment to the first year of a CDM program’s saving, the values set out in VECC 69 a) are consistent with those used in the load forecast. If not, please explain.

c) The response to VECC-69 d) only provided the requested breakdown for the total CDM savings in each year. Please also provide the breakdown by customer class as requested in the original question.

d) Please confirm that the values provided in response to VECC-69 d) are also “annualized” CDM savings values. If not confirmed, please explain what they represent.

e) Please confirm that, apart from the application of a ½ year adjustment to the first year of a CDM program’s saving, the values set out in VECC 69 d) are consistent with those used in the load forecast. If not, please explain.

f) With reference to Attachment VECC-69(A) {rows 51-78}, please confirm that neither the historical CDM values nor the forecast CDM values used included any adjustments for loss of persistence.

g) It is understood that the IESO has prepared reports setting the loss of persisting savings for LDC's CDM programs. Does Hydro Ottawa have such reports for its historic CDM program savings results and, if yes, why weren't the results incorporated into the load forecast?

RESPONSE:

a) Hydro Ottawa confirms that the values are all annualized.

b) The values set out in part (a) of the response to interrogatory VECC-69 are the basis for constructing the historical and forecasted series used in the load forecast. The annualized savings are transformed into a monthly series. In some cases, a centered moving average is used to smooth the transition from year to year. For the Residential rate class, the series is divided by customers to transform total savings into savings per customer.

   Please see Attachment OEB-134(A): CDM Savings by Program, where each class tab presents the ½ adjustment and, where applicable, a centered moving average calculation.

c) Please refer to Excel Attachment JT 3.22-Q2(A): Class Breakdown.

d) Hydro Ottawa confirms that the values are all annualized.

e) The values set out in part (d) of the response to interrogatory VECC-69 are the basis for constructing the historical and forecasted series used in the load forecast. The annualized savings are transformed into a monthly series. In some cases, a centered moving average is used to smooth the transition from year to year. For the Residential rate class, the series is divided by customers to transform total savings into savings per customer.

Please see Attachment OEB-134(A): CDM Savings by Program, where each class tab presents the ½ adjustment and, where applicable, a centered moving average calculation.

f) Hydro Ottawa confirms that neither the historical CDM values nor the forecast CDM values include any adjustments for loss of persistence.

g) Hydro Ottawa has IESO reports that consider the persistence related to IESO-incented CDM program savings. These savings reports are used in the calculation of the utility's Lost Revenue Adjustment Mechanism ("LRAM") calculations.

When considering historical CDM for future load, Hydro Ottawa assumes historical efficiencies related to CDM activities remain in place. It is assumed that customer invested efficiencies will be replaced by at least equally efficient measures when the measure has come to the end of its life. As an example, a customer purchases a new high efficiency air conditioning unit and when that unit needs to be replaced in the future, the replacement unit would be at least as efficient as the one it replaces. Essentially, once the savings occurs, those savings remain.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.22 - QUESTION 3

JT 3.22 - WRITTEN QUESTION #3

REFERENCE: 3-OEB-134 and Attachment OEB 134(A)
3-OEB-136 a)
3-VECC-69, Attachment VECC-69(A)

QUESTION:

a) With respect to Attachment OEB 134(A), Persisting Savings by Year&Prog Tab, starting at row 36 there is a determination of the savings implemented between the end of 2017 and early 2019 totalling 59,981 MWh. VECC-69 shows savings from 2018 CDM programs of 52,987 MWh. Why are the values different and what is the source of the 2018 savings values used in VECC-69?

b) Similarly, with respect to Attachment OEB 134(A), Persisting Savings by Year&Prog Tab, starting at row 61 there is a determination of the savings implemented between February 15, 2019 and December 2, 2019 totalling 46,758 MWh. VECC-69 shows savings from 2019 CDM programs of 42,991 MWh. Why are the values difference and what is the source of the 2019 savings values used in VECC-69?

c) With respect to Attachment OEB 134(A), Persisting Savings by Year&Prog Tab, starting at row 36/column G, there are estimates of the persisting savings in 2020 and subsequent years from CDM programs implemented between the end of 2017 and early 2019. Why do the savings for 2020 assume no loss of persistence and the savings for 2021-2025 assume that 2020 is the first year for each program?

d) Similarly, with respect to Attachment OEB 134(A), Persisting Savings by Year&Prog Tab, starting at row 61/column G, there are estimates of the persisting savings in 2020 and subsequent years from CDM programs implemented between February 15, 2019 and

December 2, 2019. Again, why do the savings for 2020 assume no loss of persistence and the savings for 2021-2025 assume that 2020 is the first year for each program?

e) With respect to Attachment OEB 134(A), New By Class Tab, starting at row 79 is purportedly set out the basis for Table 6 in Exhibit 3 of the Application. However, the values differ from those in Table 6 – most significantly in the case of the GS<50 class.
   i) Are the differences for the GS<50 class due to the issue discussed in OEB-136 a)?
   ii) Which values are correct, those in Table 6 of the Application or those in Attachment OEB 134(A)?

f) With respect to the derivation of Table 6 as set out in Attachment OEB 134(A), New By Class Tab, the Residential values are derived in the Residential Tab (row 263/columns P-T) of the same Attachment. Please confirm that the Residential values in Table 6 include the ½ adjustment for a CDM programs first year and that this would be the case for the other customer classes as well.

g) Please confirm that Table 6 sets out the CDM savings as used in the load forecast.

h) With respect to Attachment OEB 134(A), Residential Tab {Rows 2-3}, please confirm that these are the annualized savings used in the calculations for Table 6 and that these values do not include any loss in persistence of savings.

i) With respect to Attachment OEB 134(A), Residential Tab {Rows 2-3}, please confirm that the 2020 Residential value of 11,137,407 kWh includes (per the "New by Rate Class" Tab) Affordability Trust Savings from 2018 and 2019. If confirmed, please explain why these savings aren't already captured in the historical data used to estimate the Residential load forecast model.

RESPONSE:

a) Hydro Ottawa has answered this response with the assumption that “the savings implemented between the end of 2017 and early 2019 totalling 59,981 MWh” should be “the savings implemented between the end of 2017 and early 2019 totalling 5**5**,981 MWh”.

Both Attachment OEB-134(A): CDM Savings by Program and Attachment VECC-69(A): Impact of Historical and Forecast CDM rely on the 2018 IESO unverified savings report.

The difference between the 55,981 MWh presented in Attachment OEB-134(A): CDM Savings by Program and 52,987 MWh presented in Attachment VECC-69(A): Impact of Historical and Forecast CDM is made up of two items. The first is a credit related to the Save on Energy Home Assistance Program of 2.5 MWh that was inadvertently not included in the savings for the Load Forecast. It is therefore not part of the values presented in VECC-69(A). The second item is that VECC-69(A) does not present the savings in 2018 related to the following classes: Large Use, Unmetered Scattered Load, and Street Lighting. In addition, the savings related to the General Service 1,500 to 4,999 kW class are allocated to the General Service 50 to 1,500 kW class. The amount of savings not present represents 2,996.5 MWh.

b) As indicated in part (a) above, both Attachment OEB-134(A): CDM Savings by Program and Attachment VECC-69(A): Impact of Historical and Forecast CDM rely on the 2018 IESO unverified savings report.

The difference between the 46,758 MWh presented in Attachment OEB-134(A): CDM Savings by Program and 42,991 MWh presented in Attachment VECC-69(A): Impact of Historical and Forecast CDM is that VECC-69(A) does not present savings in 2019 related to the following classes: Large Use, Unmetered Scattered Load, and Street

Lighting. In addition, the savings related to the General Service 1,500 to 4,999 kW class are allocated to the General Service 50 to 1,500 kW class. The amount of savings not present represents 3,863 MWh.

c) Savings were persisted using the method prescribed by the IESO, as outlined on the tab “IESO Persistence table” in the same document. Some programs have savings that persist at 100% for all six years. It is a fair point that the majority of projects associated with category 1, section 2 (starting at row 37/column G) were achieved within the Retrofit Program, and after looking at data, these projects were completed in previous years (2017 and 2018). Hydro Ottawa could have chosen the first year of persistence to be 2017 or 2018, rather than 2020. The assumption is correct – 2020 was considered the first year of persistence. However, per the IESO’s methodology, Retrofit Program savings persist at 100% in year 1 and 99.5% in year six. As a result, this adjustment would only result in a very small difference (0.5% per year).

Please note the load forecast only considers new CDM savings and therefore treats persistence at 100% of year one savings through 2020-2025. Starting at row 84 of Tab “Persisting Savings by Year&Prog”, for the purpose of the load forecast, the first value of savings found on each row was carried for years 2020-2025. Similarly, please refer to Tab “New&Per By Rate Class” for savings included in the load forecast after 2019. As discussed in the response to undertaking JT 3.22-Q2 part (g), a reduction in persistence after year one savings has not been included in the load forecast.

As a final note, Hydro Ottawa should have considered the reduction in persistence not removed as inherent CDM in the base Load Forecast, and therefore the CDM threshold should have reflected persistence per the IESO report. The end result would not change the load forecast with CDM; however, it would reduce the CDM threshold.

d) Similar to part (c) above, the majority of projects that fit in this category (category 1, section 3 starting at row 62/column G) were achieved within the Retrofit Program. After looking at data, it can be observed that these projects were completed during this timeframe (i.e. between February 15, 2019 and December 2, 2019). Accordingly, it does make sense to have the first full year of persistence to be 2020 in this case. Savings were persisted using the IESO's methodology, as outlined on the tab "IESO Persistence table" in the same document.

As with part (c) above, please note the load forecast only considers new CDM savings, and therefore treats persistence at 100% of year one savings through 2020-2025. Starting at row 84 of Tab "Persisting Savings by Year&Prog", for the purpose of the load forecast, the first value of savings found on each row was carried for years 2020-2025. Similarly, please refer to Tab "New&Per By Rate Class" for savings included in the Load Forecast after 2019. As discussed in response to the undertaking JT 3.22 - WRITTEN QUESTION #2 part (g), a reduction in persistence after year one savings has not been included in the load forecast.

As a final note, Hydro Ottawa should have considered the reduction in persistence not removed as inherent CDM in the base Load Forecast, and therefore the CDM threshold should have reflected persistence per the IESO report. The end result would not change the load forecast with CDM; however, it would reduce the CDM threshold.

e)

i) As per the note in cell A81 of tab "New By Rate Class", Hydro Ottawa confirms the difference in the General Service < 50 kW relates to the discussion in response to interrogatory OEB-136. It should be noted that, as a result of this error, the load forecast is higher than it otherwise would be for this rate class.

ii) Please see a reconciliation of the two tables in Table A below. The main difference between the two data sets relates to the identified issues with the General Service < 50 kW class. Table 6 in UPDATED Exhibit: 3-1-1 Load Forecast is Hydro Ottawa's officially proposed CDM Savings Table for MWhs.

Table A – Reconciliation of CDM Savings Tables

	2021	2022	2023	2024	2025
Total MWh Sales from Table 6	162,517	185,852	207,169	228,488	247,464
Total MWh Sales OEB-136(A)	164,725	190,275	211,595	232,914	251,884
Difference	(2,208)	(4,423)	(4,426)	(4,426)	(4,420)
General Service < 50 kW Identified Issue	2,209	4,422	4,425	4,423	4,415
Difference after identified issue	**1**	**(1)**	**(2)**	**(2)**	**(5)**

f) Please refer to the response to undertaking JT 3.22-Q2 part (g). With the understanding of the centered moving average, Hydro Ottawa confirms that the Residential values in Table 6 include the ½ adjustment for CDM programs for the first year and that this would be the case for the other customer classes as well.

Please see Attachment OEB-134(A): CDM Savings by Program. Each class tab presents the ½ adjustment and, where applicable, a centered moving average calculation.

g) Hydro Ottawa confirms that Table 6 sets out the CDM savings as used in the load forecast for MWhs.

h) Hydro Ottawa confirms that Attachment OEB 134(A): CDM Savings by Program, Residential Tab Rows 2 and 3 are the annualized savings (yearly and cumulative, respectively) used in the calculations for Table 6 and that these values do not include loss related to persistence of savings. Please see the response to undertaking JT 3.22-Q2 part (g) for a discussion related to persistence.

i) Hydro Ottawa confirms that, with respect to Attachment OEB-134(A), Residential Tab Rows 2-3, the Residential value of 11,137,407 kWh per the “New by Rate Class” Tab includes the Affordability Trust Savings from 2018 and 2019. The inclusion of the 2018 and 2019 amounts as future new CDM savings was an oversight. Hydro Ottawa confirms that this would already be captured in the historical data used to estimate the Residential load forecast model.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.22 - QUESTION 4

JT 3.22 - WRITTEN QUESTION #4

REFERENCE: 3-VECC-72

PREAMBLE:

The response states that the LRAMVA threshold values for the test years are set out in Tables 6 and 7 from the Updated Exhibit 3

QUESTIONS:

a) Please confirm that the Board's LRAM model uses actual annualized CDM savings (with no ½ year adjustment for the first year) in it calculations.

b) Please confirm that Tables 6 and 7 include a ½ year adjustment for the first year a CDM program is implemented.

c) Please provide the equivalent of Tables 6 and 7 but without the ½ year adjustment.

d) The forecast CDM savings from programs implemented in 2020-2025 include the results from Hydro Ottawa's rate-based programs and savings from the Affordability Trust. Will the actual savings from these two areas be verified by a third party?
   - If yes, by who?
   - If not, why is it appropriate for the related savings to be included in the LRAMVA threshold and in future LRAM calculations?

RESPONSE:

a) Hydro Ottawa confirms that the OEB's Lost Revenue Adjustment Mechanism ("LRAM") model uses actual annualized CDM savings with no ½ year adjustment for the first year in its calculations. Hydro Ottawa also notes that projects are included in the IESO savings reports only once they are completed, therefore previous year savings are not attributed.

b) Hydro Ottawa confirms Tables 6 and 7 of UPDATED Exhibit: 3-1-1 Load Forecast include a ½ year adjustment for the first year in which a CDM program is implemented. Please note that Table 7 of UPDATED Exhibit: 3-1-1 Load Forecast was revised as part of the response to interrogatory OEB-136.

c) At this time, Hydro Ottawa has not completed the full impact on the load forecast of removing the ½ year adjustment. However, preliminary results indicate the update to Table 6 would not be significant, as the largest impact would be on the 2020 year.

Hydro Ottawa is not proposing to remove the ½ year adjustment and suggests the ½ year adjustment needs to be considered while also considering all assumptions of the timing of CDM savings within the IESO saving report.

d) For clarity, Hydro Ottawa has broken out the response into two categories:

- **Forecasted CDM Savings associated with Hydro Ottawa's rate-based activities as outlined in Table 1 of Exhibit 4-1-6: Conservation and Demand Management and as described as category 3 in the excel Attachment OEB-134(A): CDM Savings by Program**

The savings that are outlined in Table 1 of Exhibit 4-1-6: Conservation and Demand Management and are associated with commercial customer engagement will be tracked in accordance with the methodology described in the response to interrogatory OEB-134 part (v)(2). The OEB's CDM Guidelines state the following: "The Board will annually review and publish the verified results of each distributor's Province-Wide Distributor CDM Programs and Local Distributor CDM Programs and report on the progress of distributors in meeting their CDM requirement. The verified results will be provided to the Board annually by IESO."[1] Given that the proposed rate-based savings are not funded by IESO, nor will they be verified by the IESO, Hydro Ottawa requires direction from the OEB on the requirements associated with verifying results and whether third-party verification will be necessary.

- **Affordability Fund Trust Savings as described in rows 137 through 145 in the excel Attachment OEB-134(A): CDM Savings by Program**

Hydro Ottawa is not responsible for establishing the Affordability Fund Trust ("AFT") program's Evaluation, Measurement, & Verification process. However, it is the utility's understanding that the program measures being utilized in Hydro Ottawa's territory through the AFT program will not be verified by a third party. These measures have attributed energy savings as previously determined by the AFT through a third party. Hydro Ottawa believes it is reasonable to assume that these savings will persist throughout the 2021-2025 rate term. The forecasted savings associated with AFT represent less than 0.5% of the total annual forecasted persisting savings. Hydro Ottawa chose to include them in its forecast; however, they have a very minor impact on future LRAM calculations.

[1] Ontario Energy Board, *Conservation and Demand Management Requirement Guidelines for Electricity Distributors*, EB-2014-0278 (December 19, 2014; Updated August 11, 2016), page 11.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.22 - QUESTION 5

JT 3.22 - WRITTEN QUESTION #5

REFERENCE: 7-OEB-154

PREAMBLE:

The response states that Hydro Ottawa's proposal to set the primary/secondary split for conductors at the same values as used for: i) poles, towers and fixtures for overhead and ii) conduit for underground is in line with the approach previously approved in Toronto Hydro's 2020-2024 Rate Application.

QUESTION:

a) It is acknowledged that in the referenced Application Toronto Hydro used the same split for overhead conductor as it did for poles, towers and fixtures and the same split for underground conductor as it did for conduit. However, can Hydro Ottawa provide a reference to the Toronto Hydro Application that indicates this approach was based on the assumption that the two were the same as opposed to analysis that supported the two being the same?

RESPONSE:

a) Hydro Ottawa is not able to provide a specific reference to the source of proportions for primary and secondary conductors in Toronto Hydro's 2020-2024 Custom IR rate application.[1] However, the same splits were used in previous Toronto Hydro rate applications.

[1] Toronto Hydro-Electric System Limited, *2020-2024 Custom Incentive Rate-setting Distribution Rate Application*, EB-2018-0165 (August 15, 2018).

Through clarification discussion with internal stakeholders, Hydro Ottawa has concluded that there was a misunderstanding related to Account 1835 (Overhead Conductors and Devices) and Account 1845 (Underground Conductors and Devices). While both primary and secondary overhead assets are recorded in Account 1835, the underground equipment in Account 1845 all relate to primary assets. All secondary underground conductors and devices are recorded in Account 1855 (Services).

As identified in the response to interrogatory OEB-157, the OEB directed Toronto Hydro to incorporate the distinction between the primary and secondary systems in future cost allocation studies based on sufficient evidence.[2] In reconsidering this direction, and after reflecting on the discussion that occurred during the Technical Conference in the proceeding for this Application regarding the updating of primary and secondary customer count, Hydro Ottawa believes that it would seem appropriate for the utility to likewise refrain from updating primary and secondary percentage allocation for Account 1835 based upon imperfect data. Hydro Ottawa is therefore of the view that it should maintain its previous cost study inputs regarding all primary and secondary inputs until a new, full study is complete. The utility notes that some of the inputs allocate more costs to smaller consumers while other inputs allocate less costs to the smaller consumers. As signalled during Day 3 of the Technical Conference held as part of this proceeding, Hydro Ottawa's intent is to complete an updated study prior to its next rebasing application.[3]

The updated cost allocation model is attached to undertaking JT 3.1.

---

[2] Ontario Energy Board, *Decision and Order on Suite Metering Issues*, EB-2010-0142 (February 22, 2012, corrected March 9, 2012), pages 16-18.
[3] EB-2019-0261, Technical Conference Transcript dated July 17, 2020, page 164, lines 7-26.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.26

JT 3.26
[NOT DESCRIBED]

PREAMBLE:
Hydro Ottawa interprets this undertaking as relating to interrogatory VECC-100 (7.0-VECC-100). Please see pages 166-167 of the Technical Conference transcript dated July 17, 2020 for further details. A portion of the transcript is provided below.

MR. HARPER: What I was struggling with is they don't own any secondary equipment of their own. They don't use any equipment served by Hydro Ottawa. How is that possible? Is it a fact that, you know, they go straight from hydro -- like I am struggling with how that is possible. They don't own it themselves, and they don't use Hydro Ottawa's.

MS. BARRIE: Unfortunately, that is a little bit more technical than I could probably answer. I could undertake to look into that, however.

MR. HARPER: If you could, that would be greatly appreciated because it struck me that that means it doesn't exist at all. I was struggling with a little bit so if you could, that would be great, please and thank you.

RESPONSE:

Hydro Ottawa’s GS 1,500 - 4,999 kW and Large Use customers are connected to the utility’s electricity network through a primary voltage service. The primary voltage service is transformed to usable voltage, either with Hydro Ottawa-owned or customer-owned transformers. Transformed power is carried directly to the equipment via customer-owned secondary wire.

Where Hydro Ottawa owns the transformer, metering is typically installed on the secondary side of the transformer, within the customer-owned secondary switchboard. When the customer owns the transformer, it is typical for the metering to be primary, ahead of the customer-owned transformer in the customer-owned medium voltage switchgear.

Hydro Ottawa would like to take this opportunity to clarify the wording in the response to interrogatory VECC-100 part (i). The response should be revised as follows: *"The customer count originally provided includes all customers that do not own secondary equipment. However, the remaining customers should not be included because they ~~do not use any secondary equipment~~ use customer-owned secondary equipment rather than Hydro Ottawa-owned secondary equipment."* An updated version of the response to interrogatory VECC-100 is appended to this undertaking as Attachment JT 3.26(A) for reference.

INTERROGATORY RESPONSE - VECC-100

7.0-VECC-100

EXHIBIT REFERENCE:

Updated Exhibit 7, Tab 1, Schedule 1, pages 1-2

Updated 2021 Cost Allocation Model, Tabs I6.2 and I8

SUBJECT AREA: Cost Allocation

a) It is noted that in Tab I6.2 the Residential Secondary Customer Base is less than the Primary Customer Base. Please explain why this is the case.

b) Please explain why, in Tab I6.2, the Residential LT Customer Base is not equal to the Secondary Customer Base.

c) It is noted that in Tab I8 the Residential Secondary NCP4 value equals the Primary NCP4 even though in Tab I6.2 the Secondary Customer Base is less than the Primary Customer Base. Please reconcile.

d) Are any of HOL's residential customers located in multi-residential building (e.g. apartments or condominiums) where the transformer and/or the service connection to the building is not owned by HOL but rather by the building owner (e.g. the apartment building owner or the condominium corporation)?
    i) If yes, how many such Residential customers were there in 2019?
    ii) It yes, do the Residential Secondary and LT Customer counts in Tab I6.2 and the Residential Secondary and LT NCP4 values in Tab I8 reflect these circumstances?

e) Are any of HOL's GS customers located in commercial/industrial malls (e.g. shopping centres) where the transformer and/or the service connection to the "mall" is not owned by HOL but rather by the building complex (e.g. the mall owner?

i) If yes, for each GS class, how many such GS customers were there in 2019?

ii) It yes, do the respective GS class Secondary and LT Customer counts in Tab I6.2 and the GS class Secondary and LT NCP4 values in Tab I8 reflect these circumstances?

f) It is noted that in Tab I6.2 the GS<50 Secondary Customer Base is less than the Primary Customer Base. Please explain why this is the case.

g) Please explain why, in Tab I6.2, the GS<50 LT Customer Base is not equal to the Secondary Customer Base.

h) It is noted that in Tab I8 the GS<50 Secondary and LT NCP4 values both equal the Primary NCP4 value even though in Tab I6.2 the LT and Secondary Customer Bases are both less than the Primary Customer Base. Please reconcile.

i) Please explain why, in Tab I6.2, the GS1500-4999 LT Customer Base is less than the Secondary Customer Base.

j) Please explain why, in Tab I8, there is no Secondary NCP4 value for the GS1500-4999 class when in Tab I6.2 there are 65 customers in the GS1500-4999 Secondary Customer Base.

k) Please explain why, in Tab I6.2, the Large User LT Customer Base is less than the Secondary Customer Base.

l) Please explain why, in Tab I8, there is no Secondary NCP4 value for the Large User class when in Tab I6.2 there are 9 customers in the Large User Secondary Customer Base.

m) Please explain why, when there are 3 GS1500-4999 Standby customers per Tab I6.2, Tabs I7.1 and I7.2 only show 2 meters for these customers.

n) Please explain why, for the GS1500-4999 Standby class, Tab I6.2 shows zero for LT Customer Base whereas Tab I8 shows a positive value LT NCP4 value for the class.

o) For each of the 3 GS1500-4999 Standby customers, please explain what HOL facilities/assets are used to serve the customers.

RESPONSE:

a) Please see the response to interrogatory OEB-157 part (a).

b) Please see the response to interrogatory OEB-157 part (a).

c) Please see the response to interrogatory OEB-157 part (a).

d) Please see the response to interrogatory OEB-157 part (b).

e) Please see the response to interrogatory OEB-157 part (c).

f) Please see the response to interrogatory OEB-157 part (a).

g) Please see the response to interrogatory OEB-157 part (a).

h) Please see the response to interrogatory OEB-157 part (a).

i) The GS 1,500-4,999 kW class does not have secondary customers. The customer count originally provided includes all customers that do not own secondary equipment.

However, the remaining customers should not be included because they ~~do not use any secondary equipment~~ use customer-owned secondary equipment rather than Hydro-Ottawa owned secondary equipment. The secondary customer count has been revised in an updated cost allocation model, which is included as excel Attachment OEB-38(A): Updated OEB Workform - Cost Allocation Model.

j) Please see the response to part (i) above.

k) Large User customers do not use Hydro Ottawa secondary equipment. As a result, the secondary customer count has been revised in the updated cost allocation model, as found in excel Attachment OEB-38(A).

l) Please see the response to part (k) above. Refer to excel Attachment OEB-38(A) for an updated cost allocation model.

m) This has been corrected. Please see the updated cost allocation model, filed as excel Attachment OEB-38(A).

n) The inconsistency is due to a timing mismatch between the information used for customer counts and the hourly demand data used to derive demand allocators. In 2004, a Standby customer used line transformer assets (according to hourly data from the 2006 CAIF). More recent customer information shows that no Standby customers currently use those assets. As such, Line Transformer demand has been removed from the Standby class in the updated cost allocation model in excel Attachment OEB-38(A).

o) Hydro Ottawa maintains sufficient power in its distribution grid to service Standby customers in the event their supply cannot be used. As such, GS 1500-4999 Standby customers use similar facilities/assets as the GS 1500-4999 customers without Standby. The fixed monthly service charge compensates Hydro Ottawa for the administration related to standby services while the volumetric rate compensates the utility for the reserved capacity requirement.

TECHNICAL CONFERENCE UNDERTAKING - JT 3.30

JT 3.30

[NOT DESCRIBED]

RESPONSE:

The scope of this undertaking response aligns with the discussion that was captured on lines 12-28 on page 196 of the Technical Conference transcript dated July 17, 2020 (Day 3). A key segment of that exchange was as follows:

MR. LADANYI: Yes. I am looking for the opposite of that.

MR. BROWN: Just to repeat again, you want an example of an OM&A project that reduced capital?

MR. LADANYI: That's right, where you had a choice of either spending more money on capital, but instead you opted to do more maintenance, or extended maintenance, or whatever.

In step with the utility's enduring commitment to productivity and continuous improvement, as well as its established processes and practices for optimizing the coordination, scheduling, and prioritization of project expenditures and execution, Hydro Ottawa regularly assesses opportunities to reduce, defer, or eliminate capital spending through OM&A initiatives (or other alternative options).

There are several examples of this approach at play within the evidence that has been filed thus far in this proceeding:

- **Capacity Relief through CDM Programming in Kanata North** – in order to address immediate capacity and reliability needs in the Kanata North area of Hydro Ottawa's service territory, the utility is pursuing a range of solutions. These include conservation and demand management ("CDM") programs that have been approved for $6.55M in funding by the Independent Electricity System Operator ("IESO") and that will help achieve over 3 MW in demand reductions. Alongside this CDM programming, Hydro Ottawa is undertaking a series of short-term measures including load transfers to adjacent stations, distribution line extensions, and VAR control projects (with distribution grid upgrades expected to total $3.79M over the 2021-2025 period). Together, these solutions are enabling the utility to defer an estimated $36.0M investment in new station infrastructure in Kanata North. For more information, please see the following: Exhibit 2-4-3: Distribution System Plan; Attachment 2-4-3(E): Material Investments; Attachment 2-4-3(K): Local Achievable Potential Study; the responses to interrogatories OEB-59, OEB-134, and OEB-135; Attachment PP-11(A): Ottawa Sub-Region 2020 IRRP; and Attachment JT 2.4(C): Ottawa Sub-Region 2020 IRRP - Appendices.

- **Distribution System Testing, Inspection, and Maintenance Programs to Optimize Capital Expenditures** – these programs provide valuable information that is used to direct corrective maintenance actions, and to prioritize and economize capital expenditures. The collection of this data enables Hydro Ottawa to undertake replacement of assets based upon those assets' condition, rather than their age, and thus helps equip the utility to be able to defer capital investment, where appropriate. Maintaining assets so that they sustain their expected performance and collecting data to optimize capital expenditures are therefore a key focus of Hydro Ottawa's Asset Management System, and by extension, of the utility's broader efforts to control costs and achieve productivity savings on an ongoing basis.

  A tangible, illustrative example in this regard is the recent Longfields Tap Changer Rebuild project completed by the utility. Through routine testing and inspection, it was discovered that components of a station transformer tap changer had been damaged. Hydro Ottawa rebuilt the tap changer at a cost of $49K, thereby avoiding much more significant capital costs associated with replacing the entire transformer (potentially in the range of $500K to $1.0M).

For a complete overview and description of Hydro Ottawa's testing, inspection, and maintenance programs, please see Sections 5.1.3 and 6.2.2 in Exhibit 2-4-3: Distribution System Plan. For purposes of this specific undertaking response, the utility is providing the following summary of how each program contributes to optimizing spending, which can include efficiencies and/or reductions in capital expenditures, where appropriate:

- *Stations*
  - Infrared ("IR") Scans - Identifies heating components that can be cleaned or replaced, thereby reducing the need to respond reactively.
  - Switchgear Inspections - Identifies components for corrective maintenance action and allows for the deferral of capital expenditures until the assets have reached end of life.
  - Breaker & Recloser Maintenance - Prevents failures due to normal wear and collects asset condition data for use in prioritizing capital expenditures.
  - Switch Inspections - Identifies components for corrective maintenance action.
  - SCADA Inspections - Identifies components for corrective maintenance action and allows for the deferral of capital expenditures until the assets have reached end of life.
  - Relay Testing - Identifies components for corrective maintenance action and allows for the deferral of capital expenditures until the assets have reached end of life.
  - Station Inspections - Identifies components for corrective maintenance action.
  - Battery Testing - Identifies defective batteries for capital replacement.
  - Transformer Maintenance - Prevents failures due to normal wear and collects asset condition data for use in prioritizing capital expenditures.

- Transformer Testing - Identifies components for corrective maintenance action and collects asset condition data for use in prioritizing capital expenditures.
- Transformer Oil Analysis - Identifies components for corrective maintenance action and collects asset condition data for use in prioritizing capital expenditures.
- Transformer Tapchanger Maintenance - Prevents failures due to normal wear and identifies components for corrective maintenance action.

➔ *Underground*

- Underground Switchgear - Identifies heating/defective components that can be cleaned or replaced, thereby reducing the need to respond reactively. In addition, the program collects asset condition data for use in prioritizing capital expenditures, and allows for the deferral of capital expenditures until the assets have reached end of life.
- Underground Distribution Transformer - Identifies heating/defective components that can be cleaned or replaced, thereby reducing the need to respond reactively. In addition, the program collects asset condition data for use in prioritizing capital expenditures and allows for the deferral of capital expenditures until the assets have reached end of life.
- Vault Inspections - Identifies heating/defective components that can be cleaned or replaced, thereby reducing the need to respond reactively. In addition, the program collects asset condition data for use in prioritizing capital expenditures and allows for the deferral of capital expenditures until the assets have reached end of life.
- Switchgear CO2 Washing - Prevents failures due to normal wear.
- Cable Inspection - Collects asset condition data for use in prioritizing capital expenditures.
- Manhole Inspections - Collects asset condition data for use in prioritizing capital expenditures.

- ➔ *Overhead*
  - ◆ Overhead IR Inspection - Identifies heating/defective components that can be cleaned or replaced, thereby reducing the need to respond reactively.
  - ◆ Vegetation Management - Prevents failures due to unmanaged growth and creates resiliency to adverse weather conditions.
  - ◆ Pole Inspection - Collects asset condition data for use in prioritizing capital expenditures.
  - ◆ Critical Switch Inspection - Prevents failures due to normal wear. In addition, the program collects asset condition data for use in prioritizing capital expenditures and allows for the deferral of capital expenditures until the assets have reached end of life.
  - ◆ Insulator Washing - Prevents failures due to contamination build-up and allows for the deferral of capital expenditures until the assets have reached end of life.

- **Maintenance to Extend Fleet Life and Reduce Capacity Replacements** – the fleet maintenance program is designed to extend the life of the utility's fleet and help reduce the need for replacing vehicles. As specified in the response to undertaking JT 3.2, the costs associated with this program are set to average approximately $800K per year over the course of the 2016-2020 Custom IR term.

A detailed description of Hydro Ottawa's fleet maintenance practices is included in Attachment 2-4-3(F): Fleet Replacement Program. As noted in that attachment, during the 2016-2020 period the utility responsibly managed its fleet capital expenditure program, making several trade-offs to address vehicles in poor condition, including the deferral of vehicle replacements and acquisitions. Maintenance practices and operational solutions which are essential to effective fleet management include utilizing software tools (e.g. FleetWave and Geotab) to maintain up-to-date records of vehicle maintenance and optimize vehicle utilization, performing regular preventative and scheduled maintenance, regularly inspecting aerial equipment, proactively monitoring mileage and engine hours, using high-quality synthetic oils thereby enabling extension of vehicle service intervals, and extending manufacturers' rust inhibiting undercoating.

Moreover, as noted during the Technical Conference held in this proceeding, whereas 90% of the vehicles in Hydro Ottawa's fleet are slated to reach or exceed their replacement age during the 2021-2025 period, the rationalization process utilized by the utility will result in a true replacement rate of only 42%.[1] An essential determinant of the success of this process is the strength of Hydro Ottawa's fleet maintenance and management programs.

[1] Technical Conference transcript dated July 17, 2020, page 2, lines 5-15.

ADDENDUM TO TECHNICAL CONFERENCE UNDERTAKING - JT 3.1

JT 3.1

To please provide a revised version of Appendix 2-AA, and Sec-49 Attachment A, on the same basis as Jt1.1. Please also provide update opening 2021 rate base and revenue requirement impact during the plan of any update to the 2020 in-service addition forecast.

RESPONSE:

The response below is an addendum to the undertaking response JT 3.1 that Hydro Ottawa submitted on August 5, 2020 and updated on August 6, 2020.

Please find a list below of updated models appended to this addendum as Excel files. Details of the changes are provided in the ensuing paragraphs.

- Attachment JT 3.1(D): OEB Workform - 2021 Income Tax/PILS Workform
- Attachment JT 3.1(E): OEB Workform - 2022 Income Tax/PILS Workform
- Attachment JT 3.1(F): OEB Workform - 2023 Income Tax/PILS Workform
- Attachment JT 3.1(G): OEB Workform - 2024 Income Tax/PILS Workform
- Attachment JT 3.1(H): OEB Workform - 2025 Income Tax/PILS Workform
- Attachment JT 3.1(I): 2024 Schedule 8 Capital Cost Allowance
- Attachment JT 3.1(J): 2025 Schedule 8 Capital Cost Allowance
- Attachment JT 3.1(K): OEB Workform - 2021 Revenue Requirement Workform
- Attachment JT 3.1(L): OEB Workform - 2022 Revenue Requirement Workform
- Attachment JT 3.1(M): OEB Workform - 2023 Revenue Requirement Workform
- Attachment JT 3.1(N): OEB Workform - 2024 Revenue Requirement Workform
- Attachment JT 3.1(O): OEB Workform - 2025 Revenue Requirement Workform
- Attachment JT 3.1(P): OEB Workform - Cost Allocation Model
- Attachment JT 3.1(Q): HOL Bill Impacts Model 2021-2025
- Attachment JT 3.1(R): OEB Workform - Deferral and Variance Account (Continuity Schedule)

3.2 PAYMENTS IN LIEU OF TAXES

The OEB Income Tax/PILS Workforms for the 2021-2025 Test Years are appended to this undertaking response as the following Attachments:

- Attachment JT 3.1(D): OEB Workform - 2021 Income Tax/PILS Workform
- Attachment JT 3.1(E): OEB Workform - 2022 Income Tax/PILS Workform
- Attachment JT 3.1(F): OEB Workform - 2023 Income Tax/PILS Workform
- Attachment JT 3.1(G): OEB Workform - 2024 Income Tax/PILS Workform
- Attachment JT 3.1(H): OEB Workform - 2025 Income Tax/PILS Workform

Hydro Ottawa has also included supplemental Schedule 8 worksheets for Test Years 2024 and 2025 to support the Capital Cost Allowance (“CCA”) calculations in the PILS Tax Models (please see Attachment JT 3.1(I): 2024 Schedule 8 Capital Cost Allowance and Attachment JT 3.1(J): 2025 Schedule 8 Capital Cost Allowance).

4. CALCULATION OF REVENUE DEFICIENCY AND SURPLUS

More details for each year can be found in the Revenue Requirement Workforms, which have been appended as the following excel Attachments:

- Attachment JT 3.1(K): OEB Workform - 2021 Revenue Requirement Workform
- Attachment JT 3.1(L): OEB Workform - 2022 Revenue Requirement Workform
- Attachment JT 3.1(M): OEB Workform - 2023 Revenue Requirement Workform
- Attachment JT 3.1(N): OEB Workform - 2024 Revenue Requirement Workform
- Attachment JT 3.1(O): OEB Workform - 2025 Revenue Requirement Workform

5. COST ALLOCATION

5.1 COST MODEL

Hydro Ottawa has updated the Cost Allocation Model for 2021 to incorporate the changes to rate base and the resulting change to revenue requirement. As described in the response to undertaking JT 3.22-Q5, Hydro Ottawa has also updated the allocation factors for underground (account 1845) and overhead (account 1835) to remain at 100% primary until a full study is completed. The revised model has been attached as excel Attachment JT 3.1(P): OEB Workform - Cost Allocation Model.

Revenue Requirement Workforms for 2021-2025 have also been updated to reflect the revised revenue requirement and cost allocations as described above. They are included as Attachments JT 3.1(K) to (O).

5.2 COST ALLOCATION ADJUSTMENTS

The Cost Allocation Model indicates that four rate classes require adjustments to bring them within the OEB-approved ranges. General Service ("GS") <50 kW and Street Lighting were above the upper limit, while Large Use and Sentinel Lighting were below the lower limit.

Hydro Ottawa proposes to adjust the revenue requirements in a two-step process to bring three of the four rate classes into the OEB-approved ranges in 2021. Hydro Ottawa first reallocated revenue requirement within the affected rate classes to bring them within OEB-approved limits. The remaining revenue shortfall resulting from these adjustments was allocated to the GS 50 to 1,499 kW and Large Use customer classes that have revenue-to-cost ratios below 100.

It is proposed to bring the Sentinel Lighting rate class up to the lower bound over a five-year period, in order to mitigate the large bill impact of an immediate adjustment. Required adjustments to Sentinel Lighting in the 2022-2025 Test Years are offset against another unmetered customer class, Street Lighting. The impact on the Street Lighting class will be minimal at less than $720 annually.

6. RATE DESIGN

Hydro Ottawa has included Bill Impacts in excel Attachment JT 3.1(Q): HOL Bill Impacts Model 2021-2025. This includes the rate orders from 2021-2025.

As noted in the response to interrogatory OEB-38, Hydro Ottawa encountered issues with the OEB's Bill Impact Model: OEB Workform 2020 Current and 2021 Proposed Tariff of Rates and Charges. For the "Sentinel Lights Service Classification", "Unmetered Scattered Load Service Classification", and "Street Lighting Service Classification" there were errors with the rate riders. The rate rider for Group 2 accounts is being calculated at both the sub total A and sub total B; however, it should only be calculated in sub total A. In addition, the model would not allow an update to the 2021 proposed rate for retailer-consolidated billing monthly credit per customer. As a result, Hydro Ottawa has only included excel Attachment JT 3.1(Q): HOL Bill Impacts Model 2021-2025.

The annual changes in the distribution charge for Residential customers who use 750 kWh per month, as well as General Service <50kW customers with consumption of 2,000 kWh per month, are shown in Table G. The 2021-2025 average dollar and percentage change has also been provided.

Table G – Annual Impact on Customers' Distribution Rates – Updated for 2020 Forecast (Including 2021-2025 Average)

Rate Class	Change in Distribution Charge	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed	2025 Proposed	Average
Residential (750 kWh)	$ / Month	$1.65	$1.97	$1.81	$0.97	$0.63	**$1.41**
	%	5.76%	6.50%	5.61%	2.85%	1.80%	**4.50%**
General Service <50 kW (2,000 kWh)	$ / Month	$2.75	$5.27	$4.89	$3.04	$2.46	**$3.68**
	%	3.86%	7.11%	6.16%	3.61%	2.82%	**4.71%**

Table H below summarizes the updates to bill impacts, based upon this undertaking response.

Table H – Summary of Bill Impacts – Updated for 2020 Forecast

Rate Class		Approved	Proposed				
		2020	2021	2022	2023	2024	2025
Residential (750 kWh)	Distribution Charge	$28.64	$30.29	$32.26	$34.07	$35.04	$35.67
	Change in Distribution Charge		$1.65	$1.97	$1.81	$0.97	$0.63
	% Distribution Increase		5.76%	6.50%	5.61%	2.85%	1.80%
	% Increase of Total Bill		1.19%	1.39%	1.57%	0.67%	0.44%
General Service <50 kW (2,000 kWh)	Distribution Charge	$71.32	$74.07	$79.34	$84.23	$87.27	$89.73
	Change in Distribution Charge		$2.75	$5.27	$4.89	$3.04	$2.46
	% Distribution Increase		3.86%	7.11%	6.16%	3.61%	2.82%
	% Increase of Total Bill		0.54%	1.43%	1.63%	0.80%	0.64%
General Service 50 kW - 1,499 kW (250 kW)	Distribution Charge	$1,461.93	$1,530.68	$1,645.81	$1,798.45	$1,865.91	$1,919.52
	Change in Distribution Charge		$68.75	$115.14	$152.64	$67.46	$53.61
	% Distribution Increase		4.70%	7.52%	9.27%	3.75%	2.87%
	% Increase of Total Bill		2.99%	(1.05)%	1.11%	0.37%	0.30%
General Service 1,500 kW - 4,999 kW (2,500 kW)	Distribution Charge	$15,941.18	$16,524.43	$17,741.69	$19,212.82	$19,931.65	$20,400.40
	Change in Distribution Charge		$583.25	$1,217.26	$1,471.13	$718.83	$468.75
	% Distribution Increase		3.66%	7.37%	8.29%	3.74%	2.35%
	% Increase of Total Bill		2.86%	(0.99)%	1.09%	0.39%	0.26%
Large Use (7,500 kW)	Distribution Charge	$48,420.32	$51,444.32	$55,080.02	$59,719.14	$61,805.64	$63,179.64
	Change in Distribution Charge		$3,024.00	$3,635.70	$4,639.12	$2,086.50	$1,374.00
	% Distribution Increase		6.25%	7.07%	8.42%	3.49%	2.22%
	% Increase of Total Bill		3.06%	(1.21)%	1.26%	0.37%	0.24%
Sentinel Lighting (0.4 kW)	Distribution Charge	$9.53	$11.31	$13.68	$16.18	$18.35	$20.45
	Change in Distribution Charge		$1.79	$2.37	$2.50	$2.17	$2.10
	% Distribution Increase		18.74%	20.91%	18.28%	13.41%	11.44%
	% Increase of Total Bill		8.67%	9.15%	9.14%	7.05%	6.37%
Street Lighting (1 kW)	Distribution Charge	$7.76	$7.41	$7.97	$8.89	$9.20	$9.49
	Change in Distribution Charge		$(0.36)	$0.56	$0.92	$0.31	$0.29
	% Distribution Increase		(4.58)%	7.55%	11.60%	3.50%	3.15%
	% Increase of Total Bill		(0.54)%	1.79%	3.57%	0.99%	0.91%
Unmetered Scattered Load (470 kWh)	Distribution Charge	$17.08	$17.72	$19.38	$21.48	$22.79	$23.94
	Change in Distribution Charge		$0.64	$1.67	$2.10	$1.30	$1.16
	% Distribution Increase		3.75%	9.42%	10.82%	6.07%	5.09%
	% Increase of Total Bill		0.86%	1.92%	2.68%	1.44%	1.27%

7. DEFERRAL AND VARIANCE ACCOUNTS

Hydro Ottawa has included a revised DVA Continuity Schedule in excel Attachment JT 3.1(R): OEB Workform - Deferral and Variance Account (Continuity Schedule). Three Regulatory Accounts have been updated as a result of changes, subsequent to the filing of updated evidence on May 5, 2020:

- USofA 1508 - Sub-Account Earnings Sharing Mechanism Variance Account (please refer to the responses to undertaking JT 3.9 and interrogatory OEB-38 for details).
- USofA 1508 - PILS and Tax Variance for 2006 and Subsequent Year - Sub account CCA Changes (please see the response to undertaking JT 4.8 for details).
- USofA 1568 - LRAM Variance Account (as outlined in the responses to interrogatories OEB-171 and OEB-174).

The changes noted above related to interrogatory responses were incorporated into updated rates as part of the response to interrogatory OEB-38; those additional changes related to undertakings are being incorporated as part of the response to this undertaking. Table 1 from UPDATED Exhibit 9-3-1: Disposition of Deferral and Variance Accounts has been updated below as Table I - UPDATED FOR 2019 ESM, PILS and LRAM – Proposed DVA Dispositions.

1 **Table I – Proposed DVA Dispositions – Updated for 2019 ESM, PILS and LRAM**

Group	USofA Number	Group 1 and 2 Deferral/Variance Account Description	Amount	Principal	Interest
1	1550	LV Variance Account	$(313,465)	$(304,865)	$(8,600)
1	1551	Smart Metering Entity Charge Variance Account	$(77,882)	$(75,564)	$(2,317)
1	1580	RSVA - Wholesale Market Service Charge	$(2,060,384)	$(2,022,576)	$(37,808)
1	1580	Variance WMS – Sub-account CBR Class A	$0	$0	$0
1	1580	Variance WMS – Sub-account CBR Class B	$(492,601)	$(477,649)	$(14,952)
1	1584	RSVA - Retail Transmission Network Charge	$(742,184)	$(714,195)	$(27,988)
1	1586	RSVA - Retail Transmission Connection Charge	$(4,728,044)	$(4,577,938)	$(150,106)
1	1588	RSVA - Power (excluding Global Adjustment)	$757,478	$743,192	$14,286
1	1589	RSVA - Global Adjustment	$6,051,424	$5,762,960	$288,464
1	1595	Disposition and Recovery/Refund of Regulatory Balances (2016)	$66,600	$91,297	$(24,697)
1	1595	Disposition and Recovery/Refund of Regulatory Balances (2017)	$(505,116)	$(188,154)	$(316,962)
		Group 1 Subtotal (Excluding Global Adjustment)	$(8,095,597)	$(7,526,452)	$(569,145)
		Global Adjustment	$6,051,424	$5,762,960	$288,464
		Group 1 TOTAL	$(2,044,173)	$(1,763,493)	$(280,681)
		1508 Other Regulatory Assets - Sub-Account			
2	1508	Pension & Other Post-Employment Benefits (“OPEB”)	$(4,431,595)	$(4,431,595)	$0
2	1508	Energy East Cost Defer Cost	$55,424	$50,731	$4,693
2	1508	Y-Factor Variance Account	$320,332	$320,332	$0
2	1508	Gains/Losses from Sale of Existing Facilities Deferral	$(2,151,861)	$(2,151,861)	$0
2	1508	New Facilities Deferral Account	$4,627,793	$4,627,793	$0
2	1508	Gains and Loss on Disposal of Fixed Assets Variance Account	$3,677,609	$3,543,600	$134,009
2	1508	Earnings Sharing Mechanism (“ESM”) Variance Account	$(5,196,006)	$(4,985,981)	$(210,025)
2	1508	Connection Cost Recovery Agreement (“CCRA”) Payment	$836,084	$814,360	$21,724
2	1508	Efficiency Adjustment Mechanism Deferral Account	$(892,062)	$(854,169)	$(37,893)
2	1508	OEB Cost Assessment Variance	$1,989,596	$1,879,684	$109,912
2	1508	OPEB Differential	$0	$0	$0
2	1508	RCVA Retail Incremental Revenue	$(36,725)	$(35,714)	$(1,011)
2	1508	STR Incremental Revenue	$(1,005)	$(977)	$(28)
	1508	**Sub-Total of 1508 Sub-Accounts**	**$(1,202,416)**	**$(1,223,798)**	**$21,382**
2	1518	Retail Cost Variance - Retail	$(43,058)	$(39,487)	$(3,572)
2	1522	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	$(6,403)	$0	$(6,403)

2	1548	Retail Cost Variance - Service Transaction Requests (“STRs”)	$342,868	$314,008	$28,860
2	1592	PILs and Tax Variances - Sub-Account: Capital Cost Allowance (“CCA”) Changes	$(7,477,887)	$(7,291,888)	$(185,999)
		Group 2 Sub-Total Prior to Lost Revenue Adjustment Mechanism (“LRAM”)	**$(8,386,897)**	**$(8,241,164)**	**$(145,732)**
2	1568	LRAM Variance Account (“LRAMVA”)	$2,795,681	$2,563,959	$231,722
		Group 2 Sub-Total	**$(5,591,216)**	**$(5,677,206)**	**$85,990**
TOTAL DVA BALANCE (Group 1 & Group 2) TO BE MOVED TO 1595 (2021)[1]			**$(7,635,389)**	**$(7,440,698)**	**$(194,691)**

[1] Totals may not sum due to rounding.