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 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.