Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

October 26, 2021

Ms. Christine E. Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Long:

Re: Ontario Energy Board (OEB) Staff Interrogatories
Hydro One Networks Inc. (Hydro One)
2023-2027 Joint Rate Application (JRAP)
OEB File Number: EB-2021-0110

Please find attached OEB staff's interrogatories in the above referenced proceeding, pursuant to Procedural Order No. 1.

Please note, Hydro One is responsible for ensuring that all documents that it files with the OEB, including responses to OEB staff questions and any other supporting documentation, do not include personal information (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

Yours truly,

Martin Davies Digitally signed by Martin Davies
Date: 2021.10.26 15:30:56 -04'00'

Martin Davies
Project Advisor, Electricity Distribution: Major Rate Applications & Consolidations

Encl.

cc: All parties in EB-2021-0110

HYDRO ONE NETWORKS INC.

2023-2027 JOINT RATE APPLICATION

EB-2021-0110

OEB STAFF INTERROGATORIES

October 26, 2021

General

Letters of Comment

0-Staff-1

Question(s):

a) Please file a response to any letters of comment on the public record for this proceeding.

b) Going forward, please ensure that responses are filed to any subsequent letters that may be submitted in this proceeding. Please file responses prior to the argument phase of this proceeding.

2021 Third Quarter Actuals

0-Staff-2

Preamble:

OEB staff notes that Procedural Order No. 1 established November 29, 2021 as the deadline for filing interrogatory responses. OEB staff expects that Hydro One will have 2021 third quarter actuals available by the time that the interrogatory responses are due.

Question(s):

a) Please file Hydro One's 2021 Third Quarter Actual results and comment on whether or not they would have any significant impacts on the JRAP application. If so, please state where these significant impacts would be and file any necessary updates to the application.

Exhibit A – Administration

A-Staff-3
Exhibit A / Tab 4 / Schedule 2 / pp. 5, 8
Exhibit H / Tab 1 / Schedule 1

Preamble:

On page 5 of Exhibit A/4/2, Hydro One provides Table 1, summarizing the derivation of the Transmission Revenue Requirement for each year of the plan from 2023 to 2027. For 2023, the Transmission Revenue Requirement is based on a cost of service approach to rebase the revenue requirement, while, for 2024 through 2027, the annual revenue requirement will be updated in each year through an annual application. The Transmission Revenue Requirement is shown on line 14 of Table 1.

In Exhibit H/1/1, Hydro One documents its approach for determining the Transmission Revenue Requirement, and the methodology for allocating the revenue requirement to the pools. In Table 1 on page 2 of this exhibit, Hydro One shows the estimate of the total Transmission Revenue Requirement and of other revenues and costs (i.e., revenue offsets) to derive the Rates Revenue Requirement.

Question(s):

a) Please confirm that Line 14 on Table 1 of Exhibit A/4/2 is the Total or Service Revenue Requirement.

b) Are any of the other revenues and costs shown in Table 1 of Exhibit H/1/1 subject to updating as part of the annual update for 2024 through 2027 that Hydro One has documented on page 8 of Exhibit A/4/2?

c) If the answer to b) is in the affirmative, please identify which revenue offsets will be updated. Please also provide further explanation of what support Hydro One expects to file for updates to other revenues as offsets for the annual Transmission Revenue Requirement update.

A-Staff-4
Exhibit A / Tab 4 / Schedule 3 / pp. 5, 8
Exhibit L / Tab 2 / Schedule 1 / Attachment 1

Preamble:

On page 5 of Exhibit A/4/3, Hydro One provides Table 1, summarizing the derivation of the Distribution Revenue Requirement for each year of the plan from 2023 to 2027. For 2023, the Distribution Revenue Requirement is based on a cost of service approach to rebase the revenue requirement, while for 2024 through 2027 the annual revenue requirement will be updated in each year through an annual application. The Distribution Revenue Requirement is shown on line 14 of Table 1.

In Exhibit L/1/1, Hydro One documents its approach for allocating the revenue requirement between customer classes based on the OEB's cost allocation methodology, and for its rate design to determine fixed and variable rates to recover the base (distribution) revenue requirement from ratepayers based on the approved load forecast (i.e. billing determinants) for each year. In tables showing the rate design for each year from 2023 to 2027 in Exhibit L/Tab 2/Schedule 1/Attachment 1, pages 1 to 5, Hydro One shows the Total (Service) Revenue Requirement, Other Revenues and Base Revenue Requirement in total and allocated to each customer class.

Question(s):

a) Please confirm that Line 14 on Table 1 of Exhibit A/Tab 4/Schedule 3 is the Total or Service Revenue Requirement.

b) Please confirm that some of the Other Revenues are revenue for Specific Service Charges and for Pole Attachment charges, and that some of these charges are also subject to adjustments for inflation in each annual update.

c) Please identify which other revenues will be updated for inflationary adjustments, and what supporting evidence Hydro One expects to file for updates to other revenues as offsets for the annual Distribution Revenue Requirement and Distribution Rates application update.

A-Staff-5
Exhibit A / Tab 4 / Schedule 2
Exhibit A / Tab 4 / Schedule 3
Exhibit B / Tab 2 / Schedule 1
Exhibit B / Tab 3 / Schedule 1
Exhibit B / Tab 4 / Schedule 1

Preamble:

Hydro One has documented its planned capital projects for each year of the plan from 2023 to 2027 in each of its Transmission System Plan (TSP), Distribution System Plan (DSP) and General System Plan (GSP). General plant capex and capital additions in each year are allocated between Transmission and Distribution per Hydro One's proposed methodology.

OEB staff are interested in examining Hydro One's assumptions regarding inflation as factored into the capital budgets in the TSP, DSP and GSP, and hence reflected in the costs factored into Transmission and Distribution capital additions to rate base as shown in Table 1 of Exhibit A/Tab 4/Schedule 2 (Transmission) and Table 1 of Exhibit A/Tab 4/Schedule 3 (Distribution) relative to the assumed Transmission (Distribution) inflation index (Input Price Index).

Question(s):

a) Please confirm that, for both Transmission and Distribution, the rate base consists of mid-year or average in-service Net Fixed Assets, a working capital allowance plus an allocated portion of General Plant mid-year or average in-service Net Fixed Assets.

b) Please provide the assumed inflation factor in aggregate capital expenditures for each of:
   i. the TSP
   ii. the DSP
   iii. the GSP

   If different inflation assumptions are made for each year, please provide this information for each year of the plan.

c) Please provide a weighted average inflation factor for capital additions to the Transmission rate base shown in line 1 of Table 1 of Exhibit A/Tab 4/Schedule 2.

This would be a weighted average of the TSP capex inflation provided in b) i. and the GSP capex inflation provided in b) iii. above, with the weights being gross book value of Transmission capital additions for the year from the TSP and the gross book value of General Plant capital additions allocated to the Transmission rate base for that year. If the information is more easily available, Transmission capital expenditures and General Plant capital expenditures allocated to Transmission could be used as weights.

d) Please provide a weighted average inflation factor for capital additions to the Distribution rate base shown in line 1 of Table 1 of Exhibit A/Tab 4/Schedule 3. This would be a weighted average of the DSP capex inflation provided in b) ii. and the GSP capex inflation provided in b) iii. above, with the weights being gross book value of Distribution capital additions for the year from the DSP and the gross book value of General Plant capital additions allocated to the Distribution rate base for that year. If the information is more easily available, Distribution capital expenditures and General Plant capital expenditures allocated to Distribution could be used as weights.

A-Staff-6
Exhibit A/Tab 4/Schedule 3
Exhibit A/Tab 4/Schedule 1

Preamble:

Hydro One describes its general framework as a revenue cap index, of the form:

$$RR_t = RR_{t-1} \times (1 + RCI_t)$$

where

$$RCI_t = I_t - X + C_t$$

where

RR_t is the revenue requirement for period t
RCI_t is the revenue cap index for period t
I_t is the inflation (Input Price Index or IPI) for period t, as calculated and issued by the OEB
X is the productivity factor, composed on a base productivity X-factor and a stretch factor for further incented productivity gains, with the X set constant for all years at the outset of the plan
C_t is the capital factor, and is intended to compensate for the additional (incremental) in-service capital additions necessary and approved per the utility's capital system plan, beyond what is funded by the $I - X$ adjustment to the annual revenue requirement. The capital factor, proposed by Hydro One in this

application, based on previous OEB decisions, also includes an incremental capital stretch factor of 0.15%.

Both the Transmission plan documented in Exhibit A/4/2 and the Distribution plan documented in Exhibit A/4/3 use this formula.

As shown in Table 1 of each of Exhibit A/4/2 and Exhibit A/4/3, the RCI formula calculates the aggregate (in dollars) service requirement based on the prior year's approved service revenue requirement.

In traditional forms of revenue cap regulation, the revenue cap formula is often of the form:

$$RCI = I - X + G + other_{factors}$$

where

G is a measure of output growth (i.e., changes in the demand for the products and services of the firm by its customers).

The growth factor can by zero and, in revenue cap-like formulae that the OEB has approved in the past, the OEB has approved no growth factor or a value of zero for the growth factor.[1]

Question(s):

a) In line 13 of Table 1 for each of Exhibit A/Tab 4/Schedule 2 (for Transmission) and Exhibit A/Tab 4/Schedule 3 (for Distribution), regarding aggregate OM&A costs for each year from 2024 to 2027 the prior year's aggregate approved OM&A is multiplied by I -X to calculate the new rate year's aggregate OM&A. There is no adjustment for growth in economic demand (whether in customers, kWh or kW, or in some combination thereof). Is Hydro One proposing that OM&A costs are invariant to scale impacts? Please explain your response.

b) Please confirm that, for each of the Transmission and Distribution System Plans, the capital additions to rate base in each year would include capital to accommodate growth in customers, consumption (kWh) or energy demand (kW). In the alternative, please explain your response.

c) If the response to b) is confirmed, please confirm that the absence of a growth factor means that the C-factor (the capital factor) also recovers growth-related

[1] EB-2019-0082, etc.

capital additions. In other words, please confirm that the C-factor operates differently than the determination of eligible incremental capital funding per the OEB's policy on Capital Funding Options, where growth is factored into the materiality threshold for determining the amount of capex funded by price cap-adjusted rates.[2]

A-Staff-7

Exhibit A/Tab 4/Schedule 2/pp. 5-6/Tables 1, 2, 3
Exhibit A/Tab 4/Schedule 3/pp. 5-6/Tables 1, 2, 3

Preamble:

Hydro One has provided Tables 1, 2 and 3 in each of Exhibit A/Tab 4/Schedule 2, for the Transmission Custom Plan, and Exhibit A/Tab 4/Schedule 3, for the Distribution Custom Plan. These tables summarize the following information pertaining to the proposed Transmission and Distribution Custom plans:

- For Table 1, the derivation of the Total (Service) Revenue Requirement from a Cost of Service perspective, with incorporation of the inflation, productivity, and incremental capital stretch factor for each of the 2024 to 2027 years.
- For Table 2, the values of inflation (I), productivity (X), the custom Capital factor (C), and the Revenue Cap Index (RCI) for the years .
- Table 3 demonstrates that, for each year from 2024 to 2027, the Total Revenue Requirement (from Line 14 of Table 1) is calculated as (1+RCI) multiplied by the prior year's Total Revenue Requirement.

These tables were provided in the PDF document, and without showing the calculations.

Question(s):

a) For the Transmission Custom Plan documented in Exhibit A/Tab 4/Schedule 2, please provide an Microsoft Excel version of Tables 1, 2 and 3, showing all of the calculations. These calculations should also show the calculations between the tables (i.e., how the entries in Tables 2 and 3 are calculated from the data in Table 1.

[2] EB-2014-0219, *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB: New Policy Options for the Funding of Capital Investments - Supplemental Report*, January 22, 2016

b) With respect to the Transmission Custom Plan, please provide the following:

i. Please confirm that, for 2024 through 2027, the Transmission revenue requirement is calculated solely and completely through rows labelled 1 through 14 (i.e., that rows 15 through 18 of Table 1 and Tables 2 and 3 do not provide any additional reductions or additions to the Transmission revenue requirement that is to be recovered for each year). If not, please explain.

ii. Please confirm that the RCI value for each rate year is calculated as the annual percentage change of the revenue requirement in the year relative to the previous year's revenue requirement, as shown in labelled row 14 of Table 1.

iii. Table 2 of Exhibit A/4/2 shows the relationship of parameters such that $RCI = I - X + C$, and the proposed and calculated values for each year. However, I is exogenously derived, and will be updated annually, with Hydro One using the OEB-issued 2021 transmission inflation factor of 2.0% in the application, X will be set for the plan term, and Hydro One is using the proposed 0% for now, and RCI is derived as the annual percentage change in the revenue requirement in Row 14 of Table 1, so the only unknown is the capital factor C. The formula above can be rearranged in order to calculate C as $C = RCI - (I - X)$. Please confirm that the purpose of the C factor is to ensure pass-through, subject to the capital productivity target of 0.15%, of the incremental revenue requirement, associated with capital additions each year per the TSP as approved by the OEB, that are not funded through the $I - X$ adjustment of the prior year's revenue requirement.

c) For the Distribution Custom Plan documented in Exhibit A/Tab 4/Schedule 3, please provide an Microsoft Excel version of Tables 1, 2 and 3, showing all of the calculations. These calculations should also show the calculations between the tables (i.e., how the entries in Tables 2 and 3 are calculated from the data in Table 1.

d) With respect to the Distribution Custom Plan, please provide the following:

i. Please confirm that, for 2024 through 2027, the Distribution revenue requirement is calculated solely and completely through rows labelled 1 through 14 (i.e., that rows 15 through 18 of Table 1 and Tables 2 and 3 do not provide any additional reductions or additions to the Distribution revenue requirement that is to be recovered for each year). If not, please explain.

ii. Please confirm that the RCI value for each rate year is calculated as the annual percentage change of the revenue requirement in the year relative to the previous year's revenue requirement, as shown in labelled row 14 of Table 1.

iii. Table 2 of Exhibit A/4/3 shows the relationship of parameters such that $RCI = I - X + C$, and the proposed and calculated values for each year. However, I is exogenously derived, and will be updated annually, with Hydro One using the OEB-issued 2021 distribution inflation factor of 2.2% in the application, X will be set for the plan term, and Hydro One is using the proposed 0% for now, and RCI is derived as the annual percentage change in the revenue requirement in Row 14 of Table 1, so the only unknown is the capital factor C. The formula above can be rearranged in order to calculate C as $C = RCI - (I - X)$. Please confirm that the purpose of the C factor is to ensure pass-through, subject to the stretch factor of 0.3% and the capital productivity target of 0.15% (i.e., 0.45% = 0.3% +0.15%), of the incremental revenue requirement, associated with capital additions each year per the DSP as approved by the OEB, that are not funded through the I – X adjustment of the prior year's revenue requirement.

e) For both the Transmission and Distribution Custom plans, in Table 1, row 11 is labelled "Less Removing Working Capital from Capital Factor". In Line 11 of Table 1 of the Transmission Custom plan, the cell entries for 2024 through 2027 are shown as negatives and are added, along with rows 9 and 10, also shown as negatives, to row 8, "Total Capital Related Revenue Requirement (excluding working capital)" to form row 12, "Total Capital Related Revenue Requirement (excluding working capital and Productivity)". Row 12 is then added to Row 13, "OM&A" adjusted by $I - X$, to form the total revenue requirement in line 14.

The same lines and formula are also used in lines 8 to 14 of Table 1 of the Distribution Custom plan. However, OEB staff note that the entries in line 11 in Table 1 of the Distribution Custom plan are shown as positive (while the entries in lines 9 and 10 are negative).

i. Please confirm that the entries in line 11 of Table 1 of the Distribution plan should be shown as negative entries, as they are in line 11 of Table 1 of the Transmission Custom plan.

ii. Please confirm that the Distribution revenue requirement is overstated as a result of the Adjustment for Working Capital being added as a positive entry, and that the overstatement effectively doubles the value shown in line 11 for each year. Specifically, please confirm or correct the entries in the following table:

($ Million)

Year	2023	2024	2025	2026	2027
Dx Revenue Requirement (as shown in A/4/3/Table 1)	1632.4	1711.3	1785.1	1881.1	1965.0
Dx Revenue Requirement (with Line 11 entries shown as negative)	1632.4	1711.0	1784.3	1879.9	1963.3
Difference	0.0	0.3	0.8	1.2	1.7

iii. Please confirm that this overstatement has been passed through on other models and tables in Hydro One's application for the distribution rate plan. For example, for the rates for 2024 through 2027, as shown in Exhibit L/Tab 2/Schedule 1/Attachment 1/Sheets "2024", "2025", "2026" and "2027", use the revenue requirements shown on line 14 as the service revenue requirement for each year. These revenue requirements are shown as the "Total" under column "Allocated Cost" (Column D for "2024", "2025", "2026" and "2027" of Exhibit L/Tab 2/Schedule 1/Attachment 1).

A-Staff-8

Exhibit A / Tab 4 / Schedule 1 / p. 1
Exhibit A / Tab 4 / Schedule 2 / pp. 5-6 / Tables 1, 2, 3
Exhibit A / Tab 4 / Schedule 3 / pp. 5-6 / Tables 1, 2, 3

Preamble:

As documented in Exhibit A/Tab 4/Schedule 1, Hydro One has proposed a common "revenue cap index" approach applicable for both the transmission and distribution Custom Plans, of the form:

$$RCI = I - X + C$$

This is similar to a traditional price cap formula, or a revenue cap formula excluding growth (g). The inflation (I) and productivity (X) factors are derived from external data. In general, the price cap and revenue cap formulae can be derived conceptually from economic principles based on primary drivers of market forces on prices for all firms, specifically the majority of firms operating in competitive markets.

The added component in Hydro One's formula is the Capital (C) factor. OEB staff's analysis of Tables 1, 2 and 3 of each of Exhibit A/Tab 4/Schedule 2, for the Transmission plan, and Exhibit A/Tab 4/Schedule 3 for the Distribution plan, indicates that the C-factor acts to ensure pass-through (i.e., recovery through rates), subject to the incremental capital productivity target, of the incremental revenue requirement associated with capital additions each year per the approved capital plan, that are not funded through the $I - X$ adjustment of the prior year's revenue requirement.

Question(s):

a) Please provide the theoretical derivation of the C factor from economic first principles as it would relate to the drivers of price movements that firms operating in competitive markets face.

<u>A-Staff-9</u>
Exhibit A / Tab 1 / Schedule 1 / Attachment 1

Preamble:

Hydro One's consultant, Mr. Steve Fenrick of Clearspring Energy Advisors (Clearspring), has filed evidence in several proceedings on behalf of Ontario electricity utilities (transmitters and distributors). Going back to Hydro One's last distribution Custom IR plan, Mr. Fenrick has filed evidence in the following:

- EB-2017-0049 – Hydro One Distribution 2018-2022 Custom IR
- EB-2018-0165 – Toronto Hydro Electric System Limited 2020-2024 Custom IR
- EB-2018-0280 – Hydro One Sault Ste. Marie Revenue 2020-2024 Cap Plan and EB-2019-0082 – Hydro One Transmission 2020-2022 Custom IR
- EB-2019-0261 – Hydro Ottawa 2021-2025 Custom IR

OEB staff have prepared a spreadsheet (attached) with two tables. The first table, labeled "Tx_Sample", shows the U.S. and Canadian utilities that Power Systems

Engineering (PSE)/Clearspring has used in its Transmission analyses for the EB-2018-0082 application and the current application, and also identifies which utilities are included in the TFP and the total cost benchmarking analyses.

The second table, labeled “Dx_Sample”, shows the U.S. and Canadian utilities as used in the previous Hydro One Distribution case (EB-2017-0049) and the Toronto Hydro and Hydro Ottawa cases, and the current application. The distribution analyses are specifically for total cost benchmarking.

Question(s):

a) Please confirm the entries in the spreadsheet.

b) In the Transmission TFP study filed in this case, Clearspring has calculated the TFP on the sample of U.S. utilities only, and has excluded Hydro One from the sample. In the TFP analyses filed in PSE’s previous evidence filed in the EB-2018-0280 and EB-2019-0082 cases for Hydro One Sault Ste. Marie and Hydro One Transmission, Hydro One was included in the sample. Please explain why Clearspring has excluded Hydro One from the Transmission TFP analysis in its evidence filed in this proceeding.

c) In EB-2017-0049, PSE included a large sample of U.S. cooperative utilities in its U.S. sample for comparing against Hydro One’s distribution operations in the cost benchmarking analysis, but has only included U.S. Investor-owned Utilities (IOUs) who file FERC Form 1 data in its distribution cost benchmarking analysis in the current case. Please explain Clearspring’s reasons for dropping U.S. rural cooperatives from its distribution utility sample in this case.

d) In EB-2019-0261, Clearspring included Hydro One, along with a few other Ontario electricity distributors, in addition to U.S. distributors, as comparators for Hydro Ottawa in the cost benchmarking analysis. Please explain why Clearspring has excluded Hydro Ottawa from the cost benchmarking analysis of Hydro One distribution in its evidence filed in this application.

A-Staff-10
Exhibit A / Tab 1 / Schedule 1 / Attachment 1 / p. 17 of 84

Preamble:

One change that Clearspring notes that it has made to the Transmission Cost Benchmarking model is to replace transmission substation capacity with number of transmission substations:

> The final modification from the prior model specification for the transmission total cost model is using the "number of transmission substations" variable instead of the "transmission substation capacity" variable. This change is due to the substation capacity variable coming in with the correct sign but statistically insignificant, whereas the number of transmission substations variable does come in correctly signed and statistically significant at a 90% confidence level.

Question(s):

a) Does Clearspring have any conceptual basis on which it considers the number of transmission substations to be preferable to transmission substation capacity? Please explain your response.

b) Is the change to number of transmission substations from transmission substation capacity solely based on the statistical significance of the coefficient estimate? Was this relationship consistent across different model and variable specifications that Clearspring tried during its model analysis?

c) Are there other variables retained in either of the Transmission or Distribution Cost Benchmarking models which were selected solely on the basis of statistical significance (i.e., having a higher t-statistic in absolute terms) compared to alternatives, conditional on exhibiting the corrected expected coefficient sign. If so, please identify all such variables.

A-Staff-11

Exhibit A / Tab 1 / Schedule 1 / Attachment 1 / pp.10, 25, 58 of 84

Preamble:

> Clearspring notes that it has added a binary variable that it labels the "ISO variable", stating on page 25 of 84: The Independent System Operator (ISO) variable indicates if the utility was operating under an ISO or Regional Transmission Operator (RTO) in the observed year. This variable is a binary variable that will equal "1" if in the observed year the

utility is in an ISO or RTO and will equal “0” if this is not the case. We do not have an a priori expectation of the variable sign. While the ISO may take on some planning costs that the utility would have engaged in otherwise, the transmission utility may still be required to undertake some planning costs as well as added investments that the ISO may request to encourage a more efficient energy market. In the model, we find that the ISO parameter estimate is positive, indicating a positive relationship between being in an ISO and transmission total costs.

On page 6 (page 10 of 84) of its evidence, Clearspring states the following in footnote 13:[3]

> 13 As discussed in Section 6, there may be good reasons for this decline in industry TFP. Increasing but unmeasured outputs such as increased reliability, cybersecurity, environmental, DER connections, geomagnetic protections, and other well-intentioned regulations may be placing higher requirements and cost challenges on utilities, without increasing the measured output growth that impacts TFP trends.

Question(s):

a) Does Clearspring not consider that some of the “[i]ncreasing but unmeasured outputs such as increased reliability, cybersecurity, environmental, DER connections … [etc.]” faced by transmission utilities and that place higher requirements and cost pressures on them are due to oversight by their respective RTOs/ISOs? This is not to say that the RTO or ISO is the sole decision maker for these requirements, which ultimately may be due to changes in law and legislation, technology, or other societal requirements, but the RTO/ISO ensures adherence by the utilities it oversees to these new and increased requirements as part of its responsibilities.

b) If the response to a) is in the positive, then please explain why Clearspring had no *a priori* expectation of the sign of the ISO variable.

c) In Ontario, the ISO, the Independent Electricity System Operator (IESO), and Hydro One were both formed on April 1, 1999 as a result of the break-up of the former Ontario Hydro, which previously performed all such functions. Does Clearspring consider that the formation of Hydro One and the IESO is different from, and as a result, has resulted in a different working relationship between

[3] Clearspring also lists these factors under bullet 1 on page 54 (page 58 of 84) of its evidence under the topic of transmission TFP.

Hydro One and the IESO,from the situation for U.S. transmitters with their RTOs/ISOs? Please explain your response.

d) Did Clearspring consider any approaches for adjusting for these "increasing but unmeasured outputs" in its transmission TFP and cost benchmarking analyses, such as constructing and using hedonic price indices? Please explain your response.

A-Staff-12

Exhibit A / Tab 1 / Schedule 1 / Attachment 1 / p. 38 (p. 42 of 84)

Preamble:

On page 38 of its report, Clearspring provides its views on the reasonableness of the differences in the cost benchmarking rankings between Hydro One's transmission and distribution scores.

Clearspring states:

> At a high level, Hydro One's transmission system is more similar to its peers and the benchmarking sample than the distribution system is with no available distribution model variables to adjust for this dissimilarity. The transmission system is vast and transmits electricity to rural, municipal, and urban centers. This is similar to many of the transmission utilities in the sample. However, Hydro One's distribution system is unique in serving remote areas, the density of its service territory, and having most of the lower-cost municipal and suburban areas not included within its service territory. This leaves Hydro One with the much higher-cost rural territories to which the Company is required to deliver electricity. This contrasts with its sampled peers whose service territories do include these lower cost suburban areas. Since Hydro One is the only utility with this disadvantage, we cannot develop a variable to adjust for this service territory condition present on the distribution system. Given this reality, we would expect the Company's transmission operations to score better than its distribution operations.

Question(s):

a) Please provide Clearspring's definition of "remote" in stating that Hydro One "is unique in serving remote areas".

b) Please identify what remote areas that Clearspring understands that Hydro One distribution serves, as opposed to isolated communities in Remote Northern Ontario that are service by Hydro One Remote Communities, an affiliate of Hydro One.

c) OEB staff understands that Clearspring is contending that another aspect of Hydro One Distribution's uniqueness is in "having most of the lower-cost municipal and suburban areas not included within its service territory". In EB-2019-0261, Clearspring was aware that Hydro One serves areas within the City of Ottawa.

   i. Please confirm whether Clearspring is aware of Hydro One's acquisition of former municipal electrical utilities, serving some cities, towns of various sizes and outlying areas, involving over 90 MAADs applications reviewed and approved by the OEB, from late 1999 to date.

   ii. For some cities in Ontario, such as Windsor, Kingston and London, Hydro One serves the areas outside of the city boundaries, and thus is the distributor serving residential and commercial subdivision expansion beyond the city boundaries. This is in addition to the service areas of former municipal distributors acquired over the past two decades. On what basis does Clearspring consider that Hydro One does not have a growing portion of its customer base in "lower-cost municipal and suburban areas".

   iii. Can Clearspring identify how Hydro One's distribution service area is "unique" in comparison to the service areas of some of the utilities in its U.S. sample, such a Green Mountain Power, Minnesota Power, Black Hills Power and Monongahela Power Company.

<u>A-Staff-13</u>
Exhibit A / Tab 6 / Schedule 1 / p. 3

Preamble:

Hydro One Limited was granted exemptive relief by the Ontario Securities Commission (OSC) to prepare financial statements under US GAAP. The exemptive relief is to remain in effect for a period of time under certain conditions[4].

Question(s):

a) How has Hydro One evaluated and planned for any changes to the OSC exemptive relief going forward, when the relief may no longer be in effect? Please explain Hydro One's plan, including any work that has been undertaken to quantify the transitionary impacts of the initial adoption of IFRS for external reporting and disclosure purposes.

b) If/when the exemptive relief is no longer in effect, the OSC may require Hydro One to prepare its financial statements under IFRS. Does Hydro One have any views on the likelihood of this? If so, please comment.

c) If the OEB and OSC required Hydro One to prepare its regulatory/ external financial statements under MIFRS/IFRS, would Hydro One still be mandated to prepare its financial statements under US GAAP for other purposes?

    i. If so, please explain what the other purposes would be.

d) Per the Public Accounts of Ontario's Annual Report and Consolidated Financial Statements[5], under Principles of Consolidation, it states "The activities of GBEs are recorded in the financial statements based on their results prepared in accordance with International Financial Reporting Standards (IFRS) using the modified equity method." Please explain whether Hydro One prepares financial statements in accordance with IFRS for the purpose of consolidating with the Province.

    i. Please explain if Hydro One prepares its financial statements in accordance with IFRS for any other purposes. If so, please explain what the other purposes would be.

[4] Exemption is no longer effective at the earlier of (i) January 1, 2024; (ii) the first day of Hydro One Limited's financial year that commences after Hydro One Limited ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation

[5] Page 62 of the 2020-2021 Report, https://www.ontario.ca/page/public-accounts-2020-21-consolidated-financial-statements#section-2

ii. Please explain to what extent Hydro One prepares its financial statements in accordance with IFRS (e.g. financial statements fully under IFRS or a reconciliation of USGAAP to IFRS).

e) If the OEB required Hydro One to adopt MIFRS effective January 1, 2023, would Hydro One be able to update its test period revenue requirements to reflect MIFRS?

i. Please explain what would be required for Hydro One to do so.

ii. Please quantify the annual revenue requirement impact in the test period if Hydro One were to adopt MIFRS effective January 1, 2023.

A-Staff-14
Exhibit A / Tab 6 / Schedule 1 / pp. 5-8 and Attachment 1
EB-2011-0268 / Decision and Order / November 23, 2011 / pp. 11-12
EB-2013-0416 / Exhibit A / Tab 13 / Schedule 1 / Attachment 1 – 2012 Annual Report/ p. 43

Preamble:

Regarding the IFRS Transition Analysis, PwC concluded that for Hydro One to transition to IFRS, the implementation costs would be significant and there would be ongoing maintenance costs incurred. Note that the page numbers referenced in the PwC Report below refer to the page number on the bottom right corner of the page.

Questions:

a) Page 15 of the PwC Report provides two approaches in which Hydro One can convert to IFRS (i.e. all reporting or regulatory reporting only). Please provide Hydro One's estimate of the potential implementation costs and maintenance costs under the two approaches.

i. Page 8 of the PwC Report, #5 states that costs incurred to convert to IFRS would be significant and would need to be recovered through rates. In the Decision and Order that approved Hydro One's use of US GAAP at the second reference above, the OEB stated "The Board further notes that it has articulated its policy with respect to the costs of two transitions in the Addendum Report, which clarifies that the costs of two transitions may not be recoverable from ratepayers. The Board therefore considers the risk of additional costs being recovered from ratepayers due to two transitions to be minimal." Please comment on Hydro One's view on cost recovery of implementation and maintenance costs given the OEB's finding in the referenced decision.

ii. Please comment on how the ongoing maintenance costs under IFRS would differ from the ongoing maintenance costs currently incurred under USGAAP.

b) Page 19 of the PwC Report states that under IFRS, there would be a fundamental change required to Hydro One's planning process in order to accommodate planning its capital planning at the component level. Please further elaborate on how capital planning is affected by converting to IFRS. In particular, please confirm that Hydro One's overall capital planning needs would not be driven by a change in reporting standard. If not confirmed, please explain.

c) In section 4 of the PwC Report, there is discussion provided on the impacts to workstreams and reporting activities. Please discuss how Hydro One's past transition from Canadian GAAP to US GAAP compares to the impacts discussed in section 4 of the PwC Report (e.g. were there similar impacts to workstreams and reporting activities).

d) Page 43 of Hydro One's 2012 Annual Report states the following:

> Accordingly, by mid-2011, we had substantively completed our four-phase IFRS Conversion Project…As a result of our 2011 decision to adopt US GAAP, our IFRS Conversion Project efforts were effectively halted. However, our IFRS conversion work has been, and will continue to be, managed in such a way that it can effectively be restarted if a future transition to IFRS is required…Our new financial systems were designed with maximum flexibility given the uncertainty of the outcome of certain impactive IASB projects. Our financial systems have the ability and capacity to handle current accounting and reporting processes in accordance with IFRS, should that be required in the future.

i. As part of PwC's analysis, please explain whether PwC considered the previous work performed in the IFRS Conversion Project and the flexibility of financial systems.

ii. Please explain whether Hydro One would be able to leverage the work previously completed as part of the IFRS Conversion Project as referenced above. If not, please explain why not.

iii. If Hydro One is able to leverage the work previously completed as part of the IFRS Conversion Project, please discuss the amount of incremental work that would still be required to complete the transition to IFRS.

A-Staff-15

Exhibit A / Tab 6 / Schedule 1 / pp. 5-8 and Attachment 1
Exhibit E / Tab 9 / Schedule 2 / Attachment 2A

Preamble:

Page 8 of the PwC Report in Attachment 1 states:

> Subsequent to the adoption of IFRS, using the 2023 forecasted year, there could be up to $208 million of common corporate costs that would be recorded as period expenses to be recovered in the company's annual revenue requirement. Should accounting processes be amended and updated as described above, there could be specific components within these cost categories that may meet the criteria under IFRS to be directly charged to specific capital projects, thereby reducing the impact to revenue requirement. Furthermore, if the OEB maintains the same ratemaking framework and guidance described in the 2007 Handbook outlined above, agnostic to the accounting framework, we would not expect a significant impact, if any to future revenue requirements in respect of Common Corporate Costs at Hydro One.

Question(s):

a) Please clarify whether the $208 million of common corporate costs represents the total 2023 common corporate costs that have been capitalized under USGAAP in the current application or total 2023 common corporate costs (i.e. OM&A and capital).

   i. Please explain how the $208 million of corporate costs correlate to the $135.9 million ($72.6 million for Transmission, $63.3 million for Distribution) shown as capitalized overhead in the reconciliation of accounting to tax additions.

ii. Please provide the amounts of common corporate costs that have been capitalized in this application, in accordance with USGAAP for each year from 2023 to 2027.

b) Under IFRS, administration and other general overhead costs are explicitly prohibited from capitalization. Please clarify and explain whether the entire $208 million of common corporate costs would be considered administration and other general overhead costs, and therefore, prohibited from capitalization under IFRS.

i. The quote referenced above states that specific components with these cost categories may meet the criteria under IFRS to be directly charged to specific capital projects. Please provide further details and examples of specific components of common corporate costs that may meet the criteria under IFRS to be charged to specific capital projects.

ii. Please provide the net amount relating to the $208 million for 2023, and the net annual amounts for 2024 to 2027, that would no longer be allowed to be capitalized under IFRS (i.e. after considering any specific components that may meet the criteria under IFRS to be charged to specific capital projects) when compared to USGAAP.

c) Please clarify whether Hydro One has other costs beyond common corporate costs that would qualify as administration and other general overhead costs that are prohibited to be capitalized under IFRS. If so, please quantify the annual amounts for 2023 to 2027.

d) The quote referenced above states that if the OEB maintains the ratemaking framework described in the 2007 Handbook, a significant impact would not be expected to future revenue requirement relating to common corporate costs. On page 5 of the PwC Report, it states that the 2012 Handbook would be applicable to Hydro One in the event that it adopts IFRS for regulatory reporting. Please clarify why a comparison was made to the 2007 Handbook when it would not be applicable if Hydro One adopted IFRS for regulatory reporting.

i. Please explain whether a significant impact would be expected if the 2012 Handbook is applied to Hydro One's revenue requirement, and whether the impact would be the up to $208 million of common corporate costs that could be expensed. If not confirmed, please quantify the impact.

ii. Further to the above, page 8 of the first reference indicates that there would not be a significant difference in the overall recognition and measurement of common corporate costs or other costs. Please clarify if the reference to other costs is to mean all other OM&A costs or certain specific costs. If the latter, please explain the specific costs.

iii. Please clarify it the statement regarding other costs in part ii above results from a comparison of costs to the 2007 or 2012 Handbook.

A-Staff-16
Exhibit A / Tab 6 / Schedule 1 / Attachment 1

Preamble:

Page 9 of the PwC Report lists areas where there are potential differences between US GAAP and IFRS. On page 10, under the section MIFRS and IFRS 14, it states "While presentation and disclosures differences are identified, the application of IFRS 14 would act to reduce revenue requirement differences when reporting in accordance with IFRS." Page 9 indicates that IFRS 14 permits entities to continue to apply their previous GAAP accounting policies for the recognition, measurement, impairment and derecognition of regulatory deferral accounts.

Question(s):

a) Please explain the above referenced statement and explain how IFRS 14 would act to reduce revenue requirement differences as regulatory assets and liabilities are not a direct line item in revenue requirement.

A-Staff-17
Exhibit A / Tab 6 / Schedule 1 / pp. 5-8 and Attachment 1

Preamble:

Page 20 of the PwC Report in Attachment 1 states that under USGAAP certain leases are accounted for as operating leases. For revenue requirement and regulatory purposes, Hydro One treats lease costs as operating leases.

Question(s):

a) Please clarify whether the above statement means that Hydro One may account for leases differently for external and regulatory reporting purposes (e.g. treats certain leases as finance leases for external reporting purposes, but treats all leases as operating leases for regulatory purposes).

b) If part a above is confirmed, please explain why there is a misalignment in lease treatments between external reporting and regulatory reporting purposes.

c) For any leases requested for recovery in this application, where there is such a misalignment, please quantify the revenue requirement impact for i) the difference between the current amount included for recovery and the amount that would be included for recovery if the leases were treated on the same basis as external reporting purposes, and ii) any cumulative revenue requirement transition impact at December 31, 2022 for any leases that were included in a prior application and continues to exist in the current application.

A-Staff-18
Exhibit A / Tab 6 / Schedule 1 / p. 11
Exhibit A / Tab 6 / Schedule 2 / Attachment 1 and 3

Preamble:

Hydro One early adopted ASU 2018-15 on April 1, 2019. The ASU allows Hydro One to capitalize implementation costs on hosting arrangements that is a service contract.

Question(s):

a) In Hydro One Transmission and Distribution's 2019 audited financial statements, it is indicated that the adoption of ASU 2018-15 was applied prospectively and there was no material impact on adoption. Please quantify the cumulative amount of implementation costs that have been capitalized in the 2023 test year as a result of the adoption of ASU 2018-15.

b) Please explain whether any of the amounts quantified in part a, above, have previously been recovered as OM&A in a prior rate application. If so, please explain why Hydro One is requesting for recovery for these amounts again.

c) Please provide the amounts that have been capitalized each year from 2023 to 2027, that would previously had been expensed prior to the adoption of ASU 2018-15.

A-Staff-19
Exhibit A / Tab 6 / Schedule 1 / p.10 and Attachment 1
Exhibit A / Tab 6 / Schedule 2 / p.10 and Attachments 2, 4

Preamble:

Hydro One has discussed past changes in accounting policy. In the audited financial statements for Transmission and Distribution, new accounting pronouncements are discussed.

Question(s):

a) Please explain whether there is any new accounting standard(s) effective 2021 and beyond that will have an impact to Hydro One's test period revenue requirements.

b) If so, please identify and explain the new accounting standard(s) and its impact to Hydro One's application, including quantification of the revenue requirement impact.

A-Staff-20
Exhibit A / Tab 6 / Schedule 2 / Attachment 2 and 4

Preamble:

Under Note 2 of Hydro One Transmission and Distribution's 2020 audited financial statements, under Environmental Liabilities, it indicates that the Transmission and Distribution businesses' record a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment.

Under Asset Retirement Obligation, it indicates that the Transmission and Distribution businesses' asset retirement obligations recorded to date relates to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

Question(s):

a) Please confirm that the environmental liability referenced in the financial statements is referring to the expenditures to remediate past environmental contamination as discussed in Exhibit E / Tab 8 /Schedule 1 / p. 9, and is proposed for recovery under amortization expense. If not confirmed, please explain whether Hydro One is requesting recovery of environmental liabilities.

   i. If so, quantify the amount and reference the evidence that lays out Hydro One's proposed recovery for environmental liabilities.

b) Please explain whether Hydro One has requested recovery for asset retirement costs. If so, please quantify the amount and reference the evidence that lays out Hydro One's proposed recovery for asset retirement costs.

A-Staff-21

Exhibit A / Tab 6 / Schedule 4 / Attachment 2 and 4
Exhibit C / Tab 4 / Schedule 4 – Appendix 2-BA

Preamble:

In the first reference, Hydro One provides for an income statement reconciliation of regulatory financial results to audited financial statements. OEB staff notes that there are differences between the PP&E amounts as shown in Hydro One Transmission and Distribution 2020 audited financial statements (PP&E and Intangible Assets notes) and as shown in Appendix 2-BA. The differences are as follows.

		Transmission ($M)	Distribution ($M)
2020 Financial Statements			
	NBV PPE	$ 13,433	$ 8,092
	CWIP	$ (970)	$ 342
	Future Use Assets	$ (103)	$ (61)
	NBV Intangibles	$ 203	$ (150)
		$ 12,563	$ 8,223
Appendix 2-BA		$ 12,621	$ 8,056
Difference		$ 58	$ (167)

Question(s):

a) Please reconcile and explain the differences.

Customer Engagement

B-Staff-22

Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p. 11
Exhibit B / Tab 2 / Schedule 1 / Section 2.7 / p. 4
Exhibit B / Tab 2 / Schedule 1 / Section 2.9 / Attachment 1
Exhibit B / Tab 1 / Schedule 1 / Section 1.6 / p 9

Preamble:

> *As described in the IRG Report, key customer feedback from Phase 1 in respect of transmission included the following:*
>
> - *…*
> - *Most customers want Hydro One to make investments to improve power quality and reduce the number of momentary outages.*

The application also discusses the importance of power quality in noting "large industrial customers are a critical part of Ontario's economy and … transmission outages and issues can cause significant and costly interruptions to industrial processes and customer equipment." Hydro One also notes "the outcomes of the TSP align with the principles of the [Renewed Regulatory Framework] with the aim to achieve … outcomes" including "Customer Focus: maintaining and improving power quality, equipment availability and customer reliability".

The "Capital Projects Table" in the application identifies that Hydro One made $7.6 million in investments to improve power quality over the three-year 2018 to 2020 period and plans to invest $0 between 2023 and 2027.

Question(s):

a) Please provide a list of projects/programs with associated capital and/or OM&A costs, per year during the test period, that will positively impact power quality for transmission connected customers.

b) Given the importance Hydro One has placed on power quality for industrial customers in the application, please explain why Hydro One is planning $0 in investments to improve power quality over the five-year 2023 – 2027 test period.

B-Staff-23
Exhibit A / Tab 7 / Schedule 2 / Attachment 1
Exhibit B / Tab 3 / Schedule 1 / Section 11 / SS-04 p 5

Preamble:

ISD D-SS-04 outlines Hydro One's plans for station battery storage solutions to improve reliability for customers who experience long interruption durations.

> In cases where traditional solutions are unable to sufficiently improve reliability in a cost effective manner, battery storage is considered as a viable option to reduce supply interruption and improve reliability. Hydro One proposes to target 24 communities over the plan period.

Question(s):

a) Please reconcile the list of First Nation candidate communities for energy storage, on page 9 of the *First Nations Reliability Report 2021,* with *Appendix A: Reliability Data by First Nations Community* of the same report.

b) Page 9 of the *First Nations Reliability Report 2021* contains a list of 24 communities being considered for station battery solutions. How will Hydro One revise its investment plans if detailed studies find that 1 or more of the candidate communities are found to be unsuitable for station battery storage solutions?

Exhibit B – System Plans

Exhibit B-01 System Plan Framework

B1-Staff-24
Exhibit B / Tab 1 / Schedule 1 /Section 1.4 / pp. 3-4
Exhibit B / Tab 1 / Schedule 1 /Section 1.4 / Attachment 1 / p. 8

Preamble:

As stated on pages 3 through 4:

> Through the planning process, each of Hydro One's LOBs are asked to identify incremental productivity initiatives that can produce savings. In consultation with Finance, the LOBs are required to demonstrate that each proposed initiative has

an objective baseline as well as a defined and auditable measurement methodology.

Once these points are demonstrated, Finance works with initiative owners to validate specific planning assumptions in order to quantify demonstrable savings, and the LOBs are then asked to embed anticipated productivity improvements in the company's annual business plan and the associated investments. The embedded savings result in actual reductions in the costs required to achieve desired outcomes, which would otherwise not have been attainable if the initiatives were not identified.

Question(s):

a) Please provide the business cases produced by LOBs and Finance for the following incremental productivity initiatives identified in the chart on page 8 of Attachment 1.

   i. Move to Mobile / Distribution Optimization & Transformation
      a. Field Force
      b. Workforce Planning

   ii. Telematics, Fleet Telematics and Right-Sizing

   iii. Operations, Flexible Bill Window

   iv. Administrative, Corporate Common Head Count Reductions

B1-Staff-25

Exhibit B / Tab 1 / Schedule 1 /Section 1.4 / p 3
Exhibit B / Tab 1 / Schedule 1 /Section 1.4 / Attachment 1 / p. 3
Exhibit B / Tab 1 / Schedule 1 /Section 1.4 / Attachment 2 / pp. 23-24
Exhibit B / Tab 1 / Schedule 1 /Section 1.4 / Attachment 1 / p. 8

Preamble:

At the first reference above, the following statement is made:

> Through the planning process, each of Hydro One's LOBs are asked to identify incremental productivity initiatives that can produce savings. In consultation with Finance, the LOBs are required to demonstrate that each proposed initiative has

an objective baseline as well as a defined and auditable measurement methodology.

Attachment 1, page 3 states:

Capital: In 2018, Hydro One achieved $33.5 million in capital related productivity savings as compared to the $36.4 million previously forecasted in the Application. The main drivers for the lower productivity savings achieved are as follows:

- Hydro One achieved lower than planned savings in the Move to Mobile initiative due to higher than planned unit costs relative to the baseline; and

Attachment 2, page 23 through 24 states (page 21-22 of the report):

Criteria 7 – A productivity program drives benefits that can be considered true productivity gains
Concentric understands that the Productivity Framework itself does not incorporate capital costs incurred to achieve savings. Capital costs incurred to achieve savings (often referred to as "costs to achieve," or "CTAs"), are a common variable considered in savings analyses. For instance, following utility M&A activity, utilities are often provided the opportunity to recover CTAs (e.g., investments in IT) from customers to the extent they can show net savings. While Hydro One does not embed CTAs directly in its Productivity Framework calculations, it instead captures such costs in its business case analyses, from which Hydro One identifies and sets targets for many Productivity Framework initiatives.

Page 8 of Attachment 1 contains a chart (the chart) showing the filed and actual productivity initiative savings from projects from 2018 through 2022.

Question(s):

a) Explain in detail how the components of the productivity savings contained in the table were calculated.

b) If capital costs to implement the initiative were included in the chart, were the capital costs the
    i. Capital expenditures that occurred for the year,
    ii. the revenue requirement for the capital additions related to the project for that year,

iii. a net present value of the revenue requirements of the capital additions for the initiative, or
iv. another model?

c) Please add the following columns to the chart

2018A	2019A	2020A	2021B	2022P	Capital Investment	Cap Years	Dep Years
a	a	a	a	a	b	c	d

Populate the chart with the following:

i. Savings realized by the initiative in that year
ii. Total capital expenditures to implement the initiative
iii. Years in which the capital expenditures occurred, for example, 2016-2018 or 2018
iv. Depreciation time of the investment in years, or if multiple asset classes were invested in, the weighted average depreciation time of the assets in years.

If one capital project has been reflected in the chart through multiple row entries, the investment should be shown in one row, with the other rows referencing the spend elsewhere in the table.

B1-Staff-26

Exhibit B-1-1 / Section 1.6 / Overview: 2023-2027 Draft Investment Plan (Transmission System), p.30

Preamble:

The 2023-2027 Draft Investment Plan discusses “How Does Hydro One’s Transmission System Reliability Compare to Others?” and notes “Between 2014 and 2018, the typical Hydro One delivery point experienced about 60% fewer interruptions per year than the Canadian average. When it comes to the duration, the typical Hydro One delivery point has been interrupted for 55 minutes each year since 2014 — about 38 minutes less than the Canadian average.” It further notes “Over the past five years, failing equipment has been the biggest contributor to transmission system outages.”

Questions(s):

a) Please clarify the percentage contribution of failing equipment to transmission system outages over the past five years.

b) Please identify the duration and frequency of interruptions, for 2020, on the same basis as 55 minutes and 60% were derived relative to the “Canadian average”.

c) Please clarify what HONI used to represent the “typical” delivery point. Was it the average across 100% of delivery points? If not, please explain what HONI excluded, why those delivery points were excluded and provide the same comparison based on all delivery points.

d) In the TSP, the frequency of two types of outages -- momentary and sustained -- are addressed separately. What did HONI use to represent “interruptions” in this document? If one of those types was used, please use the other reliability measure in providing the same comparison.

e) Was the CEA Composite that was used in the TSP for comparison purposes used to represent the “Canadian average” in this document. If not, please explain why not and identify what was used.

B1-Staff-27

Exhibit B / Tab 1 / Schedule 1 / Section 1.1 / p. 15
Exhibit B / Tab 1 / Schedule 1 / Section 1.4 / p. 9
Exhibit B / Tab 1 / Schedule 1 / Section 1.4 / Attachment 1 / p. 11
Exhibit B / Tab 1 / Schedule 1 / Section 1.4 / Attachment 2

Preamble:

At the second reference, Hydro One states that:

> Hydro One has embedded $61.0M annually from 2023 to 2027, as outlined in Table 1 below, which represents the 2022 capital commitment in the last Transmission application. Once Hydro One is able to identify $61.0M worth of productivity savings, it expects that these savings will continue in the 2023-2027 period, consistent with the goal of finding sustained productivity improvements. As at the time of filing this application, approximately $36.0M of the $61.0M has been defined by way of specific productivity initiatives annually.

At page 22 of 36 at the fourth reference, Concentric states that “if the Company re-baselines its initiatives, it may be more challenging to continually find meaningful new initiatives that meet the rigorous standards of the Productivity Framework on a long-term basis."

Question(s):

a) Table 2 at the first reference includes a Progressive Productivity Placeholder category. Please explain why this is described as a "placeholder". When and how will the progressive productivity value be finalized?

b) Please identify the $36 million of specific productivity initiatives that have been identified.

c) Please provide the documents (business cases) produced by LOBs and Finance for the following incremental productivity initiatives identified in the table on page 11 of Attachment 1.
   i. Capital, Operations, Fleet Telematics and Right-Sizing
   ii. Capital, Operations, Procurement
   iii. OM&A / External Revenue, Information Technology, Contract Reductions
   iv. OM&A / External Revenue, Facilities and Real Estate, Secondary Land Use Revenue
   v. CCC, Corporate, Corporate Initiatives

d) Please comment on how Hydro One intends to address the challenge identified by Concentric of continually finding meaningful new initiatives on a long-term basis.

<u>Exhibit B-02 Transmission System Plan</u>

<u>B2-Staff-28</u>
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p.2

Preamble:

At the above reference, Hydro One states that "The proposed System Service and System Access investments are non-discretionary and account for 10% of the total capital plan."

Question(s):

a) Please explain why the proposed System Service and System Access investments are non-discretionary.
b) Please comment on whether Hydro One has discretion regarding how it implements a System Service or System Access request.
c) Please explain how Hydro One will ensure System Service and System Access expenditures will be incurred prudently.

B2-Staff-29
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / pp.2-3

Preamble:

At the above reference, Hydro One states that:

> The TSP investments target the most pressing needs (based on asset condition, criticality, performance, etc.) at a pace that maintains the population of deteriorated assets at a manageable level or avoids a material negative impact on system operations and reliability.
> System Renewal investments have been reasonably paced to address assets that are in poor condition, have inadequate performance or are obsolete including 3.3% of the transformer fleet per year, 2.5% of the breaker fleet, 3.4% of the protection fleet per year, 1.1% of the conductor fleet per year, 3.3% of the insulator fleet per year, 2.7% of the wood pole fleet, and to coat 1.0% of the steel structure fleet per year to extend their useful life.

Question(s):

a) What is “a manageable level of deteriorated assets”? Is this level the same for every asset type (i.e. transformers, breakers, protection, etc.)? How is this level determined? How is the level of deteriorated assets managed?

b) What is a “material negative impact on system operations and reliability?”

B2-Staff-30
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p. 3
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p. 21-22

Preamble:

At the first reference, Hydro One states that "Notably, the unprecedented growth in the Windsor-Essex region of Southwest Ontario is expected to double the region's electricity demand in the next 5 years, requiring significant transmission reinforcements on Hydro One's system at the direction of the IESO."

At the second reference, Hydro One states that:

> The IESO has directed Hydro One to develop new 230 kV lines between Chatham and Lakeshore (West of Chatham) and Lambton and Chatham (West of London) because of unprecedented growth in the agricultural sector in the Windsor-Essex region of Southwest Ontario and the need to ensure the necessary bulk transfer capability to support growth in load and generation.

Question(s):

a) Please explain the IESO's authority to direct Hydro One to undertake transmission investments or provide clarification.

B2-Staff-31
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p. 4

Preamble:

At the above reference, Hydro One states with respect to Air Blast Circuit Breakers (ABCBs) that "By replacing ABCBs with modern technology, Hydro One ensures the integrity of provincial power flow, avoids generation bottlenecks and loss of production as well as secures import and export of electricity in and out Ontario."

Question(s):

a) How does replacing ABCBs avoid "generation bottlenecks"? What is the value of the bottlenecked generation?

b) How does replacing ABCBs avoid "loss of production"? What is the value of the lost production?

c) How does replacing ABCBs "secure import and export of electricity"?

B2-Staff-32
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.1 / pp. 4-5

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / p. 2

Preamble:

As identified in Table 1:

- Project T-SR-01 “Network Stations Asset Replacement”
- Project T-SR-02 “Air Blast Circuit Breaker (ABCB) Replacement”
- Project T-SR-03 “Connection Stations Asset Replacement”
- Project T-SR-04 to T-SR-08, T-SR-13, T-SR-17: “Transmission Line Components Refurbishment”

As indicated in Lines 11 to 17 in Section 2.2:

> Asset condition is generally categorized as “good”, “fair” or “poor”. Assets with no or out-dated condition data are categorized as “needing assessment”.
>
> I. Good: These assets are new or show minimal signs of deterioration.
> II. Fair: Assets that are experiencing deterioration and the condition of these assets is monitored for progression of further deterioration.
> III. Poor: Assets that have deteriorated to a point where they can no longer provide the intended functionality or service.

Question(s):

a) Regarding the Section 2.2 preamble, please explain the differences between Hydro One’s use of the following terms: *“poor condition”, “poor performing”, and “inadequate performance”*.

b) According to the definition above, “poor condition” assets can no longer provide the intended functionality or service. Please provide a table listing the total number of “poor condition” assets in the first column, and the number of “poor condition” assets that no longer provide the intended functionality or service in the second column.

    i. Please explain how Hydro One maintains reliability if a significant proportion of its assets have been assessed as being in the following condition: *“can no longer provide the intended functionality or service”*.

B2-Staff-33

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.1 / pg. 6

Preamble:

As stated in Lines 1 through 7:

> Through Hydro One's mature capital delivery process based on strong oversight and governance and an experienced execution organization (see TSP Section 2.10), Hydro One has the ability to carry out the proposed capital plan and continue its successful track record in executing capital investments. In this regard, Hydro One has demonstrated the ability to successfully deliver large capital work plans and reduce the variability of capital expenditures and in-service additions using a skilled internal workforce and qualified third-party contractors (see TSP Section 2.09 Attachment 2).

Question(s):

a) Please state whether it is Hydro One's standard practice to not make any further maintenance or refurbishment investments into assets that have passed their Expected Service Life ("ESL").

i. If this is not Hydro One's standard practice, please describe both from a policy perspective and using specific documented examples the circumstances under which Hydro One would continue to maintain or refurbish assets that have passed their ESL.

ii. Please provide the criteria or calculation methodology used by Hydro One to determine maximum funding available for ongoing maintenance or refurbishment of individual assets, and the asset age at which such investments should no longer be made.

iii. Please discuss the cost/benefit trade-off associated with replacement versus repair/refurbishment for equipment that is at or beyond ESL?

   a. Please provide specific examples of the estimated life extensions for assets that Hydro One has repaired or refurbished (for example, steel structures that have been recoated).

B2-Staff-34
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.1 / pp. 13-14

Preamble:

As stated in Lines 21 to 25 on pg. 13 and Lines 1 to 3 on pg. 14:

> Accordingly, Hydro One cannot wait for delivery point performance to deteriorate before undertaking required investments on dual supplied delivery points where a failure has occurred. Delivery point performance is a lagging indicator of asset condition and the impact of renewal investments (or the absence thereof) and cannot be used to drive future investment decisions. By the time reliability degradation manifests for dual-supplied delivery points, equipment performance would have already unacceptably worsened, with associated impact on customer delivery continuity, system operability, and public safety.

Question(s):

a) Please define asset “failure” as used in the above reference.

b) Please list the number of occurrences during the past five (5) years where dual supplied delivery points experienced simultaneous failures on both delivery paths.

c) Please contrast the anticipated reliability degradation for a dual-supplied delivery point if a single path experiences a failure versus if both delivery paths experience failures.

d) Please state how Hydro One assesses and quantifies the extent of reliability mitigation delivered by its renewal expenditures.

    i. Please provide detailed documentation of specific examples.

B2-Staff-35

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.1 / pg. 15 of 30

Preamble:

As identified in Table 4, regarding the OEB Investment Category *“Progressive Productivity” [table not provided in preamble].*

Question(s):

a) Regarding Table 4, has an escalation factor been applied to the annual progressive productivity savings?

    i. If yes, what is the escalation factor?
    ii. If not, please explain why not.

B2-Staff-36
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p. 18

Preamble:

At the above reference, Hydro One states that:

> System Renewal investments have been reasonably paced to predominantly address deteriorated assets including 3.3% of the transformer fleet per year, 2.5% of the breaker fleet, 3.4% of the protection fleet per year, 1.1% of the conductor fleet per year, 3.3% of the insulator fleet per year, 2.7% of the wood pole fleet per year, and to coat 1% of the steel structure fleet per year to extend their useful life.

Question(s):

a) In Hydro One's view, what constitutes a reasonable pace?

b) How is a reasonable pace determined for each asset category? For example, how has 3.3% of the transformer fleet per year been determined as a reasonable pace of renewal? How has 2.5% of the breaker fleet per year been determined as a reasonable pace of renewal, etc?

B2-Staff-37
EB-2019-0082 / Exhibit B / Tab 1 / Schedule 1 / Section 1.4 / Attachment 13
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / pp. 26-28

Question(s):

a) Please explain whether and how Hydro One has modified its asset analytics, asset risk assessment and reliability risk model frameworks since the assessment of these elements, dated May 8, 2018, was completed by METSCO and submitted as part of Hydro One's 2019 application.

B2-Staff-38
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.1 / pg. 29 of 30

Preamble:

As stated in Lines 5 to 6:

> Once candidate investments have been scored and flagged, enterprise-wide calibration sessions occur to ensure comparable and consistent evaluation across investments and lines of business.

Question(s):

a) Please define what activities occur during the *"enterprise-wide calibration sessions"* and provide detailed documentation pertaining to the specific sessions held when preparing the capital expenditure plans included in the present application. Documentation should include meeting agendas, meeting minutes, and any reports/spreadsheets and other quantified data and/or calculations supporting the deliverables produced during these sessions.

b) Please explain how Hydro One, within the context of the "enterprise-wide calibration sessions", compares investment programs with specific projects. In other words, how does Hydro One determine that the marginal value of the budgetary envelope for a specific investment program is comparable to the marginal value of a distinct project within that program?

c) Please explain how these sessions ensure standardized economic and risk scoring practices among the project and program portfolio candidates being evaluated and provide documentation of specific examples representing significant investments.

B2-Staff-39
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pp. 1-2

Preamble:

As stated in Lines 28 and 29 of pg. 1 and Lines 1 of pg. 2:

As the primary driver of replacement decisions, asset condition is verified through the asset risk assessment (ARA) process prior to any replacement being undertaken through investments.

Question(s):

a) Please confirm that asset condition is the primary driver for most asset replacement decisions made by Hydro One.

b) Are there asset types or classes for which asset condition is not the primary driver for asset replacement decisions?

   i) If yes, please identify these asset types or classes and the primary replacement driver(s) for these asset types or classes.

   ii) Please explain why asset condition is not the preferred primary driver in these cases.

B2-Staff-40
EB-2019-0082 Exhibit B / TSP Section 2.2 / p.3
Exhibit B / Tab 2 / Schedule 1 / Section 2.2 / pp. 2, 11, 24, 82, 91, 100, 124, 131, 137

Preamble:

Table 1 at the first reference summarizes the condition of major asset types using the following categories: Very Low Risk, Low Risk, Fair Risk, High Risk, Very High Risk, and To be Assessed.

At the second reference, Hydro One states that "Asset condition is generally categorized as "good", "fair" or "poor". Assets with no or out-dated condition data are categorized as "needing assessment"."

The following table assembles asset condition information from Section 2.2:

	Poor	Fair	Good	Needs Assessment
Transformers	198	74	449	-
Breakers	541	1510	2705	-
Overhead Conductor	3874	3329	13620	7728

Underground Cable	8	92	173	-
Wood Poles	4693	-	23866	11482
Rights-of-Way (hectares)	9110	13422	58987	-
Shieldwire Assets (circuit kms)	3105	7051	15644	8967
U-Bolt Assets (circuit structures)	2644	30651	11331	37446

Question(s):

a) Please provide the units for the overhead conductor condition shown in Figure 16 on page 82 at the second reference (and copied into the above table)?

b) Please provide the units for the underground cable condition shown in Figure 20 on page 91 at the second reference (and copied into the above table)?

c) Please state whether or not Hydro One still uses the Very Low Risk, Low Risk, Fair Risk, High Risk, Very High Risk, and To be Assessed asset condition categories for major assets? If yes, please complete the following table:

	Very Low Risk	Low Risk	Fair Risk	High Risk	Very High Risk	To Be Assessed
Transformers						
Breakers						
Overhead Conductor						
Underground Cable						
Wood Poles						
Rights-of-Way (hectares)						
Shieldwire Assets (circuit kms)						

U-Bolt Assets (circuit structures)						

d) If the answer to part a) is No, please explain why Hydro One has discontinued use of these categories.

e) If the answer to part a) is No, please state whether or not the Very Low Risk, Low Risk, Fair Risk, High Risk, Very High Risk, and To be Assessed asset condition categories have been replaced by the Poor, Fair and Good condition categories described in the second reference?

f) If the answer to part c) is Yes, why are these categories preferable?

g) Please state how the Very Low Risk, Low Risk, Fair Risk, High Risk, Very High Risk categories align with the Poor, Fair and Good condition categories used in the current application?

h) In Hydro One's view, do poor condition assets necessarily pose a high risk?

i) Table 1 at the first reference included information on protection system condition, which has not been provided in the current application. If this information is available, please provide it. If not, please explain why not.

B2-Staff-41
Exhibit B-2-1 / Section 2.2 / pp.28, 86, 104, 125, 132

Preamble:

There appears to be a relatively common trend throughout Hydro One's TSP related to the duration of outages getting longer over time including some instances where the frequency has declined over the years (with outlier years in some cases). For example:

- Figure 7: Circuit Breaker Forced Outage Duration
- Figure 19: Overhead Conductor Forced Outage Duration
- Figure 29: Forced Outage Duration due to Wood Pole Failures
- Figure 45: Duration of Vegetation Related Outages on Hydro One Circuits
- Figure 48: Duration of Shieldwire Related Outages

Question(s):

a) Please explain why this trend related to longer outage durations is occurring across a number of different types of transmission assets.

B2-Staff-42
Exhibit B-2-1 / Section 2.4 / pp.15, 16, 17

Preamble:

Hydro One has included charts in the application showing different measures of customer delivery point performance including the list set out below. Those charts provide performance at the provincial level. For regional planning purposes, 21 regions have been established for Ontario.

- Figure 6: Frequency of Momentary Interruption, Hydro One vs CEA Composite
- Figure 7: Frequency of Sustained Interruption, Hydro One vs CEA Composite
- Figure 8: Overall Frequency of Interruptions, Hydro One vs CEA Composite
- Figure 9: Average Duration of Interruption, Hydro One vs CEA Composite

Question(s):

a) Please revise the charts listed above as follows: (1) Hydro One provincial bars removed and (2) CEA Composite retained (as it is) and the following charted as lines in a manner that is the same as the CEA Composite – the three (3) regions with the worst delivery point performance and the three (3) regions with the best delivery point performance.

b) Please identify the entities that are currently included in the CEA Composite for the purpose of determining the "Canadian Transmission Utility average performance". Please also clarify if Hydro One remains included in the CEA Composite for the purpose of the benchmarking comparisons to Hydro One that are set out in this application.

B2-Staff-43
Exhibit B-2-1 / Section 2.4 / p.18
Exhibit A-3-1 / Attachment 1 / p.26

Preamble:

Hydro One's Business Plan states that "The TSP is targeting to maintain first quartile system reliability performance throughout the Plan". OEB staff notes there are two key charts in the application that benchmarks Hydro One's "system" reliability" against the "CEA 5 year moving average". Those charts are "Unavailability of Major Transmission Station Equipment" (Figure 12) and "Unavailability of Transmission Lines" (Figure 11).

- For Transmission Lines, with the exception of an improvement in 2020, the chart shows a significant and steady increase in unavailability from 2013 to 2019 for Hydro One (while the CEA average steadily improved until an uptick in 2019).

- For Major Transmission Station Equipment, except for 2013, the chart shows there was a similar material and steady increase in unavailability (while the CEA average steadily improved every year). Staff also notes Hydro One's highest unavailability was during the most recent three years (2018-2020) for Major Station Equipment.

Question(s):

a) Given the benchmarking results against the CEA composite discussed above, please explain the basis of this "first quartile" designation in relation to "system reliability".

b) In relation to unavailability of Major Transmission Station Equipment, according to Hydro One, "deterioration of this measure" is due to a combination of factors that include the following: (1) transformers were about to be retired and forced outages counted towards unavailability until they were decommissioned; (2) forced outages that occur just before a transformer replacement project causes the whole duration to be counted towards unavailability measures; and (3) repairs to capacitor banks and breakers are usually deferred for significant periods of time since their unavailability does not immediately impact the system. Please clarify the following:

    i. Did the same factors apply before the step jump in unavailability in 2018? For example, were repairs to capacitor banks and breakers also deferred in prior years?

    ii. Would those same factors not apply to other utilities in the CEA Composite? If not, please explain why Hydro One is different from other utilities across Canada.

B2-Staff-44
Exhibit B-2-1 / Section 2.4 / Attachment 2 / p.5

Preamble:

At the above reference, it is stated that:

> For Group Performance outliers, Hydro One's level of incremental investment for improving the performance of an outlier beyond what was designed originally will be limited to the present value of three years' worth of transformation and/or transmission line connection revenue associated with the delivery point. Any funding shortfalls for improving delivery point reliability performance will be contributed by affected delivery point customers.

OEB staff's understanding is that the limitation referenced above of "three years' worth of transformation and/or transmission line connection revenue" has been in place since Hydro One's CDPP standards document was initially prepared about 15 years ago.

Question(s):

a) Please clarify how three years of connection revenue was initially determined to be the appropriate approach to determine the amount the customer should not be responsible for paying.

b) Please identify if Hydro One has done any analysis since 2005 to ascertain if this results in an appropriate amount (i.e., aligns with beneficiary pay principle)? If so, please explain the results of Hydro One's analysis.

B2-Staff-45
Exhibit B-2-1 / Section 2.5 / p.3

Preamble:

At the above reference, it is noted that the percentage of outliers in 2020 increased by 0.5% (compared to 2019) and the performance trend is indicating an increase in the percentage of delivery point outliers. It is also noted that Hydro One's performance was better than target in each of the years 2018-2020, as shown in the table below.

Table 1 - CDPPS Outliers as Percentage of Total Delivery Points (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	13.0	12.0	11.7	
Actual	9.7	9.5	10.1	10.9	11.4	▲

It is further indicated that Hydro One's customer DP performance has steadily declined from 2016 to 2020 (9.7% to 11.4% outliers), with an average of 10.3% outliers over that five-year period. The application also provides the target for each year during the 2023-2027 test period which ranges from 11.5% to 10.2%. Hydro One is therefore targeting a declining percentage of outliers to 10.2% by 2027.

Question(s):

a) Based on OEB staff's calculations for the 2023-2027 test period, Hydro One's goal is targeting the percentage of outliers to average 10.6%. Please explain why Hydro One expects reduced reliability (i.e., higher percentage of outliers) for customers over the 2023-2027 test period relative to the historic five-year period average of 10.3%.

b) The application also notes "Hydro One's performance was better than target in each of the years 2018-2020." Staff notes that Hydro One's actual performance was 9.7% in 2016, which improved to 9.5% in 2017. Please clarify why Hydro One targeted a material reduction in customer reliability during 2018-2020, with an increase in outliers from below 10% to 13% in 2018 and then remaining relatively high in 2020 at 11.7%?

c) Hydro One notes that it is targeting a steady improvement in outliers over the 2023-2027 test period from 11% to 10.2%. However, there is no explanation of that improvement. Given the application notes "the performance trend is indicating an increase in the percentage of delivery point outliers", please explain how Hydro One expects to turn that trend around and achieve the referenced targeted decline in outliers.

B2-Staff-46

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.7 / pg. 8 of 12

Preamble:

As stated in Lines 4 to 9 of the above reference:

For each investment candidate, Hydro One assesses the amount of risk that is expected to be mitigated across three risk taxonomies as applicable – safety, reliability, and environmental. Each risk taxonomy features clear definitions and a consistent approach to permit a proper assessment of the risk mitigated for each candidate investment. The assessment considers both the probability and consequence of an event materializing, relying on historical data, condition information and experience to the extent possible and taking into account the risk mitigated by each candidate investment through the comparison of the risk profile pre and post investment.

Question(s):

a) Please confirm that the failure probabilities used by Hydro One to calculate asset-related risks are directly correlated to the consequences used in the risk calculations for those asset classes. For example, when calculating risk, if the consequence is derived assuming peak loading conditions, then the probability that should be used to calculate the associated risk is the chance of failure occurring during peak loading conditions (i.e., heaviest loading hours of the year).

b) Please provide specific quantified examples of pre and post mitigation risk calculations carried out by Hydro One when assembling and prioritizing the project portfolios that comprise the largest Transmission spending programs (e.g. ISD T-SR-01, ISD T-SR-02, ISD T-SR-03, ISD T-SR-04, ISD T-SR-09 and ISD T-SR-13).

B2-Staff-47

EB-2019-0082 Exhibit B / TSP Section 2.2 / pp. 8
Exhibit B / Tab 2 / Schedule 1 / Section 2.2 / pp. 11-14
Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p. 15

Preamble:

The first reference, from the EB-2019-0082 application, contains the following breakdown of transformer condition:

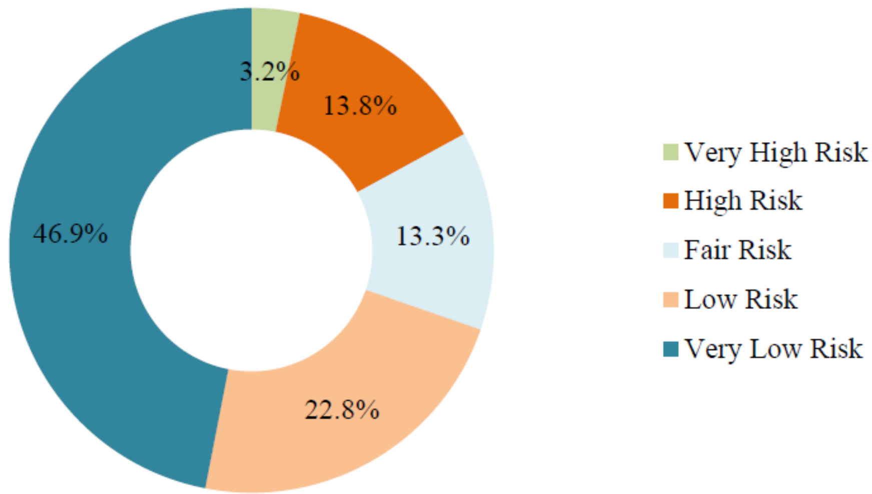


Figure 3 – Transformer Fleet Condition Assessment

Footnote 3 at the second reference (current application) states that:

> In the prior transmission application (EB-2019-0082, TSP Section 2.2, p. 8), the 122 (17%) transformers identified as being in poor condition reflected the main tank oil tests results only at a point in time, and not the other condition indicators as discussed below. Based on Hydro One's detailed transformer condition assessments, the number of poor condition transformers at the time of the prior application would have been 181 (as noted above). Similarly the 2016 values displayed in Figure 1 above have been updated to 116 based on the detailed transformer condition assessment whereas the values shown in the rate application were solely based on the main tank oil assessment at a point in time (EB-2016-0160). It is important to note that Hydro One's approach for assessing transformer condition (and for prioritizing replacements) has not changed since the last rate application.

The following figure is included at the second reference (current application):

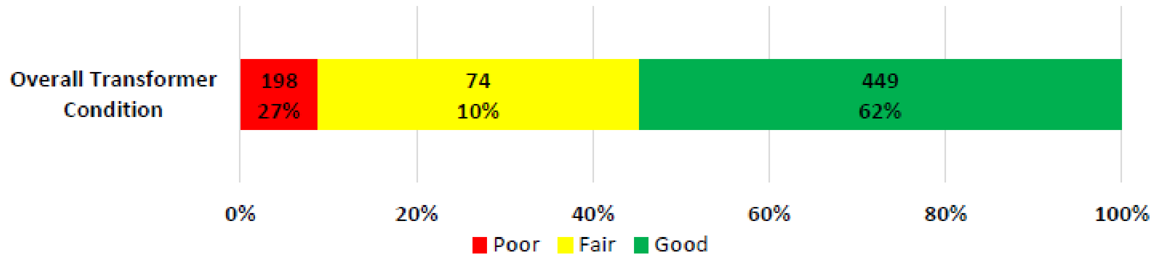


Figure 2: Transformer Condition

Page 13 at the third reference references Figure 2, shown above, stating that:

> As shown in Figure 2, out of a total of 721 transmission transformers (i.e., 743 transformer tanks) in service at the end of 2020, 198 transformers (i.e., 208 transformers were deemed to be in poor condition based on a combination of main tank deterioration, oil leaks, cooling system failures, tap changer malfunction, defect reports, and/or PCB contamination.

Page 14 at the third reference states that:

> Hydro One engaged Electric Power Research Institute (EPRI) to assess the conclusions of Hydro One's transformer condition assessment process in respect of the transformer main tank insulating oil condition indicator. EPRI assessed the main tank insulating oil condition of all 198 poor condition transformers (i.e., 208 transformers tanks - see TSP Section 2.3 Attachment 3). EPRI found main tank degradation in 155 transformer tanks and deemed them to be in deteriorated condition, 17 transformer tanks were found to be in marginal condition (i.e. close to EPRI's deteriorated condition threshold) based on their level of main tank degradation, and the remaining 36 transformer tanks were not deemed to have main tank deterioration.

Question(s):

a) Please explain how the information presented in Figure 3 (first reference), which uses the categories Very High Risk, High Risk, Fair Risk, Low Risk, and Very Low Risk; corresponds to 17% of transformers being identified as being in poor condition.

b) Please explain how Hydro One has increased the number of poor condition transformers at the time of the prior application (from 122 to 181) if Hydro One's approach for assessing transformer condition has not changed.

c) Please specify the condition assessments that have been used to assign transformers to the Poor, Fair, and Good, categories used in Figure 2 (second reference). Please provide the measure (e.g. unit of measurement, or scale) for each condition assessment.

d) Please provide the formula, factor weightings and/or detailed methodology for combining the results from the condition assessments identified in part c) to assign each transformer to either the Poor, Fair, or Good category.

e) Please confirm that applying the methodology described in response to part d) to condition assessment data that was available at the time of the previous application resulted in 181 transformers being assigned to the Poor category. Using this approach, at the time of the previous application how many transformers would be assigned to the Fair category, and to the Good category?

f) Please explain why the methodology described in response to part d) is preferable to the methodology used at the time of the previous application to assign each transformer to either the Very High Risk, High Risk, Fair Risk, Low Risk, or Very Low Risk category.

g) Please explain why Hydro One didn’t engage an expert, such as EPRI, to assess the conclusions of Hydro One’s transformer condition assessment process in respect of all condition indicators?

h) Please state whether or not the “transformer main tank insulating oil condition indicator” that was assessed by EPRI is the same thing as the “main tank oil tests” that were the sole condition assessment used to categorize transformers at the time of the previous application?

i) Please explain what condition assessments were used to identify the 198 poor condition transformers that were assessed by EPRI. On what basis were these transformers categorized as being in poor condition? Why wasn’t EPRI asked to test more transformers?

j) Of the 208 transformer tanks tested, EPRI found 17 transformer tanks to be in marginal condition. How many transformers does this correspond to? EPRI found 36 transformer tanks did not have main tank deterioration. How many transformers does this correspond to?

k) Please confirm that the transformers identified in part j) are within the 198 transformers categorized in the application as being in poor condition. Please explain on what basis these transformers are in poor condition.

l) Did the EPRI study results influence the categorization of transformers into the Poor, Fair and Good categories? If yes, please explain and quantify what changes to the transformer categorization were made because of the EPRI study. If no, please explain why not.

m) What was the cost of the EPRI study?

B2-Staff-48

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pp. 21-22

Preamble:

At the above reference, Hydro One states that:

> Assessments to refurbish or replace transformers are done on an individual basis considering factors such as condition, performance, utilization, demographics, criticality and environmental factors as well as cost comparison between refurbishment and replacement. Hydro One employs a model that derives the Present Value for three options: maintain status quo, refurbish, or replace. The model uses several factors such as maintenance cost, replacement cost, tax capital cost allowance, and the discount rate to select the appropriate option. Transformers in poor condition are prioritized for replacement with consideration of those with known manufacturing defects, are obsolete, have higher repair costs or have undergone short term repairs to restore its functionality but continue to pose a performance risk. Transformers that do not meet replacement criteria (particularly those that have reported severe oil leaks or verified PCB concerns) will be prioritized for refurbishment to preserve their expected service life and reliability.

Question(s):

a) Please state how many of the 198 transformers that Hydro One has identified as being in poor condition are planned to be refurbished? Please identify the station locations of each of these transformers.

b) Please state how many of the 198 transformers that Hydro One has identified as being in poor condition are planned to be replaced.

B2-Staff-49
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pp. 32-34

Question(s):

a) Please state how many of the 541 breakers that Hydro One has identified as being in poor condition are planned to be refurbished.

b) Please state how many of the 541 breakers that Hydro One has identified as being in poor condition are planned to be replaced.

B2-Staff-50
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pp. 36-44

Question(s):

a) Please provide the percentage of beyond ESL protection system assets that are being replaced in the plan.
b) Please also break down this amount across solid state, electro-mechanical, and microprocessor assets.

B2-Staff-51
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pg. 47 of 140

Preamble:

Regarding Table 14 – Summary of Defect Reports (2011 – 2020) *[Table not provided in preamble].*

Question(s):

a) Please state what is considered to be a defect and how a defect occurs.

b) Please describe any means of mitigation used to address these defects and state whether any of the devices were replaced because of a defect.

c) Please state whether it is possible that the same device is counted as having a defect in more than one year, i.e. it was not replaced and then had another defect.

d) Please provide total portfolio numbers and the associated percentage of portfolio failures for each asset type listed in Table 14.

B2-Staff-52
Exhibit B / Tab 2 / Schedule 1 / Section 2.2 / p. 55

Preamble:

Table 15 summarizes power system telecom asset demographics.

Question(s):

a) Please state for each of the asset types shown in Table 15, what portion of the beyond ESL devices are being replaced in the plan?

B2-Staff-53
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pg. 57 of 140

Preamble:

As stated in Lines 15 to 22 with respect to the expected service life (ESL) of All-Dielectric Self-Supporting (ADSS) fibre cable:

> The ESL of fibre optic cable is based on the type of cable. The manufacturers' recommended ESL is 40 years for OPGW and 25 years for ADSS. Historical performance shows that mechanical stress on ADSS fibre cable installations has prematurely reduced the cables' life span. In the case of ADSS cables, at the time when they were first installed by Hydro One, there was limited research available to fully understand the design principles, maintenance requirements and operational risk related to ADSS cables. Since then, historical performance has shown that a combination of these factors have contributed to unusual mechanical stresses on ADSS cables, as well as some of the early ADSS cable failures, resulting in its ESL being lowered to 15 years.

Question(s):

a) Please describe what design principles and/or maintenance practices Hydro One has introduced or modified in an attempt to achieve a higher ESL than 15 years for ADSS cable.

b) Please clarify whether or not Hydro One is planning to reduce the ESL of its entire ADSS fleet to 15 years, regardless of installation vintage?

c) Please confirm that the problems identified in the reference apply primarily to ADSS cables installed by Hydro One when it first began using ADSS technology.

    i) If not confirmed, please describe all applicable scenarios.

d) What is Hydro One's proposed ESL for its modern ADSS installations?

e) Please categorize Hydro One's ADSS fleet into vintages by installed length.

    i. Please identify which vintages would count as "early" installations, and which would count as "modern" installations.

B2-Staff-54

Exhibit B / Tab 2 / Schedule 1 / Section 2.1 / p.19
Exhibit B / Tab 2 / Schedule 1 / Section 2.2 / p. 80-87
Exhibit B / Tab 2 / Schedule 1 / Section 2.8 / p.13
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-13

Preamble:

At the third reference above, the application states that Hydro One is planning to spend with respect to North American bulk electric system (BES) requirements:

> $833M over the five-year period to replace poor condition line assets that form part of BES or regional supply systems serving local areas including 1,571 circuit-kms, or 41% of the known poor condition conductors in the fleet.

Page 81 at the second reference states that:

> Testing is limited to conductor spans greater than 50 years of age since based on Hydro One's operating experience, conductors less than 50 years of age have

a low likelihood of being in a deteriorated condition and are therefore assumed to be in good condition.

Page 87 at the second reference states with respect to Aluminum Conductor Steel Reinforced (ACSR) type conductors that:

Since 2016, Hydro One has been performing the majority of its ACSR conductor condition assessments through the Kinectrics LineVue tool.

Page 82 at the second reference states that:

The subset of conductors in poor condition includes copper conductors that can no longer be repaired due to components being out of production.

Page 2 at the fourth reference states that:

Hydro One plans to replace 1,879 circuit-kms (of which 1,571 circuit-kms will be in-serviced during the 2023-2027 period) or 49% of the known poor condition conductors in the fleet.

Question(s):

a) Please provide an augmented version of Table 20 on page 80 at the second reference, adding a column to show the circuit-km beyond 50 years of age for each conductor type.

b) Please confirm that all conductor less than 50 years old is classified as being in 'good' condition.

c) Please explain the 27% of conductor that is classified as 'needs assessment'.

d) Please complete the following table:

	Poor Condition (Circuit-km)	Fair Condition (Circuit-km)	Good Condition (Circuit-km)	Needs Assessment (Circuit-km)	Total (Circuit-km)
ACSR					27,929
Copper					464
Aluminum					21

ACSS					138
Total	3874	3329	13620	7728	28,552

e) Please describe the condition testing program that has been undertaken since 2016 for ACSR conductors beyond 50 years of age. This should include:

   i. The number of circuit-km tested per year by LineVue and the criteria for prioritizing conductors to be tested using LineVue

   ii. The number of laboratory tests conducted and the criteria for prioritizing conductors for laboratory testing.

f) Please provide the cost of the condition testing program described in response to part e) per year.

g) Please describe how ACSR conductor has been categorized into ‘poor’, ‘fair’, ‘good’ or ‘needs assessment’, based on the results of LineVue testing and laboratory testing. If additional criteria are used for this categorization, please explain.

h) Please state the proportion of the ACSR conductor that has been categorized as being in poor condition that has been tested with LineVue testing or laboratory testing. If this proportion is less than 100%, please explain on what basis these conductors have been categorized as being in poor condition.

i) For the copper conductor in poor condition identified in part d), please divide this, by circuit-km, into copper conductor that can no longer be repaired due to components being out of production, and other copper conductor that is in poor condition.

j) The expected service life of ACSR conductor has been increased from 70 years to 90 years. Please comment on the potential to increase this further.

k) One of the key criteria for replacing conductors appears to be the conductors being located in “publicly accessible areas”. What other criteria did Hydro One use to select the 41% of the known poor condition conductors for replacement?

l) Please explain the potential implications in terms of system and customer reliability (i.e., delivery point performance) for the remaining 59% that will remain in poor condition over the next five years. Please also identify if any of those are located in “publicly accessible areas”?

m) Please explain how Hydro One reached a conclusion that less than half (41%) of the conductors in poor condition should be replaced over the five-year period and please discuss Hydro One’s plan to address the remaining 59%.

n) The ISD states that “49% of the known poor condition conductors” would be addressed. This is different from other sections in the application which state that the “$833M would address 41%” of the known poor condition conductors in the fleet, Please clarify whether the portion of conductors in poor condition that are being replaced is 41% or 49%.

B2-Staff-55
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pg. 96 of 140

Preamble:

As stated in Lines 13 to 19:

> Hydro One has approximately 49,200 lattice steel structures and approximately 1,750 steel poles supporting 115kV to 500kV transmission lines. Current steel structures have an average age of 63 years and an ESL of 80 years if they are not re-coated. However, if re-coated, the steel structures’ service life can extend beyond the ESL. The demographics of the steel structure population are outlined in Table 22 below [table not provided in preamble].

Question(s):

a) What is the average (or most likely) service life extension that Hydro One anticipates will be achieved by structure re-coating?

b) In addition to Table 22, please provide a table that separately lists re-coated structures and compares their average ages relative to the extended ESLs that Hydro One expects to achieve by re-coating.

B2-Staff-56
Exhibit B / Tab 2 / Schedule 1 / Section 2.2 / p. 98

Preamble:

At the above reference, it is stated that:

> In 2018, Hydro one [sic] discovered that around 7,000 of its 230-kV towers are prone to experiencing middle arm hanger vibration and fatigue causing cracks…. Approximately 2,000 towers have either previously been fixed or will be as part of refurbishment projects, and about 5,000 towers are still in need of repair.

Question(s):

a) Please explain how the above discovery was made in 2018.

b) Please state whether or not this discovery was identified in Hydro One's most recent rate application (2019-0082).

c) Please describe the plan to repair the 5,000 towers that are still in need of repair.

d) Please state how many circuits are affected by the 5,000 towers that are still in need of repair? Please comment on the geographic distribution of these towers around Ontario.

e) Please state whether or not the location of the 5,000 towers that are still in need of repair influenced the prioritization of transmission line refurbishments that make up T-SR-13, or any other investment? If yes, please explain how.

B2-Staff-57
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pg. 103 of 140

Preamble:

At the above reference, it is stated at Lines 9 to 12 that:

> As shown in Figure 28, the number of forced outages due to wood pole structure failures has increased over the past ten years. Wood pole failure is the result of a combination of factors, such as pole condition, weather condition, physical loading, and the local environment, so the increasing trend is not necessarily indicative of worsening pole condition.

Question(s):

a) Please state whether or not pole condition would be expected to significantly influence the probability of transmission wood pole failure for each of the following event types? Please explain for each of the cases shown below:

    i. Trees falling on structures and/or conductors.

    ii. Extreme wind events (e.g., microbursts or tornados).

    iii. Extreme ice loading.

    iv. External interference (e.g., vehicle and equipment contacts).

    v. Forest fires.

    vi. Spontaneous failure due to deteriorated pole condition during meteorological conditions that do not exceed structure design loads.

    vii. Other (please elaborate)

b) Please provide the percentage of transmission wood pole failures attributable to each of these event types for the past five (5) years.

c) Please explain how Hydro One's proposed accelerated rate of transmission pole replacements will directly correlate to improved reliability or safety performance for each of these failure event types.

B2-Staff-58

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.2 / pg. 117 of 140

Preamble:

The above reference states at Lines 10 to 17:

> The need to address the polymer insulator issue is underscored by two failures which occurred in October and November 2016. Both failures resulted from 230 kV polymer suspension insulators on C28C failing mechanically, resulting in a conductor drop, as shown in the photos in Figure 37 through Figure 39. The dropped conductor did not contact the ground but was held in the structure window. Hydro One began replacing polymer insulators in 230 kV dead-end

configuration in 2016, and Hydro One is currently in the process of identifying the number of impacted polymer insulators and will explore incorporating them into the insulator replacement program once more information is available.

Question(s):

a) Please state whether or not Hydro One is prioritizing replacement of high-risk polymer insulators used in tension applications prior to undertaking replacements of suspension strings that utilize the same insulator types?

   i. If no, please explain why not.

   ii. Is the probability of failure higher for insulators in tension applications?

B2-Staff-59

Exhibit B / Tab 2 / Schedule 1 / Section 2.2

Question(s):

a) Please complete the attached spreadsheet, which is based on the spreadsheet provided by Hydro One in response to Undertaking JT 1.24 in EB-2019-0082. In addition, please update any of the previous values that may have changed since the time of the previous application.

B2-Staff-60

Exhibit B / Tab 2 / Schedule 1 / Section 2.5 / pp. 28-31

Page 29 at the above reference states that:

> Zero tolerance enforcement of the NERC FAC-003 Standard regarding minimum clearances for vegetation growth has led Hydro One to increase its urban vegetation management resulting in higher costs per kilometer.

With respect to the line clearing cost per kilometer ($/km), pages 29-30 at the above reference further states that:

> Over the 2023-2027 period, Hydro One aims to achieve line clearing unit costs averaging $2,927, and to execute over 2,100 km annually. Based on customer feedback, Hydro One introduced flexibility into the Vegetation Management

> Standard for line clearing, such as increased discretion in clearing or trimming incompatible vegetation in border zones of corridors.

Finally, page 31 at the above reference states that:

> Over the 2023-2027 period, Hydro One is targeting average brush control unit costs of $1,712 and planning to execute an average of 11,500 hectares annually.

Question(s):

a) Please explain how Hydro One arrived at the target line clearing unit cost average of $2,927 for the 2023-2027 period.

b) Please explain why the $2,927 target is reasonable, considering that in 2020 the actual cost was $3,368/km.

c) Please state whether or not zero tolerance enforcement of the NERC FAC-003 standard is a new policy? If so, please indicate when this policy changed. Is this a policy being enforced by NERC, or is it a Hydro One policy? Please explain.

d) Please state how Hydro One is able to introduce flexibility into the vegetation management standard for line clearing while maintaining zero tolerance enforcement of the NERC FAC-003 standard? Please explain or clarify.

e) Please explain how Hydro One arrived at the target brush control cost average of $1,712 for the 2023-2027 period.

f) Please explain why the $1,712 cost is reasonable.

B2-Staff-61
Exhibit B-1-1 / Tab 2 / Schedule 1 / Section 2.5 / pp. 33-34
Exhibit B-1-1 / Tab 1 / Schedule 1 / Section 1.2 / pp. 3-13

Preamble:

Page 3 at the second reference states that “It is intended that regional planning is to be undertaken for each of the planning regions identified in the PPWG Report every five years.”

Question(s):

a) Please provide the PPWG report.

b) With respect to Table 2, Regional Planning Status Summary, on pages 9 and 10 at the first reference, are the months shown in the table those when the steps (i.e. Needs Assessment (NA), Scoping Assessment (SA), etc.) were initiated, or completed?

c) Please provide a revised version of Table 2, updating the status, where applicable, and including a clarification with respect to part b).

d) For regions where Hydro One is the lead transmitter, does Hydro One determine when the needs assessment will be initiated at the beginning of a regional planning cycle?

e) If the response to part d) is 'yes', please explain how Hydro One determines when to initiate the needs assessment for a region. If the answer to part d) is no, please indicate who makes this determination.

f) For the Chatham/Lambton/Sarnia, Niagara, North/East of Sudbury, Renfrew, and St. Lawrence regions, how does Hydro One expect to meet the PPWG Report expectation that regional planning is to be undertaken every five years if, for each of these regions, more than five years has passed since the previous Needs Assessment, and these Needs Assessments have not yet been initiated? Please explain or clarify.

g) Please explain how the response to part f) aligns with Hydro One's claim in Table 34 and Table 35 at the first reference that Hydro One has met 100% of its regional infrastructure planning deliverable obligations, within the allotted time, for the period 2016 to 2020 inclusive, and plans to maintain performance at 100% from 2021 to 2027 inclusive.

B2-Staff-62
Exhibit B / Tab 2 / Schedule 1 / Section 2.5 / pp. 34-35

Preamble:

Page 34 at the above reference describes the "End-of-Life Right-Sizing Assessment Expectation" measure as the following:

> This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing end-of-life equipment are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year.

It is also stated that "Based on condition assessment, this application includes over 70 EOL assets projects that have been assessed to be replaced with right size consideration."

Question(s):

a) Please list the assessed regions that the evaluation of this measure was based on for each of the years 2018, 2019 and 2020.

b) Please provide for the same years the number of opportunities for right-sizing end-of-life equipment that were missed during each of these years, for the same regions as in part a) above.

c) Please describe any opportunities for right-sizing end-of-life equipment that were identified in response to part b).

d) Please state how many of the 70 EOL assets that have been assessed to be replaced with right size considerations that are included in this application were right-sized. Please confirm that the remainder of the 70 EOL assets were replaced like-for-like or describe other outcomes.

e) Please identify seven examples of assets that were right-sized that are included in this application, or as many as indicated in response to d), if that number is less than seven.

B2-Staff-63
Exhibit B / Tab 2 / Schedule 1 / Section 2.7 / pp. 9-12

Preamble:

This section discusses the TSP Investment Planning Process and the approaches used for prioritization and optimization of investments.

Question(s):

a) Please explain how the magnitude and pacing of the draft plan is determined. For example, are these based on total risk mitigated, risk level remaining, or total investment?

B2-Staff-64
Exhibit B / Tab 2 / Schedule 1 / Section 2.8 / p. 13

Preamble:

At the above reference, Hydro One states that:

> For the five year period, individual equipment replacements have been bundled into integrated, larger scale station and line projects in order to address multiple assets and system needs at a specific station or circuit within a single investment. This integrated approach enables efficient project delivery by optimizing project planning and execution, minimizes outage requirements and customer impacts, and achieves outcomes valued by customers (as further discussed in SPF Section 1.6).

Question(s):

a) Does Hydro One only bundle investments that have been individually validated and that would be pursued during the plan term?

b) If the response to part a) is no, are investments, which by themselves may not be needed yet or are not cost effective bundled with investments that would individually qualify?

c) If the answer to b) is yes, how does Hydro One evaluate whether the cost savings resulting from bundling investments outweigh the early triggering of investments in assets that otherwise would have remained untouched during the plan term?

B2-Staff-65
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.9 / pg. 8 of 16

Preamble:

At the above reference, it is stated at Lines 6 to 10:

> Over the 2023-2027 period, Hydro One plans to invest an average of $1,452M per year in Transmission capital, for a total of approximately $7,258M to maintain transmission reliability performance, to address customer needs and preferences, and to mitigate asset and operational risks by accomplishing the planned capital work. Hydro One's historical capital spending relative to the 2023-2027 amounts is shown in Table 5 and Figure 1 [Table 5 and Figure 1 not included in preamble].

Question(s):

a) Please provide a detailed justification for the lack of pacing demonstrated by the proposed significant step increase in capital expenditures between 2022 and 2023, with particular focus on the step increase in Renewal spending.

b) Please state whether or not Hydro One has quantified the risks of adopting a more paced approach to implementing System Renewal spending, for example, by limiting annual System Renewal spending equivalent to the past 4-year average plus inflationary escalation?

    i. If yes, please provide the anticipated reliability performance degradation associated with this spending level.

    ii. If no, explain why not.

c) If Hydro One was limited to the past 4-year average spending levels plus inflationary escalation, please identify which projects would be eliminated or deferred.

d) If Hydro One was limited to the past 4-year average spending levels plus inflationary escalation, which programs would have the lowest risk impact associated with the decreased spending forecast?

<u>B2-Staff-66</u>

Exhibit B / Tab 2 / Schedule 1 / Section 2.9 / p. 11

Preamble:

Based on Table 7 at the above reference, the average actual/forecast system renewal expenditure for 2018 – 2022 inclusive is $816.78 million. The planned average system renewal expenditure, for 2023-2027 inclusive is $1,239.84 million. This is a 51.8% increase in the five-year average.

Question(s):

a) Please explain why the proposed 51.8% increase in the five-year average system renewal expenditure is reasonable.

B2-Staff-67
Exhibit B / Tab 2 / Schedule 1 / Section 2.9 / p. 15
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SS-03

Preamble:

At the second reference above, Hydro One states that "On December 2, 2020, Hydro One applied for "Leave to Construct" approval under Section 92 of the Ontario Energy Board Act (EB-2020-0265)." The same reference goes on to say that "On April 22, 2021 Hydro One received OEB-approval for its "Leave to Construct" application to replace the conductors on the 230kV circuits M30A and M31A."

Question(s):

a) Please add the Merivale Ts To Hawthorne Ts: 230kv Conductor Upgrade project (T-SS-03) to Section 2.9.4 (first reference), Table 9.

b) Please confirm that with the addition of investment T-SS-03, Section 2.9.4 is complete.

B2-Staff-68
Exhibit B / Tab 2 / Schedule 1 / Section 2.9 / Attachment 2, pp.9-10, 13

Preamble:

On page 13, Hydro One states that:

> The Lennox TS Bulk: ABCB Component Replacement Project is forecasting to exceed its total budget by $33.9M as a result of work definition issues that resulted in scope evolution and additions subsequent to the project's funding

approval, as well as, a reprioritization of resources for customer driven work. Finally, the Cherrywood TS 230 kV Bulk: ABCB and Component Replacement project is forecasting to exceed its total budget by $21.3M due to multiple execution factors including complexity of replacing the station service systems, setup of site facilities, overruns on two buildings, relocation of fiber cables, and scope additions.

Question(s):

a) Please state why the Bruce B ABCB replacement project (T-SR-02.03) is not included in Table 2 of Attachment 2.

b) Please state the ongoing risks that have been identified for each of the following projects and how they are being mitigated?

    i. Beck 2 TS, ABCB Replacement & Yard Upgrade

    ii. Cherrywood TS 230kV BULK; ABCB &Component Replacement

    iii. Lennox TS BULK: ABCB Component Replacement

    iv. Middleport TS ABCB Replacement

    v. Nanticoke TS ABCB Replacement

    vi. Bruce B ABCB Replacement

B2-Staff-69

Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SA-03 / p.1
Transmission System Code / Section 6.3.10

Preamble:

The application notes this investment in Halton TS is required to facilitate a request from Milton Hydro to increase transformation capacity to accommodate forecasted customer load growth and the required in-service date identified by Milton Hydro is Q2 2027.

The proposed project involves the construction of a new 230/27.6kV DESN station at the existing Halton TS site. Table 2 indicates the Gross Investment Cost is $34.9 million and the Capital Contributions amount to $26.9 million. Table 2 also indicates Capital

Contributions begin in installments three years *before* the station goes into service with $24.2 million recovered from Milton Hydro before 2027. The application notes "capital contributions will be determined as per Hydro One's Transmission Customer Contribution Policy".

OEB staff notes that section 6.3.10 of the [Transmission System Code (TSC)] states:

> Where the security deposit is in a form other than cash, the transmitter shall return the security deposit to the customer once the customer's facilities are connected to the transmitter's transmission facilities and any capital contribution has been paid.

In other words, a security deposit can be required before an asset is connected to the system, which does not need to be a cash payment (e.g., can be a letter of credit under s.6.3.11), and any capital contribution payment is required when the asset goes into service.

OEB staff also notes that section 6.3.19 was added to the TSC in December 2018 to allow for the capital contribution to be paid by LDCs in installments over five years (rather than through a single payment) starting at the time the asset goes into service.

Section 6.3.19 of the TSC states "the interest charges shall accrue monthly commencing on the date the connection asset goes into service … as part of each installment payment."

OEB staff further notes that this is one example where the application shows capital contributions being required before the in-service date. Another example is T-SA-09 (New Transformer Station In Northern York Region).

Question(s):

a) Please explain why Hydro One is requiring virtually all the capital contribution amounts to be paid before the in-service date.

b) Please provide the document setting out Hydro One's "Transmission Customer Contribution Policy".

c) Please confirm that Hydro One expects to recover only $8 million (of the $34.9 million) in rates over the next 25 years (i.e., "low risk" economic evaluation period) from Milton Hydro.

d) Please clarify the amount of excess capacity on the new DESN station and please also identify whether or not the station could be sized to better meet the customer's capacity needs.

B2-Staff-70

Exhibit B2 / ISD T-SA-05 / p.1
Transmission System Code / Section 6.3.1
OEB Notice of Revised Proposal to Amend a Code, Regional Planning and Cost Allocation Review (EB-2016-0003) / p.17

Preamble:

Hydro One states that it is requesting $38.5M over the five-year test period

> …to accommodate future requests from load customers to connect to Hydro One's transmission system where the need and scope have yet to be determined. This investment anticipates load customer requests that are expected to arise during the test period but are currently unknown.

OEB staff notes that, under the TSC, the full cost of a new or modified facility is intended to be recovered from the requesting load customer. For example, section 6.3.1 states:

> Where a load customer elects to be served by transmitter-owned connection facilities, a transmitter shall require a capital contribution from the load customer to cover the cost of a connection facility required to meet the load customer's needs...

At the third reference above, the OEB proposed "Advanced Funding Options" that

> …would provide distributors with a pool of funds before the new or upgraded connection investment goes into service to reduce the capital contribution when it is due to be paid in relation to distributors.

The OEB decided not to proceed with those advanced funding options at the time due, in part, to stakeholder concerns as described in the OEB's Notice of Revised Proposal to Amend a Code.

Question(s):

a) Please clarify how requesting recovery of those costs in rates from all ratepayers and then also requiring the load customers to pay the full cost when they connect to the system will not result in Hydro One recovering costs twice for the same project.

b) Please also clarify how recovery of those costs in rates from all ratepayers aligns with the beneficiary pays principle.

c) Please explain how Hydro One's above-noted request for $38.5 million differs from the type of advanced funding options that the OEB decided not to proceed with, as also discussed above.

B2-Staff-71
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SA-10

Question(s):

a) Please provide a copy of the document *Need for Bulk Transmission Reinforcement in the Windsor-Essex Region, IESO, Published June 13, 2019* that is referenced in footnote 1 on p. 2 at the above reference.

b) Please provide a copy of the document *2019 Windsor-Essex Integrated Regional Resource Plan (IRRP), IESO, Published September 3, 2019* that is referenced in footnote 2 on p. 2 at the above reference.

c) Please provide the addendum to the Windsor-Essex IRRP that was expected to be published in Q3, 2021, that is referenced on p. 2 at the above reference.

d) Please provide the forecast, including information on the location, size, and timing of new connection customers, that supports the need for T-SA-10 consisting of three new DESN stations in the Kingsville-Leamington area.

e) Please provide the status of the environmental assessment process for each of the three new station sites.

f) Please provide the breakdown of costs for each of the three stations that make up T-SA-10 on an annual basis, including for years before and after the plan years, where applicable, such that the total cost for each station is reflected.

g) Please describe the flexibility of the plan for this investment, if, for example, demand for new customer connections increases, or decreases, or is advanced or delayed. In addition, please explain how changes in the geographic distribution of the new customer connections would be accommodated.

B2-Staff-72

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01 through ISD T-SR-18

Preamble:

OEB staff has prepared a table summarizing Hydro One's investment plans T-SR-01 through ISD T-SR-18 which is attached. The following questions relate to these investment plans.

Questions(s):

a) Please describe how Hydro One formulates the different alternatives it examines in the business plans.

    i. How does Hydro One economically optimize the pacing that is implicitly embedded in the selected alternatives, such as alternative 2 in ISD T-SR-04, ISD T-SR-11 or ISD T-SR-16?

b) Please state how Hydro One represents alternatives that are not like for like replacements, but rather incorporate larger projects such as rebuilding one larger transmission station as a replacement for two older stations?

c) OEB staff notes that the decision to maintain assets occurs at the individual asset level, and not the fleet level. Please state why the listed implementation alternatives (e.g., reactive, programmatic, bundled) are applied at a program level, instead of at an individual asset level (for example in ISD T-SR-01 and ISD T-SR-03)?

    i. Please identify any individual projects within each Investment program that depart from the selected program-level implementation alternative.

d) Please provide quantified evidence to demonstrate that the capital spending solutions proposed by Hydro One in the alternatives describes as "Planned Replacement" (which generally appear as Alternative 2 in the above table) are the optimal solutions?

i. What is the increase in risk that would be created by a decrease in capital expenditures by 10% for each of the listed programs?

ii. What is the decrease in risk that would be created by an increase in capital expenditures by 10% for each of the listed programs?

iii. How has Hydro One determined that the planned expenditures are the most cost-effective way to reduce the risks that are intended to be addressed by each program?

    a. Please show quantified calculations.

iv. Please provide specific project examples where risk will be mitigated to an acceptable level by reducing the probability of asset failure without significantly changing the consequence of failure.

    a. Please explain why the selected approach to failure probability reduction is the economically preferred risk mitigation choice.

v. Provide specific project examples where risk will be mitigated to an acceptable level by reducing the consequence of failure without significantly changing the probability of individual asset failure.

vi. For each example, explain why the selected approach to failure consequence reduction is the economically preferred risk mitigation choice.

B2-Staff-73

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01 / pg. 17 and 18 of 32
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-03 / pg. 16 to 18 of 46
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-13 / pg. 12 to 14 of 24

Preamble (T-SR-01):

Alternative 1: Reactive Component Replacement
Alternative 2: Planned Programmatic Replacement of Components (Unbundled)
Alternative 3: Bundled Integrated Replacement of Components

Preamble (T-SR-03):

Alternative 1: Reactive Component Replacement
Alternative 2: Planned Programmatic Replacement of Components (Unbundled)
Alternative 3: Bundled Integrated Replacement of Components

Preamble (T-SR-13):

Alternative 1: Reactive Component Sustainment
Alternative 2: Programmatic Sustainment of Components (Unbundled)
Alternative 3: Comprehensive Line Section Refurbishment (Bundled)

Questions(s):

a) Please provide the five (5) largest individual projects (or sub-projects) from each of the referenced programs (T-SR-01, T-SR-03 and T-SR-13) over the past five (5) years for which Hydro One selected Alternative 3 - Bundled Integrated Replacement of Components. Please also provide the following information for each of these projects (preferably in tabular format):

   i. The year the project was completed;

   ii. The name of the associated substation or line (as applicable);

   iii. The actual total project expenditure;

   iv. What would have been spent on the project if Hydro One had only replaced the components identified as being at End of Life;

   v. The incremental “bundling” expenditure (i.e., the difference between amounts c. and d.);

   vi. A quantified explanation of the value delivered to ratepayers by the incremental amount of spending.

B2-Staff-74
Exhibit B3-1 / Section 3.3 / pp. 9 and 10 of 36

Preamble:

At the above reference, it is stated:

Finding 5: Focused more on component-centric projects
Under its current approach for managing the distribution station transformer fleet, Hydro One releases projects that focus on planned transformer replacements and other station component replacements as required to accommodate the transformer replacement. If there are other station assets that are in poor condition and in need of replacement, they are bundled with the transformer replacement project, however other component assets in good or fair condition are not [be] replaced. Through this approach, Hydro One aims to more effectively target the high risk components in Hydro One's distribution stations. Programs for the replacement of individual stations components including reclosers and MUS connection structures, will continue. Hydro One's planned approach is in line with the finding that most comparator utilities also focus more on component-centric projects.

Questions(s):

a) Please reconcile the referenced component centric replacement philosophy being followed in the Distribution System Plan with the bundled replacement philosophy being applied in T-SR-01, T-SR-03 and T-SR-13.

B2-Staff-75
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01 / pg. 9 to 11 of 32
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-03 / pg. 8 to 11 of 46

Preamble:

At Lines 1 to 4 of page 9 of 32, it is stated that:

A large number of the breakers in Hydro One's fleet contain PCBs. As of December 2020, 420 breakers that were manufactured pre-1985 require PCB remediation work including bushing retro-filling (i.e., putting in new PCB free oil to lower the PCB ppm concentration) or replacements to meet the PCB Regulation requirements.

At Lines 11 to 16 of page 11 of 32, it is stated that:

Bushings from oil circuit breakers need to undergo oil retro-fill or replacement in order to satisfy federal PCB regulatory requirements[1] to remove equipment containing concentrations of PCB greater than 50 ppm from service by 2025. All transmission station oil-filled equipment manufactured prior to 1985 are expected

> to be sampled by the end of 2022, so that the PCB contained in such equipment can be removed or retro-filled to less than 50 ppm by the end of 2025.

At Lines 10 to 13 of page 8 of 46, it is stated that:

> A large number of the breakers in Hydro One's fleet contain PCBs. As of December 2020, 420 breakers that were manufactured pre-1985 require PCB remediation work including bushing retro-filling (i.e., putting in new PCB free oil to lower the PCB ppm concentration) or replacements to meet the PCB Regulation requirements.

At Lines 11 to 16 of page 11 of 46, it is stated that:

> Bushings from oil circuit breakers need to undergo oil retro-fill or replacement in order to satisfy federal PCB regulatory requirements1 to remove equipment containing concentrations of PCB greater than 50 ppm from service by 2025. All transmission station oil-filled equipment manufactured prior to 1985 are expected to be sampled by the end of 2022, so that the PCB contained in such equipment can be removed or retro-filled to less than 50 ppm by the end of 2025.

Question(s):

a) Please explain why PCB remediation work has not been completed prior to now considering the legislative deadlines that have been known for many years?

    i. Was spending on this matter deferred in prior years?

b) Please explain Hydro One's risk analysis regarding keeping equipment with PCBs in operation.

c) Please explain why Hydro One did not begin surveying the PCB concentration in its distribution equipment at an earlier date.

d) Please state if all assets with excessive PCB levels are to be taken out of service by 2025 and given that the program budget ends in 2025, whether or not there will be any disposal costs associated with this program extending into 2026 or beyond?

B2-Staff-76
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01 / pg. 21 to 29 of 32
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-03 / pg. 20 to 38 of 46

Preamble:

The following questions relate to Appendix A – Description of Investments.

Question(s):

a) Please provide further details on the stations identified in ISD T-SR-01 *"Transmission Station Renewal – Network Stations"* and ISD T-SR-03 *"Transmission Station Renewal – Connection Stations"* identified in Appendix A to justify investments. For example, applicable documents such as:

- Inspection reports;
- Description of any specific problems or concerns with equipment;
- Annual maintenance reports for the past 5 years;
- Photos;
- Descriptions of alternative mitigation options considered;
- An economic analysis of repair/refurbishment vs. replacement options, including cost benefit assessment (NPV);
- Any other quantified information used to select the proposed alternative.

B2-Staff-77
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-02
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-03

Preamble:

For the combination of investments T-SR-01, T-SR-02, and T-SR-03, Hydro One appear to be replacing a total of 867 breakers. As summarized in B2-Staff-49, 541 breakers are identified as being in poor condition.

Question(s):

a) Please state why Hydro One is replacing 326 (60%) more breakers than the number of poor condition breakers?

B2-Staff-78
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01
EB-2019-0082 Exhibit B / ISD SR-03 and ISD SR-04

Preamble:

Hydro One's EB-2019-0082 application included a Bulk Station Transformer Replacement Projects System Renewal investment (SR-03) and a Bulk Station Switchgear and Ancillary Equipment Replacement Projects System Renewal investment (SR-04). The current application has one Transmission Station Renewal - Network Stations (T-SR-01) System Renewal investment.

Question(s):

a) Please state whether or not for this application, Hydro One has combined projects that would have been separated into two investment documents in the previous application framework into a single investment document? If yes, please explain why.

B2-Staff-79
Exhibit B / Tab 2 / Schedule 1 / Section 2.3 / Attachment 3
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01

Question(s):

a) Please state why transformer replacements are being undertaken at Fort Frances TS (T-SR-01.23) and Merivale TS (T-SR-01.24) given that these transformers do not appear on the list of transformers deemed to be in poor condition by Hydro One, as contained in the EPRI benchmarking report.

Please explain why a transformer replacement is being undertaken at Sarnia Scott TS (T-SR-01.09) given that one transformer is listed on Table 3 of the EPRI benchmarking report, which lists “Transformers deemed in poor condition by Hydro One and not deemed in poor condition by PTX”.[6]

b) Please explain why transformer T6 is being replaced at Middleport TS (T-SR-01.14) given that this transformer is listed on Table 3 of the EPRI benchmarking report, which lists “Transformers deemed in poor condition by Hydro One and not deemed in poor condition by PTX”.

c) The following four investments include the replacement of a single 230/115 kV autotransformer: Sarnia Scott TS (T-SR-01.09), Mackenzie TS (T-SR-01.17), Fort Frances (T-SR-01.23), and Merivale TS (T-SR-01.24). Please explain why the costs for these investments range from $20.6 million at Fort Frances TS, $26.4 million at Sarnia Scott TS, $51.4 million at Mackenzie TS, to $168.4 million at Merivale TS.

d) Please explain why two transformers are being replaced at Wawa TS when one transformer at Wawa TS (T1) is listed on Table 2 of the EPRI benchmarking report, which lists “Transformers deemed in poor condition by Hydro One and deemed in marginal condition by PTX” and no other transformers at Wawa have been deemed in poor condition.

e) Please explain why two transformers are being replaced at Owen Sound TS when one transformer at Owen Sound TS (T4) is listed on Table 1 of the EPRI benchmarking report and one transformer at Owen Sound TS (T5) is listed on Table 3 of the EPRI benchmarking report which lists “Transformers deemed in poor condition by Hydro One and not deemed in poor condition by PTX”.

f) Please explain why autotransformers T3, T4 and T8 are being replaced at Porcupine TS (T-SR-01.15) given that these transformers appear on Table 3 of the EPRI benchmarking report, which lists “Transformers deemed in poor condition by Hydro One and not deemed in poor condition by PTX”.

B2-Staff-80

Exhibit B / Tab 2 / Schedule 1 / Section 2.3 / Attachment 3
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-03

[6] Power Transformer Expert System

Question(s):

a) Please explain why transformer replacement is being undertaken at Bunting TS (T-SR-03.42) and at Allanburg TS (T-SR-03.94) given that these stations are not included in the EPRI benchmarking report.

b) Please explain why 115 kV step-down transformer is being replaced at Timmins TS (T-SR-03.57) when the EPRI benchmarking report does not include a 115 kV transformer at Timmins TS.

c) Please explain why transformer replacement is being undertaken at Midhurst TS (T-SR-03.34) and at Birmingham TS (T-SR-03.46) given that T4 at Midhurst TS and T1 at Birmingham TS are listed in Table 3 of the EPRI benchmarking report, which lists "Transformers deemed in poor condition by Hydro One and not deemed in poor condition by PTX".

d) Please explain why transformer replacement is being undertaken at Kent TS (T-SR-03.55), Leslie TS (T-SR-03.63) and Lisgar TS (T-SR-03.73) given that T2 at Kent TS, T1 at Leslie TS and T1 at Lisgar TS are listed in Table 2 of the EPRI benchmarking report, which lists "Transformers deemed in poor condition by Hydro One and deemed in marginal condition by PTX".

B2-Staff-81
Exhibit B / Tab 1 / Schedule 1 / Section 1.2 / Attachment 3
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01

Preamble:

According to page 40 of the Greater Ottawa Regional Infrastructure Plan (first reference), Merivale TS "houses a 230 kV GIS switchgear with six SF6 breakers two 230/115 kV auto-transformers T21 and T22 and a 115 kV switchyard with four oil circuit breakers and twelve SF6 circuit breakers." A total of 22 circuit breakers are therefore described.

On page 40 Hydro One also states that:

> The existing 230 kV breakers have been in-service from 1977 and are approaching end of life. The existing auto-transformer T22 has been in-service since 1978 and is approaching end of life. The 115 kV oil circuit breakers came to service between 1973-1976 and have been identified for replacement.

Question(s):

a) Please confirm that the 22 circuit breakers described on page 40 are the 22 circuit breakers that are planned to be replaced as part of T-SR-01.24.

b) Please state whether or not Merivale autotransformer T22 was repaired or replaced in 2018 as part of the tornado recovery work? If yes, please describe the repair or replacement that was carried out.

c) Please state whether or not any of the 22 circuit breakers described on page 40 of the Greater Ottawa Regional Infrastructure Plan were repaired or replaced in 2018 as part of the tornado recovery work?

d) Please provide the ESL of T22 in years.

e) Please state whether the T22 transformer is in good, fair or poor condition, based on the categorizations used for transformers in TSP Section 2.2. If T22 is in fair or good condition, please state why it is being replaced.

f) Please confirm that T22 is being replaced on a like-for-like basis.

g) Please provide the cost for the replacement transformer itself.

h) Please complete the following table:

	In-Service Date	ESL (years)	Good, fair or poor condition, based on the categorizations used for circuit breakers in TSP Section 2.2	Cost for each replacement circuit breaker
Six 230 kV SF6 circuit breakers				
Four 115 kV oil circuit breakers				

Twelve SF6 circuit breakers				

i) Please state whether or not any of the circuit breakers are in good or fair condition, and if so, please explain why they are being replaced.

<u>B2-Staff-82</u>
Exhibit B / Tab 1 / Schedule 1 / Section 1.2 / Attachment 3
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01.24
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SS-05

Preamble:

The Greater Ottawa Regional Infrastructure Plan (first reference) is dated December 18, 2020. Table 1-1 on page 8 includes the following as item number 10:

No.	Need	Recommended action plan	Expected I/S
10	Merivale TS: Autotransformation capacity and end of life of T22, 230 kV breakers, 115 kV breakers.	Replace T22.**	2025
		Review recommendations of Ottawa 115 kV System Supply and Gatineau Corridor EOL studies to develop plan for Merivale TS.	2028

Footnote **, referenced in the above table, states that: "Replacement of T22 with like for like transformer planned for completion by 2025. Inputs from the Gatineau Corridor EOL study and Ottawa 115 kV study may impact the timing of the replacement.

Question(s):

a) Please provide the 2015 Greater Ottawa Regional Infrastructure Plan.

b) Please provide the "Greater Ottawa Area Region's Needs Assessment" that was completed in June, 2018.

c) Please provide the “Ottawa Sub-Region’s Integrated Regional Resource Plan” that was completed in March, 2020.

d) Please provide the “Ottawa 115 kV System Supply” study, if available.

e) Please provide the “Gatineau Corridor EOL” study, if available.

f) Please state at what point in the regional planning process the need for autotransformation capacity at Merivale TS was identified (e.g. during the needs assessment)? Please reference corresponding regional planning documents (e.g. needs assessment).

g) Please state at what point in the regional planning process end of life of T22, 230 kV breakers, 115 kV breakers at Merivale TS was identified (e.g. during the needs assessment)? Please reference corresponding regional planning documents (e.g. needs assessment).

h) Please state how the recommendations of the Ottawa 115 kV System Supply study and the Gatineau Corridor EOL study influenced the plan for the replacement of T22? If these studies are not yet available, please explain how Hydro One has determined that T-SS-05 is an appropriate plan for Merivale TS.

i) Please state whether or not the execution plans for projects T-SR-01.24 and T-SS-05 have been integrated for efficiency? If yes, please explain and provide an estimate of the cost savings compared to if the two projects were executed individually. If no, please explain why not.

j) Please define the Ottawa West 115kV area that is referenced on page 1 of the T-SS-05 investment document. How is this area presently supplied?

B2-Staff-83
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01
EB-2019-0082 Exhibit B / ISD SR-04

Preamble:

Page 26 at the first reference states that the T-SR-01.24 project at Merivale TS is forecast to consist of replacing one transformer (T22), 22 breakers and 58 protection system assets. Page 31 at the first reference states that the project has a total cost of

$168.4 million and an in-service year of 2027. It is also stated that this project was part of SR-04 in the EB-2019-0082 application.

On page 16 of the ISD SR-04 document from the 2019 application (second reference), the scope of the project at Merivale TS is described as replacing four breakers and 55 protection system assets. The in-service year is 2025. This document also states on Page 10 that the project total cost is $18.9 million.

Question(s):

a) Please confirm that the scope of the SR-04 project is contained in the scope of the SR-01.24 project (i.e. four of the 22 breakers and 55 of the 58 protection system assets that make up the SR-01.24 project were the same as those previously described in the SR-04 project).

b) Please explain why the scope has expanded between the 2019 application and the current application.

c) Please explain why the increase in the project cost from $18.9 million for SR-04 in the 2019 application to $168.4 million for SR-01.24 in the current application is reasonable.

d) Please provide a breakdown of the $168.4 million project cost for T-SR-01.24 into three portions: the cost for replacing one transformer, the cost for replacing 22 breakers, and the cost of replacing 58 protection system elements.

B2-Staff-84
Exhibit B / Tab 1 / Schedule 1 / Section 1.2 / Attachment 3 / pp. 28-29
Exhibit B / Tab 2 / Schedule 1 / Section 2.9 / Attachment 2, p. 11
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-01

Preamble:

At the first reference, Hydro One states that:

> Table 6-1 summarizes the results of the adequacy studies and identifies the need dates for reinforcement of the 230/115 kV autotransformer facilities at Hawthorne TS and Merivale TS. Assuming no change in the system configuration the Limited Time Rating ("LTR") of the Merivale autotransformers, T21 and T22, are

exceeded in 2020. The continuous rating of the Merivale autotransformers are exceeded by 2024/25 for T21 and T22 respectively.

At the first reference, Hydro One states that:

Replacement of autotransformer T6 at Hawthorne TS was completed in 2017 and T5 is undergoing replacement with a projected in-service date in Q2 2021. The need dates assume that the Hawthorne TS 225 MVA, 230/115 kV autotransformer T6 have been replaced with new 250 MVA unit.

Table 2 at the second reference includes a System Service project under the heading "Local Area Supply Adequacy" called "Hawthorne TS: Replace 2 Existing Transformers" with a forecast in-service date of 2021. This project has a forecast project total of $20.4 million.

Page 28 at the third reference states that the T-SR-01.31 project at Hawthorne TS is forecast to consist of replacing 8 breakers and 111 protection system assets. Page 31 at the third reference states that the project has a total cost of $33.7 million and an in-service year of 2028.

The following table summarizes information about Hawthorne TS and Merivale TS projects contained in the application:

Hawthorne TS	**Merivale TS**
Replace 2 autotransformers	Replace 1 autotransformer
Replace 8 breakers	Replace 22 breakers
Replace 111 protection system assets	Replace 58 protection system assets
Total cost: $20.4 million + $33.7 million **= $54.1 million**	Total cost: **$168.4 million**
In-Service dates: 2017 to 2028	In-Service date 2027

Question(s):

a) Please provide a revised version of Table 6-1 that includes the information about Hawthorne TS autotransformer facilities that is indicated in the description, but not included in Table 6-1.

b) Please clarify whether with respect to the bottom two rows of Table 6-1, if the 2020 MVA loading (255 and 252, for T21 and T22, respectively) exceeds the MVA load meeting capability (250 for both T21 and T22) that means the "need date" is 2020 in both cases? Please explain why the need date says 2024 and 2025 for T21 and T22, respectively?

c) Please confirm that the Hawthorne TS project described at the first reference is the same as the Hawthorne TS project in Table 2 at the second reference.

d) Please provide a detailed comparison of the Hawthorne T6 and T5 autotransformer replacement project described in part a) with the Merivale T22 autotransformer replacement project (T-SR-01.24).

e) Please state whether or not the Hawthorne T6 and T5 autotransformer replacement project was an integrated station project? If yes, how many circuit breakers and how many protection assets were replaced as part of the project?

f) Please explain why the cost of $168.4 million for replacing one transformer plus 22 breakers plus 58 protection system assets at Merivale TS is reasonable compared to the cost of $54.1 million for replacing two transformers plus eight breakers plus 111 protection assets at Hawthorne TS.

B2-Staff-85
Exhibit B2 / ISD T-SR-02 / pg. 1 of 16

Preamble:

As indicated in the Summary:

> This investment involves the replacement of all Air Blast Circuit Breakers (ABCBs) at Hydro One's transmission stations due to asset's poor condition, obsolescence, and poor performance. The primary trigger for the investment is significant reliability risk and high operation and maintenance costs. The investment is expected to increase reliability performance, reduce operation and

maintenance costs, and decrease unplanned outages within major bulk transmission stations.

Questions(s):

a) Please explain and quantify how Hydro One determined that spending $575 million dollars over the next five (5) years replacing ABCBs represents the optimal balance of capital spending pace vs. performance risk mitigation vs. OM&A costs to keep the targeted ABCB's in service.

b) Please quantify the risk associated with spending only half of this amount over the five (5) years and show how this increased risk exposure was calculated.

B2-Staff-86

Exhibit B2 / Tab 2 / Schedule 1 / Section 2.11 / T-SR-02 / Appendix A / pg. 13 of 16
Exhibit B2 / Tab 2 / Schedule 1 / Section 2.1 / pg. 29 of 30

Preamble:

It is stated in Appendix A of ISD T-SR-02 that:

- ABCB breakers at Bruce A 500kV are over 48-year-old and based on the asset condition assessment are determined to be in poor condition. The autotransformers are also in poor condition.
- Consistent with the ABCB breaker replacement strategy, this investment will replace nine 500 kV ABCBs, one SF6 breaker, three autotransformers at Bruce A 500kV and associated switches and other poor condition and/or obsolete assets, as well as P&C system upgrades with a new GIS station.
- Ten breakers remain to be replaced. Replacing these units will maintain reliability of power delivery to high voltage network.

It is also stated in Lines 5 and 6 of Section 2.1 that:

> Once candidate investments have been scored and flagged, enterprise-wide calibration sessions occur to ensure comparable and consistent evaluation across investments and lines of business.

Questions(s):

a) Please explain why Sub-project *T-SR-02.09,* an ABCB replacement project, also includes replacement of three autotransformers at Bruce 500kV?

b) Please identify the individual costs of each component identified in Sub-project T-SR-02.09, i.e.:
    i. Nine (9) ABCB Breakers;
    i. One (1) SF6 breaker;
    ii. Three (3) Autotransformers; and
    iii. Applicable P&C system upgrades.

c) Please explain how Hydro One determined that expenditures on autotransformers, for example, should be included as part of the ABCB breaker replacement program?

d) Please state whether or not inclusion of the non-ABCB assets was identified as part of sub-project T-SR-02.09 evaluated during the "enterprise-wide calibration sessions", as indicated in Section 2.1.

    i. If yes, please provide documentation.

    ii. If no, explain how this sub-project was evaluated and prioritized.

<u>B2-Staff-87</u>
Exhibit B2 / ISD T-SR-09 / pg. 1 of 8

Preamble:

At the above reference, it is stated as follows:

> This investment involves procuring spare transmission station equipment and securing the resources required for (i) emergency replacements of transmission station equipment that has failed while in service and (ii) replacements of deteriorated assets that are not addressed through station-centric investments. The purpose of the investment is to ensure that Hydro One maintains an adequate inventory of spares for its transmission station assets in order to facilitate the expedient replacement of a failed or deficient component at a transmission station, and that Hydro One continues to comply with its legal obligations while mitigating safety, system reliability, and environmental risks that an unforeseen failure might cause.

Question(s):

a) Please provide the Hydro One expenditure for this asset category for the previous five (5) years.
b) Please state how often spares have been used in the past five (5) years, and at which substations.
c) Please state whether or not the proposed investments in spare equipment reduce the required level of System Renewal capital expenditures over the test period or beyond the test period? Please elaborate.
d) Please explain how Hydro One determines the appropriate level of spare equipment.
e) Please explain how Hydro One accounts for spares within rate base. Please provide examples.

    i. Are different spares for different asset classes treated differently? Please provide examples.

    ii. What is the value of assets in this program at the start of the test period?

    iii. What is the estimated value of assets in this program at the end of the test period?

B2-Staff-88
Exhibit B2 / ISD T-SR-13 / pg. 9 of 24

Preamble:

At the above reference, it is stated that:

> Based on the above need, Hydro One currently has 3,874 circuit-kms (or 14%) of its conductor fleet in poor condition, with another 3,329 circuit-kms (or 12%) exhibiting some deterioration, but not to an extent necessitating replacement at this time. Hydro One plans to replace 1,879 circuit-kms (of which 1,571 circuit-kms will be in-serviced during the 2023-2027 period) or 49% of the known poor condition conductors in the fleet over the 2023-2027 planning period.

Question(s):

a) Hydro One defines poor condition as: “Assets that have deteriorated to a point where they can no longer provide the intended functionality or service.” Please state whether or not this definition applies to conductors.

    i. If yes, please explain how conductor assessed to be in poor condition no longer functions as intended.

b) Please state whether or not the remaining 51% of conductors assessed as being in poor condition will remain in service through and beyond the test period?

    i. If yes, how will system reliability be maintained, in consideration of Hydro One’s definition of poor condition assets as no longer providing intended functionality or service? Please elaborate.

    ii. Does Hydro One’s definition of poor condition conductors overstate the actual severity of risk posed by some conductors assessed as being in poor condition? Please elaborate.

c) Please explain how the proposed pacing of spending on this program has been optimized. Please provide detailed calculations.

d) OEB staff notes that in past applications, Hydro One has stated that the cost of replacing splices is approximately 5% of the cost of replacing entire conductor systems between splices. Please confirm that this ratio remains valid or provide an updated cost ratio.

e) Please state whether or not Hydro One records if conductor failures occur at splices versus at locations on conductors between splices?

    i. If yes, please quantify the proportion of conductor failures that occur at splices versus at locations that do not have splices.

    ii. If no, explain why not, particularly in consideration of the much lower cost of just replacing splices that might be in poor condition.

<u>B2-Staff-89</u>

EB-2019-0082 / ISD-SR-19
EB-2019-0082 / ISD-SR-20
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-13
Exhibit B / Tab 1 / Schedule 1 / Section 1.2 / Attachment 9 / p.8

Exhibit B / Tab 1 / Schedule 1 / Section 1.2 / p. 22

Preamble:

At the fifth reference above, it is stated that

> In response to the RIP recommendations, the TSP contemplates the following investment over the 2023 to 2027 period: … 115kV E1C Circuit – Ear Falls TS x Slate Falls DS Refurbishment; Etruscan Jct x Crow River DS Refurbishment (T-SR-13).

Question(s):

a) For each of the following investments, please indicate the bulk or regional plan(s) that recommends the investment and provide the plan(s) if not already included in the application. For investments where no such plan exists, please explain why not.
   i. T-SR-13.1
   ii. T-SR-13.2
   iii. T-SR-13.4
   iv. T-SR-13.6
   v. T-SR-13.8
   vi. T-SR-13.10
   vii. T-SR-13.11
   viii. T-SR-13.14
   ix. T-SR-13.15
   x. T-SR-13.16

b) Table 2 on page 13 at the first reference shows the project total for the refurbishment of D2/3H & D4 & D6T between Hunta SS and Abitibi Canyon SS as being $36.0 million, with an expected in-service date of 2022. Page 22 at the third reference shows the same project (T-SR-13.4) as having a project total of $89.9 million, with an expected in-service date of 2025. Please explain why the cost of this project has increased from $36 million to $89.9 million.

c) Table 4 on page 8 at the second reference shows the project total for the refurbishment of L22H between Easton JCT and Hinchinbrook N JCT as being $41.9 million, with an expected in-service date of 2024. Page 23 at the third reference shows the same project (T-SR-13.8) as having a project total of $58.2

million, with an expected in-service date of 2026. Please explain why the cost of this project has increased from $41.9 million to $58.2 million.

d) Please provide the IRRP that is referenced under the status for item No. 1 (Circuits E1C and E4D capacity) at the fourth reference.

e) Please provide the specific RIP or other regional planning references that recommend the 115kV E1C Circuit – Ear Falls TS x Slate Falls DS Refurbishment; Etruscan Jct x Crow River DS Refurbishment project.

B2-Staff-90
Exhibit B2 / ISD T-SS-01 / pp.2 - 5

Preamble:

The application notes this investment is required to facilitate the request from Lake Erie Connector LLC (ITC), to connect a 1,000 MW high-voltage direct current (HVDC) line between Ontario and Pennsylvania to the Ontario grid at Nanticoke TS and this will require expansion of the Nanticoke TS 500kV switchyard. The current planned in-service date is anticipated to be in Q4 2024. It also notes the costs are fully recoverable through capital contributions from ITC in accordance with the CCRA. It further notes "The CCRA will allow Hydro One to recover the actual costs incurred even if the customer ultimately decides to cancel the project."

Question(s):

a) Given that Nanticoke TS is a network asset, please clarify if the reason for all the costs to be recovered via capital contributions is because Ontario ratepayers will not benefit from this investment in Nanticoke TS (i.e., sole trigger and beneficiary is ITC).

b) The May 13, 2021 letter from the Minister of Energy to the IESO states that "Should IESO be unable to agree to terms with the Proponent … the project would not proceed to contract execution." Please state whether or not Hydro One plans to wait until the IESO completes its negotiations with ITC (and the CCRA is executed) before making any investments in the Nanticoke TS related to this project?

   If Hydro One does not plan to wait until the IESO completes its negotiations (and the CCRA has been executed), and the contract with ITC is not ultimately executed, does Hydro One expect to recover any costs from ratepayers. If so, why?

B2-Staff-91
Exhibit B2 / ISD T-SS-02 / pg. 1 of 6

Preamble:

> This investment is required to replace the phase shifters (PS33, PSR34) at St. Lawrence TS. Phase shifter (PS33) failed in April 2018 and is no longer serviceable. Phase shifter (PSR34) has exceeded its expected service life of 40 years and is to be replaced to avoid the risk of another unexpected phase shifter failure at the intertie. The planned in-service date for this investment is Q1 2023.

Question(s):

a) Please provide the incremental cost of replacing the second transformer (PSR34).

b) Please state why PSR34 needs to be replaced at this time?

c) Please quantify the incremental value provided by replacing PSR34 relative to the incremental cost of doing so.

B2-Staff-92
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SR-15

Question(s):

a) Please provide the five-year historical spending for transmission line emergency restoration referenced on line 2 of page 7 of the investment document.

B2-Staff-93
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SS-06

Question(s):

a) Please provide the Toronto Integrated Regional Resource Plan (IRRP).

b) Please provide the study addendum to the Toronto IRRP that was expected to be completed in Q3 2021.

c) Please separate the total cost for T-SS-06 into the cost for Stage 1 and the Cost for Stage 2 on an annual basis.

d) Please state whether or not the “future 230kV breaker replacement work at Manby TS” is included in the application?

e) Please describe the rationale for the future 230kV breaker replacement work at Manby TS.

f) Please describe the scope and expected timeframe of the 230 kV breaker replacement work at Manby TS.

B2-Staff-94
Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SS-07
Exhibit B / Tab 2 / Schedule 1 / Section 2.9 / pp./ 7-8
EB-2019-0082 Exhibit B / ISD SS-13

Preamble:

Page 1 at the first reference states that “This investment involves the expansions at the terminal stations, Lakeshore Transformer Station (TS) and Chatham Switching Station (SS), to facilitate the connection of the new 230kV double Circuit….”

Page 3 at the first reference states that:

> The new 230kV transmission circuits are expected to be owned by and included in the rate base of a newly licensed partnership. These assets will not form part of Hydro One’s rate base and, as such, the associated capital expenditures have been excluded from the 2023-2027 forecast. Hydro One submitted an application to the OEB to establish a Deferral Account for these Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169).

At the second reference, Hydro One states that “The variance in 2021 is primarily due to the increased scope, complexity and cost associated with the Lakeshore TS project….”

Question(s):

a) Please explain what is meant by “expansion” at Lakeshore TS, which is a new station currently under construction with expected completion in 2022.

b) Please state why the work required to facilitate the connection of the new 230 kV double circuit transmission line between Chatham SS and Lakeshore TS has not been integrated into the ongoing construction of Lakeshore TS?

c) Please describe the scope of the station work at Chatham SS that is included in this investment.

d) Please provide the expected timeframe for the work described in response to c).

e) Please explain the statement that the associated capital expenditures have been excluded from the 2023-2027 forecast.

f) Please provide the West of London Bulk Planning Study, if available.

g) Please explain how the scope of the Lakeshore TS project compares to the scope of SS-13 from the previous application (third reference).

h) Please state what is the variance due to the increased scope, complexity and cost associated with the Lakeshore TS project that is indicated at the second reference.

B2-Staff-95

Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SS-08

Question(s):

a) Please provide historic costs and show how these were used to calculate the annual expenditures for the Future Transmission Regional Plans investment.

b) Please explain how work that is not yet specifically identified could trigger $10.7 million of expenditure in 2023, in as short a timeframe as less than two years from now.

B2-Staff-96

Exhibit B / Tab 2 / Schedule 1 / Section 2.11 / T-SS-09

Preamble:

Page 4 at the above reference states that:

> Consequently, based on preliminary discussions with the IESO, the proposed investment also anticipates constructing the necessary expansions at the terminals stations, Longwood TS and Chatham TS for Stage 2 to facilitate potential 230kV (or 500kV) lines between London and Chatham.

Page 5 at the above reference states that:

> The new transmission circuits are expected to be owned by and included in the rate base of a newly licensed partnership(s). These assets will not form part of Hydro One's rate base and, as such, the associated capital expenditures have been excluded from the 2023-2027 forecast.
> Hydro One submitted an application to the OEB to establish a Deferral Account for these Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169).

Question(s):

a) Please describe the scope of the station work at Chatham SS that is required to facilitate the connection of the new 230 kV double circuit line between Lambton TS and Chatham SS.

b) Please provide the expected timeframe for the work described in response to a).

c) Please describe the scope of the station work at Chatham SS that is required to facilitate the connection of "potential 230kV (or 500kV) lines" between Longwood TS and Chatham SS.

d) Please provide the expected timeframe for the work described in response to c).

e) Please separate the total cost for T-SS-09 into the cost for Stage 1 and the cost for Stage 2 on an annual basis.

f) Please state how Hydro One has estimated the work required to facilitate the connection of "potential 230kV (or 500kV) lines" between Longwood TS and Chatham SS if the voltage and number of potential lines is not yet known?

g) Please explain whether and how the station work at Chatham SS that is described in response to part a), the work that is described in response to part c) and the work that is required to integrate the new 230 kV double circuit transmission line between Lakeshore SS and Chatham SS (T-SS-07) has been integrated and optimized.

h) Please discuss how Hydro One has maintained flexibility in planning for Chatham SS, given that the scope of the "potential 230kV (or500kV) lines" between Longwood TS and Chatham SS is not yet known?

i) Please clarify whether or not the statement that the new transmission circuits are expected to be owned by and included in the rate base of a newly licensed partnership(s) applies to both Stage 1 and Stage 2 described in the investment document?

j) Please explain the statement that the associated capital expenditures have been excluded from the 2023-2027 forecast.

Exhibit B-03 Distribution System Plan

B3-Staff-97

Exhibit B3 / Tab 3 / Schedule 1 / Section 3.5 / pg. 17 of 66

Preamble:

At the above reference, it is indicated that:

- The number of general public incidents has been increasing over the historical period from 11 in 2016 to 33 in 2020. The OEB target for this criterion for 2020 is 5, which is significantly lower than Hydro One's historical performance.

- Motor vehicle collisions represent the largest contributor to the company's serious electrical incidents during 2016 to 2020.

Question(s):

a) Please provide a breakdown of causes for all general public incidents during 2016 to 2020.

b) Please state whether or not Hydro One has a plan to reduce the number of general public incidents to match OEB targets in the forecast period.

   i. If yes, please provide more details of the plan and if Hydro One has performed any study as a basis for the plan.

c) Please state whether or not Hydro One has a plan to reduce the number of motor vehicle collisions.

   i. If yes, please provide more details of the plan and if Hydro One has performed any study as a basis for the plan.

   ii. Has Hydro One considered installing guard rails to reduce the number of motor vehicle collisions?

B3-Staff-98
Exhibit B3 / Tab 3 / Schedule 1 / Section 3.5 / pp. 20-22

Preamble:

At the above reference, Figures 2 and 3 respectively show that; (i) the largest contributors to SAIDI are: tree contacts and defective equipment and (ii) the main contributors to SAIFI are: defective equipment, tree contact and scheduled outages.

Question(s):

a) Please provide the steps Hydro One is taking to address the largest contributors to SAIDI and SAIFI noted above.

b) Please explain the impact Hydro One expects vegetation management and system renewal expenditures to have on the SAIDI and SAIFI values during the forecast period.

c) Please state whether or not Hydro One anticipates the largest contributors to SAIDI and SAIFI to change in the forecast period compared to the historical period? If yes, please explain.

B3-Staff-99
Exhibit B3 / Tab 3 / Schedule 1 / Section 3.5 / pp. 25-26

Preamble:

The above reference indicates that total cost per customer and total cost per km of line has increased over the 2016 to 2020 period.

Question(s):

a) Please state whether or not Hydro One has a plan to address this cost increase trend for the forecast period. If yes, please explain.

    i. If not, does Hydro One anticipate the total cost per customer and total cost per km to increase during the forecast period?

B3-Staff-100
Exhibit B3 / Tab 3 / Schedule 1 / Section 3.5 / pp. 40-41

Preamble:

At the above reference, it is indicated that customer satisfaction with the myAccount portal has declined from 79% in 2016 to 52% in 2020. Hydro One explains that the decline is due to the "increasingly higher expectations for digital products and services." Moreover, Hydro One explains that it has implemented a new transactional survey methodology to track myAccount customer satisfaction and found that the old survey methodology resulted in higher satisfaction rates.

Question(s):

a) Please explain in detail the improvements Hydro One is planning to make to the myAccount portal.

b) Please state whether or not Hydro One has asked customers how to improve the myAccount user experience.

    i. If yes, please explain how Hydro One is taking customer input into account when planning for myAccount improvements.

c) Please explain the process Hydro One follows to make changes or implement new functionality to myAccount. Does Hydro One consider industry standards and innovations? If yes, please explain.

B3-Staff-101
Exhibit B3 / Tab 3 / Schedule 1 / Section 3.5 / pg. 42 of 66

Preamble:

At the above reference, it is stated that the gross cost per pole replacement has increased from $8,350 in 2016 to $10,624 in 2020. Hydro One attributes the increase to its focus on replacing poor condition poles that have the highest potential reliability impact if they were to fail.

Question(s):

a) OEB staff notes that the pole replacement program represents a significant capital expenditure in Hydro One's capital program.

    i. Please explain what analysis has been done on how to mitigate the increasing cost trend and what mitigation strategies are being incorporated.

    ii. Please state the level of cost mitigation that has been achieved.

b) Please state whether given Hydro One's focus on replacing poor condition poles that have the highest potential reliability impact, any poles are being replaced that are still serviceable and have residual life?

B3-Staff-102
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / p. 49

Preamble:

As stated in Lines 2 to 5:

> Due to the nature of Hydro One's largely radial distribution system, pole failures directly impact customer reliability. The number of interruptions attributed to pole failures has been increasing at a steady rate between 2011 and 2020.

Figure 33 shows that the number of outages attributed to pole failures has increased from 134 in 2011 to 360 in 2020 [figure 33 not provided in preamble].

Question(s):

a) Would pole condition be expected to significantly influence the probability of distribution wood pole failure for each of the following event types? Please explain how in each case:
    i. Trees falling on structures and/or conductors
    ii. Extreme wind events (e.g., microbursts or tornados)
    iii. Extreme ice loading
    iv. External interference (e.g., vehicle and equipment contacts)
    v. Forest fires
    vi. Spontaneous failure due to deteriorated pole condition
    vii. Other (please elaborate)

b) Please provide the percentage of distribution wood pole failures attributable to each of these event types for the past 5 years.

c) Explain how Hydro One's proposed accelerated rate of distribution pole replacements will directly correlate to improved reliability or safety performance for each of these failure event types.

B3-Staff-103
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / pp. 90-91
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / p. 97

Preamble:

As stated in Lines 2 to 4 on page 90:

> Figure 69 and Table 10 provide an overview of the age demographics of Hydro One's WRMI meters. Approximately 72% (598 meters) are 10 years of age or less while the remaining 28% (230 meters) are between 11-15 years of age [figure not provided in preamble].

As stated in Lines 3 to 5 on page. 97:

> Figure 75 below illustrates the failure rates of meters by age for the meter population. The figure shows that older meters fail at a greater rate than newer meters, with the oldest population of meters (13 to 14 years old) failing at a rate of 4% and 6% per year respectively.

Question(s):

a) Please confirm that a “run-to-fail” approach is preferred for meters to maximize ratepayer value of the capital investment, considering that individual meter failures are typically low risk events.

    i. If not, please explain why not.

b) Please provide a quantified economic and technical justification for replacing the entire meter portfolio prior to failure or reaching end of expected service life of the individual meters being replaced.

B3-Staff-104
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / p. 96

Preamble:

As stated in Lines 3 to 5 of page 96:

> Figure 74 presents the annual volume of Trilliant L+G ALF meter failures for the period 2017-2020. Meter failures have almost doubled over this period, with approximately 22,500 meters (1.8% of the total meter population) failing in 2020. [Citation omitted.]

Question(s):

a) Hydro One’s current meter management and renewal methodology appears to anticipate “waves” of mass meter retirements into the future, as the bulk of the meter fleet can be expected to simultaneously approach end of life on a cyclical basis. Has Hydro One evaluated alternative replacement or refurbishment programs for this asset class that would avoid similar future “waves” of simultaneous meter retirements?

    i. If yes, please provide documentation of the evaluation and any findings.

    ii. If no, please explain why not.

b) What was the originally expected service life of the Trilliant L+G ALF meters at the time of installation and what is the average service life that will actually have been achieved under Hydro One’s proposed meter replacement program?

i. Please explain any difference between the expected and actual average service life.

B3-Staff-105
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / p. 100

Preamble:

As stated in Lines 6 to 14 of page 100:

> Unlike traditional electromechanical meters, AMI systems are complex and subject to both physical mortality (discussed above) and technological obsolescence factors. The Ontario Auditor General, in its report on Ontario's smart meter initiative, found a 15-year service life estimate for meters is likely overly optimistic given technological obsolescence considerations. AMI systems, in general, are subject to significant technological changes and are similar to other types of information technology requiring significant upgrades or more frequent replacement as the technology matures. However, unlike other forms of information technology, making physical updates to already installed meters is more challenging given the number of devices and their geographic distribution across an expansive service territory.

Question(s):

a) Which components or functionality of the AMI meters are becoming obsolete? In other words, what do they need to do but cannot do at present?

b) Given Hydro One's large size and appreciable market influence relative to many of its utility peers, has Hydro One lobbied or in any way attempted to raise expectations for meter suppliers to provide more reliable and durable products with longer expected service lives?

   i. If yes, please provide documentation of those efforts.

   ii. If no, please explain why not.

B3-Staff-106
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / p. 95

Preamble:

As stated in Lines 17 to 20 of page 95:

> Meter age and meter failures are key indicators of the health of the retail revenue meter population. Figure 73 below provides the age distribution of meters by year and vendor for the meter population. Approximately 840,000 meters (approximately 65% of the meter population) are between 11-13 years old and will begin to reach the end of their 15-year service life in 2022. [figure not provided in preamble]

Question(s):

a) Is implementing mass meter replacements (e.g., over a 3-year period) more cost effective than following a more paced replacement/ refurbishment plan extending over a longer period (e.g., 6 years)? Please elaborate.

    i. Please provide a business case that shows the relative economic cost of implementing complete fleet replacements in 3 years vs. a 6-year alternative (or equivalent timeframes). Please consider availability and capacity of qualified meter technicians in the business case.

b) Is Hydro One prioritizing meter replacements to implement remote disconnect capabilities at customer sites located in remote or difficult to reach locations, to reduce the operating costs associated with manual disconnects and reconnects? Please elaborate.

B3-Staff-107
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / p. 102

Preamble:

As stated in Lines 17 to 22:

> Hydro One's WRMI replacement strategy has historically been run to failure. This strategy has had minimal impact on customer load as WRMI failures in the majority of cases have not resulted in customer load interruption. Typically, one component of the WRMI fails (either a meter which has backup or one of the 6 instrument transformers), allowing the WRMI to continue to operate (although

with reduced accuracy where the instrument transformer failed) while corrective maintenance or full installation replacement plans are executed.

Question(s):

a) Do retail and wholesale meters have the same life expectancy?

    i. If yes, has Hydro One made efforts to offset the synchronization of end-of-life for these different meter classes to avoid overlapping mass end-of-life failures (and the corresponding need for asset replacements) of both classes? Please provide metrics to support this claim.

B3-Staff-108
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / p. 104

Preamble:

As stated in Lines 17 to 24:

> In order to verify vendor meter service life attestations, confirm industry benchmarking data, corroborate information from other sources, and better understand root causes, Hydro One engaged Hydro Quebec to independently design and perform an ALT study, as noted above. The ALT study found critical failure modes involving the rapid degradation of the capacitor that enables GEN 1 meters to reliably communicate (GEN 1 meters were the vendor's initial meter design deployed in the 2007-2009 period totaling approximately 661,000 meters). Meter failure projections, based on ALT study results and recommended confidence levels, estimate approximately 579,000 meter failures by the end of 2027.

Question(s):

a) Please state whether the common early failure mode indicates a type of fault in the Trilliant meters.

    i. If not, please explain why not.

b) Please provide the terms of reference and study scope documents provided to Hydro Quebec when initiating the ALT study.

B3-Staff-109
Exhibit B3/ Tab 3 / Schedule 1 / Section 3.2 / p. 107

Preamble:

As stated in Lines 22 to 26:

> The continued refurbishment/repair of AMI 1.0 meters is not feasible or cost effective given a variety of considerations, including: (i) the volume and geographic distribution of individual meters (over 1.4M devices distributed across 90% of the Province of Ontario); and (ii) the high costs of refurbishment (shipping, lab assessing and diagnostics, repairing if feasible, resealing, and re-shipping back to the field) relative to the cost of a new meter.

Question(s):

a) Are other Local Distribution Companies in Ontario experiencing the same issues?

    i. If yes, please explain what they are doing to address this problem.

B3-Staff-110
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 3

Preamble:

As stated in the *Executive Summary – Pole Replacement:*

- Hydro One's service territory covers more surface area than the average comparator and includes a significant proportion of rural and remote locations that can be difficult or require specialized equipment and procedures to access.
- In 2020, Hydro One initiated an annual standardized pole refurbishment program and a test and treat program that are similar to those of comparator utilities.
- Hydro One utilizes both visual and data dependent sound and bore inspection methods, with inspection rates that are lower than comparators.
- Hydro One's distribution poles are on average older than the comparator group.

- Hydro One replaces poles based upon condition and has a higher pole replacement rate (including poles replaced upon failure) as compared with comparators.
- Hydro One's pole replacement costs are comparable to the mean of the comparator group.

Question(s):

a) From the reference, "Hydro One replaces poles based upon condition and has a higher pole replacement rate (including poles replaced upon failure) as compared with comparators." What is the basis of replacement followed by the comparators?

b) Does Hydro One have fewer pole-failure driven outages than its comparators?

    i. If not, please explain what benefit is being provided to ratepayers by Hydro One's higher pole replacement rate?

    ii. Are some treefall driven pole failures being recorded as pole failures?

B3-Staff-111
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 9
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 6 / p. 9

Preamble:

As stated at the first reference:

> Hydro One has a vast service territory that is much larger than even the nearest comparator in size. It includes large portions of remote and rural territory with difficult to access locations, some of which require specialized equipment and procedures to safely service assets. Hydro One's territory is also the least densely populated relative to the comparator group. Figures 4 and 5 below show comparisons of Hydro One service territory to comparator utilities by customers per distribution circuit-km and customers per square km [Figures not provided in preamble].

As stated at the second reference:

HONI's service territory is the least densely populated as compared with comparators and includes a significant proportion of rural and remote locations that may be difficult or take longer to access. Figure 4 shows the relative density of the comparator panel.

Question(s):

a) Regarding Figure 5, (first reference), please state the number of square km used to calculate the number of Hydro One customers per square km and provide a corresponding map of the Hydro One service territory. Were water bodies included the surface area used to calculate the customer density?

b) Regarding Figure 5, please provide a revised table showing Hydro One customer density calculated using a service area that excludes the remote northern parts of the province that do not presently have grid service.

c) Regarding Figure 4, (second reference), please state the number of square km used to calculate the number of Hydro One customers per square km and provide a corresponding map of the Hydro One service territory. Were water bodies included the surface area used to calculate the customer density?

d) Regarding Figure 4, please provide a revised table showing Hydro One customer density calculated using a service area that excludes the remote northern parts of the province that do not presently have grid service.

B3-Staff-112
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 12

Preamble:

As stated in *3.1 Distribution Poles (3.1.4 Pole Replacements):*

> One variable that helps in understanding the replacement rates for wood distribution poles is the age of the pole inventory. In this case, the average age of HONI's poles is the second highest within the comparison panel at 39 years, compared to the group average of 34 years. Figure 9 shows this average age pattern for the comparison group [Figure 9 not provided in preamble].

Question(s):

a) Regarding Figure 9, please provide information regarding the proportion of respondents' poles consisting of the following species of wood:

    i. Western Red Cedar;

    ii. Douglas Fir;

    iii. Red Pine;

    iv. Southern Yellow Pine; and

    v. Other (please elaborate)

b) What proportion of Hydro One's pole fleet do each of the above tree species comprise?

B3-Staff-113

Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 15

Preamble:

As stated in *3.1 Distribution Poles (3.1.4 Pole Replacements):*

> When a determination is made that a pole should be replaced, it is typically placed on a list of poles awaiting replacement, so that the work can be prioritized and scheduled in the most cost-effective way possible. In Hydro One's case, its current list of poles identified as requiring replacement represents 4.62% of its entire pole inventory, as shown in Figure 12. Any other poles that are determined to require replacement through inspections in the next five years will be in addition to the ones already identified/planned [Figure 12 not added in preamble].

Question(s):

a) Does Figure 12 indicate that Hydro One is using more stringent pole condition criteria to determine when poles need replacement than are its peers?

b) Does Hydro One benchmark or calibrate its pole replacement criteria against its peers and industry best practices?

    i. If yes, please provide quantified examples.

    ii. If not, please explain why not.

c) Is Hydro One's rate of condition-driven pole failure significantly higher than that of its peers?

    i. Please provide a quantified comparison with representative peers.

B3-Staff-114
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 16

Preamble:

As stated in *3.1 Distribution Poles (3.1.4 Pole Replacements):*

> A secondary aspect of planning is the time lag from a failed pole inspection to actual refurbishment or replacement. Most companies try to keep that time under one year. Figure 13 shows the actual time from identification until treatment/replacement [Figure not provided in preamble].

Question(s):

a) When Hydro One assesses that a pole requires replacement or refurbishment, does this mean that there is a very high probability of imminent pole failure? Please elaborate.

b) Since the average Hydro One lag is almost four (4) years from identification that a pole needs replacement to the actual replacement or refurbishment, this means that the average pole survives four (4) more years in service without failing after having been assessed as needing imminent replacement or refurbishment.

    i. Does the existence of this replacement/refurbishment backlog indicate that Hydro One is applying more stringent condition-based tests to identify poles that require replacement than are its peers?

B3-Staff-115
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 17

Preamble:

As stated in *3.1 Distribution Poles (3.1.4 Pole Replacements):*

> A final observation is that the industry as represented by the comparator group appears to be replacing or refurbishing its poles at a rate that is insufficient to sustain it over the long term. The stated expected service life for wood poles for most utilities is an average of 47 years. The average wood pole is 34 years old, with many older than that, indicating that in 13 years, the average pole will reach its expected lifespan. The comparator utilities' actions are more consistent with an expected 75–100-year lifespan for the average pole, yet it is clear to industry observers that achieving this lifespan is unlikely. The gap between the expected service life for poles and the current replacement rates is cause for concern for the industry.

Question(s):

a) Does this indicate that most comparator utilities believe that their wood poles will survive longer than their stated Expected Service Lives for wood poles?

    i. If not, what does it indicate?

    ii. Does Hydro One consider that the comparator utilities are acting imprudently by "replacing or refurbishing…poles at a rate that is insufficient…over the long term"? Please elaborate.

B3-Staff-116
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 20

Preamble:

As stated in *3.2 Distribution Substations (3.2.1 Service Territory):*

> With a large number of small single-transformer substations in service across Hydro One's system, the average loading of those transformers is higher than

average, as would be expected. Hydro One's Distribution substation transformers have the highest peak loading (as a percentage of nameplate rating) among the comparison group, as shown in Figure 17 below [Figure not provided in preamble].

Question(s):

a) What percentage of Hydro One transformers are serving areas with winter peaking loads?

b) What is the winter peaking transformer percentage for the comparator utilities?

    i) If unknown, please confirm that most of the comparator utilities are in locations that would be expected to have summer peaking loads.

c) Regarding Figure 17, have the nameplate ratings used been adjusted to account for the higher winter operational ratings that would normally apply to transformers that serve winter peaking load areas?

B3-Staff-117
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 23

Preamble:

As stated in *3.2 Distribution Substations (3.2.2 Cost for Substation Refurbishment and Transformer Replacement):*

> Hydro One has lower than average costs to replace substation transformers. Hydro One's average cost to replace power transformers is an all in cost of $709K, and is lower than the mean of $1.8M ($1.3M excluding company 48 outlier). The lower costs are partially attributable to greater use of smaller transformers – a higher percentage of 5 kV class (1-9 kV) transformers within HONI's service territory versus the comparator group, who have the majority of power transformers within the 15 kV class (9-15 kV), as described above. Figure 22 shows the cost range within the comparison group [Figure not provided in preamble].
>
> Hydro One has lower than average costs for distribution substation refurbishments on a per transformer basis. These costs represent all equipment, labour and overhead costs for station refurbishment normalized per transformer.

Hydro One averaged $2.4M (across 4 representative refurbishment projects) compared to the mean of $3.1M. In conducting the comparisons, costs were normalized per transformer to be consistent with the single-transformer configuration of most of Hydro One's distribution substations.

Question(s):

a) Please confirm that Figures 22 and 23 compare refurbishment projects without reference to the capacities of the associated transformers.

   i. Is the cost of a transformer refurbishment usually correlated to the MVA rating of transformer being refurbished? Please elaborate.

   ii. Please provide revised versions of Figures 22 and 23 that compare average per-unit refurbishment project costs derived using the MVA ratings of the refurbished equipment.

B3-Staff-118
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1 / p. 24

Preamble:

As stated in *3.2 Distribution Substations (3.2.2 Cost for Substation Refurbishment and Transformer Replacement):*

> Recently, Hydro One has focused more on component-centric projects, which is true of most other comparator companies, as shown in Figure 24. Prior to 2015, Hydro One focused on full rebuilds and station-centric refurbishments. In addition to the shift to more component-based projects, HONI has also introduced a lower cost unfenced pad mount transformer solution for smaller substations. Most of the comparators have not considered this option (2 of 12 have such solutions). Where feasible, this solution is more cost efficient in HONI's experience relative to a full station rebuild. Over the next 5 years, HONI expects to continue the trend of increased component-focused projects, as shown below in Figure 25 [Figures not provided in preamble].

Question(s):

a) Regarding Figures 24 and 25, please describe refurbishment projects that are categorized as "Other".

B3-Staff-119
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 2 / p. 13

Preamble:

As stated in *3.2 Program Attributes*, regarding Figure 9*:*

> To assist in funding the high hazard tree removal rate, Hydro One reduced herbicide use, pausing roadside brush and most spray work. HONI's low use of herbicide is of concern if it persists. IVM is considered a best management practice by system foresters, vegetation managers, academic research, the US Environmental Protection Agency, and many other environmental groups. It has been championed by the ROW Stewardship Council through its Accreditation Standards for Assessing IVM Excellence and is the chosen methodology for many arboriculture, forestry and landscape industry professionals. One of the primary tools advocated in IVM is the use of herbicides to prevent ingrowth and reduce resprouting of removed trees. A six-year study by the Electric Power Research Institute (EPRI) determined herbicide control could reduce stem counts of trees in the ROW by 70% compared to manual and mowing cutting methods alone [Figure 9 not provided in preamble].

Question(s):

a) Does Hydro One intend to increase its use of herbicide over the test period?

    i. If yes, what is the associated cost and where is it found in the application?

    ii. If no, what is the estimated future cost impact on Hydro One's vegetation management program of following a herbicide treatment regime over the test period that is significantly less aggressive than regimes followed by its peers and industry best practice?

b) What is the expected reliability performance impact of following the proposed herbicide application program by the end of the test period, expressed as changes in SAIDI and SAIFI?

B3-Staff-120
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 2 / p. 15

Preamble:

As stated in *3.2.2 Expenditures*:

> While total program expenditures do not allow for a perfect one-to-one comparison, one of the common ways to normalize data for comparison between companies is to analyze costs on a per unit basis. This section 3.3.2 discusses program expenditures by various common unit measures. As HONI has a distribution system with more than twice the pole kilometers of the Peer 2019 group and nearly four-times larger in pole kilometers than the AR 2019 average, examining UVM distribution expenditures on a per managed ROW km basis helps to normalize HONI's data. The HO 2020 cost per managed kilometer (avg. 2018-2020) is statistically different from that of other respondents excepting, Peer 2016 (Figure 12). Cost per managed distribution ROW km is higher than the Peer 2019 mean and lower than the AR 2019 mean. [Figure 12 not provided in preamble].

Question(s):

a) What would the incremental unit cost in 2018 – 2020 have been if Hydro One had followed an herbicide treatment regime more in-line with those of its peers and best industry practice.

<u>B3-Staff-121</u>
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 2 / pp. 17 - 18

Preamble:

As stated in *3.2.2 Expenditures*:

> Labour has been highlighted in previous CNUC benchmarking reports as a primary cost driver of the HONI UVM program which also contributes to the discrepancy. With respect to UVM salaries and UVM hourly wages (Figures 16 and 17), HONI does appear statistically higher for all positions. For salaried positions, HONI is around 1.4 times that of the Peer 2019 group and hourly wages range from 1.2 to 1.8 times higher than the Peer 2019 averages [Figures not provided in preamble].

Question(s):

a) Regarding Figure 16 and 17, please explain the significant disparity between Hydro One salaries and those of its peers and other respondents for the respective roles shown in the figures.

B3-Staff-122
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 2 / p. 20 - 21

Preamble:

As stated in *4.4 Optimal Cycle Protocol Results*:

> Despite having a naturally challenging UVM setting, HONI has seen notable improvements to its UVM program through the implementation of the OCP. In the period since OCP was fully implemented in 2018 to 2020 HONI has seen:
> - A reduction of maintenance interval from 9.5 to 4.1 years.
> - A more than 50% reduction in cost per managed ROW km when comparing 2016 to the average of the OCP period (2018-2020).
> - A positive reversal of total distribution system non-FM SAIDI in minutes, resulting in a total decrease of 13% in non-FM SAIDI minutes by 2020 (compared to 2017).
>
> CNUC expects that HONI's maintenance interval, expenditures, and reliability will improve further as the OCP is refined/optimized in the coming cycles through HONI's defect-focused, data-driven approach.

Question(s):

a) Does the statement regarding Hydro One's maintenance interval, expenditures, and reliability improving hold true if Hydro One continues to follow an herbicide treatment regime that is significantly less aggressive than those of its peers or industry best practice? Please elaborate.

B3-Staff-123
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 3 / p. 2

Preamble:

As stated in *1.3 Key Findings:*

> The assessment found that defects are being controlled, preventing defects reduces the frequency of TCOs, and the projected workload was within the margin of error. However, notification and execution unit costs were above modeled projections.
>
> - A statistically valid and random sampling of completed OCP feeders found a 96% improvement in the number of defects from the 2017 survey relative to 0-2-yr. slot class.
> - An analysis of TCOs comparing non-OCP feeders with feeders on which OCP work has been executed demonstrated an improvement of between 23% and 41% (as illustrated in Section 3, Table 7), which suggests the 20% to 40% reduction of TCOs modeled in the 2017 assessment is achievable.
> - First cycle workload (i.e., number of trees trimmed or removed pursuant to the OCP) for 2018-2020 was 13% greater than 2017 modeled projections.
> - Actual unit cost (trees & km) was significantly higher than 2017 modeled cost, due to factors that were not known or anticipated and could not reasonably have been accounted for in the initial projections, as described in Section 5.3, including higher than projected defect workload.
> - Potential opportunity to modify cycle length on certain feeders or areas.

Question(s):

a) Please provide a detailed explanation of the noted departure from modeled projections of notification and execution unit costs.

b) Does Hydro One anticipate that actual workload will more closely approach modeled projections in subsequent cycles? Please elaborate.

B3-Staff-124
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 3 / p. 6

Preamble:

As stated in *2.4 Conclusion:*

There is evidence from the survey of opportunities to lengthen the cycle from 3 to 4 (or more) years in certain areas where trees may hold (i.e., not become a defect) beyond 3 years. This is particularly true for portions of Zones A & D warranting further investigation but outside the scope of this report.

Question(s):

a) Will Hydro One be taking action to address the indicated opportunities? Please elaborate.

b) Has Hydro One estimated the potential annual vegetation management cost savings that can be achieved by extending the cycle length from three (3) to four (4) (or more) years in certain areas, and particularly for Zones A and D?

i. If yes, please quantify the estimated savings.

ii. If no, please explain why not.

B3-Staff-125
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 3 / p. 7

Preamble:

As stated in *2.4 Conclusion:*

Based on the following factors, a system defect rate of 0.88 per km could be reasonably expected based on an approximate 4-year cycle. While higher than that of a 3-year cycle, this defect rate represents a significant improvement compared to the pre-OCP defect rate of 8.0 per km.

- 26,250 feeder km (25% of total feeder km) 1-year old at 0.12 defects per km derived from the 2021 survey.
- 26,250 feeder km (25%) 2-year-old at 0.22 defects per km derived from the 2021 survey.
- 26,250 feeder km (25%) 3-year-old at 0.96 defects per km derived from the 2021 survey.
- 26,250 feeder km (25%) 4-year-old forecasted at 2.2 worst case scenario based on the difference between the 2017 survey 0-2 slot class and 3-5 slot class.

Question(s):

a) Please compare the SAIFI and SAIDI contributions from vegetation related events prior to and following the first completed Optimal Cycle Protocol (OCP) cycle. Use forecast data for the remainder of Year 4, as necessary.

b) What is the forecast contribution to SAIDI and SAIFI from vegetation-related events following completion of the second OCP cycle? Please provide assumptions used to develop the forecast, including any customized cycle lengths in selected areas.

c) What is Hydro One's actual/forecast net SAIDI and SAIFI due to vegetation events for:

    i. The year immediately prior to adopting OCP;

    ii. The year of completing the first OCP cycle; and

    iii. The year of completing the second OCP cycle.

d) Has Hydro One incorporated the anticipated SAIDI and SAIFI performance attributable to adopting the OCP vegetation management approach when determining the need for capital investments during the test period that are intended to improve reliability performance?

    i. If yes, please provided quantified details of the affected capital programs and projects.

    ii. If no, please explain why not.

B3-Staff-126
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 3 / p. 20

Preamble:

Section 5.2 *Unit Cost Performance* states that "Tables 12 and 13 illustrate 3-year cost performance relative to the 2017 assessment projections." [Tables not provided in preamble.]

Question(s):

a) Please explain the relatively poor Modeled vs. Actual performance for non-contractor executed work activities.

b) What specific actions is Hydro One taking to ensure that the cost of non-contractor executed work activities approaches the cost of contractor executed work activities?

B3-Staff-127

Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 3 / p. 21

Preamble:

As stated in *5.3 Unit Cost Variance:*

> Factors that contributed to the variance include:
>
> - Defect density per km in 2018-2020 was 13% greater than projected as described in Section 4, contributing $609 or 11.6% to the per km unit cost.
> - **Notification cost** – Notification cost was modeled at $2.5Mper year, per zone. Actual cost 75% higher than the modeled cost. There were other factors involved as further described in this section.
> - **Distribution of units** – the projection model assumed a 50:50 removal to trimming ratio to mitigate defects. Higher removal ratios are preferred for long term maintenance but have a higher degree of difficulty and thus higher one-time cost (Table 11). The actual removal to trim/prune ratio was 60:40 resulting in a higher one-time cost. However, benefits will be seen in future years as removed trees will not need to be worked again.
> - **Crew labour** – costs were based on Hydro One labour rates and projected contract rates for industry standard 2-person crews with one utility arborist and one lower cost apprentice, climber, or ground person. Union agreements precluded the use of standard crew complements, thus increasing the labour cost. (Emphasis added.)

Question(s):

a) Regarding distribution of units, please quantify the expected benefits in the next cycle, expressed in terms of annual cost savings.

b) Regarding crew labour, please elaborate on the specific union agreement components that caused this result.

i. Did these restrictions exist at the time the OCP vegetation management proposal was originally presented to the OEB?

a. If yes, please explain why this foreseeable cost impact was not identified at that time.

B3-Staff-128

Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 3 / pp. 21-22

Preamble:

As stated in *5.3.2 Other Factors Contributing to Variances:*

Changes to OCP Work Scope

- Brush work performed on sub-transmission M-Class (44kV) feeders not included in the cost models contributed approx. $7M (2.5%) to the execution cost.

New Technology Deployment

- Forestry Technology Enablement Project (FTEP) deployed in 2019 (in order to better support forestry work performance and associated work management processes) contributed an estimated $5M (9%) to notification and $5M (2%) to execution costs due to training and other operational impacts.

Contracting

Execution strategy included contracted resources to augment in-sourced crews at approx. $18M per year ($55M over a 3-year period). Contracting is approx. 19% less than in-sourced crews (Table 12). Less than $25M was spent on contracting due to various unanticipated constraints, which contributed to a $5.7M (2%) variance in the execution cost.

Significant Events

- Safety stand-down due to a major catastrophic event in 2019 impacting the entire forestry organization over 8 working days equating to a one year 4% loss in productivity and estimated $4.7M.
- The COVID-19 pandemic in 2020 impacted the entire organization, including the performance of forestry work.

Question(s):

a) Regarding *Changes to OCP Work Scope,* please explain why M-Class feeders were not included in the cost models.

b) Regarding *Changes to OCP Work Scope* and *New Technology Development,* please identify the proportions of the identified variances that are either one-time variances or ongoing variances.

c) Please provide, in tabular format, Hydro One's average actual or forecast annual vegetation management costs for the following periods:

   i. Pre-OCP actual;

   ii. First cycle OCP Forecast at prior filing;

   iii. First cycle OCP Actual to-date; and

   iv. Second cycle OCP Forecast.

d) Regarding *Contracting,* please identify each "unanticipated constraint" and quantify its cost impact.

e) Please identify the 2019 "catastrophic event" cited in *Significant Events.*

B3-Staff-129

Ref. 1: Exhibit B / Tab 3 / Schedule 1 / Section 3.6 / p. 8
Ref. 2: Exhibit B / Tab 3 / Schedule 1 / Section 3.8 / p. 22
Ref. 3 Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / Att. 2 / p. 25
Ref. 4: Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SS-04 / p. 5, 6, 8
Ref. 5: Exhibit A / Tab 7 / Schedule 2 / Att. 1 / p. 6
Ref. 6: Exhibit B / Tab 3 / Schedule 1 / Section 3.5 / p. 52, 53

Preamble:

At the first reference above, Hydro One describes "grid scale" and "residential scale" (battery) storage as "a new category of distribution investments as of this rate filing" that "will be employed to provide a temporary source of backup power when the upstream supply is lost. Many of Hydro One's customers are rural and are supplied by lengthy, radial feeders that are vulnerable to prolonged outages. Since radial distribution feeders do not have an alternate source of supply, the cause of any outage must be corrected before power can be restored." (Ref. 1; p. 8)

This category of investment includes two programs:

- $115.3 million over five years for 'Grid Scale Storage' to install a battery-based backup supply in some "20 BESS sites". (Ref. 4, p. 8; Ref. 2)
- $61.9 million over five years for 'Residential Storage' to be installed BTM in 2,100 "homes around the province".(Ref. 4, pp. 6, 8)

Question(s):

a) Hydro One states in Exhibit A regarding the Grid Scale Storage proposal that on average, its customers residing within First Nation communities experienced nearly 26 hours of interruption and over seven sustained interruptions per year over the 2018 – 2020 period. (Ref. 5)

   Please provide information on the duration and causes of sustained interruptions in the First Nations communities targeted for Grid Scale Storage investments, and indicate the number of outage hours per sustained interruption that will be avoided by the employment of the battery backup supply.

b) Please state whether or not any of the target First Nations communities are currently equipped with conventional backup generation either at the grid level or supplying critical loads?

c) The "Nakina DS F2 BESS" project is described as "a pilot initiative for a Hydro One owned and operated Battery Storage facility in rural Ontario which is intended to provide backup power to the Aroland First Nation community where the community has been susceptible to prolonged outage durations. The project incurred increased costs as a result of complexities in finalization of the engineering design, COVID-19 restrictions, construction, commissioning and in-servicing which has also resulted in delays to the original in-service date." (Ref. 3; p. 25)

   Hydro One states that it is "implementing a pilot battery energy storage project with Aroland First Nation, a community of approximately 135 residents located around 350 km northeast of Thunder Bay", that the total cost of the project "is approximately $10M", and that compared "to traditional alternatives, this is a cost-effective solution that is anticipated to improve the reliability of the community by approximately 60%." (Ref. 4; p. 5)

i. Please confirm that the “Nakina DS F2 BESS” and “Aroland BESS pilot project” are the same project?

ii. Please state whether or not this pilot project has been commissioned and if so, how long has it been in operation?

iii. Please state whether or not a formal internal review has been conducted to collect learnings from this pilot project, and if so please provide this information.

iv. Please explain the role the pilot project played in designing Hydro One’s GSS proposal, and in particular Hydro One’s expectations regarding the reliability improvement related to it.

d) Please provide the number of target residential customers in each of the UR, R1 and R2 rate classes for the Residential Storage proposal.

e) OEB staff notes that Hydro One provides reliability data on ‘SAIDI - Rural - duration in hours’ and for ‘SAIFI – Rural – frequency of outages’ for “Rural” customers for the 2016 – 2020 period (Ref. 6). Please clarify whether ‘Rural” aggregates data for Hydro One’s UR, R1 and R2 customers.

f) Please state whether or not the reliability data referenced above aggregates UR, R1 and R2 customers. If it does, please provide 2016 – 2020 SAIDI and SAIFI data as above by rate class where represented in Hydro One’s Residential Storage target customer group.

g) How many R1 and R2 customers experience more than 50 hours of outage per year?

i. What is the average number of outages for these R2 customers?

ii. How many hours of interruption are these customers forecast to experience each year after the installation of BTM storage? Will other investments need to be made to achieve this? If yes, at what cost?

h) OEB staff notes that to be eligible for the installation of a Residential Storage backup supply, a customer must have an “acceptable internet signal and available wall space in a temperature-controlled room” (Ref. 4; p. 6) Please state whether or not Hydro One also would consider a customer eligible if they meet these criteria and have a conventional backup generation system already installed?

i) OEB staff notes that Hydro One states that the purpose of its Residential Storage investments in customer homes is “to provide a temporary source of backup power when the upstream supply is lost.” (emphasis added) (Ref. 1)
Please state whether or not Hydro One believes that a target customer with conventional backup generation would no longer need to use it? Please clarify whether or not Hydro One’s investment would eliminate the need for conventional backup generation for every eligible customer, regardless of load characteristics?

j) Please describe the method by which Hydro One determined the appropriate energy storage capacity of the systems to be installed, with reference to the longest-duration outages expected, the frequency of these outages and the cost of storage.

k) What measures will Hydro One implement to maintain control of the BTM batteries once they are installed within a customer premise? How will Hydro One ensure the batteries are available when an outage occurs?

l) What control, if any, will customers have over the BTM facilities?

m) Will any costs related to the BTM assets be recovered from the residential customers who receive them?

n) Please describe what steps Hydro One has taken to estimate the value of improved reliability to these customers. Please explain how this value is factored into the scope of investments proposed. Please discuss the cost-effectiveness of this reliability program relative to other opportunities to improve reliability, including for customers who experience fewer than 50 hours of outage per year.

o) Under what conditions would Hydro One expand the program scope beyond the 2,100 homes planned for installation?

p) Under what conditions would hydro One reduce the scope of the program and provide fewer than 2,100 homes?

q) What cost analysis has Hydro One performed to assess of the relative costs of locating the storage in front of and behind the customer's meter for the residential household battery backup eligible customers? Please provide examples.

r) What other alternatives has Hydro One explored to remediate reliability for these customers? Please provide a cost benefit comparison between BTM storage, in front of the meter storage and other alternatives.

s) Is there any overlap between the Worst Performing Feeder program and the Residential Storage trial project?

t) Is Hydro One evaluating the suitability of customers served by any of the Worst Performing Feeders as participants in the Residential Storage trial project? Please explain why or why not.

u) The fourth reference above states that "Hydro One is currently undertaking a pilot project to improve the reliability for around 100 rural residential customers through residential household battery backup. …The customer selection criteria and process for the wider rollout of the program will be refined based on learnings from the pilot. Residential household battery backup is anticipated to reduce both outage duration and outage frequency by around 60%." (Ref. 4; pp. 6 – 7)

    i. Please state whether or not this pilot project has been commissioned and if so, how long it has been in operation?

    ii. Please state whether or not Hydro One has conducted a formal internal review of this pilot project, and if so please provide documentation on any findings and lessons learned.

    iii. Please describe the role of the pilot project in designing the Residential Storage program proposal, including Hydro One's expectation for the 60% reliability improvement, including whether Hydro One expects the individual installations to eliminate the need for conventional backup generation?

<u>B3-Staff-130</u>

Exhibit B / Tab 3 / Schedule 1 / Section 3.8 / p. 18
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SS-05 / p. 2

Preamble:

As stated in Lines 15 to 19 of Section 3.8 page 18:

> Hydro One customers on average have experienced about 15 hours of outage annually from 2011 to 2020, including all major weather events and loss of upstream transmission supply. Long duration of outages impact customer's negatively interrupting the regular flow of life, prevents business from providing normal service to their customers, and result in manufacturing delays and potential product loss.

As stated in Lines 15 to 20 of D-SS-05 page 2:

> 500 feeders, serving over 600,000 customers, with the highest average contribution to SAIDI have been targeted to be addressed over the 2023-2027 investment plan. Historically these 500 feeders cumulatively contribute to a quarter of Hydro One's overall SAIDI. Improving performance of this group of feeders is expected to reduce the average duration of outages by over 40% for about 600,000 customers, which represents a significant portion of the 1.4 million customers served by Hydro One.

Question(s):

a) How did Hydro One determine that the appropriate cut-off count for the worst performing feeder program is exactly 500 feeders (rather than, say, 100 or 250 feeders)?

    i. Please demonstrate quantitatively that the program is economically efficient, in other words, that the choice of 500 worst performing feeders achieves the most cost-effective balance between "worst feeder" focused investments and any other asset investments being made to improve overall customer service performance.

    ii. Are any of the 500 worst performing feeders achieving at or near system average levels of performance?

    iii. Does Hydro One apply a minimum customer count threshold when assembling the 500 worst performing feeder portfolio?

b) Please confirm that the 500 worst performing feeders, which serve 600,000 customers out of 1,400,000 total (~43% of customers) contribute 25% of SAIDI.

   i. If confirmed, this indicates that the feeders serving the remaining 57% of customers contribute 75% of SAIDI. Please explain and quantify why Hydro One considers this expenditure targeting to be an economically efficient approach to improving reliability performance.

B3-Staff-131
Exhibit B / Tab 3 / Schedule 1 / Section 3.8 / pp. 20-24

Preamble:

As stated in Lines 16 to 26 on page 20:

> These OM&A expenditures, forecasted to be $20.2M in total for 2023, fund the work required to inspect, repair or maintain distribution stations or individual station components, as well as assess and carry out remedial work to reduce environmental contamination at distribution stations. Overall, planned capital investments will put upward pressure on stations OM&A costs over the plan period, as investments that result in OM&A savings by reducing the number of stations are offset by new OM&A expenditures required to maintain new stations and future energy storage systems. Since OM&A expenditures for energy storage systems will not be incurred until these systems are in-service, these expenditures are not reflected in the 2023 Sustainment OM&A forecast. Not proceeding with capital investments in some cases will result in increased Stations OM&A costs. Expenditure categories for Stations Sustainment OM&A are further discussed in the following sections.

Question(s):

a) Please provide historical trends for the individual O&M spending categories listed in this section.

b) If forecast 2023 O&M spending in any of the listed categories represents a significant departure from or discontinuity with past spending trends, please explain the reasons for the departure or discontinuity for each identified category.

B3-Staff-132
Exhibit B / Tab 3 / Schedule 1 / Section 3.8 / p. 22

Preamble:

As stated in Lines 1 to 9:

> System Upgrades Driven by Load Growth (DSP Section 3.11, D-SS-01) addresses station capacity through new or upgraded stations, in response to system needs driven by load growth. Since these investments may result in the construction of a new station (or expansion of existing station), they are expected to increase station inspection and preventive maintenance costs. The construction of a new station will require cyclical inspections to maintain regulatory compliance and increased preventive maintenance requirements such as oil tests or diagnostic tests. Over the course of the 2023-2027 capital plan, load growth investments will result in an increase of 8 new distribution stations, and 4 new stations transformers that will be added to existing sites.

Question(s):

a) Please confirm that for the initial years following commissioning of new stations, the preventative maintenance costs should be significantly lower than for comparable older stations, due to the "as new" condition of the facilities.

   i. If not confirmed, please explain why not.

   ii. Do Hydro One's O&M procedures recognize that new facilities typically require significantly less maintenance effort than do older facilities? If not, please explain why not.

B3-Staff-133
Exhibit B / Tab 3 / Schedule 1 / Section 3.8 / p. 28

Preamble:

As stated in Lines 15 to 23:

> Distribution Lines Sustainment Initiatives (DSP Section 3.11, D-SR-10) fund the rebuilding of line sections that are in poor condition. In cases where the line section is off-road, the line may be relocated to road allowance, which provides easier access for future corrective maintenance activities. The number of

corrective maintenance activities is also expected to be reduced for newly build line sections. While corrective maintenance costs are anticipated to be lower for newly build line sections, less than one percent of the system will be rebuilt over the plan period. Thus, the overall equipment population condition is not sufficiently impacted by this investment to make a material difference on system maintenance costs.

Question(s):

a) Are the predominant failure mechanisms demonstrated by poles located on-road allowance and off-road allowance the same or different? For example, poles located on road allowance will presumably be more susceptible to vehicle contacts than will poles located off road allowance, but poles located off road allowance may have a greater risk of treefall induced failures. Please elaborate.

b) Is there any overlap or redundancy between Distribution Lines Sustainment Initiatives and the 500 Worst Performing Feeders program?

    i. How does Hydro One determine which program would be most appropriate to categorize mitigation work to address a poor performing feeder that is also in poor condition? Please provide specific decision examples.

B3-Staff-134
Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / p. 5

Preamble:

Regarding *Table 1 – Historical and Bridge Years Capital Expenditure Summary*

Question(s):

a) Please explain the differences between 2022 approved and 2022 forecast spending in the System Access, System Renewal and System Service categories, as shown in Table 1. Forecast spending for System Access and System Service is expected to be 26% and 49% higher, respectively, than approved, whereas forecast System Renewal spending is expected to be 12% lower than approved.

i. Do these differences indicate that Hydro One considers System Renewal investments to be non-essential, and therefore able to be deferred if capital is required for projects and programs in other spending categories? Please elaborate.

ii. Is capital being diverted from System Renewal spending to support more aggressive System Access and System Service spending?

a. If yes, please explain the reasoning for this decision.

iii. Does this spending pattern indicate that the reliability benefit that will be gained by increased System Service investments will more than offset any reliability deterioration that might result from reducing System Renewal spending? Please explain in detail and quantify.

B3-Staff-135
Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / p. 6

Preamble:

As stated in Lines 7 to 12:

> As shown in Table 2 [not provided in preamble], over the 2019 to 2022 period, System Access expenditures have been higher, and are forecast to remain higher, than OEB-approved levels. Expenditures have exceeded approvals primarily due to non-discretionary expenditures associated with the design and construction of new load customer connections and service upgrades (DSP Section 3.11, D-SA-02). These increased expenditures were driven by higher than forecast connection volumes and an increase in large expansion projects.

Question(s):

a) Has Hydro One correlated this increased connection volume with socioeconomic trends or other growth drivers in its service area?

    i. If yes, please provide documentation.

    ii. If no, does Hydro One have any indication as to what is driving these unexpected growth trends?

b) How confident is Hydro One that the trends will drop off to the extent implied by the forecast decreasing System Access investment trend over the test period?

    i. Please provide reasoning for this confidence.

c) If System Access trends higher than forecast through the test period, will that impact funding or capacity available to support Hydro One's forecast System Renewal spending trend?

B3-Staff-136
Exhibit B / Tab 3 / Schedule 1 / Section 3.11

Preamble:

Credits for removal are identified in the Total Investment Cost tables for various investments. For example, Table 2 on page 6 of ISD D-SA-01 shows a total removal cost of $35.7 million.

Question(s):

a) Please explain what removal costs are, and why they are deducted from gross investment costs.

b) Please explain the methodology Hydro One used to forecast the removal costs.

c) Why are there no removal costs shown in the ISD's for the following programs:

    i. D-SR-02: Mobile Unit Substation Program

    ii. G-GP-01: Transport and Work Equipment

    iii. G-GP-02: Helicopter Removal

B3-Staff-137
Exhibit B / Tab 3 / Schedule 1 / Section 3.11/ ISD D-SA-02
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-10

Preamble:

ISD D-SR-10 states:

A significant number of station egresses that serve Hydro One Distribution's 1.4 million customers rely on underground cables to both enter and exit the stations. Underground cables also serve large residential and industrial subdivisions in more populated areas. Failures of underground cables may result in significant outages to customers due to a more complex and time-consuming restoration process. Crews would have to locate the issue, conduct excavation (by digging or hydrovac) to examine the asset, evaluate whether the defect is repairable, and conduct repairs or splice in a new cable as required.

Question(s):

a) What is Hydro One's current standard for installing new underground medium voltage cables as substation egress, in residential subdivisions and industrial subdivisions, direct buried or in duct?

b) As the first generation of underground medium voltage XLPE cables are direct buried and nearing end of service life, has Hydro One evaluated the cost benefit of installing new medium voltage cables direct buried versus in duct, and what has it determined?

c) Please complete the table below for SA-02 New Load Connections, Upgrades and Cancellations.

($M)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast
Gross Investment Cost					
Less Removals					
Capital and Minor Fixed Assets					
Less Capital Contributions					
Net Investment Cost					

B3-Staff-138
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SA-04
Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / Attachment 1

Preamble:

As stated in Lines 14 to 17 of page 5 and Lines 1 to 12 of page 6:

The Metering Sustainment program funds the following needs over the test period:

- Replacing failed AMI 1.0 meters (approximately 316,000 meters);
- Ensuring there are sufficient meters to address sampling and reverification regulatory requirements (approximately 12,700 meters);
- Upgrading non-standard meter installations to Hydro one Distribution's current wholesale and retail revenue meter standards because of acquisition due to a boundary change or the acquisition of an LDC;
- Upgrading WRMI to a retail revenue meter when customers choose to become a retail customer of Hydro One Distribution;
- Replacing WRMI Instrument transformers with a high degree of failure risk
- Replacing aging and obsolete meter lab equipment to ensure compliance with Measurement Canada requirements to maintain accreditation as a licensed meter service provider for testing, verification, and sampling of meters;
- Upgrading aging 600V self-contained meters with 120V transformer rated meters, since vendors are no longer supporting this form factor. Replacing these 600V meters with an inherently safer 120V unit increases employee and customer safety, and allows Hydro One Distribution to meet expired seal obligations.

Based on information found at the second reference, the five-year average (2018-2022) cost for the metering sustainment program (D-SA-04) is $20.4 million.

Question(s):

a) Please provide a table for each item listed above, modeled after Table 2 – Total Investment Cost (per the template below):

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Costs						
Less Removals						
Capital and Minor Fixed Assets						
Less Capital Contributions						
Net Investment Cost						

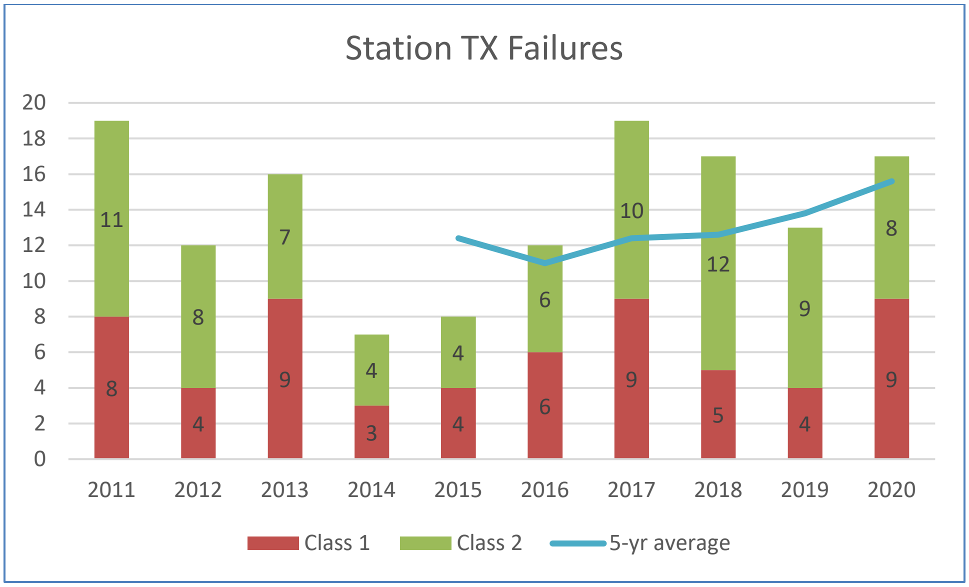
b) Expenditures in 2023 of $62.6 million represent a $44.1 million (238%) increase compared to $18.5 million in 2022, and $42.2 million (207%) from previous 5-year (2018-2022) average of $20.4 million. For the items in part a) responsible for this increase, please provide a business case for the increased expenditures including options considered, requirements mandated through legislation, and cost control measures implemented.

B3-Staff-139
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-01
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-04

Preamble:

The following table and chart reproduce the station transformer failure information contained in Figure 3 at the first reference. The five-year average of station transformer failures is increasing with time.

Failures	Class 1	Class 2	Total	5-yr average
2011	8	11	19	NA
2012	4	8	12	NA
2013	9	7	16	NA
2014	3	4	7	NA
2015	4	4	8	12.4
2016	6	6	12	11.0
2017	9	10	19	12.4
2018	5	12	17	12.6
2019	4	9	13	13.8
2020	9	8	17	15.6



At the second reference, Hydro One states that currently 237 substation transformers (20%) are in poor condition. Hydro One plans to replace 118 transformers over the test year period, which represents 10% of the total asset population and 50% of the transformers in poor condition.

Additionally, on page 5 at the second reference, Hydro One states that “These station refurbishments – together with other investments addressing poor condition transformers and corrective maintenance – are expected to maintain the current proportion of poor condition transformers at approximately 20%.”

Question(s):

a) What proportion of Hydro One transformers are expected to be in good condition and fair condition at the end of the test period?

b) Hydro One has determined that maintaining 20% of its distribution station transformer fleet in poor condition by the end of the Planning Period represents an acceptable risk. Does this indicate that:

   i. Hydro One is using overly conservative parameters to assess transformer condition?

   ii. Running this equipment to failure is acceptable; or

   iii. Something else (please describe)?

B3-Staff-140
Exhibit B / Tab 3 / Schedule 1 / Section 3.2 / pp. 34-36
Exhibit B / Tab 3 / Schedule 1/ Section 3.11 / ISD D-SR-02 / p. 9

Preamble:

As stated at the first reference:

> Failure modes and condition defects of MUSs include the typical defects that station transformers, switches, fuses and reclosers experience. Additional defects that MUSs can experience include trailer defects such as rust, worn suspension, brakes or landing gear and damage to MUS feeder connection cables. Currently, 40% of the MUS transformers and 26% of the MUS trailers are in poor condition, as shown in Figures 19 and 20 [figures not included in preamble].

At the second reference, Hydro One states that they plan on replacing 8 of 14 MUS transformers that are in poor condition and 2 of 9 MUS trailers that are in poor condition.

Question(s):

a) Please elaborate on the relationship between the population metrics identified in Figures 19 and 20 (first reference) and the corresponding MUS asset age demographics shown in Figure 17 and 18 on page 34 at the first reference.

b) Is the condition of some MUS units deteriorating faster than anticipated?

   i. If yes, has Hydro One investigated and identified if its operating and maintenance practices are contributing to the accelerated deterioration, including "trailer rust, worn suspension, brakes and landing gear", or "MUS feeder connection cables"? Please elaborate.

c) How does the number of annual road kilometres typically experienced by an MUS unit compare to the number of annual road kilometres typically experienced by a Hydro One service vehicle?

   i. If MUS units typically experience fewer annual road kilometres than service vehicles, what is causing the MUS trailers to experience the identified deterioration?

ii. Does Hydro One fully wash down and remove salt from the MUS trailers after each exposure to salted roadways? If not, why not?

d) How many MUS transformer trailers are expected to move from the fair and good to poor condition classification over the test period?

e) What is the threshold proportion of MUS assets being maintained in poor condition that Hydro One considers to be acceptable? Please explain.

B3-Staff-141
EB-2017-0049 / Exhibit B / Tab 1 / Schedule 1 / Section 3.8 / ISD-SR-06

Preamble:

Pages 3 through 5 at the first reference contain a list of proposed distribution station refurbishment projects.

Question(s):

a) Please identify all projects from the referenced list that Hydro One now forecasts will not be completed by the end of 2022.

    i. For each project not expected to be completed by the end of 2022, please explain why the project was deferred and how Hydro One plans to address the originally identified need driving the project.

B3-Staff-142
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-05

Question(s):

a) Please explain the rationale for charging capital contributions for storm repairs.
    i. Do these charges cover the cost of Hydro One repairs of customer-owned lines and facilities?
    ii. If the answer to part i) is yes, please explain why this is not treated as a non-regulated business activity.

B3-Staff-143
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-06

Preamble:

As stated on page 1 at the above reference:

> This investment involves the replacement of oil filled distribution lines equipment that exceed federal regulatory thresholds for PCB. The primary trigger of the investment is a statutory requirement to remove all equipment exceeding 50 ppm PCB by the end of 2025. The investment is expected to mitigate health and safety risks associated with PCB contaminated line equipment and ensure compliance with federal legislation.

Question(s):

a) Please explain why Hydro One has not yet addressed this matter, considering that it has been identified as a concern for several decades.

    i) When did Hydro One first become aware of the problem?

    ii) Has spending on this program been deferred to address reliability priorities? Please elaborate.

b) Please explain why Hydro One chose to accept the liability of keeping equipment with unacceptable levels of PCBs in operation, despite the risk that doing so could cause more expensive clean ups following equipment leaks or failures.

c) Please explain why Hydro One did not begin surveying the PCB concentration in its distribution equipment at an earlier date.

d) If all assets with excessive PCB levels are to be taken out of service by 2025 and given that the program budget ends in 2025, please state whether there will be any disposal costs associated with this program extending into 2026 or beyond. If so, please identify the costs for each year these costs will be incurred.

B3-Staff-144
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-07
Exhibit B / Tab 3 / Schedule 1 / Section 3.3 / Attachment 1
Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / Attachment 2 / pp. 14 and 21

Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / Attachment 1
Exhibit B / Tab 3 / Schedule 1 / Section 3.5 / p. 42

Preamble:

As stated on page one at the first reference:

> This investment involves the planned replacement and chemical and mechanical refurbishment of distribution poles where they have been assessed to be in poor condition or require ground line retreatment. The primary trigger of the investment is asset condition. By proactively targeting poor condition poles that pose higher reliability risk, this investment is expected to help maintain reliable operation of the distribution system and reduce the number of potential interruptions to customers. Additionally, chemically retreating poles proactively will result in mitigation of ground line rot and prevent further deterioration of poles at the ground line which is expected to extend pole life.

As stated in Lines 7 to 10 on page 3 at the second reference: "…poor condition poles include a subset of 17,000 red pine poles that were found to not be fully treated… and have demonstrated premature rot and degradation".

On page 14 at the third reference, Hydro One notes that the pole replacement program in 2019 was reduced by $8.9 million, which resulted in completion of 2,986 fewer pole replacements compared to the plan.

Based on information found at the fourth reference, the five-year average (2018-2022) cost for the pole sustainment program (D-SR-07) is $54.68 million.

Question(s):

a) Please explain the methodology and practices used by Hydro One to determine that "a subset of 17,000 red pine poles…were found not to be fully treated…and have demonstrated premature rot and degradation".

b) What is the actual number of "not fully treated" red pine poles found to demonstrate premature rot and degradation?

    i. Is this number known or speculated?

c) Does the number of “not fully treated” red pine poles (e.g., 17,000) represent a subset of the 22,000 poles that were investigated since 2018?

d) Please provide the justification for pole sustainment expenditures nearly doubling in 2023 relative to the average of the previous 5 years.

e) How many composite poles does Hydro One plan to install per year over the test period?

f) Please provide the quantified evaluation criteria used to determine if a deteriorated wood pole should be replaced with a composite pole.

g) How does Hydro One identify and prioritize poles for treatment?

h) What percentage of Hydro One’s wood pole fleet is tested and expected to be treated each year over the test period?

i) How many distribution poles are untreated vs. fully treated?

j) Please provide the actual number of poles replaced and the average cost of pole replacement in each of 2018, 2019 and 2020.

k) Page 21 at the third reference states that the 2020 pole replacement program was reduced by $16 million, which resulted in completion of 3,639 fewer pole replacements compared to the plan, which implies an average cost of $4,397 per pole for each foregone replacement. Please explain and quantify any discrepancy with Hydro One’s actual average cost of pole replacements in 2020.

l) The pole benchmarking report states that Hydro One’s average cost to replace a pole over the period 2018 to 2020 is $10,994. D-SR-07 also stated that an unplanned pole replacement takes 9.0 hours, and a planned replacement takes 2.4 hours. Please confirm the average cost to replace a pole in:

    i. Planned conditions; and

    ii. Unplanned conditions.

m) Hydro One has approximately 79,000 poles in poor condition and plans to continue replacing the worst condition poles at a rate of about 10,300 per year. What is the basis for Hydro One setting pole replacement costs in its 2021 through 2024 performance targets less than the average of 2018-20020 actual per unit pole replacement costs?

i. How does Hydro One expect to achieve significantly lower per unit pole replacement costs in 2021 through 2023 compared to past years' actual costs?

ii. Was the same per unit cost and annual replacement quantity used to develop the pole replacement cost forecast for the test period? If not, what per unit replacement costs were used, and how were they determined?

n) The benchmarking report (second reference) states that "The gap between the expected service life for poles and the current replacement rates is cause for concern for the industry". Is Hydro One confident that it is replacing the correct number of poles each year to optimally manage associated risks?

i. If yes, please explain quantitatively how Hydro One arrived at that determination.

ii. If no, explain why not.

iii. Is it possible that Hydro One's calculation of expected service life for wood poles is too conservative? Please elaborate in consideration of the actual age demographics of Hydro One's existing wood pole portfolio.

B3-Staff-145
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-09

Preamble:

As stated at the above reference:

> This investment involves the replacement and refurbishment of submarine cables when they are found to be damaged or exposed. The primary trigger of the investment is the condition of individual submarine cables. The investment is expected to reduce the public safety risk due to damaged or exposed cables as well as maintain reliability by preventing unplanned interruptions to customers from defective submarine cable.

Question(s):

a) Please provide an update of forecast expenditures by end-of-year 2021.

B3-Staff-146
EB-2017-0049 / Exhibit B / Tab 1 / Schedule 1 / Section 3.8 / ISD-SR-12
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-10

Preamble:

Pages 3 and 4 at the first reference contain a list of proposed distribution line sustainment initiatives.

Question(s):

a) Please identify all projects from the referenced list that Hydro One now forecasts will not be completed by the end of 2022.

b) For each project not expected to be completed by the end of 2022, please explain why the project was deferred and how Hydro One plans to address the originally identified need driving the project.

B3-Staff-147
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SR-12 / p. 29

Preamble:

As stated in Lines 3 to 8:

> The 5-year pacing option (option 1) involves replacing all AMI 1.0 meters and network equipment with AMI 2.0 equipment over a 5-year period beginning in 2024 through 2028. This option involves conducting an end-to-end system pilot with 3,000-4,000 meters in 2023; a one-year ramp up to replacing approximately 150,000 meters in 2024; the sustained mass deployment of approximately 370,000 meters per year from 2025 through 2027; and ramping down to completion in 2028 with the installation of approximately 224,000 meters.

Question(s):

a) What is Hydro One's resource plan for project implementation, including warehousing, physical meter changes, data management, and quality control for the planned 370,000 replacements per year between 2025 and 2027?

    i. If Hydro One plans to use internal resources, please describe how Hydro One's staff will participate in this activity.

b) How is Hydro One planning to integrate the requirements of Green Button? Is it included in the scope of the AMI 2.0 project?

B3-Staff-148
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SS-01

Preamble:

As stated at the above reference:

> Load Growth investments address system capacity issues that arise as a result of changes to the distribution system caused by regional load growth. The trigger for this investment is system capacity. This investment addresses these capacity issues through system upgrades or modifications, resulting in the continued ability of the system to meet forecast customer demand.

Question(s):

a) Were non-wires solutions considered as options for any of the proposed projects?

    i. If yes, please provide a summary of each non-wires option considered.

    ii. If no, please explain why not.

b) Do any of the existing non-residential customers in the Leamington area have behind the meter load displacing generation or energy storage?

    i. If yes, please identify the total number of such customers, their cumulative peak load and their cumulative displacing generation and energy storage capacity.

c) Has Hydro One been informed by any of the pending customers in the Leamington area that they will have load displacing generation or energy storage?

    i. If yes, has Hydro One taken into consideration the net demand of these customers when developing this plan? Please explain and quantify.

d) Have the forecasts that these investments are based on been updated to reflect the impact of COVID-19? Please explain.

B3-Staff-149
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SS-02

Question(s):

a) For each of the projects listed in Appendix A of D-SS-02 please provide: the number of affected customers, the project cost per affected customer and the project cost per reduced customer outage-minute.

B3-Staff-150
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SS-03

Preamble:

As stated at the above reference:

> This non-discretionary investment addresses near term system needs that arise as a result of localized growth on the distribution system, resulting in equipment overload or power quality issues. The primary trigger of this investment is capacity. Demand-driven system modifications are minor investments that enable localized load growth by promptly addressing capacity limitations.

Question(s):

a) Please explain the yearly variance of actual and forecast spending in this program over the period 2018 – 2020.

B3-Staff-151
Exhibit B / Tab 3 / Schedule 1 / Section 3.11 / ISD D-SS-06
Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / Attachment

Exhibit E / Tab 3 / Schedule 3 / p. 11

Preamble:

As stated at the first reference:

> This non-discretionary investment involves the investigation and resolution of power quality and stray voltage issues that adversely impact customer experience. The power quality and stray voltage issues are typically identified through customer complaints. The investment is expected to mitigate the customer issues and ensure the system is operating as intended.

Based on information found at the second reference, capital expenditures for D-SS-06 in 2021 are forecast to be more than double the annual expenditures in each of the preceding 3 years and to remain at the higher value throughout the test period. Table 7 at the third reference shows that Customer Power Quality Program OM&A expenses remain constant over the period of 2018-2023.

Question(s):

a) Please provide any available information that supports Hydro One's forecast of increased capital expenditures on this program in 2021 and beyond.
b) Please provide an updated forecast for 2021 capital expenditures for this program.

Exhibit B-04 General Plant System Plan

B4-Staff-152

Exhibit B / Tab 4 / Schedule 1 / Section 4.0 / p. 3

Preamble:

At the above reference, it is stated in Lines 4 to 6 that:

> Hydro One Networks Inc. (Hydro One) has prepared a General Plant System Plan (GSP) for the 2023 to 2027 period, which presents proposed investments in the General Plant assets and functions that are relied on and shared by the Transmission and Distribution businesses.

Question(s):

a) Please state the assumption with respect to the percentage of employees working from home for the 2023-2027 period Hydro One's General Plant System Plan is based on.

b) Please state the percentage of Hydro One employees currently working from home.

c) If the percentages identified in response to Questions 1 and 2 are different, please describe how the General Plant System Plan will change (e.g., facility requirements, IT requirements) if the same percentage of employees are working from home during the 2023-2027 period as are currently working from home.

B4-Staff-153

Exhibit B / Tab 4 / Schedule 1 / Section 4.1 / pp. 3 - 4
Exhibit B / Tab 4 / Schedule 1 / Section 4.1 / p. 5
Exhibit B / Tab 4 / Schedule 1 / Section 4.1 / p. 13

Preamble:

As stated in Lines 24 and 25 of pg. 3 and Line 1 of pg. 4:

> By providing ready access to this equipment, Fleet enables the lines of business to efficiently and safely complete their work. This function directly contributes to Hydro One's focus on continuous improvement in productivity and cost performance.

As stated in Lines 14 to 16 of pg. 5:

> Similar to the Fleet function, F&RE enables the lines of business to efficiently and safely complete their work and contributes to Hydro One's focus on continuous improvement in productivity and cost performance.

As stated in Lines 21 to 29 of pg. 13:

> Through this GSP, Hydro One is maintaining its focus on continuous improvement through various initiatives, including:
> - Adjusting the fleet lifecycle replacement strategy to more closely align with third-party expert recommendations to reduce overall lifecycle costs;
> - Prudently consolidating facilities and real estate to provide field operations with adequate accommodations, address operational

limitations/inefficiencies arising from sub-optimal facility configurations, and reduce operating costs such as leases; and

- Transitioning to a new target operating model for its Information Solutions Division, which provides sustained overall savings through a revised outsourcing strategy.

Question(s):

a) Please provide quantified information and cost metrics to demonstrate the claimed improvements for Transport and Work Equipment ("TWE"), for example, the number of km's travelled, or total cost per km (including and excluding fuel costs).

b) Please state how Hydro One tracks continuous improvement in productivity and cost performance. Please provide quantified examples.

c) Please provide relevant quantified information and cost metrics, similar to those requested, for the following General Plant ("GP") asset classes:

    i. Facilities & Real Estate;

    ii. Information Solutions;

    iii. System Operations; and

    iv. Other assets.

B4-Staff-154
Exhibit B / Tab 4 / Schedule 1 / Section 4.11 / ISD G-GP 14
EB-2017-0049 / Exhibit B / Section 3.8 / ISD GP-23

Preamble:

In EB-2017-0049, ISD GP-23 Integrated Voice Communications and Telephony Refresh, the Integrated Voice Communications and Telephony System (IVCT) system was described as requiring replacement in 2021 to maintain support and reliability of the system. The IVCT was to be replaced for a total of $6.5M over 2021 and 2022, and in service for Q4 2022. The ISD states " Based on the current vendor support schedules and hardware lifecycles the IVCT system will require replacement in 2021 to maintain support and reliability of the system and the ability to recover in the event that a failure is experienced."

The investment in EB-2021-0110 ISD G-GP-14 Integrated Voice Communications Technology (IVCT) Refresh involves the continuation of the upgrade of the IVCT system with forecast expenditures of $2.3M in 2023. The ISD states "The existing system has been in service since 2015" and "requires upgrade before 2024 when it will no longer serve the control rooms' voice communication need."

Question(s):

a) Please state why the system previously stated to require replacement by 2021 is now presented as suitable for use until 2024?

b) Please provide the actual and forecast yearly capital expenditures for the IVCT project, and the total project costs.

c) Please state what impacts, if any, have been experienced due to the delayed implementation of the IVCT refresh?

B4-Staff-155
Exhibit B / Tab 4 / Schedule 1 / Section 4.1 / pp. 9 - 10

Preamble:

At the above reference, it is stated, regarding Facilities and Real Estate that:

> The current sites are sub-optimal for operations due to overcrowding conditions, inefficient configurations, and disparate sites for field teams.

Question(s):

a) Please state when were assessments undertaken to conclude that the Hydro One Facilities and Real Estate sites are sub-optimal for operations?

    i. Please provide documentation detailing how Hydro One determined that the sites are "sub-optimal" for operations, including quantification of the performance impairment and/or higher capital and/or operating costs associated with continuing to maintain the existing sites.

b) Please state what are the specific factors or events that have triggered the need to spend now for each of the sites affected?

c) Please provide responses to the following regarding impacts attributable to the ongoing COVID-19 pandemic:

i. Does Hydro One now have more personnel working remotely than it did at the time it identified the need for the proposed Facilities and Real Estate investments included in this application?

a. If yes, please provide quantified information.

b. Please state when Hydro One expects its personnel work location mix to return to pre-COVID-19 ratios.

ii. Please state when Hydro One assessed, or had assessed, leasing costs and market rates, and the extent to which any such assessment accounted for the effects of COVID-19 impacts.

a. Please provide details.

iii. Please explain how the above information has been incorporated into establishing the proposed Test Period expenditures.

<u>B4-Staff-156</u>
Exhibit B / Tab 4 / Schedule 1 / Section 4.1 / p. 11
Exhibit B / Tab 4 / Schedule 1 / Section 4.2 / p. 32

Preamble:

At Lines 10 to 17 of the first above reference, it is stated that:

> System Operations – These investments decrease over the forecast period, starting from $27.4M in 2023 and decreasing to $6.5M in 2027. This trend reflects the upgrade of all critical systems applications that are or are nearing the end of vendor support, including the Network Management System, Outage Response Management System and Distribution Management System. Details on the System Operations investments can be found in GSP Section 4.11, G-GP-12 through G-GP-18.

At Lines 9 to 15 of the second above reference, it is stated that:

Cybersecurity assets and any physical or personnel security assets that require vendor supported technology follow the same methodology as IT and OT assets. They are considered end of life when they are no longer vendor supported. Vendor support is essential for these systems, as inoperability would leave Hydro One vulnerable to security breaches with potential cascading impacts on its Transmission and Distribution network and its IT and OT systems. Further details on security asset replacement plans can be found in GSP Section 4.11, G-GP-09, G-GP-10 and G-GP-11.

Question(s):

a) Please state whether or not the end of vendor support for System Operations assets equates to mandatory asset replacement? That is, when a vendor gives notice that it is terminating ongoing support for a system, does that always (or typically) render the associated system functionally obsolete and thereby trigger a mandatory replacement?

    i. If yes, please explain what steps Hydro One has taken to insulate its ratepayers from bearing the costs of what in many cases are vendor marketing decisions and which may be (at least partly) intended to stimulate sales of new systems.

b) Please define and provide metrics on weighting criteria used during procurement evaluations regarding future vendor support and obsolescence of assets.

B4-Staff-157
Exhibit B / Tab 4 / Schedule 1 / Section 4.1 / p. 16

Preamble:

At the above reference, it is stated in Lines 1 to 5:

GSP investments that will contribute towards lower overall GHG emissions include:

- Transport and Work Equipment renewal (GSP Section 4.11, G-GP-01) – Hydro One's commercial fleet is beginning the gradual transition to low or zero emission technology, increasing the rate of electric vehicles from an estimate 5% of the renewal forecast in 2021 to 50% by 2030. The rate of vehicle replacement will be done as needed to maintain an optimized fleet,

> and where the total cost of ownership of an electric vehicle versus conventional fuel-based has no significant incremental cost.

Question(s):

a) Please discuss regarding the proposed fleet transition to EVs, whether or not Hydro One has considered the common-mode failure risk of the fleet in the event of a widespread storm outage?

    i. Please discuss the extent of the risk that the vehicles that would normally be dispatched to resolve storm-related power outage problems could become incapacitated due to the inability to recharge them.

    ii. Please provide details of the associated contingency plan and any other analysis performed when developing the EV transition plan.

B4-Staff-158
Exhibit B / Tab 4 / Schedule 1 / Section 4.1 / p. 18

Preamble:

At the above reference, it is stated in Lines 1 to 5:

> To provide an understanding of how this plan compares to historical investments, Figure 2 displays the total General Plant net capital expenditures next to the planning period. [Figure 2 not provided in preamble]

Based on Figure 2 at the above reference, the average net capital expenditure for 2018 – 2022 inclusive is $240.76 million. The average net capital expenditure, excluding planned security investments, for 2023-2027 inclusive is $289.04 million. This is a 20% increase in the five-year average.

Question(s):

a) Please explain in detail why the forecast level of General Plant expenditures during the 2022 Bridge Year shown in Figure 2 is so much lower than the planned average annual level of General Plant investments during the test period. What factors are driving the discontinuous pacing of General Plant investments?

b) Please explain why, beginning in 2023, security investments have been reclassified from System Renewal to General Plant, as indicated in Footnote 4 on page 18.

c) Please explain why the 20% increase in the 5-year average General Plant expenditure is reasonable.

B4-Staff-159
Exhibit B / Tab 4 / Schedule 1 / Section 4.2 / p. 31

Preamble:

At the above reference, it is stated at Line 29 that:

> Security assets are managed with a philosophy that a failure would result in high-consequences…

Question(s):

a) Please discuss whether or not adopting a philosophy that any failure would result in a high consequence outcome would appear to apply an unusually conservative risk assessment approach that would be expected to produce higher risk scores for some assets than would be generated by following a more industry standard asset-specific risk assessment methodology.

b) Please provide a quantitative evaluation that justifies Hydro One's adoption of such a conservative risk assessment philosophy for this asset class.

c) Please provide quantified examples showing how Hydro One has applied this philosophy to justify individual projects that are included in this application.

B4-Staff-160
Exhibit B / Tab 4 / Schedule 1 / Section 4.3 / p. 11

Preamble:

At the above reference, it is stated in Table 6 Line Item #4:

> Use the Run, Grow and Transform categorizations to help communicate the funding needed for business transformation and the cost to maintain legacy

business models. Divide “Run” spending by business outcome metrics (or business capabilities) to show per unit-cost productivity improvement, with the related volumes, to better show its value to the enterprise.

Question(s):

a) Please explain how Hydro One has implemented this recommendation and discuss whether or not these categorizations were used in this application. If not, please explain, why not.

B4-Staff-161
Exhibit B / Tab 4 / Schedule 1 / Section 4.3 / Attachment 3 / pp. 4-5

Preamble:

OEB staff has summarized information at the above reference in the table below and is requesting some additional information in this area.

Question(s):

a) Please complete the following table:

		2015 (Source: B-4-1 Section 4.3 Attachment 3, p.4)		2019 (Source: B-4-1 Section 4.3 Attachment 3, p.4)		2023 Plan		2024 Plan		2025 Plan		2026 Plan		2027 Plan	
		% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)
IT Spend as a % of Revenue	Operational	2.2%	$140	2.1%	$136										
	Capital	0.8%	$55	1.8%	$115										
	Total	3.0%	$195	3.9%	$251										
IT Spend as a % of OpEx	Operational	2.6%	$140	2.6%	$136										
	Capital	1.0%	$55	2.3%	$115										
	Total	3.6%	$195	4.9%	$251										
Run, Grow, Transform (% of Total IT Spend)	Run %	79%	$154	69%	$173										
	Grow %	20%	$39	17%	$43										
	Transform %	1%	$2	14%	$35										
	Total	100%	$195	100%	$251										
IT Spend per Cost Category	Outsourcing	66%	$129	59%	$147										
	Personnel	14%	$27	9%	$23										
	Software	11%	$21	20%	$51										
	Hardware	9%	$18	12%	$30										
	Total	100%	$195	100%	$251										
IT Spend Distribution by Area	Enterprise Computing	25%	$49	26%	$65										
	End User Computing	14%	$27	20%	$52										
	IT Service Desk	2%	$4	2%	$4										
	Voice & Data Network	10%	$20	9%	$23										
	Applications	44%	$85	38%	$94										
	IT Mgmt. & Admin	5%	$10	5%	$13										
	Total	100%	$195	100%	$251										

B4-Staff-162
Exhibit B4 / Tab 4 / Schedule 1 / Section 4.1 / pg. 5 of 24

Question(s):

a) Please state for each year from 2023 to 2027, inclusive, how many leases will be: (1) ending; (2) renewed, and (3) terminated.

B4-Staff-163
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-03 / p. 9

Preamble:

At the above reference, it is stated in Lines 2 to 12:

> Hydro One's current warehouses in the City of Barrie are scattered across disparate facilities, with no opportunity for building and site expansion to facilitate consolidation or expansion to accommodate growth in work demands. Moreover, the leased main warehouse is a repurposed manufacturing plant that has a sub-optimal configuration and is subject to increasing maintenance requirements and operational limitations (including inability to adopt improved logistics management). Development of the Orillia Warehouse on a site acquired in 2020 will serve to address gaps in operational requirements, accommodate future growth, eliminate inefficiencies from operating across disparate facilities, and provide the opportunity to fully implement industry leading logistics practices/strategies. The Orillia Warehouse will allow for the consolidation of three facilities in Barrie (as shown below in Figure 3), with the opportunity to terminate two leases (Barrie Warehouse and Cross Dock) [Figure 3 not provided in preamble]

Question(s):

a) Regarding Figure 3, three facilities are identified: two of these are in Barrie as well as the new facility in Orillia. Please clarify the discrepancy in the preamble that identifies three (3) facilities in Barrie.
b) Please state whether or not the planned Orillia OC will be co-located with the planned Orillia Warehouse?

B4-Staff-164
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-03 / pp. 10 - 11

Preamble:

At the above reference, it is stated at Lines 9 and 10 of pg. 10 and Lines 1 to 5 of pg. 11:

> Development of the Orillia OC on a site acquired in 2020 will serve to address these requirements/objectives together while aligning to current operating practices. This OC will allow for the consolidation of five facilities as shown below in Figure 4, with the opportunity to terminate three leases in Orillia (Orillia Office, Forestry Area Office and Service Centre) [Figure 4 not provided in preamble].

Question(s):

a) Please state whether or not the Barrie OC and the Oro OC facilities are owned or leased by Hydro One?

   i. If leased, please state when the leases are being terminated.

b) What is the plan for these existing sites after the facilities are consolidated into the Orillia OC?

B4-Staff-165
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-03 / pp. 11-12

Preamble:

At the above reference, it is stated in Lines 9 to 11 of pg. 11:

> In general, Hydro One's Timmins operations serves as an operational hub for the Northeast region of Ontario. The current operations is split between the Hydro One-owned Timmins TS Maintenance Centre and a leased site, which resulted from a legacy arrangement dating back to the demerger of Ontario Hydro in the late 1990s.

Question(s):

a) Please clarify what each of the three (3) sites are used for and indicate for each site whether it is owned or leased by Hydro One.

b) When does Hydro One plan to acquire a new site in Timmins?

  i. Please provide the budget for this site.

  ii. What is the plan for the three (3) existing sites in Timmins after the new site is acquired?

    a. If leases are being terminated, please indicate when.

B4-Staff-166
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-03 / p. 12

Preamble:

At the above reference, it is stated in Lines 1 to 5:

> The sub-optimal conditions include inadequate spaces to meet growing operational requirements, as the current structures are overcrowded and the storage facility is inadequate given the growing work program being carried out and the specialized equipment, such as mobile unit stations (MUS), being stored and serviced from this location.

Question(s):

a) Please describe and quantify the “growing operational requirements” and “growing work program” that are driving the need for a new facility in Timmins.

B4-Staff-167
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-03 / p. 15

Preamble:

At the above reference, it is stated in Lines 2 to 8 that:

> The existing Hydro One Peterborough OC is reaching end of life, requires significant capital repairs, and is sub-optimally configured with reliance on several temporary structures. It is also situated within a defined floodplain with significant historical impacts. Development of the new Peterborough OC on lands acquired in 2020 will address condition concerns and facilitate operational synergies through consolidation of four facilities (the existing Peterborough OC,

Peterborough Ashburnham Office, Pole Yard and Lindsay Service Centre, as shown below in Figure 8) [Figure not provided in preamble].

Question(s):

a) Please indicate for each of the four sites, whether the site is owned or leased by Hydro One.

b) Please state what the plan for the four existing sites in the Peterborough area is after consolidation into the new site?

    i. If leases are being terminated, please indicate when.

c) Please provide a revised version of Figure 8 that includes the new site for the Peterborough Fleet Maintenance Garage that was acquired in 2020.

B4-Staff-168
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-03 / p. 16

Preamble:

At the above reference, it is stated in Lines 10 to 12 that:

> The existing Newmarket OC, established as a lease following the sale of the former facility in 2002, has become undersized relative to the substantial operational growth in the area. To mitigate this inadequacy, area operations are supported by an off-site material storage yard and the use of the Newmarket Fleet Maintenance Garage parking, yard and office.

Question(s):

a) Please describe and quantify the "substantial operational growth" that is driving the need for a new Newmarket OC.

b) Please provide a map showing the location of the existing and new sites in Newmarket.

    i. If a new site has not yet been acquired, when does Hydro One plan to acquire a new site in Newmarket?

ii. Please provide the budget for this site?

c) Please indicate for each existing site shown in the map requested in b) whether it is owned or leased by Hydro One.

   i. If leases are being terminated, please indicate when.

   ii. Please state what the plan is for each of these existing sites after consolidation into the new site.

d) Please state whether or not Hydro One plans to sell any existing sites or facilities because of site consolidation plans?

   i. If yes, please indicate which sites Hydro One plans to sell and what the current market value is for each.

B4-Staff-169
Exhibit B4 / Tab 4 / Schedule 1 / ISD-G-GP-4 / pp. 9-14

Preamble:

At the above reference, it is stated in Lines 6 to 10 of pg. 14 that:

> The details obtained from the BCAs assist in prioritizing investments that have been identified in poor condition that should be addressed to ensure business continuity. Sustainment work for the assets in good/fair condition into future years. On-going sustainment (improvements and asset replacements) investment targets key building assets that are likely to pose significant reliability or safety risks in the vent of failure, for example…

a) Please clarify the above quoted section.

b) Please provide more detail of the scope of the On-going Sustainment: Improvements and Asset Replacements line of Table 1 on page 9 at the above reference, including the number of sites that will be subject to sustainment work for each year from 2023 to 2027, inclusive, and the nature of the work at these sites.

B4-Staff-170
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-10 / p. 4 and p. 6

Preamble:

At the above reference, it is stated in Lines 4 to 8 of pg. 4 that:

> Hydro One has seen escalating break-fix and replacement costs in recent years as a result of the expanding network of devices and increasing average age (and therefore failure rate) of the assets. Approximately 75% of Hydro One's security hardware and assets have exceeded or will reach the end of their useful lives in the 2023-2027 period.

At the above reference, it is stated in Lines 25 to 29 of pg. 6 that:

> The current population of security cameras is shown in Figure 1 below. Security cameras have a useful life of between seven and ten years, meaning that all cameras installed before 2012 are already beyond the end of their useful lives. By the end of the 2027, all cameras installed prior to 2018 will have exceeded their useful lives. Under this ISD, Hydro One plans to prioritize replacement of the oldest cameras [Figure not provided in preamble].

Question(s):

a) Please provide break-fix and replacement costs for the past five years.

b) Please quantify and describe the "expanding network of devices" over the past five years.

c) What is the current average age of the assets?

    i. Please provide a trend of the average age of the assets over the past five years.

d) Please explain how an increasing average age is consistent with an expanding network of devices, which suggests the addition of new devices.

e) Please provide a breakdown of the number of security hardware and assets by category.

    i. Please provide the expected service life for each category.

ii. Please indicate the number of devices in each category that currently exceeds the expected service life.

iii. Please indicate the number of additional devices in each category that will reach the expected service life between today and the end of the 2023-2027 term.

f) What is the basis for Hydro One's statement that the useful life of security cameras is between seven to ten years?

i. Regarding Figure 1, Hydro One installed over 400 cameras in 2008 and 2009. Please explain why these cameras are still operational if they have exceeded their useful life.

B4-Staff-171
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-11 / pp. 2 - 4
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-11 / p. 7

Preamble:

At the first reference above, it is stated in Lines 21 to 23 of pg. 2 that:

> The investments in this ISD address the following needs:
> i. updating the company's Cyber Security Event Monitoring (SEM) solution to account for the increasing volume of cybersecurity event data that over the 2023-2027 period;

At the first reference above, it is stated in Lines 17 to 21 of pg. 3 that:

> The volume of cyber security events is expected to increase due to a range of factors including the modernization of the technology supporting Hydro One's OT environment being ongoing targets from external threats and the ability to capture more events through the planned implementation of a situational awareness solution to monitor and secure the grid of the future.

At the first reference above, it is stated in lines 11 to 13 of pg. 4 that:

> Hydro One forecasts that many of the company's physical security system assets (core servers, appliances and networking assets) will be at or beyond end of life

during the 2023-2027 period and will no longer be able to provide ongoing and effective security monitoring.[7]

At the second reference above, Table 1 below is shown:

Table 1 – Physical Access Control and Monitoring Security Asset Summary

Description	Quantity	End of Life (Years)	Average Age in 2021 (Years)
Video Surveillance Telecom System Networking Assets	715	5	5.5
Virtual Servers, Hosts and Storage Infrastructure	25	5	3.0

Question(s):

a) Please clarify the need for updating Hydro One's Cyber Security Event Monitoring (SEM) solution to account for the increasing volume of cybersecurity event data as noted in the first reference above.

b) Please explain how "the modernization of the technology supporting Hydro One's OT environment being ongoing targets from external threats" contributes to an expected increase in cyber security events.

c) Please provide a forecast as to what proportion of physical security system assets will be at or beyond end of life during the 2023-2027 period?

    i. Please provide the basis for this forecast.

d) Please confirm that Table 1 is the forecast for physical security system assets that is described on pg. 4.

e) Please clarify what the column title "End of Life (Years)" represents?

    i. If this column represents the expected service life in years, please provide the basis for the five year expected service life.

[7] Hydro One defines a security asset's end of life as the date in which the asset has reached its expected useful life as recommended by the manufacturer and where the use of such assets have reached operational obsolescence due to technology limitations, end of manufacturer support, including the ability to obtain ongoing security patches and firmware updates and where such assets no longer integrate effectively with present-day security monitoring systems.

f) Please explain how the timing of this replacement program is consistent with a five year expected service life given that based on the information in Table 1, by 2024 Video Surveillance Telecom System Networking Additions will have an average age of 8.5 years, and Virtual Servers, Hosts and Storage Infrastructure will have an average age of 6 years.

g) Please state whether or not the site of the back-up Joint Security Operations Centre ("JSOC") location will be owned or leased by Hydro One?

    i. Are the costs of acquiring or leasing the site included in the $2.5 million budget?

B4-Staff-172

Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-16 / pp. 2 – 3

Preamble:

At the above reference, it is stated in Lines 26 to 28 of pg. 2 that:

> These components require updates every 5-7 years as newer and more up-to-date applications for management of electrical power systems become available, so as to ensure the continuity of vendor support and stay ahead of evolving cyber security threats.

At the above reference, it is stated in Lines 5 to 7 of pg. 3 that:

> This investment is wholly allocated to the Transmission business. The projected costs of the investment for the ongoing version upgrade are $7.6M in 2023 (in addition to $32M in the 2020-2022 period).

Question(s):

a) Please explain why the ongoing version upgrade. discussed in the second reference above, appears to be taking three years?

    i. Please clarify whether this upgrade is taking up three years of the expected five to seven year update cycle?

b) Please state when the next upgrade is anticipated to begin after the current upgrade is completed in 2023?

B4-Staff-173
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-19 / pp. 4 - 5
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-19 / pp. 13 - 14

Preamble:

At the first reference above, it is stated in Lines 21 to 24 of pg. 4 that:

> To date, 4 hubsites and 100 stations have been converted to the Direct SCADA. Approximately 36 hubsites and 200 stations remain to be migrated to Direct SCADA, and 100 stations remain to be migrated over to the Manby TS hubsite.

Also at the first reference above, it is stated in Lines 14 to 16 of pg. 5 that:

> Appendix 4.21 of the IESO Market Rules requires that high-performance assets have data measurements and equipment status changes available at the IESO communications interface in less than two seconds.

At the second reference above, it is stated in Lines 12 to 15 of pg. 13 that:

> Table 2 below summarizes historical and projected spending on the aggregate investment level [Table not provided in preamble].

Also at the second reference above, it is stated in Lines 6 to 8 of pg. 14 that:

> With respect to component replacement, the current integrated station investment practice at Hydro One is to evaluate the need to perform work at each station on a seven-year cycle. Under this alternative, end-of-vendor-support equipment would not be replaced in a timely manner.

Question(s):

a) Please state the date on which these IESO Market Rules Appendix 4.21 come into effect?

b) Please state whether or not the IESO has informed Hydro One that it is not in compliance with these rules?

i. If yes, please provide the date on which the IESO informed Hydro One and the compliance timeline required by the IESO.

ii. If no, please explain the statement that the hub site network topology fails to meet the IESO Market Rules requirements.

c) Please state for the existing network topology, how many seconds it takes to have data measurements and equipment status changes available at the IESO communications interface?

d) Please provide a reference to the investment in the EB-2019-0082 application that includes the costs for converting hubsites and stations that will be incurred before 2023.

i. Please provide an annual breakdown of the actual costs spent to date for converting hubsites and stations.

e) Please provide an annual breakdown for 2021 through 2027 of the number of hubsites and stations that will be converted each year.

f) Please state how the annual removal value of $0.2 million in Table 2 was determined?

g) Please explain the current integrated station investment practice to evaluate the need to perform work at each station on a seven year cycle.

i. Please explain the basis for the seven year duration of the cycle.

B4-Staff-174
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-20 / p. 2

Preamble:

At the above reference, it is stated in Lines 20 to 22 that:

> A conceptual pilot project has been completed in late 2020 to test the system, to analyze and identify the best solution to meet the needs of the investment, and to ensure the most effective implementation.

Question(s):

a) Please describe the scope and duration of the pilot project that was completed in late 2020.

b) Please state whether or not the pilot project has been decommissioned, or is it still providing value?

c) Please state what the criteria or measures used were to evaluate the pilot project?

    i. What was the outcome of the evaluation?

    ii. Please provide the evaluation report, if one exists.

<u>B4-Staff-175</u>
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-20 / p. 11

Preamble:

At the above reference, it is stated in Lines 22 and 23 that:

> The implementation plan involves multiple [Lines of Business] LOB in a staged approach. Each LOB will develop their respective systems after which pilot sites will be targeted for proof-of concept validation.

Question(s):

a) Please provide the following information for the pilot sites mentioned on page 11.

    i. the nature of these sites (e.g., are they stations, poles, or control centres)?

    ii. how these pilot sites relate to the pilot project that was completed in late 2020?

b) Please state for how long the pilot sites mentioned on page 11 will be assessed for. What criteria or measures will be used to evaluate these sites?

c) Pages 11-12 describe the criteria for selecting pilot sites. Page 12 states that “The overall plan will be to implement the system at as many sites as possible.” Please state what criteria will be used to determine the number of sites that are implemented?

d) Please state whether or not the pilot sites mentioned on page 11 are the only sites that will be implemented for this project?

    i. If they are not, please describe the number of additional sites that will be implemented, and how the scope of those sites differs from the scope of the pilot sites.

B4-Staff-176
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-20 / pp. 13
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-20 / pp. 5

At the first reference above, it is stated in Lines 5 to 13 of pg. 13 that:

> Table 2 below summarizes the projected spending on the aggregate investment level during the planning period. In addition to these costs, $10.8M is forecasted to be spent prior to 2023 [Table not provided in preamble].
>
> The ultimate cost of the investment will depend on the following several factors:
> - An evaluation of whether existing corporate systems meet the functional requirements or whether a new system is required to be implemented. Accordingly, there may be additional upfront costs to facilitate new hardware, software, and licensing.

At the second reference above, it is stated in Lines 23 and 24 of pg. 5 that:

> The assets to be monitored will include, but will not be limited to, transformers, breakers, capacitors, reactors, batteries, intelligent electronic devices (IEDs), buildings, cables and lines.

Question(s):

a) Please provide “the functional requirements” referenced on page 13.

b) Please describe the evaluation of existing corporate systems described on page 13, including the objective, criteria, measures, timeline, and cost.

    i. Is the cost of this evaluation included in the G-GP-20 project budget?

a. If no, please explain the plan to add asset monitoring capability, including the pace, prioritization, timeline, and cost for adding asset monitoring capabilities.

c) Please provide the reference(s) for the investment of $10.8 million prior to 2023 from Hydro One's previous application(s).

i. Please provide an annual breakdown of the $10.8 million, including actual expenditures, if available.

ii. For each year, please indicate whether these are actual costs, or forecast costs.

d) Please confirm that the conceptual pilot project cited on pg. 3 of this investment summary document (see above reference) was part of the $10.8 million investment.

e) Please state whether or not the cost of this project includes the cost of transformer, breaker, capacitor, reactor, battery, intelligent electronic device (IED), building, cable and/or line monitoring mentioned on page 5?

i. If yes, please indicate the number of each asset category that will be monitored.

f) Please provide the timeline for reducing OM&A costs because of this project.

g) Please provide Hydro One's internal business case for this project.

h) Please state whether or not OM&A costs have been reduce

i) d in this application because of the $10.8 million forecast to be spent prior to 2023?

i. If yes, please provide a detailed description and references to Hydro One's OM&A evidence with respect to these impacts.

ii. If no, please explain why not.

B4-Staff-177

Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-20 / p. 15

At the above reference, it is stated in Lines 2 to 8 that:

> Alternative 2 is to make improvements to existing non-operational systems that are segregated in nature. The current system was developed without anticipating the potential to incorporate aspects of CBM or system integration. Automation of some of the non-operational systems is possible, but the remainder will still require either manual intervention or personnel dispatch to retrieve data due to limitations of the existing technology. This alternative has been ruled out, since the existing systems do not have the archival, analytic, or integration capabilities for systems that would properly facilitate the CBM approach.

Question(s):

a) Please provide further explanation as to why Alternative 2 was ruled out as discussed above. Please include discussion as to why the existing systems do not have the archival, analytic, or integration capabilities for systems that would properly facilitate the CBM approach and what if anything is being done by Hydro One to deal with this situation and why.

<u>B4-Staff-178</u>
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-21 / p. 4

At the above reference, it is stated in Lines 13 to 17 that:

> Hydro One currently has a total of 1005 RTUs installed in the province. Table 1 depicts the number and types of RTU installations currently in service [Table not provided in preamble].

Question(s):

a) For each RTU in Table 1, please provide:

    i. The expected service life, in years;

    ii. The source, or basis for the expected service life; and

    iii. The number of assets that exceed the expected service life.

b) Please explain how and why Hydro One continues to have 35 GE D200 RTUs in-service if, as noted in the above reference, GE issued end of life notice for the D200 RTU in 2006.

B4-Staff-179
Exhibit B / Tab 4 / Schedule 1 / ISD-G-GP-21 / p. 7

At the above reference, it is stated in Lines 11 to 14 that:

> The costs have been determined on a per unit basis. The per-unit cost was estimated based on historical costs of RTU replacements previously performed. Since the cost varies depending on the type of the station and the specific scope required, previous projects of the same scope for the same type of station were used to estimate costs in this Investment.

Question(s):

a) Please provide the per-unit cost as referenced in the preamble above.

b) Please describe the RTU replacements that were previously performed, and their associated historical costs.

Exhibit C – Rate Base

C-Staff-180
Exhibit C / Tab 1 / Schedule 1 / p.8
EB-2013-0196/0187/0198, EB-2014-0244, EB-2014-0213

Preamble:

Hydro One Distribution’s rate base for 2023 to 2027 includes the Acquired Utilities’ rate base. Regarding the Acquired Utilities, Norfolk last rebased in 2012 under MIFRS, Haldimand last rebased in 2014 under Canadian GAAP, after implementing the OEB mandated capitalization and policy changes, and Woodstock last rebased in 2011 under Canadian GAAP, before implementing the OEB mandated capitalization and depreciation policy changes. In In the MAADS proceeding for each of the Acquired Utilities, the OEB accepted the use of US GAAP for each of the Acquired Utilities.

Question(s):

a) Please quantify the 2023 opening rate base impact resulting from the transition from the prior accounting policies reflected in each Acquired Utility's last approved cost of service proceeding to the accounting policies under US GAAP, which is proposed to be used in this proceeding.

b) Please discuss Hydro One's views on the treatment of this transitional impact to opening rate base.

C-Staff-181
Exhibit C / Tab 4 / Schedule 4 – Appendix 2-BA

Preamble:

In Appendix 2-BA for Transmission and Distribution, there are no amounts in Account 1995 Contribution & Grants or Account 2440 Deferred Revenue for 2018 to 2027.

Question(s):

a) Please confirm that any capital contributions have been offset against the specific asset accounts. If not confirmed, please explain how capital contributions have been reflected for rate base purposes.

b) If possible, please provide the total capital contributions per year from 2018 to 2027 for each of Transmission and Distribution.

PWC's Report for Capitalization on Corporate Common Cost Review
C-Staff-182
Exhibit C/Tab 8/Schedule 2/p. 6
Exhibit C/Tab 8/Schedule 2/Attachment 2

Preamble:

In Reference 1, Hydro One states that:

> Based on its review, PwC concluded that Hydro One's proposed methodology for capturing overhead costs and allocating such costs to capital activities is reasonable, supportable and consistent with the principle that the assignment of such costs to capital work should be based on a causal link, as well as consistent with applicable regulatory guidance from each of the OEB and Federal Energy

> Regulatory Commission (FERC) and accounting guidance under both US GAAP and IFRS.

The Executive Summary of PWC's report states that:

> In our comparison of common corporate costs capitalized at Hydro One to those that are capitalized by other regulated utilities, we observed that the Company fell within the range of its Canadian peers. When compared to US utilities, while Hydro One's capitalization percentage was **at the upper end of the peer group**, there was a large range of results which can be attributable to factors such as company size, size of the construction program, different definitions of the costs to be considered and involvement of third-party contractors. These differing factors make a comparison between Hydro One and other utilities difficult as many are not comparable. Of particular significance is that Hydro One self-constructs most of their capital work. In our experience, this is in contrast to many of its peers which generally perform more construction activity through the use of third parties. **[Emphasis added]**

From Table 4 in PWC's report, OEB staff notes that Hydro One was compared to five Canadian companies where quantitative information is available (three reporting under IFRS and two under US GAAP) and Hydro One's capitalization measure of 18% falls within the capitalization rates of 3% to 32%.

From Table 3 in PWC's report, OEB staff notes that Hydro One was compared to four US companies where quantitative information is available (all reporting under US GAAP) and Hydro One's capitalization measure of 48% falls outside of the range of capitalization rates between 8.57% and 24.05% of these four US companies.

With respect to the comparison to regulatory and accounting guidance, page 17 of PWC's report states that:

> There is no regulatory guideline, statement or source that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes what types of indirect costs should be considered for capitalization nor how such costs are allocated to capital. Canadian utility regulators and FERC have historically accepted that indirect activities support capital work and, to the extent that there is a causal link to the capital activities, have allowed the associated costs to be allocated to capital. US GAAP and IFRS allow for the capitalization of costs by rate-regulated entities to the extent that it is probable that those costs will be recovered in future rates.

Based on our understanding we believe Hydro One's process and methodology for the capitalization of common corporate costs is reasonable based on the guidance issued by the OEB and FERC for entities that follow US GAAP and IFRS.

Question(s):

a) Please clarify why the executive summary of PWC's report states that when compared to US utilities, Hydro One's capitalization percentage was at the upper end of the peer group while the data in Table 3 shows that Hydro One's capitalization rate falls outside of US peer companies' range.

b) Please explain the impact of the small sample size on the conclusion of the report.

c) Please elaborate on the sentence "In our experience, this is in contrast to many of its peers which generally perform more construction activity through the use of third parties" and provide specific examples for these peers who perform more construction activity using third parties. Please explain the source of the information.

d) Please explain how PWC concluded that Hydro One's process and methodology for the capitalization of common corporate costs is reasonable based on the guidance issued by the OEB and FERC for entities that follow US GAAP and IFRS, given that there is no regulatory guideline, statement or source that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes what types of indirect costs should be considered for capitalization nor how such costs are allocated to capital.

e) Please elaborate on the statement "US GAAP and IFRS allow for the capitalization of costs by rate-regulated entities to the extent that it is probable that those costs will be recovered in future rates." Specifically, please discuss whether this is in reference to capitalization of costs as regulatory assets, rather than capitalization of costs that form, for example, part of the gross property, plant, and equipment amounts. Please cite the specific IFRS and US GAAP standards associated with this statement.

Exhibit D – Operating Revenue

D1-Staff-183
Exhibit D / Tab 2 / Schedule 1 / pp. 3-4

Preamble:

The transmission external revenues for secondary land use includes an amount for the Waterdown to Finch Pipeline project.

OEB staff have calculated a normalized historic secondary land use revenue of $25.1 million in 2020 based on the 2020 actual revenue of $29.1 million less $4 million related to the pipeline project. Similarly, OEB staff have calculated normalized external revenue of $23.5 million in 2021, $23.8 million in 2022, and $24 million in 2023. Using these figures, the 2018-2020 average revenue is $26.1 million.

Question(s):

a) Please confirm or correct OEB staff's calculations

b) Please explain why revenues, after removing the pipeline project have fallen from an average of $26.1 million to $23.5 million in 2021 and are projected to remain below the historical average.

D1-Staff-184
Exhibit D / Tab 2 / Schedule 2 / p. 8/Table 9

Preamble:

At the above reference, Hydro One has recorded Storm Revenue in the 2018 to 2020 period, but not in subsequent years.

Question(s):

a) Please provide historical storm revenue for the years 2011-2017.

b) Please confirm that any recurring costs associated with storm readiness borne by Ontario rate payers are incurred to ensure the availability of resources to respond to storm events within Ontario or explain.

c) Please provide historical costs for the years 2011-2020 directly associated with the provision of services resulting in storm revenue.

d) Please indicate separately how much of the costs identified in parts b) and c) are included in the historic and forecast revenue requirement to be recovered from rate payers.

D2-Staff-185

Exhibit D / Tab 2 / Schedule 2 / p. 5
Exhibit B / Tab 3 / Schedule 1 / Section 3.9 / Attachment 1

Preamble:

At the first reference above, Hydro One states that there are 560 agreements in place with joint use partners such as telecommunications companies, local distribution companies, generators and municipalities.

Based on the second reference above, OEB staff observe that expenditures for *D-SA-01 Joint Use and Relocations* in 2023 are 7% higher than the average of the 5 preceding years (2018-2022) and 30% higher than the forecast amount for 2022.

Question(s):

a) Please state how many telecommunications companies Hydro One has joint use agreements in place with?

b) Please complete the table below to show the number of attachments for telecommunications companies and other parties

Table – Joint Use Regulated Connections (number)

	Historical			Bridge		Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Telecommunications										
Other Parties										
Total										

c) Please complete the following table to show the amount of revenue that is attributable to telecommunications companies and other parties

Table – Joint Use Regulated Revenues ($M)

	Historical			Bridge		Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Telecommunications										
Other Parties										
Total	13.0	14.4	14.9	14.8	15.1	15.7	15.8	15.8	15.9	15.9

d) Please complete the following table to provide a breakdown of expenditures and contributions attributable to each of Joint Use and Relocations.

Table – Joint Use and Relocations Capital Expenditures ($M)

	Historical			Bridge		Forecasting Period				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Joint Use Gross										
Joint Use Capital Contributions										
Relocations Net										
Total	20.4	28.8	26.2	21.4	19.1	24.8	29.0	27.0	26.5	27.2

e) Please state the specific factors that resulted in the increased amount forecast for Joint Use and Relocations capital expenditures from 2023 through 2027? Please provide details.

D1-Staff-186

Exhibit D / Tab 4 / Schedule 1 / pp. 20-34
Exhibit D / Tab 5 / Schedule 1 / pp. 20-34

Preamble:

OEB staff notes that several models are mentioned in the testimony, including the weather normalization model, the monthly models, the annual models, the end use models and the hourly electric load model (HELM).

Question(s):

a) Please explain how the multiple models are integrated to produce the final load forecast.

b) Please state whether or not Hydro One has considered using the Statistically Adjusted End Use (SAE) models?

c) Two of the models, COMMEND and HELM, were developed at EPRI. EPRI also developed the REEPS and INDEPTH models for forecasting residential and industrial energy consumption. Please explain why the latter two models are not used?

d) What is the price elasticity of demand by sector? Does it differ between the short run and the long run?

e) Complex estimation algorithms such as three-stage least squares and seemingly unrelated regressions are used in model estimation. How do the results compare if simple ordinary least squares models had been used instead?

D1-Staff-187
Exhibit D / Tab 4 / Schedule 1 / pp. 4-7
Exhibit D / Tab 5 / Schedule 1 / p. 9

Preamble:

The load forecast provided includes manual adjustments for CDM.

Question(s):

a) Please state how Hydro One knows that the impacts of CDM measures do not duplicate the estimates for efficiency improvements that are embedded in the load forecasting models?

D1-Staff-188
Exhibit D / Tab 5 / Schedule 1 / pp. 5-7, 16-18, 37-38

Preamble:

Hydro One has included the demand associated with the acquired utilities in its load forecast for 2023-2027.

Question(s):

a) Please state what share of total Hydro One distribution demand is coming from the Acquired Utilities in each of 2023-2027?

D1-Staff-189
Exhibit D / Tab 3 / Schedule 1 / pp. 1-4
Exhibit D / Tab 4 / Schedule 1 / pp. 1-40
Exhibit D / Tab 5 / Schedule 1 / pp. 1-40

Preamble:

Hydro One has provided the key economic and demographic assumptions underpinning its proposed load forecast. The load forecast does not explicitly explain how the impact of the COVID-19 pandemic is reflected in the proposed load forecast.

Question(s):

a) What impact has Hydro One observed from COVID-19 in 2020 and 2021 using the most recent information available in aggregate, by sector, and by rate class?

b) What impact does Hydro One expect COVID-19 to have on load in the 2023-2027 period in aggregate, by sector, and by rate class?

c) Please explain how Hydro One has captured the historic impacts of COVID-19 in its load forecasting models?

d) Please explain how, and to what extent, the impacts of COVID-19 are reflected in the 2023-2027 load forecast?

D1-Staff-190
EB-2018-0165 / Decision and Order / December 19, 2019 / pp 126-127

Preamble:

At the above reference, the OEB directed Toronto Hydro to undertake a more detailed analysis of the impact of electric vehicles (EVs) and distributed energy resources (DERs) on load and load profiles in future load forecasts.

Question(s):

a) Please state what analysis Hydro One has undertaken to determine the impact of EVs and DERs on 2023-2027?

b) Please explain how EVs and DERs are reflected in the proposed load forecast.

D1-Staff-191
Exhibit D / Tab 4 / Schedule 1 / p. 4

Preamble:

At the above reference, it is stated that:

> In EB-2010-0002, the OEB directed Hydro One to "work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA." In EB-2012-0031, Hydro One worked with stakeholders and the OPA to satisfy this directive, and the methodology set out in the report "Incorporating CDM Impacts in the Load Forecast" was accepted by the OEB.

Question(s):

a) Please provide a copy of the report "Incorporating CDM Impacts in the Load Forecast" referenced above.

D1-Staff-192
Exhibit D / Tab 4 / Schedule 1 / p. 6

Preamble:

At the above reference, it is stated that in relation to Ontario demand, a total of 586 MW of embedded generation was assumed to be in place in 2017, with an additional 20 MW in 2018, 8 MW in 2019, 21 MW in 2020, 36 MW in 2021, and 2 MW in 2022. No new embedded generation is assumed in the load forecast after 2022.

Question(s):

a) Please define the term embedded generation.

b) Please state why there is no new embedded generation included in the load forecast after 2022.

D1-Staff-193
Exhibit D / Tab 4 / Schedule 1 / p. 7

Preamble:

At the above reference, it is stated that:

> Hydro One's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity.

Question(s):

a) How many transformer stations or delivery points are used in the forecast? Please also state whether or not any econometric model or end use model is used to forecast loads at this level of geographical detail.

D1-Staff-194
Exhibit D / Tab 4 / Schedule 1 / pp. 8-9

Preamble:

At the above reference, it is stated that Hydro One completed a study in 2008 on weather normalization practices by surveying over 50 utilities in North America and that the study was submitted to the OEB for review in the transmission rate case EB-2008-0272. Two of the major findings of this study were that:

- Very few utilities have changed their weather normalization practices in response to global warming or other reasons.
- The survey results were supportive of Hydro One's weather-normalization methodology, which is based on the use of 31 years of weather data to define normal weather conditions.

Question(s):

a) Please provide evidence to support the assertion that very few utilities had changed their weather normalization in response to global warming.

b) Please state whether or not Hydro One has considered using a shorter time interval, such as 10 or 20 years of data, to see if that would make a difference in the weather normalization results?

D1-Staff-195
Exhibit D / Tab 4 / Schedule 1 / p. 11
Exhibit D / Tab 5 / Schedule 1 / p. 11

Preamble:

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the total transmission system load. The model links monthly energy consumption to Ontario GDP and residential building permits.
The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the distribution system load. The model links monthly energy consumption to Ontario GDP and residential building permits.

Question(s):

a) How are these models estimated?

D1-Staff-196
Exhibit D / Tab 4 / Schedule 1 / p. 14
Exhibit D / Tab 5 / Schedule 1 / p. 14

Preamble:

The customer survey results are used in the preparation of the customer forecast.

Question(s):

a) Please provide copies of the survey instruments. How many customers responded to the survey?

Preamble:

For industrial customers, several information sources are used to prepare the forecast.

Question(s):

b) How accurate are these forecasts?

D1-Staff-197
Exhibit D / Tab 4 / Schedule 1 / p. 32

Preamble:

At the above reference, Hydro One has provided an equation for the Industrial Model. Hydro One has described the Industrial Model as a total energy model. The model's variables include:

LENIND = logarithm of electricity consumption in Ontario industrial sector.
D13 = a dummy variable, equals 1 in 2013 and zero elsewhere.

Question(s):

a) Please state whether the left hand side variable is total energy consumption or electricity consumption?

b) Please explain what happened in 2013 to require a dummy variable?

D1-Staff-198
Exhibit D/ Tab 4 / Schedule 1 / p. 35

Preamble:

At the above reference it is shown that the regression results demonstrate that the model has a good fit with historical values and all the model parameters are statistically significant.

Question(s):

a) Please provide the implied price and GDP industrial elasticities of total energy consumption and of electricity consumption. Please distinguish short run from long run elasticities.

D1-Staff-199
Exhibit D/ Tab 4 / Schedule 1 / p. 36

Preamble:

At the above reference it is stated that the regression results show the model captures most of the variations in the agricultural load in Ontario despite a great volatility in the data series.

Question(s):

a) Please state why there is no measure of agricultural output included in the equation?

D1-Staff-200
Exhibit D/ Tab 4 / Schedule 1 / p. 47

Preamble:

At the above reference it is stated that over the 17-month forecast period starting in February 2021, for which the IESO has a monthly peak forecast, the difference between IESO and Hydro One forecasts averages to 658 MW.

Question(s):

a) Please provide the difference expressed in percentage terms.

D1-Staff-201
Exhibit D/ Tab 5 / Schedule 1 / pp. 8, 37

Preamble:

OEB staff has calculated that there was a total of 1,122,826 customers in the Hydro One legacy residential rate classes of UR, R1, R2, and seasonal in 2015, and that this had increased to 1,176,424 customers in 2020. This reflects a growth rate of 0.94% over the historic period. In 2022 these rate classes are forecast to have 1,196,059 customers, and in 2027 they are forecast to have 1,243,488 customers. This reflects a growth rate of 0.78% over the 2022-2027 period.

Similarly, declining growth rates in the forecast period relative to the historic period can be seen in both acquired residential rate classes, and several general service rate classes.

Question(s):

a) Please detail the methodology used to arrive at the customer connection forecast and provide any relevant derivation of the forecast customer connections.

b) Please explain the cause of the apparent declining growth rates in the residential and general service rate classes.

D1-Staff-202
Exhibit D / Tab 5 / Schedule 1 / p. 5
Exhibit D / Tab 5 / Schedule 1 / p. 37

Preamble:
Table 3 at the first reference does not match the total consumption in Table E.3 at the second reference. Both quantities are described as GWh Delivered.

Question(s):

a) Please indicate which methodologies are used to forecast each table.

b) Please detail what load is counted in each table, and what accounts for the difference between the tables.

c) If the difference is due to differences in forecasting methodologies, please explain the purpose of Table 3 in setting rates.

Exhibit E Operating, Maintenance and Administrative Costs

E-Staff-203
Exhibit E
EB-2019-0082 / Decision and Order / April 23, 2020 / pp. 114-115

Preamble:

At the second reference above, the OEB highlights the following:

> The OEB realizes that there may be a time lag between capital investments and corresponding reduced need for maintenance. The OEB also realizes that, as assets are refurbished or replaced, other assets continue to age requiring more maintenance. However, the OEB finds that Hydro One has not demonstrated or explained in this Application the correlation between its increased capital expenditures and potential reductions in OM&A costs. It is the OEB's expectation

> that, when a business case is prepared for capital investments, an assessment of the impact of that investment on OM&A cost is typically addressed. The OEB expects that, in future rate applications, Hydro One will provide a high level assessment of such correlation, or lack of, at the program level.

Question(s):

a) Please discuss how Hydro One has reflected this direction in the application.

E-Staff-204
Exhibit E / Tab 2 / Schedule 1 / p. 3

Preamble:

At the above reference, it is stated that:

> Starting in 2023 Hydro One needs to increase its OM&A spending in some respects, mainly to: (i) address deferred stations maintenance that allowed Hydro One to continue funding PCB remediation work as planned in 2019-2022; (ii) address security needs related to evolving security threats and NERC CIP standard; and (iii) fund planned corrective maintenance work on overhead lines.

Question(s):

a) Please provide for each year from 2019 to 2022, the amounts of spending that was deferred on station maintenance and other areas and was moved to the funding of the PCB remediation work in the same period.

b) Please state what the impacts would have been had Hydro One completed the station maintenance work concurrently with the PCB remediation work in the 2019 to 2022 period.

c) Please state the extent to which transmission system safety and reliability would have been impacted had Hydro One continued to defer the station maintenance spending beyond 2023.

E-Staff-205
Exhibit E / Tab 2 / Schedule 1 / p. 3

Preamble:

At the above reference, it is stated that:

> The budgeted OM&A costs in 2021 have been reduced by expected productivity savings, and reflect sustained cost control. Forecasted OM&A productivity savings through to end of 2022 are reflected in the OM&A budget in 2023, by having these OM&A efficiencies become part of regular business planning and thus reducing upward pressure on future OM&A expenditures. These forecasted and continuing savings help to reduce the OM&A amounts being requested in this application and are largely attributable to: (i) stations scheduling efficiencies and lower ground and site maintenance costs; (ii) lower costs associated with repatriating Inergi staff; and (iii) the corporate costing initiative which significantly reduced vacancies and limited contract spending to critical functions.

Question(s):

a) Please state how expected productivity savings are differentiated from sustained cost control.

b) Please state the amount of 2023 OM&A expenditure reductions reflected in the 2023 budget resulting from: (i) expected productivity savings; and (ii) sustained cost control.

c) Please also break this amount down between the three sources of savings cited in the second part of the above reference, specifying which of these are considered to be expected productivity savings and which are considered to be reflections of sustained cost control.

E-Staff-206
Exhibit E / Tab 2 / Schedule 2 / pp. 3-4
Exhibit E / Tab 2 / Schedule 2 / pp. 41-42

Preamble:

At the first reference above, Hydro One discusses its plans to increase funding for cyber security requirements to maintain compliance with regulatory obligations and notes that it intends to insource key aspects of its security operations through a new in-house Joint Security Operations Centre (JSOC), which is described as a 24/7 centre for monitoring cyber and physical security.

At the second reference above, Hydro One further discusses the JSOC and notes that:

> Hydro One anticipates completing its JSOC in 2022 and beginning the process of hiring, testing, and training new staff, who will take on primary monitoring functions in the JSOC, in 2023. Additional staff are to be on-boarded in 2023 in anticipation of Hydro One fully assuming all primary cyber and physical security monitoring and system operations functions from its existing managed service providers by the end of 2023.

-and-

> The insourcing of these activities will lead to improved incident monitoring, triage assessment, and proactive security and response capabilities, which will in turn improve the resiliency of Hydro One's transmission system. Current outsourced service providers are not able to access certain internal Hydro One systems and tools that help drive more effective and efficient triage, assessment, and response to physical and cyber alerts. Instead, these providers rely on existing Hydro One staff to provide input and perform these functions on their behalf. Through the JSOC, security personnel will have direct access to security-related information provided by Hydro One's internal systems and will be able to leverage the on-site presence of Hydro One teams located at the Integrated Systems Operating Centre (ISOC). In addition, given Hydro One's current reliance on outsourced service providers to carry out certain tasks required to ensure regulatory compliance with NERC CIP, insourcing such roles and tasks will lead to increased compliance oversight and assurance.

Question(s):

a) Please state when the need for cyber security requirements to maintain compliance with regulatory obligations was identified and the nature of such obligations.

b) Please state when the services referenced above as being insourced were originally outsourced and why this was done given the problems with the outsourcing of these services identified above. Please provide the results of any cost / benefit study that was undertaken at the time to support this outsourcing.

c) Please discuss why the problems identified with the outsourcing above could not be resolved without insourcing these services.

d) Please state whether a cost / benefit study of this insourcing was done and, if so, please provide the results of the study.

e) Please reconcile the decision to outsource these services in the past with the current decision to in-source.

f) Please identify the number of all new staff that Hydro One intends to hire to take on the primary monitoring functions in the JSOC. In detailing the number of staff, please provide a breakdown of the type (i.e., Regular or Casual) and representation (i.e., MGT/Non-represented, Society, PWU, temporary, etc.).

E-Staff-207
Exhibit E / Tab 2 / Schedule 2 / p. 4

Preamble:

At the above reference, it is stated that:

> Hydro One plans to increase funding for planned corrective maintenance work on overhead lines to address hardware defects affecting Bulk Electric System (BES) transmission lines. In particular, there are several 500-kV guyed towers that need to have their bolts re-torqued and their guy wires re-tensioned. Additionally, several circuits have defective dampers installed, which are now failing and need to be replaced. The increase in the proposed expenditures has been partially offset by productivity savings in patrol cycles, and lower insulator washing costs.

Question(s):

a) Please state when the need for this corrective maintenance work was identified and why it came about.

b) Please discuss whether the need for this corrective maintenance indicates any issues with Hydro One's current approaches to the acquisition of equipment from suppliers of the types discussed above and, if so, whether or not any changes were made to these processes. If changes were made, please describe what they were. If no changes were made, please explain why not.

c) Please discuss the specific additional costs related to the defects identified above which have been incurred and whether any of these costs are expected to be recovered from the suppliers.

d) Please state the amount of these additional costs that have been offset by the productivity savings referenced above from patrol cycles and lower insulator washing costs and whether or not these savings would have also been achieved in the absence of the increased expenditures identified above.

E-Staff-208
Exhibit E / Tab 2 / Schedule 2 / p. 10 / Table 5
EB-2019-0082 Exhibit F / Tab 1 / Schedule 3 / p. 10

Preamble:
At the first reference above, a 2020 actual of $9.9 million is shown for expenditures for PCB retirement and waste management.

At the second reference above, a 2020 forecast of $14.6 million was shown.

Question(s):

a) Please explain the reason for this difference of $4.7 million, including a discussion as to whether or not the reasons for this variance could have been anticipated at the time of the 2020 forecast and, if not, why not.

E-Staff-209
Exhibit E / Tab 2 / Schedule 2 / p. 11

Preamble:

At the above reference, it is stated that:

> In addition to work for critical customers, during the 2021-2022 period, Hydro One has also prioritized transformer bushings and auto-transformer bushings for PCB remediation work. This type of equipment requires outage planning and scheduling as well as significant lead time to procure materials. As a result, the remediation cost for transformer bushings is on average four times more expensive compared to medium-voltage oil breaker bushings.

Question(s):

a) Please state to what extent the remediation cost for transformer bushings compared to medium voltage oil breaker bushings being on average four times more expensive, is due to the prioritization of this work by Hydro One and the other specific circumstances in which Hydro One was incurring these costs as compared to being an industry norm. If these costs were higher due to Hydro One's specific circumstances, please state what the additional costs were due to these circumstances.

E-Staff-210
Exhibit E / Tab 2 / Schedule 2 / p. 18

Preamble:

At the above reference, it is stated that:

> Hydro One approached the deferral of preventive maintenance activities by using updated asset condition data to identify assets for which certain preventive maintenance activities could be deferred for a short period of time with comparatively lower risk to system performance and reliability.

Question(s):

a) Please provide an example of an asset for which Hydro One determined the referenced preventative maintenance activities could be deferred for a short period of time with comparatively lower risk to system performance and reliability and an asset for which it was determined that such a deferral could not be undertaken.

b) Please explain the process by which Hydro One arrived at the different deferral classifications, as well as the determinative criteria for reaching these decisions, for these two assets.

c) Please state whether or not Hydro One has delayed preventative maintenance on any assets for 2023 using a similar assessment approach to that outlined above. If yes, please state the impact any such deferrals had on the preventative maintenance forecast for 2023, if not, please explain why not.

E-Staff-211
Exhibit E / Tab 2 / Schedule 2 / p. 21

Preamble:

At the above reference, it is stated that:

> In addition to transformer refurbishments, a number of smaller transformer programs are being implemented under this category to reduce the risks of equipment failure. These programs have been developed as a result of failure investigation findings or to align with current industry best practices.

Question(s):

a) Please confirm if the “smaller transformer programs” were included in Transformer Refurbishment OM&A in the historical years. If not, please identify the year in which the programs will be included in Transformer Refurbishment OM&A (and for how long), and why they were included.

b) Please identify the amounts for each year in Transformer Refurbishment OM&A that are attributed to the “smaller transformer programs”.

c) Please discuss whether these programs being developed as a result of failure investigation findings indicates any issues with Hydro One’s current approaches to maintenance of transformers and, if so, whether or not any changes were made to maintenance processes. If changes were made, please describe what they were. If no changes were made, please explain why not.

<u>E-Staff-212</u>
Exhibit E / Tab 2 / Schedule 2 / pp. 27-28

Preamble:

At the above reference when discussing the increase in Other Maintenance Programs OM&A, it is stated that:

> The increase in 2023 expenditures is primarily driven by the need to address certain grounding system deficiencies, including a new initiative to fund the maintenance and standardization of temporary portable grounds that have been identified as posing health and safety risks. The grounding system is an essential component at a transmission station, as it ensures public and employee safety in the station by keeping all equipment at the same electrical potential and directing unwanted energy away from equipment and other connected metallic objects into the earth during electrical faults. Under this program, Hydro One inspects and

repairs (where needed) grounding systems to ensure they are in good condition and workable order.

Question(s):

a) Please state how Hydro One’s approach to addressing the above-referenced grounding system deficiencies changed as a result of the new initiative to fund the maintenance and standardization of temporary portable grounds that have been identified as posing health and safety risks and whether or not the previous approach has now been identified as having inadequacies and, if so, what they were and how they were determined.

b) Please state what the incremental costs of the new initiative are.

E-Staff-213
Exhibit E / Tab 2 / Schedule 2 / p. 28 / Table 19
EB-2019-0082 Exhibit F / Tab 1 / Schedule 3 / p. 26

Preamble:

At the first reference above, a 2020 actual of $25.4 million is shown for expenditures for Telecom.

At the second reference above, a 2020 forecast of $21.5 million was shown.

Question(s):

a) Please explain the reason for this difference of $3.9 million, including a discussion as to whether or not the reasons for this variance could have been anticipated at the time of the 2020 forecast and, if not, why not.

E-Staff-214
Exhibit E / Tab 2 / Schedule 2 / p. 35

Preamble:

At the above reference when discussing the reduction in Operation of Power Telecom System Services expenditures, it is stated that:

> Under this program, Hydro One receives coordinated network management, vendor management, real-time alarm-based monitoring, and system analysis services from Hydro One Telecom. Expenditures in this program expected to decline as components of services retained for project-related work are allocated to capital projects.

Question(s):

a) Please provide further explanations as to why expenditures in this program are expected to decline as components of services retained for project-related work are allocated to capital projects, including whether or not this decline arose from any changes in capitalization policy and, if so, what they were and when they were implemented.

b) Please provide the amounts that were allocated to capital projects for each of the years shown in Table 24.

E-Staff-215
Exhibit E / Tab 2 / Schedule 2 / p. 44

Preamble:

At the above reference, the following statement was made in discussing Hydro One's proposed increase in Site Infrastructure Maintenance OM&A:

> The slight increase is primarily due to spending that will enable Hydro One to continue to address deficiencies within its station building infrastructure that pose a risk to reliability if not remedied. This work includes addressing leaking roofs, which is necessary to protect Hydro One's electrical equipment within relay buildings, and ensuring that basement sump pumps and backflow are in good working order, which protects Hydro One's electrical equipment from flooding events.

Question(s):

a) Please state when the need for addressing such deficiencies was identified and how it came about.

b) Please discuss whether the need for this corrective maintenance indicates any issues with Hydro One's current approaches to maintaining station building infrastructure and, if so, whether or not any changes were made to its approach. If changes were made, please describe what they were. If no changes were made, please explain why not.

E-Staff-216
Exhibit E / Tab 2 / Schedule 2 / p. 59

Preamble:

At the reference above, the following statement was made in discussing Hydro One's previous approach to preventative maintenance and asset condition assessment:

> Previously, Preventive Maintenance and Asset Condition Assessment was conducted uniformly without distinction between the age of circuits, type of structure, and the efficiency of each patrol type.

Question(s):

a) Please explain why the previous approach did not distinguish between the age of circuits, type of structure and the efficiency of each patrol type.

E-Staff-217
Exhibit E / Tab 2 / Schedule 2 / p. 61

Preamble:

At the above reference, it is stated that:

> The decrease in forecast expenditures for the 2021-2022 period relative to the prior years is primarily due to an anomalous increase in Demand Maintenance expenditures in 2018 and 2019 (in the amounts of $4.5M and $4.7M, respectively) to address unplanned repair work on loose bolts and guy wires on several 500 kV circuits. In addition, starting in 2021, Hydro One shifted its low-priority demand work from the Demand Maintenance Program to the Planned Corrective Maintenance program, where this type of work is more appropriately addressed.

Question(s):

a) For the years 2021 and beyond, please provide the amounts that have been shifted from the Demand Maintenance Program to the Planned Corrective Maintenance program.

b) Please identify when and explain why Hydro One determined it to be appropriate to start shifting low-priority demand work to the Planned Corrective Maintenance program.

E-Staff-218
Exhibit E / Tab 2 / Schedule 5 / p. 10

Preamble:

At the above reference, Hydro One addresses initiatives it has undertaken to improve the efficiency of work program delivery, and it is stated that:

> Work program execution has been improved by the optimal deployment of Hydro One internal resources. To accomplish this, the company temporarily re-assigns staff to areas of specific project work demand.

Question(s):

a) Please explain why the previous approach to work program execution did not consider the optimal deployment of Hydro One internal resources.

b) Please clarify if the temporary re-assignment of staff is in reference to staff being re-assigned between the Transmission and Distribution lines of business (or vice versa). If so, please further elaborate on how this has increased efficiency.

E-Staff-219
Exhibit E / Tab 3 / Schedule 1 / pp. 2-3

Preamble:

At the above reference, Hydro One lists five factors accounting for higher achieved productivity relative to amounts forecasted in the 2018-2022 Distribution application.

Two of these five factors relate to in-sourcing initiatives, which are:

- accelerated saving in the In-Sourcing of the IT contract initiative
- savings realized due to Customer Call Centre Insourcing initiative

Question(s):

a) Please state for each of the above-referenced in-sourcings when these services were originally outsourced and what the rationale and estimated cost savings were at the time of the outsourcing.

b) Please state whether or not these savings were realized and, if so, please state the total amount of the realized savings and when they occurred. If the anticipated savings were not realized, please state why this was the case and the amount of any additional costs that were incurred as a result of the outsourcings and when these costs were incurred.

c) Please reconcile the decision to outsource these services in the past with the current decision to in-source.

E-Staff-220
Exhibit E / Tab 3 / Schedule 2 / p. 14

Preamble:

At the above reference regarding stations PCB retrofill, it is stated that:

> Instrument transformers contaminated with PCB content are planned for replacement under a capital investment.

Question(s):

a) Please state whether the replacement of PCB-contaminated instrument transformers under a capital investment is the result of any changes in capitalization policy. If so, please explain why, when it was implemented, and identify the amounts for each year.

E-Staff-221
Exhibit E / Tab 3 / Schedule 2 / p. 24

Preamble:

At the above reference discussing trouble call expenditures, it is stated that:

> Relative to 2020, the forecast expenditure for the 2023 Test Year is a decrease of $12.5M due to an expected reduction in trouble call volume primarily resulting from Hydro One continuing through the Optimal Cycle Protocol (OCP) program, and is $0.5M lower compared to 2018 actuals.

The 2023 Test year forecast level is shown in Table 8 at the same reference to be in the range of $64 million, as was the 2018 Actual. However, the 2019 and 2020 actuals are both in the $75 to $76 million range.

Question(s):

a) Please provide further explanation as to how Hydro One was able, by continuing through the Optimal Cycle Program, to achieve the decrease in trouble call volume leading to the referenced $12.5 million of trouble call expenditure reduction in the 2023 Test year relative to the 2020 Actual level of expenditures. Please provide a breakdown of this decrease between the key contributing factors.

b) Please state why the 2019 and 2020 Actual levels of trouble call expenditures were significantly higher than both the 2018 Actual level and the current forecast levels.

E-Staff-222

Exhibit E / Tab 3 / Schedule 2 / p. 27

Preamble:

At the above reference, it is stated that:

> The trouble call program is reactive in nature and as such its volume of work varies based on a number of external factors. These factors include weather, equipment failure, and the volume of customer complaints. Due to the variable nature of demand work, Hydro One develops investment levels based on forecast volumes and costs using observed historical averages.

Question(s):

a) Please provide a table showing the number of trouble calls from 2017 to 2021.

E-Staff-223
Exhibit E / Tab 3 / Schedule 2 / pp. 29-30

Preamble:

With regard to Disconnects / Reconnects, Hydro One's evidence shows that proposed spending for the 2023 test year is based on an expected volume of 18,000 disconnect and reconnect calls per year. Hydro One also notes that the number of service disconnection and reconnection requests has increased over the past several years.

Question(s):

a) Please provide a table showing the number of disconnection and reconnection requests per year from 2018 to 2021.

b) Please comment on the trend of the cost per disconnection and reconnection per year.

c) Has Hydro One determined why the number of disconnection and reconnection requests has increased over the past several years? If so, please explain.

d) Please state why the 2019 and 2020 Actual levels of disconnection and reconnection expenditures were significantly higher than both the 2018 Actual level and the current forecast levels.

E-Staff-224
Exhibit E / Tab 3 / Schedule 2 / p. 36

Preamble:

At the above reference, when discussing expenditures in the category "Meters, Telecom and Control", it is stated that:

> The $4.9M increase in the 2023 forecast relative to 2020 reflects a combination of lower 2020 actuals relative to forecast and an increase in forecast expenditures for 2023. 2020 actuals were lower than forecast due to COVID related reductions in non-mandatory field work and delays in fulfilling staff vacancies. The 2023 forecast reflects an increase in field work associated with AMI 1.0 meter failures, increasing regulatory compliance meter sample testing,

as well as filling previously approved staff vacancies in 2021 to address sustainment work requirements.

Question(s):

a) Please provide a breakdown of this $4.9 million increase between each of the factors cited above.

b) Please explain why there was an increase in field work associated with AMI 1.0 meter failures including why the AMI 1.0 meters are failing.

E-Staff-225
Exhibit E / Tab 3 / Schedule 2 / p. 46

Preamble:

At the above reference, when discussing Defect Correction (OCP) program spending, it is stated that:

> The OCP has been a success in delivering better cost and reliability outcomes. Hydro One reduced the total line clearing unit cost per km by nearly 50% over the first three years of the OCP program.

Question(s):

a) Please provide the total line clearing unit cost per km for each of the first three years of the OCP program.

b) Please provide a breakdown of the factors that produced the nearly 50% reduction in this unit cost over this time period and the amount of their contribution to it.

E-Staff-226
Exhibit E / Tab 3 / Schedule 2 / p. 48 / Table 21

Preamble:

At the above reference, Hydro One provides OCP performance actuals for 2018 through 2020.

Question(s):

a) Please complete the following table by adding in historical actuals for kilometres cleared and unit cost for 2015 through 2017. Please provide the forecast for kilometres cleared for 2021 through 2023.

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Kms cleared (km)				26,070	28,009	23,006			
Unit cost ($/km)				4,910	5,609	5,670	-	-	-

E-Staff-227
Exhibit E / Tab 3 / Schedule 2 / p. 48 / Table 22

Preamble:

At the above reference, Table 22, which provides information on Public Safety and Reliability Program Spending and Projection, shows an increase in these expenditures from a 2020 Actual level of $9.2 million to a 2023 Test year level of $16.1 million.

Question(s):

a) Please provide an explanation for this increase including a breakdown of the major factors contributing to it.

E-Staff-228
Exhibit E / Tab 3 / Schedule 2 / p. 48 / Table 22
Exhibit E / Tab 3 / Schedule 2 / p. 49 / Tables 23 and 24

Preamble:

At the first reference, Hydro One provides Public Safety and Reliability (PSR) program spending and projections.

At the second reference, Hydro One indicates that the Public Safety and Reliability (PSR) program is broken down into two subsections: (i) the Demand PSR program; and (ii) the Planned PSR program.

		Cost ($M)					
		2018	2019	2020	2021	2022	2023
(a)	Demand PSR[1]	11.1	7.2	9.2	8.2	8.3	8.5
(b)	Planned PSR[2]	-	-	-	7	7	7
Total: (a) + (b)		11.1	7.2	9.2	15.2	15.3	15.5
(c)	PSR[3]	10.9	7.2	9.2	15.2	15.3	16.1

Notes:
1: Values reported in Table 23
2: Values reported in Table 24
3: Values reported in Table 22

Question(s):

a) Please explain why the expenditures in 2018 and 2023 for Demand PSR (Table 23) and Planned PSR (Table 24) do not add up to the 2018 and 2023 expenditures reported for PSR (Table 22). If necessary, please correct Tables 22, 23 and / or 24 and include an explanation for any corrections made.

b) How did Hydro One determine the 2021 to 2023 expenditures for Demand PSR and Planned PSR?

c) Please explain how the expenditures for Planned PSR can be maintained at the same level from 2021 to 2023 given that the program is being reactivated after it was paused from 2018 though 2020.

d) Please state the extent to which distribution system safety and reliability would have been impacted had Hydro One continued to defer Planned PSR spending beyond 2023.

E-Staff-229
Exhibit E / Tab 3 / Schedule 3 / pp. 8-9

Preamble:

The above reference, Table 6, which provides a summary of Research Development and Demonstration OM&A, shows an increase from a 2020 Actual of $2.3 million to a 2023 Test year level of $5.9 million. This is explained as follows:

> These increases are attributable to the further study and assessment of new technologies and practices and to provide access to and facilitate industry research and engagement with organizations (such as EPRI, CEATI, and CEA) to obtain insights into new and emerging technologies, and challenges associated with incorporating said technologies.

Question(s):

a) Please provide further explanation as to why the factors cited in the explanation above caused anticipated expenditures in this category to more than double from the 2020 Actual to the 2023 Test year forecast, including a breakdown of the amounts contributing to this increase.

E-Staff-230
Exhibit E / Tab 3 / Schedule 4 / p. 4

Preamble:

At the above reference, it is stated that:

> Since the insourcing of the Call Center in March 2018, the company has been able to realize significant efficiencies and reduce costs for customers in 2019 and 2020. Driving these efficiencies were an improved organizational structure and a drop in call volume due to customers transitioning to self-serve solutions, such as the Hydro One website and the myAccount customer portal.

Question(s):

a) Please provide further explanation as to how the referenced efficiencies of an improved organizational structure and a drop in call volume due to customers transitioning to self-serve solutions reduced costs for customers in 2019 and 2020. Please include a discussion of the type of costs that were reduced.

E-Staff-231
Exhibit E / Tab 3 / Schedule 4 / p. 5

Preamble:

At the above reference, when discussing increases in meter reading OM&A expenses, it is stated that:

> These fluctuations in this expense category are driven by the volume of manual meter reads. The volume of manual meter reads decreased between 2018 and 2020, compared to previous years, as a result of process enhancements and program optimization leading to efficiencies. Starting in 2021, the need for manual meter reads is expected to go up due to an increase in failing meters that have reached the end of their expected service lives.

Question(s):

a) Please provide further explanation as to why, beginning in 2021, the need for manual meter reads is expected to go up due to an increase in failing meters that have reached the end of their expected service lives. Please discuss why this increase began to occur in 2021, how long it is expected to last and by how much it might increase costs in this area before it comes to an end.
b) Please explain why there is an increase in failing meters given Hydro One's planned capital expenditures in this area.

E-Staff-232
Exhibit E / Tab 3 / Schedule 4 / pp. 6-7

Preamble:

At the above reference, when discussing the increase in Third Party Support OM&A shown in Table 4 from a level ranging from $15.5 million to $17.6 million in 2018 to 2020 Actuals to anticipated levels of $24.7 million in 2021 with a 2023 Test year level of $25.0 million, the following explanation is provided:

> Relative to 2020, the increase in Third Party Support OM&A in 2021 is primarily due to a renewed focus on customer experience and the expansion of customer programs and services, which are required to meet customers' evolving needs and help them manage their energy consumption. This includes more proactive outreach to customers to help them make informed decisions about their energy consumption and lower their bill, as well as the expansion of digital services to present customers with more choice and convenient solutions. This also includes performance enhancements to the myAccount portal, outage and service alerts

> via email and text messages, and the development of a new application. Further included in Third Party Support OM&A is the development and sustainment of a new density review program designed to provide higher accuracy of information, reduce the number of customer complaints—thereby increasing customer satisfaction—and reduce on-site field investigations, which will lead to savings in future years.

Question(s):

a) Please provide a breakdown of the increase from the 2020 Actual level of $17.6 million to the 2023 Test year level of $25 million between the above-referenced factors.

b) Please state why all these changes occurred in 2021 after relatively stable levels of spending in the 2018 to 2020 period.

<u>E-Staff-233</u>
Exhibit E / Tab 3 / Schedule 4 / p. 8

Preamble:

At the above reference, when discussing forecast Field Support OM&A, it is stated that:

> In 2020, field support expenditures were $1.2M lower than 2019 due to a COVID-related suspension of field collections. Disconnections were put on hold for almost all of 2020, and field operations are expected to resume in 2021 at a higher than normal level to make up for the suspension in 2020. Outer year forecasts reflect back to normal levels, and the 2023 forecast expenditure is in line with the forecast and bridge years.

Question(s):

a) Please reconcile the statement of “outer year forecasts reflect back to normal levels” given the fact that the 2022 Bridge Year and 2023 Test Year forecasts are only $0.1M less than the 2021 forecast (a forecast characterized as being at a “higher than normal level”).

<u>E-Staff-234</u>
Exhibit E / Tab 3 / Schedule 4 / p. 12

Preamble:

At the above reference, when discussing the increase in Customer Care Staffing OM&A from a 2020 Actual level of $9.8 million to a 2023 Test year level of $13.9 million, it is stated that:

> Test Year expenditures are forecasted to be $4.1M higher relative to 2020 actuals which is due to filling vacancies within the team to deliver customer programs, such as the Account Manager Program for C&I customers, and provide a high level of customer service across all segments. Compared to 2018 Actuals, the 2023 forecast is $1.4M lower. Customer Care Staffing OM&A costs dropped by $5.4M between 2018 and 2019, mainly due to lower executive compensation, vacancies within in the customer service team, and a decrease in costs for long-term incentive plans (LTIP). 2020 expenditures remained at the same low level, as vacancies remained open due to the COVID-19 pandemic.

Question(s):

a) Please state how many vacancies are being filled by the 2023 Test year relative to the actual 2020 levels and how long these positions have been vacant.

b) Please provide a breakdown of the $5.4 million drop in these expenditures between 2018 and 2019 by the factors cited above as being the reasons for it.

c) Please state why vacancies for these positions remained open due to the COVID-19 pandemic.

E-Staff-235

Exhibit E / Tab 3 / Schedule 5 / p. 14

Preamble:

At the above reference, when discussing Hydro One’s resourcing strategy, it is stated that:

> Some additional Forestry Technician resources are also anticipated to be required to accommodate work program requirements, with increased levels of Hiring Hall Forestry Technicians required for 2021-2025, returning to 2020 levels in 2026.

Question(s):

a) Please state why the increased levels of Hiring Hall Forestry Technicians required for 2021-2025 is expected to return to 2020 levels in 2026.

E-Staff-236
Exhibit E / Tab 3 / Schedule 5 / p. 16

Preamble:

At the above reference, when discussing productivity, it is stated that:

> After reaching an agreement with the PWU in early 2015, Hydro One received approval to outsource Distribution Cable Locates, an initiative that has realized significant savings and will continue to be pursued by the organization. Hydro One also joined the Locate Alliance Consortium (LAC) to facilitate the transition to outsource locates. The LAC is a group of underground facility owners within the province that engage in a group RFP process to leverage their collective volume to negotiate low-cost locates through LSPs. By joining LAC, Hydro One was able to benefit from LAC's cost-effective, efficient locate service delivery model and take advantage of established multi-utility discounts offered by LSPs under contract to LAC. Additionally, After Hours Emergency Cable Locates were diverted from the Trouble Call Program and outsourced to LSPs in 2018, eliminating the need to roll a trouble truck.

Question(s):

a) Please state the annual cost savings that have been realized from: (i) outsourcing of Distribution Cable Locates, (ii) joining LAC, and (iii) outsourcing of After Hours Emergency Cable Locates.

b) Please state whether there have been any potential concerns identified with these three initiatives since they were implemented and, if so, what they are.

E-Staff-237
Exhibit E / Tab 3 / Schedule 5 / p. 17

Preamble:

At the above reference, when discussing productivity, it is stated that:

As trouble calls are the largest driver of O&M spend within Distribution, Hydro One has focused on finding ways to better utilize resources and reduce costs. Historically, standard practice at Hydro One was to dispatch two Distribution Lines staff to all trouble calls. Hydro One has determined that a portion of after-hours trouble calls could be responded to with one person. It was also confirmed that the majority of calls occurred outside core business hours, resulting in an increased cost to the work program. To drive efficiencies within this program, Distribution implemented an initiative to reduce the cost per trouble call by altering shift schedules and dispatching a single person for trouble calls, provided it does not increase trouble call recordable incidents or materially impact customer satisfaction and restoration times.

Question(s):

a) Please state when this initiative was implemented and what the annual cost savings have been.

b) Please state whether there have been any increases in trouble call recordable incidents or material impacts on customer satisfaction and restoration times arising from the implementation of this initiative and, if so, what they were.

E-Staff-238
Exhibit E / Tab 4 / Schedule 1 / p. 2 / Table 1

Preamble:

At the above reference, Table 1 provides a summary of total common and other OM&A costs for the 2018 to 2023 period.

Question(s):

a) Please provide a breakdown of the increase in the total amount of these costs from the 2020 actual level of $170.7 million to the 2023 Test year level of $206.1 million.

b) Please discuss this increase in the context of the 2021 and 2022 forecast total levels of $153.9 million and $145.8 million.

E-Staff-239
Exhibit E / Tab 4 / Schedule 1 / p. 3 / Table 3

Preamble:

At the above reference, Table 3 provides a summary of total common and other OM&A costs for the 2018 to 2023 period allocated to Distribution.

Question(s):

a) Please provide a breakdown of the increase in the total amount of these costs from the 2020 actual level of $79.7 million to the 2023 Test Year level of $110.0 million.

b) Please discuss this increase in the context of the 2021 and 2022 forecast total levels of $68.0 million and $67.0 million.

E-Staff-240
Exhibit E / Tab 4 / Schedule 2 / p. 9 / Table 4

Preamble:

At the above reference, Table 4 provides a summary of allocated corporate management costs and states that the majority of the costs are not recoverable from transmission or distribution customers.

Question(s):

a) Please provide an updated version of Table 4 reflecting only the costs that are recoverable from transmission and distribution customers.

b) Please discuss the reason(s) for the variances in the levels Allocated to Other in the context of the 2020 actual of $12.0 million, 2021 forecast of $24.5 million, 2022 Bridge Year of $17.7 million, and 2023 Test Year of $20.5 million.

E-Staff-241
Exhibit E / Tab 4 / Schedule 2 / p. 19

Preamble:

At the above reference it is stated that:

> The Reporting and Analytics team, a relatively new prong of the HR function, supports HR metrics reporting, headcount and resource planning, predictive analytics, and workforce optimization. This group is focused on evolving the existing operational activities into a more strategic/proactive program which supports the business. To drive this effort, current HR processes and technology must be enhanced through investment in replacing legacy systems, and establishing analytics-focused decision-making reflexes.

Question(s):

a) Please identify when the Reporting and Analytics team was established and provide further reasoning for the need to establish this team.

b) Please explain how the Reporting and Analytics team will assist the Human Resources function in implementing changes to its core operating model.

E-Staff-242
Exhibit E / Tab 4 / Schedule 2 / p. 32 / Table 13

Preamble:

At the above reference, Table 13 provides a summary of allocated facilities and real estate costs for the 2018 to 2023 period.

Question(s):

a) Please provide a breakdown of the increase in the total amount of these costs allocated to Transmission from the 2020 actual level of $34.3 million to the 2023 Test Year level of $38.7 million.

b) Please provide a breakdown of the increase in the total amount of these costs allocated to Distribution from the 2020 actual level of $25.2 million to the 2023 Test Year level of $30.8 million.

c) Given the occurrence of the COVID-19 pandemic, has Hydro One’s current and future anticipated buildings and work space accommodation needs changed? If so, please identify and explain the changes in such needs.

E-Staff-243
Exhibit E / Tab 4 / Schedule 2 / Attachment 1 / pp. 7-8
Exhibit E / Tab 4 / Schedule 2 / Attachment 1 / p. 10

Preamble:

At the first reference, the comparator group and normalization factor development for the common corporate costs benchmarking study completed by UMS Group Inc. are provided. It is noted that Hydro Ottawa and Toronto Hydro declined to participate in the study. As a result, the benchmarks were developed based on data from their recent distribution rate filings for comparison purposes.

At the second reference, it is stated:

> It should be noted that the Hydro One common corporate costs benchmarked are *pre-allocation costs*; therefore, some of them are borne by Hydro One entities other than Transmission and Distribution, so not all of them go into T&D rates. In addition, investor costs (i.e., those which are borne by shareholders, rather than customers) are also included in the Hydro One benchmark numbers. Therefore, the results shown in Table 5 below should not be considered as a complete representation of comparative position without an understanding of the related analysis for each function.

Question(s):

a) Please provide the proceeding numbers of the Hydro Ottawa and Toronto Hydro distribution rate filings that were used for developing benchmarks of these utilities.

b) Please identify any other normalization factors that were considered for the study, but were ultimately not included. For such factors, please explain why they were chosen not to be included.

c) For each function (i.e., Corporate Management, Finance, Real Estate, etc.), please identify whether the relevant costs are either a direct driver or a representative of the key drivers.

d) Please explain why for the Real Estate function the normalizer of Employees was used instead of square footage. If square footage information is available, please update the Real Estate benchmark to reflect a square footage normalization.

e) Please state if there was any normalization for the System Operation function to account for overhead and underground circuits. If not, please explain why this was not accounted for.

f) Please explain why it is appropriate to conduct the study using common corporate costs that are pre-allocation. Was an analysis done examining only costs that would be recovered by Transmission and Distribution rates? If so, please provide the analysis. If not, please explain why.

E-Staff-244
Exhibit E / Tab 4 / Schedule 4 / p. 6 / Table 4
Exhibit E / Tab 4 / Schedule 4 / p. 8

Preamble:

At the first reference, Table 4 provides a summary of IT sustainment OM&A costs for the 2018 to 2023 period.

At the second reference, it is stated in the bullet listing that:

> Certain third party contract costs that were originally being funded through other Hydro One lines of business were moved to be captured within this IT OM&A sub-program to better reflect total IT contract costs.

Question(s):

a) Please provide a breakdown of the increase in the total amount of Third Party Contracts from the 2020 actual level of $36.7 million to the 2023 Test Year level of $44.9 million.

b) Please identify the third party contracts (and the associated costs in the 2018 to 2023 period) that were originally funded by “other Hydro One lines of business”, but are now captured in Third Party Contracts. Please provide a rationale for why such costs were moved to be captured within the Third Party Contracts IT OM&A sub-program.

E-Staff-245
Exhibit E / Tab 4 / Schedule 4 / p. 16 / Table 7

Preamble:

At the above reference, Table 7 provides a summary of general security OM&A costs for the 2018 to 2023 period. Hydro One also provides a bulleted listing of the reasons for the expected increase in general security OM&A.

Question(s):

a) Please provide a breakdown of the increase in the total amount of Total General Security from the 2020 actual level of $4.6 million to the 2023 Test Year level of $8.5 million.

b) With respect to the new team that will be managing the new system (SailPoint), please identify: (i) the number of staff that will comprise this team; (ii) the representation and type of staffing positions that will comprise the positions of the team; and (iii) the total compensation associated with this team for the 2018 to 2023 period.

E-Staff-246
Exhibit E / Tab 4 / Schedule 4 / p. 19 / Table 9

Preamble:

At the above reference, Table 9 provides a summary of NERC cyber security OM&A costs for the 2018 to 2023 period.

Question(s):

a) Please provide a breakdown of the increase in the total amount of NERC cyber security OM&A costs from the 2020 actual level of $13.7 million to the 2023 Test Year level of $21.5 million.

b) Please identify and explain the NERC CIP standards with (or expected to have) compliance due dates in 2022-2024 that Hydro One is required to meet and will be funded through NERC cyber security OM&A.

E-Staff-247
Exhibit E / Tab 4 / Schedule 8 / Attachment 1

Preamble:

At the above reference, Black & Veatch's report on corporate cost allocation review is provided.

Question(s):

a) Please describe the updates made in the latest iteration of the Black & Veatch report, when compared to the last report conducted, and identify if any of these changes would materially impact the 2023 revenue requirement.

E-Staff-248
Exhibit E / Tab 5 / Schedule 1 / p. 5
Exhibit E / Tab 5 / Schedule 1 / p. 6

Preamble:

At the first reference, the following is stated:

> The scope of work under the Inergi Agreement is comprised of services (Base Services) and project services performed over a finite period to produce a project deliverable, solution or result (Project Services). Base Services that remain under the Inergi Agreement in 2021 are divided into the following areas (individually, a Statement of Work or a SOW), each of which relates to a line of business within Hydro One: (1) supply chain services; (2) payroll; and (3) finance and accounting services.

At the second reference, Hydro One indicates that a benchmarking review of Inergi fees was completed:

> In the third quarter of 2020, Hydro One opted for a benchmarking review of Inergi fees for the supply chain services SOW. The report was completed October 2020 by Information Services Group Inc. (ISG), an outsourcing advisory firm, retained as an independent third party to undertake the review. The results of this benchmarking review do not affect the fees paid by Hydro One for supply chain services due to its fixed fee structure. Hydro One will be insourcing these services once the Inergi Agreement expires.

Also at the second reference, the results of client satisfaction surveys are detailed:

> Client satisfaction surveys conducted for services provided in 2020 showed scores of 3.35 out of 5 for Base Services and 4.34 out of 5 for Project Services and service desk support.

Question(s):

a) Please explain why a benchmarking review of Inergi fees for the supply chain services SOW was undertaken given that the results of the benchmarking review did not affect the fees paid by Hydro One for supply chain services.

b) Please provide the benchmarking review completed by Information Services Group Inc. in October 2020.

c) Please comment on the above scores, in particular the 3.35 out of 5 for Base Services and whether these scores reveal any issues with the services provided by Inergi to Hydro One. If the scores reveal any issues, please explain if this was a driver for the remaining services of the Inergi Agreement being transitioned. If they do not, please explain why not.

E-Staff-249
Exhibit E / Tab 5 / Schedule 1 / p. 7

Preamble:

At the above reference, it is stated that:

> In its evaluation of sourcing options for expiring services, Hydro One engaged ISG to assist in developing a sourcing solution and to provide negotiation support.

Question(s):

a) Please explain the sourcing solution that was developed with ISG and whether it differed from previous solutions Hydro One has developed. If the solution did differ, please explain how it differed and why.

E-Staff-250
Exhibit E / Tab 5 / Schedule 1 / p. 7

Preamble:

At the above reference, it is stated that:

> Hydro One decided to pursue a contract with Capgemini for information technology services in order to achieve the benefits as described below, while minimizing the risk to Hydro One operations and transition costs. The agreement with Capgemini achieves greater flexibility as Hydro One's service needs change over time, providing Hydro One with the ability to redistribute funds allocated for sustainment services towards project investments. The agreement also achieves lower rates for project resources, a lower fee commitment, and a lowered total cost of ownership to Hydro One.

Question(s):

a) Please state whether or not Hydro One considered other vendors at the time when outsourcing. If so, please provide reasoning for why Capgemini was selected and the results of any cost / benefit study that was undertaken at the time to support this outsourcing.

b) Please explain how Hydro One's service needs, with respect to information technology services, will change over time and how Capgemini is able to meet such needs.

E-Staff-251
Exhibit E / Tab 5 / Schedule 1 / pp. 7-8
Exhibit C / Tab 9 / Schedule 4 / p. 2-3

Preamble:

At the first reference, it is stated that:

> Upon expiry of the Inergi Agreement relating to supply chain services, work activities will be transitioned into Hydro One to be self-performed effective November 1, 2021.

At the second reference, it is stated that:

> In late 2020, Hydro One transferred all Stock Keepers from Distribution Lines to Supply Chain Services. Although the labour costs already resided with Supply Chain services, there are other costs which have now transferred from

Distribution to Supply Chain Services. Supply Chain Services are now responsible for these Stock Keepers fleet and procurement card expenses.

Supply Chain Services is undergoing a transformation that will focus on driving continuous improvement in people, processes and technology while improving the service and value it delivers, particularly in the company's Category Management. A major component of this transformation is the insourcing of all Supply Chain Services functions as of November 1st, 2021, as summarized in Exhibit E-05-01. By the end of 2021, Hydro One will have insourced all Supply Chain Services functions which will result in approximately 50 full time employees added to this organization (43% Society, 53% PWU, 4% management staff).

Question(s):

a) Please state when the services referenced above as being insourced were originally outsourced and why this was done. Please provide the results of any cost / benefit study that was undertaken at the time to support this outsourcing.

b) Please state whether a cost / benefit study of this insourcing was done and, if so, please provide the results of the study.

c) Please provide the costs associated with the insourcing of Supply Chain Services in the 2022 Bridge Year and 2023 test year revenue requirement.

E-Staff-252
Exhibit E / Tab 6 / Schedule 1 / p. 13

Preamble:

Hydro One notes that resourcing decisions are impacted by the type of work to be performed. Further, Hydro One states that resourcing options for each line of business depend on a variety of factors which must be considered, including:

- Cost
- Workforce balance
- Duration and scope of work
- Complexity / specialization
- Specialized equipment
- Technical, security, and risk-related considerations

Question(s):

a) Please state whether or not the above listing of factors includes the complete variety of factors that were considered? If not, please list and describe any other factors that are considered in resourcing decisions.

b) Please state whether the variety of factors are weighted equally in terms of resourcing decisions. If not, please explain when and why certain factors would be given priority over others.

E-Staff-253
Exhibit E / Tab 6 / Schedule 1 / pp. 14-15 / Figure 5

Preamble:

Hydro One notes that approximately 12% to 17% of its workforce is, or will become, retirement eligible over the rate period.

Question(s):

a) Please populate all the fields in the table below with information regarding actual retirement eligibility. For purposes of this table, eligibility is defined as the ability to retire with an undiscounted pension. If actual information is not available, please provide the forecast (and note where forecast information was provided).

	2018	2019	2020	2021
Number of Hydro One Employees Eligible for Retirement				
Number of Actual Hydro One Employee Retirements				

b) Please provide a table showing the number of Hydro One employees eligible to retire in each year between 2023 and 2027. For purposes of this table, eligibility is defined as the ability to retire with an undiscounted pension.

E-Staff-254
Exhibit E / Tab 6 / Schedule 1 / p. 18 / Table 1

Preamble:

Between 2023 and 2027, Hydro One projects the total number of FTEs to increase by 1.4%. Details of the projection are provided in Table 1.

Question(s):

a) Please complete the following table and supplement the values reported with commentary explaining any differences between planned and actual FTEs for each year.

Type	Representation	2018		2019		2020		2021	
		Planned	Actual	Planned	Actual	Planned	Actual	Planned	Actual
Regular	MGT/Non-Represented				613		647	724	
	Society				1425		1449	1674	
	PWU				3534		3603	3704	
	Total Regular				5572		5699	6103	
Casual	PWU Hiring Hall				1373		1197	1329	
	CUSW				936		948	938	
	EPSCA				217		223	198	
	LIUNA				272		291	247	
	Total Casual				2798		2659	2712	
	Temporary				194		152	175	
Total					8564		8509	9077	

b) Please state whether or not Hydro One has ever conducted an external benchmarking analysis of staffing levels? If not, please explain why not. If yes, please provide the most recent analysis and provide rationale for current and planned staffing numbers.

E-Staff-255

Exhibit E / Tab 6 / Schedule 1 / p. 18 / Table 1

Preamble:

At the above noted reference, Hydro One provides actual and planned FTEs for 2019 to 2027.

Question(s):

a) Please provide Hydro One's actual vacancy rate for each year between 2018 and 2021.

b) Please provide the forecast vacancy rate for 2023, and the basis for the forecast.

c) Please confirm that Hydro One has built into its budget for 2023 its forecast vacancy rate for 2023.

d) If (c) is confirmed, please explain how Hydro One has translated the forecast vacancy rate into a budgeted number.

e) If (c) is not confirmed, please explain why not.

E-Staff-256
Exhibit E / Tab 6 / Schedule 1 / p. 18

Preamble:

At the above reference, Hydro One states that the planned increases to regular FTEs for 2021 and 2022 noted above are attributable to the addition of approximately 250 employees into the Shared Services & Information Services lines of business due to the repatriation of Inergi employees.

Question(s):

a) Please provide the exact number of employees that will be repatriated.

b) Please quantify the impact (in total compensation) that these repatriated employees will have in 2021 and 2022.

c) Please provide an updated version of Table 1 (Exhibit E / Tab 6 / Schedule 1 / p. 18) reflecting the removal of the FTEs who are repatriated into the Shared Services & Information Services lines of business.

E-Staff-257
Exhibit E / Tab 6 / Schedule 1 / pp. 22-23 / Tables 2 and 3

Preamble:

Hydro One states that as of April 2021, approximately 2,300 PWU-represented employees and 1,100 SUP-represented employees were receiving share grants. However, as employees retire, Hydro One anticipates that the number of share grants provided will decline. Details of the declines are provided in Tables 2 and 3.

Question(s):

a) Please state whether the share grants issued are determined by a pre-determined dollar value or based on a pre-determined number of shares.

b) Please state how much of the anticipated share grant reduction is based on changes in the anticipated share price of Hydro One stock?

E-Staff-258
Exhibit E / Tab 6 / Schedule 1 / p. 36

Preamble:

Hydro One states that it is working to achieve market levels of compensation. During the rate period, collective agreements with the PWU and SUP will expire.

Question(s):

a) For the purposes of the forecasts (going to 2027) that Hydro One has developed in this application, what underlying assumptions or principles have been used for the PWU and SUP after the expiry of their current agreements?

E-Staff-259
Exhibit E / Tab 6 / Schedule 1 / p. 43

Preamble:

In discussing workforce flexibility, Hydro One states:

> Letter of Understanding (LOU) # 107 provided greater flexibility in: (i) the use of composite crews (crews staffed by a mix of regular employees and HH members); (ii) work assignments outside of base classifications where appropriate; and (iii) expanding the scope of flexible working hours and adapting to local work requirements. In the most recent round of PWU bargaining that

concluded in the fall of 2020, the parties agreed to maintain this LOU for the term of the renewal agreement.

Question(s):

a) Please provide a copy of the Letter of Understanding # 107.

E-Staff-260
Exhibit E / Tab 6 / Schedule 1

Preamble:

In past Hydro One distribution and transmission proceedings, reports by Willis Towers Watson regarding Management and Non-represented Role Benchmarking and Compensation Structure Recommendations have been filed.

Question(s):

a) Please state whether or not Hydro One recently (i.e., in 2020 or 2021) replicated a similar Willis Towers Watson report(s) regarding Management and Non-represented Role Benchmarking and Compensation Structure Recommendations? If not, please explain why? If so, please provide the report(s).

b) If the response to (a) is that no report(s) was replicated, please indicate if Mercer or Willis Towers Watson would be able to conduct such a report and how long it would take to do so.

c) If the response to (a) is that no report(s) was replicated, please explain why the sample of benchmarks examined in the benchmarking compensation study by Mercer was not expanded.

E-Staff-261
Exhibit E / Tab 6 / Schedule 1 / Attachment 1

Preamble:

At the above noted reference, Hydro One has included a compensation benchmarking study conducted by Mercer (Canada) Limited. In the summary of the benchmarking results, the following is stated:

On an overall weighted average basis, for the jobs Mercer reviewed in 2020, Hydro One is positioned approximately 9% above the market total compensation ("total remuneration") 50th percentile ("P50" or "median"). In comparison to the 2017 study, Hydro One's overall weighted average positioning has improved (i.e. trended towards the market median) from 12% above the market total compensation 50th percentile. When assessing compensation competitiveness, Mercer considers compensation levels to be competitive, on an overall/employee group basis, when it is within +/- 5% from the target market positioning, which is the median for Hydro One. Hydro One is positioned 4% above this defined competitive range; down from 7% above the competitive range in the 2017 Study.

Question(s):

a) Please provide detailed reasoning for why Mercer considers compensation to be competitive, on an overall / employee group basis, when it is within +/- 5% from the target market positioning. In the reasoning provided, please detail how this aligns with market practice.

b) Please list all types of compensation (e.g., salary, overtime, share grant, STIP, LTIP, etc.) that were paid in 2020 which were included in the study.

c) Please list all types of compensation there were paid in 2020, but were not included in the study. If types of compensation were not included, please explain why and identify the percentage of total compensation that they comprise in each year of the rate period (2023-2027).

d) Will there be any types of compensation that will be paid during the rate period (2023-2027) that were not paid in 2020. If so, please provide identify the type(s) of compensation and identify the percentage of total compensation that they comprise in each year of the rate period (2023-2027).

e) Please state whether or not there would be a difference between the average total compensation for Hydro One employees and the P50 median used in the study. If so, please provide a table detailing the amount of the difference in the study year (2020) and for each year from 2023 to 2027. As necessary, please explain how the amount was determined.

E-Staff-262
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 6 / Table 2

Preamble:

In the compensation benchmarking study, Mercer concludes that "…Hydro One's overtime pay practices are, as a whole, generally aligned with or are less generous than overtime practices in the market."

Question(s):

a) Please state whether actual overtime compensation paid is included in the competitive benchmarking.

b) Please provide a breakdown of the hours reported for overtime by Hydro One and the comparator group. If this cannot be provided, please explain why.

E-Staff-263
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 6

Preamble:

In the compensation benchmarking study, Mercer states that "…the design (i.e. target incentive levels) of Hydro One's short-term incentive program is more aligned with the market median of the comparator group. Variations in actual total cash positioning are driven by Hydro One's business performance relative to comparator organizations within the context of the short-term incentive plan design."

Question(s):

a) Please explain how the target incentive levels compare to market prices.

b) Please state whether or not there is any analysis of actual bonus payouts versus targets? If so, please provide such analysis.

c) Please state whether the market data is based on actual base salary or job rate.

d) Please state what other "wages" are included in the Hydro One data?

E-Staff-264
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 7

Preamble:

At the above noted reference, there is a discussion about workforce effectiveness.

Question(s):

a) Please provide an analysis of total labour costs per dollar of revenue versus comparator group for all employee and / or the selected benchmarks.

E-Staff-265
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 12
EB-2019-0082 / Decision and Order / April 23, 2020 / pp. 142-143

Preamble:

At the first reference above, the following is stated:

> Mercer reviewed the OEB's comments in its decision in EB-2019-0082 that stated that it would be beneficial if the Study included comparison with non-utility companies that employ Trades and Technical unionized staff.
>
> *-and-*
>
> Mercer has determined that comparing Hydro One to a non-utilities peer group would provide a market perspective that is not an accurate reflection of Hydro One's talent market, especially with respect to the Trades and Technical group (if it were even possible to attract participation from non-utility organizations). As such, the methodology of this Study aligns with that of previous years in that it compares Hydro One to Transmission and Distribution Utilities, Generators as well as comparable regulated businesses across Canada.

At the second reference above, the OEB states the following:

> The OEB directs Hydro One to complete an updated benchmarking study using the same Mercer methodology for its upcoming combined rebasing application. To the extent possible, this benchmarking study should address the impact of items like overtime and utilization of contract staff on the results and should include all forms of compensation such as share grants and lump sum payments. It would also be beneficial if the study included comparison with non-utility

companies which employ trades and technical unionized staff. The study should also compare management group incentive programs (STIP and LTIP) to similar programs in comparator companies.

Question(s):

a) Please discuss how Hydro One has reflected the OEB's direction from EB-2019-0082 in this application. Please provide further discussion as to why a comparison to non-utility companies was not undertaken.

E-Staff-266
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 13 / Table 3

Preamble:

At the above noted reference, there is an overview of the participating organizations in the compensation benchmarking study.

Question(s):

a) Please confirm that no U.S. resident employee data was included in the data submission. If it was, please explain the reasoning and basis for its inclusion.

E-Staff-267
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 14

Preamble:

In the compensation benchmarking study, the following is stated regarding benchmark jobs:

> To assist with study-over-study comparisons, it was determined that the Study should collect incumbent data using 31 of 34 benchmark jobs surveyed in the 2017 study. In an effort to capture the changing talent landscape and nature of the work at Hydro One, the following jobs have been removed from the 2017 job list:
>
> - System Operator (Controller): responsibility of job at Hydro One has broadened and would not be comparable to similar jobs within the comparator group

- Service Dispatcher: No longer exist at Hydro One; responsibilities have been rolled into newly created job
- Carpenter – Construction: limited comparability in market due to peers outsourcing this work

Question(s):

a) Please explain why the three benchmark jobs excluded in the study were not replaced by other benchmark jobs to enhance the robustness of the sample?

b) Please detail how many incumbents there are in the benchmark jobs that were excluded from the study.

c) Please state what other changes to benchmark selection were necessary to maintain the same percentage of the population (59%) in the 2020 Study as that in the 2017 Study?

d) Please state how the percentage of FTE compares to the percentage of population used in the 2017 Study and explain why such a change in reporting methodology was necessary?

E-Staff-268
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 15 / Table 4

Preamble:

At the above noted reference, there is a summary of the benchmark jobs organized by employee group.

Question(s):

a) Please state the percentage of the Non-Represented population that is reflected by the Non-Represented benchmark.

b) Please provide the distribution of benchmarks by employee salary grade.

E-Staff-269
Exhibit E / Tab 6 / Schedule 1 / Attachment 1 / p. 18

Preamble:

At the above noted reference, there are details regarding immediate and trailing impacts. Of which, is noted an enhanced review of merit increases and broader salary management practices for the Non-Represented group and lower short-term incentive payouts to the Non-Represented group.

Question(s):

a) Please state what the overall salary increase budgets for this group have been since the last analysis and how these compare to the actual increases in the peer group?

b) Please describe the broader salary management practices and the impact.

c) Please state what Hydro One's average short-term incentive plan payout was as a percentage of target and how that compares to peer group practice?

E-Staff-270
Exhibit E / Tab 6 / Schedule 1 / Attachment 1
Exhibit E / Tab 6 / Schedule 1 / pp. 15-18

Preamble:

At the above reference, the data indicate that the reduction in variance to P50 is in part due to the retirement (average of 12% per year) of higher workers and the resulting shift in the mix to younger workers who are paid below those who are replaced.

It is observed that Regular FTE levels are planned to be relatively the same during the rate period, while the FTE levels of Casual Trades is planned to increase.

Question(s):

a) Please provide an analysis, recognizing the change in employment mix over the rate period, showing a comparison of actual to job rate for the retired workers to the younger worker (non-casual) who will continue.

b) Please state if this analysis was based on intended compensation, job rate, mid-point, etc., what the variance to market would be?

c) Please state what the change in total employment cost would be over the rate filing period considering overtime costs.

d) Please provide the overall change in employment costs including overtime and casual workers.

E-Staff-271
Exhibit E / Tab 6 / Schedule 1 / Attachment 1.1 / p. 3

Preamble:

On September 30, 2021, Hydro One filed an addendum to the compensation benchmarking study. The addendum pertains to a compensation benchmarking forecast, in which the following is stated:

> Projections for Hydro One's compensation levels took into account assumptions in respect of a range of potential bargaining outcomes, during the rate period, for the union groups as well as assumed merit increases for the non-represented group. In addition to changes in compensation levels, assumptions were also made for changes in Hydro One's workforce over the forecast period. Specifically, retirements/exits from Hydro One were based on pension retirement scales, historical turnover rates as well as FTE plans.

Question(s):

a) Please explain each outcome that was considered in the "range of potential bargaining outcomes" and explain how they would impact the assumptions used in the forecasting model and the outcomes generated.

Pension and OPEB

E-Staff-272
Exhibit 4/Tab 6/Schedule 1/Attachment 2A
Exhibit 4/Tab 7/Schedule 1

Preamble:

OEB staff compared the pension costs in two schedules of Exhibit 7 and noted the following differences:

Hydro One Transmission					
	2023	**2024**	**2025**	**2026**	**2027**
Per Exhibit 4/Tab 6/Schedule 1/Attachment 2A Appendix 2-K					
Pension - (in $000)	46,137	47,881	47,891	48,590	51,621
Pension - (in $M)	46	48	48	49	52
Per Exhibit E/Tab 7/Schedule 1					
Pension - Table 2 ($M)	45	46	46	47	49
Difference ($M)	**1**	**2**	**2**	**2**	**3**

Hydro One Distribution					
	2023	**2024**	**2025**	**2026**	**2027**
Per Exhibit 4/Tab 6/Schedule 1/Attachment 2A Appendix 2-K					
Pension - (In $000)	61,125	62,612	63,149	65,010	66,789
Pension - (In $M)	61	63	63	65	67
Per Exhibit E/Tab 7/Schedule 1					
Pension - Table 2 ($M)	59	60	61	62	64
Difference ($M)	**2**	**3**	**2**	**3**	**3**

OEB staff notes that the differences appear to be caused by more than rounding.

OEB staff also compared the OPEB cost in two schedules of Exhibit 7 and noted that there is a $4M difference between the OPEB cost of $78M in 2023 per Appendix 2-K and the OPEB cost of $74M in 2023 per Table 4b in Exhibit 4/Tab 7/Schedule 1.

Question(s):

a) Please confirm the differences as identified by OEB staff above and explain the reasons for the differences if confirmed.

b) Please clarify which tables/appendix have the correct figures for pension and OPEB costs that are included in the rates.

E-Staff-273
Exhibit 4/Tab 7/Schedule 1, pp. 5-6
Exhibit 4/Tab 7/Schedule 1/Attachment 1

Preamble:

Using the Table 1a and Table 1b in Reference 1, OEB staff summarized Hydro One's pension costs on a cash basis in Table 1 and pension costs on an accrual basis in Table 2 as below:

Table 1: Pension Cost - Cash basis (in M$)					
	2023	**2024**	**2025**	**2026**	**2027**
Transmission (Table 1a)	45	46	46	47	49
Distribution (Table 1b)	59	60	61	62	64
Total for Hydro One	**104**	**106**	**107**	**109**	**113**

Table 2: Pension Cost - Accrual basis (in M$)					
	2023	**2024**	**2025**	**2026**	**2027**
Transmission (Table 1a)	123	120	114	109	108
Distribution (Table 1b)	162	157	150	145	140
Total for Hydro One	**285**	**277**	**264**	**254**	**248**

OEB staff has compared Hydro One's total pension costs on a cash basis and on an accrual basis from 2023 to 2027 to the projected costs in the 2018 actuarial report in Reference 2 and has noted some discrepancies:

Table 3: Discrepancies in Pension Cost- Cash Basis

	2023	**2024**	**2025**	**2026**	**2027**
Attachment 1 Actuarial Report - Appendix A1 Hydro One Pension Plan					
F (Line 3) Employer contributions made in the financial year (In $000)	107,448	110,630	110,998	113,353	118,073
in M$	107	111	111	113	118
Pension Cost - Cash Basis (in M$) - (from Table 1)	104	106	107	109	113
Difference (in M$)	**3**	**5**	**4**	**4**	**5**

Table 4: Discrepancies in Pension Cost- Accrual Basis

	2023	**2024**	**2025**	**2026**	**2027**
Attachment 1 Actuarial Report - Appendix A1 Hydro One Pension Plan					
D. Disclosed Benefit Cost (in $000)	180,023	172,329	158,743	149,028	142,805
D. Disclosed Benefit Cost (in M$)	180	172	159	149	143
Pension Cost - Accrual Basis (in M$) - (from Table 2)	285	277	264	254	248
Difference (in M$)	**(105)**	**(105)**	**(105)**	**(105)**	**(105)**

Question(s):

a) Please confirm the information in tables 1 to 4 compiled by OEB staff or revise the figures as necessary.

b) Please explain the discrepancies noted in Table 3 and Table 4.

E-Staff-274
Exhibit 4/Tab 7/Schedule 1, pp. 12-13
Exhibit 4/Tab 7/Schedule 1/Attachment 1

Preamble:

Using Table 4a and Table 4b in Reference 1, OEB staff summarized Hydro One's OPEB costs included in rates, as below:

$M	**2023**
Transmission (Table 4a)	56
Distribution (Table 4b)	74
Total OPEB Cost	**130**

OEB staff has compared Hydro One's total OPEB cost of $130M in 2023 to the projected costs in the 2018 actuarial report in Reference 2 and has noted a discrepancy:

	2023
Attachment 1 Actuarial Report	
Appendix A2 Supplemental Plan - D. Disclosed Benefit Cost ($000)	7,202
Appendix B3. Non-Pension Post Retirement Benefit - D. Disclosed Benefit Cost ($000)	108,377
Appendix B4. Post-Employment Benefit - D. Disclosed Benefit Cost	23,473
Total in $000	139,052
Total in M$	139
Hydro One's OPEB Cost included in rates (M$) (per Table above)	130
Difference (M$)	**9**

Question(s):

a) Please confirm the tables compiled by OEB staff or revise the figures as necessary.

b) Please explain the discrepancy of $9M between the OPEB costs included in rates and the projected OPEB costs in 2023 as per the actuarial report.

E-Staff-275
Exhibit 4/Tab 7/Schedule 1, p 3
Exhibit 4/Tab 7/Schedule 1, pp. 5-6

Preamble:

In Reference 1, Hydro One states that:

> DB Plan pension cost in 2018, 2019 and 2020 was $75M, $73M and $69M, respectively. For the transmission business, this translated into annual pension costs of $36M, $35M and $33M, and for the distribution business this translated into annual pension costs of $37M, $36M and $34M, for 2018, 2019 and 2020.

OEB staff compiled the actual costs information with the pension costs in Table 1a and Table 1b on Reference 2 as below:

Hydro One's Defined Benefit Pension Cost - Cash Basis (in M$)										
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
	Actual			**Forecast**		**Forecast**				
Transmission	36	35	33			45	46	46	47	49
%	48%	48%	48%			43%	43%	43%	43%	43%
Distribution	37	36	34			59	60	61	62	64
%	52%	52%	52%			57%	57%	57%	57%	57%
Total	**75**	**73**	**69**	**0**	**0**	**104**	**106**	**107**	**109**	**113**

Question(s):

a) Please complete the table above by including the 2021 and 2022 pension cost for transmission and distribution.
b) Please provide a variance analysis between Hydro One's pension cost (actual and forecast) in 2018 to 2022 and the pension cost approved in transmission and distribution's last rebasing applications.
c) Please explain why the allocation % of defined benefit pension cost to Hydro One transmission has decreased from 48% in the historical period to 43% in the test period of 2023 to 2027.

E-Staff-276
Exhibit 4/Tab 7/Schedule 1, p 4
Exhibit G/Tab 1/Schedule 1/p.18 and p.48

Preamble:

Hydro One states that:

> Management filed annual valuations for each of the years ended December 31, 2016, 2017 and 2018 as it resulted in lower contributions, and chose not to file valuations for the years ended 2019 and 2020 as it would have resulted in increased contributions. Actual contribution requirements in 2022, 2023 and 2024(period covered by the next required valuation) and any future years during the test period beyond 2024 may vary depending on market conditions, funding position of the pension fund and the level of base pensionable earnings and the resulting required contribution rates used to compute monthly contributions. The difference between the forecast and actual OM&A component of pension costs is tracked in a variance account.

In Reference 2, Hydro One has recorded the $(7.5) M balance as at December 31, 2020 in the Pension Cost Differential Variance Account for distribution and $(23.7) M as at December 31, 2020 in the equivalent account for transmission.

Question(s):

a) Please explain why Hydro One believes that the actuarial valuations for the years ended 2019 and 2020 would result in increased contributions.

b) Please confirm that the credit balances in Pension Cost Differential Variance Account for transmission and distribution represent the over-forecast of the pension costs embedded in rates up to 2020 for transmission and distribution.

c) If b) is confirmed, please provide the quantum of the over-forecasted capitalized portion of pension costs up to 2020 for transmission and distribution.

d) If b) is confirmed, please explain whether the capitalized portion of pension costs in rates are subject to a true-up adjustment.

   i) If not, please explain why not.

ii) Please also confirm that Hydro One is not requesting to recover the additional capitalized portion of the pension cost based on the 2021 actuarial report if the contributions based on the 2021 report have increased compared to the 2018 actuarial report.

E-Staff-277
Exhibit 4/Tab 7/Schedule 1, pp. 4-6

Preamble:

Hydro One proposed to include the pension costs in rates for transmission and distribution on a cash basis, which is consistent with prior decisions and orders. Hydro One states that:

> Hydro One Inc. considers this method to be more beneficial to its customers than the accrual basis because it generally results in lower yearly costs recovered through rates, it results in less volatile forecasting of the cost, and it is thus more consistent with actual expenses for the applicable years.

Using Table 1a and Table 1b in Reference 1, OEB staff compiled the following tables showing the annual differences of pension cost between the cash basis and the accrual basis for transmission and distribution:

Table 1: Hydro One Transmission's DB Pension Cost – Cash vs. Accrual

in M$	**2023**	**2024**	**2025**	**2026**	**2027**
Cash Basis	44	46	46	47	50
Accrual Basis	75	72	65	61	60
Difference	31	26	19	14	10

Table 2: Hydro One Distribution's DB Pension Cost – Cash vs. Accrual

in M$	**2023**	**2024**	**2025**	**2026**	**2027**
Cash Basis	59	61	61	62	64
Accrual Basis	99	94	87	82	77
Difference	40	33	26	20	13

OEB staff notes from the two tables above that the differences between cash basis and accrual basis are forecasted to decline over the test period of 2023 to 2027.

Question(s):

a) Please confirm that the pension costs on an accrual basis generally represent the annual costs of services providing by Hydro One's employees in that given period. If not, please explain.

b) Please provide a table comparing the pension costs on a cash basis with the pension costs on an accrual basis in the historical period to show that the cash basis is less volatile than the accrual basis.

c) Please confirm that over the lifetime of the pension plan, costs on an accrual basis should equal costs on a cash basis, and that the differences pertain to the timing of recognizing costs. If not, please explain.

d) If c) is confirmed, please also confirm that if the year-to-date pension costs on a cash basis have exceeded the costs on an accrual basis, one would expect the cash basis costs to exceed the accrual basis in the future, resulting in lifetime costs that are equal under both methods. If this is not the case, please explain.

e) Please provide an estimate of when the pension costs on a cash basis will exceed the pension costs on an accrual basis for transmission and distribution.

f) Please confirm whether the lower rates to current customers is one of the main considerations for Hydro One's proposal of pension costs on cash basis.

    i. If so, please explain how Hydro One's has considered the impact of pension costs in rates when the yearly costs on a cash basis eventually exceed costs on an accrual basis.

E-Staff-278

Exhibit 4/Tab 7/Schedule 1, pp.6-7
Hydro One Transmission's Decision and Order EB-2019-0082
Hydro One Distribution's Custom IR Decision and Order EB-2017-0049

Preamble:

Based on Table 2 in Reference 1, OEB staff calculated the OM&A % and capitalized % of the DB pension costs from 2023 to 2027 for transmission and distribution as follows:

	Transmission DB Pension Costs (in M$)						
	2020 (Approved in EB-2019-0082)	**2023**	**2024**	**2025**	**2026**	**2027**	**Average %**
OM&A	**9**	11	11	11	12	12	
%	28%	25%	24%	24%	26%	24%	24%
Capital	**23.8**	33	35	35	35	38	
%	72%	75%	76%	76%	74%	76%	76%
Total	**33**	**44**	**46**	**46**	**47**	**50**	

	Distribution DB Pension Costs (in M$)						
	2018 (Approved in EB-2017-0049)	**2023**	**2024**	**2025**	**2026**	**2027**	**Average %**
OM&A	**17**	20	20	20	20	21	
%	46%	34%	33%	33%	32%	33%	33%
Capital	**20**	39	41	41	42	43	
%	54%	66%	67%	67%	68%	67%	67%
Total	**37**	**59**	**61**	**61**	**62**	**64**	

OEB staff notes that the capital % of pension cost for Transmission has increased from 72% as approved in Transmission's last revenue cap application to an average of 75% in the test period from 2023 to 2027. In addition, the capital % of pension cost for Distribution has increased from 54% as approved in Distribution's last Custom IR application to an average of 67% in the test period from 2023 to 2027.

Question(s):

a) Please explain why the capital % of pension cost has increased as compared to the capital % approved in transmission and distribution's last rebasing application.

b) Given that the capital % of pension cost is not trued up, please discuss the ramifications for Hydro One's customers, from the perspective of their exposure to rising costs, when the forecast capital % is greater than the actual capital % of pension cost.

E-Staff-279
Exhibit 4/Tab 7/Schedule 1, pp.8-9
Exhibit 4/Tab 7/Schedule 1/Attachment 1

Preamble:

With respect to the pension contribution holiday, Hydro One stated that:

> Effective May 1, 2018, the PBA and regulations provide that an employer like Hydro One may only take a contribution holiday in a year if an actuary certifies that a defined benefit plan has a funded ratio of at least 105% calculated on a wind-up basis. Under the December 31, 2018 valuation report, which is operative until December 31, 2021, Hydro One's DB Plan is 73% funded on a wind-up basis.

Hydro One further stated that:

> New valuation report for the DB Plan as at December 31, 2021, will be effective for the years 2022 to 2024, and thus will be in effect at the start of the test period on January 1, 2023. It is highly unlikely that the wind-up funded position of the DB Plan will improve so as to meet the 105% threshold at any time during the test period. Therefore, assuming the DB Plan remains less than 105% funded on a wind-up basis, Hydro One will not be able to take a contribution holiday and pension contributions will be required over the 2023 to 2027 period.

OEB staff notes from the 2019 actuarial report (specifically section 2.1 Statement of Solvency and Hypothetical Windup Financial Position) that the windup position is depending on 1) market value of assets 2) solvency value of liability. OEB staff notes that the market value of assets may have increased from 2018 year end to 2020 year end.

Question(s):

a) Please explain why Hydro One thinks that it is highly unlikely that the wind-up funded position of the DB plan will not improve to meet the 105% threshold.

b) Please provide the market value of plan assets as at December 31, 2020.

c) Please provide estimated solvency value of liability as at December 31, 2020.

d) Please calculate the windup position by the information provided in b) and c).

E-Staff-280
Exhibit 4/Tab 7/Schedule 1, p. 12

Preamble:

With respect to Other Post Employment Benefits (OPEBs), Hydro One stated that:

> Hydro One uses the accrual method of accounting for OPEBs. OPEB benefit costs for the year are determined by the actuaries. Components of the cost include the accrual of current employee service cost for that year towards a liability for their retirement years and non-service costs, which include loss/gain amortization and interest adjustments.

OEB staff notes that Hydro One filed this application under USGAAP. In addition, OEB staff notes that the amortization of actuarial gains/losses is recognized in income under USGAAP while the amortization of actuarial gains/losses is recognized in other comprehensive income under IFRS.

Question(s):

a) Please provide the quantum of the loss/gain amortization that was included in the approved OPEB costs for transmission and distribution in last rebasing applications.

b) Please provide the actual loss/gain amortization that have been recorded by Hydro One on its Audited Financial Statements for both transmission and distribution since last rebasing and compare to the approved figures provided in a).

c) Please provide the quantum of loss/gain amortization that are included in the OPEB costs for transmission and distribution in this application.

d) If Hydro One is approved to remain on USGAAP, please explain how Hydro One addresses the differences between IFRS and USGAAP with respect to the treatment of actuarial gains/losses.

e) Irrespective of the reporting standard applied by Hydro One throughout the 2023-2027 rate-setting term, for rate-making purposes, would Hydro One be aggregable to notionally excluding all actuarial gains and losses from revenue requirement, and instead, capture those impacts in a deferral and variance account? Please discuss.

E-Staff-281
Exhibit E / Tab 8 / Schedule 1 / pp.5-7

Preamble:

At the above reference, it is stated that increase in 2023 depreciation on fixed assets expense for Transmission and Distribution relative to the 2022 amount is due to the higher level of fixed assets in service. Transmission and Distribution depreciation on fixed assets steadily increase from 2023 to 2027.

Questions:

a) Please explain if the rising depreciation throughout the 2023 to 2027 period pertains to any other factors other than increases in rate base.

b) Please also explain how the use of the Broad Group Depreciation Methodology has impacted the 2023 to 2027 depreciation.

E-Staff-282
Exhibit E / Tab 8 / Schedule 1 / pp.5-6

Preamble:

Hydro One has not forecasted any gains/losses on asset disposition for the bridge or test years. Per Table 1 and 2, losses/gains on asset disposition have been gains ranging from $0.5M to $2.4M for Transmission and $0.5M to $1.3M for Distribution from 2018 to 2020. It appears to OEB staff that Hydro One has typically realized gains on these transactions.

Question:

a) Please explain if Hydro One has historically typically experienced gains on the disposition of assets.

b) Has Hydro One considered including the effects of these gains, either through an adjustment to the forecast test year, or by use of a variance account? If not, why not?

E-Staff-283
Exhibit E / Tab 8 / Schedule 1 / p.9

Preamble:

The environmental regulatory asset is amortized on a basis consistent with the pattern of current expenditures expected to be incurred up to the year of 2025, when the polychlorinated biphenyls (PCB) program is expected to end.

Question:

a) At the end of the PCB program, when the environmental regulatory asset is de-recognized, would a gain (or loss) be expected to be realized?

b) If so, what would the potential magnitude of the gain or loss be?

E-Staff-284
Exhibit E / Tab 8 / Schedule 1 / pp. 3-6 and Attachment 1
Exhibit C / Tab 4 / Schedule 4 – Appendix 2-BA

Preamble:

Regarding the Depreciation Rate Study in Attachment 1,

Questions:

a) Page 4 states that the impact of the proposed depreciation rates when applied to Hydro One's 2019 assets do not reflect changes that will occur for periods from 2023 and forward, which will be calculated once the rate application is prepared. Please provide the depreciation difference between using the proposed depreciation rates and using existing depreciation rates for each year in the test period.

    i. Please explain whether Hydro One generally expects the annual depreciation expense in the test period to be lower using the proposed depreciation methodology as compared the existing depreciation methodology.

b) Page 5 shows a breakdown of the depreciation impact based on Hydro One's 2019 assets by utility function, comparing depreciation at existing and proposed depreciation rates. Total depreciation at existing rates is $753.0M. In Tables 1 and 2 in Exhibit E / Tab 8 / Schedule 1 / pp. 5-6, 2020 Depreciation on Fixed Assets is $766.3M ($410.9M and $355.4M for Transmission and Distribution, respectively).

   Page 5 of the Depreciation Rate Study also shows total plant as at December 31, 2019 to be $30,357M. The total 2019 ending gross book value for Transmission and Distribution per Appendix 2-BA is $31,575M ($19,094M and $12,481M for Transmission and Distribution, respectively). Please explain the differences in 2020 depreciation and ending 2019 gross book value noted above.

c) Page 20 indicates that using the proposed Broad Group Depreciation Methodology (BG), the annual depreciation assumes that all units of plant in a plant account are considered one group. Depreciation is calculated based on these groups. The Vintage Group Depreciation Method (VG) assumes that each vintage within a plant account is a separate group. VG requires that each vintage group be analyzed separately, then average lives of all vintages are composited to produce an average life for the group.

   i. Per Article 410 of the Accounting Procedures Handbook, effective January 1, 2012, page 28 states that significant parts of components of an asset that are significant in relation to the total cost of an asset are to be depreciated separately. In Hydro One's view, please explain whether the BG method of depreciation would be in accordance with IFRS.

   ii. In Hydro One's view, please explain whether the straight line, vintage-group, remaining life (SL-VG-RL) depreciation methodology previously used by Hydro One would be in accordance with IFRS.

E-Staff-285

Exhibit E / Tab 9 / Schedule 1 / pp. 3
Exhibit E / Tab 9 / Schedule 2 / Attachment 2
Exhibit E / Tab 9 / Schedule 3 / Attachment 1

Preamble:

Regulatory taxes are stated as being included in Hydro One's proposed Transmission and Distribution revenue requirements for the 2023 to 2027 period exclude any further Future Tax Savings to customers.

Question(s):

a) For the assets that were revalued and received a fair market value bump as a result of the IPO, please confirm that the Undepreciated Capital Cost (UCC) used in the calculation of regulatory taxes would be equal to the continued UCC of those assets prior to the revaluation (i.e. UCC did not receive a fair market value bump).

    i. Please confirm that this would mean that Hydro One needs to maintain two sets of books to track the different UCCs.

b) If part a above is not confirmed, please explain the mechanics of how opening 2021 UCC is determined for regulatory tax purposes.

c) Please provide a reconciliation between the ending 2020 UCC as filed in Schedule 8 of Hydro One's tax return (Attachment 1) to the opening 2021 UCC as shown this application (Attachment 2).

d) In the event that recapture, capital gains, or terminal losses relating to the assets that received a fair market bump are generated in the future for Hydro One's actual taxes, please explain how these would be treated for regulatory tax purposes.

<u>E-Staff-286</u>
Exhibit E / Tab 9 / Schedule 1 / pp. 17
Exhibit E / Tab 9 / Schedule 2 / Attachment 3
Exhibit E / Tab 9 / Schedule 3 / Attachment 1

Preamble:

In Schedule 4 of the 2020 tax return, part 6 shows $1,041,297,507 of tax losses available for use at the end of the year. Hydro One states that "Loss carry forwards on Schedule 4 of the 2018 Income Tax Return arose as a result of the additional tax deductions from the fair market value revaluation as a consequence of the IPO and the departure from the PILs regime. These non-capital losses arise from the shareholder portion of the CCA bump and are not considered in the calculation of regulatory taxes for the test period".

Questions:

a) It appears that $180,287,846 of the total $1,041,297,507 of tax losses were from 2019. Please confirm. If not confirmed, please explain what year the $180,287,846 pertains to.

    i. Please provide the T2, schedules 1, 4, 8, 13 from Hydro One's tax return (redacted where applicable for any personal information) in which the $180,287,846 tax loss arose.

    ii. Please provide a reconciliation showing how the tax return would reconcile to the calculation of utility income taxes in Attachment 3 (e.g. reconcile the net income before taxes).

b) Please explain the drivers for the tax loss of $180,287,846.

c) Please explain whether any of this tax loss should be applied for regulatory purposes. Please explain why or why not.

E-Staff-287
Exhibit E / Tab 9 / Schedule 1 / pp.8-9
Exhibit E / Tab 9 / Schedule 2 / Attachment 1

Preamble:

Regarding the tax treatment of Pension and Other Post Employment Benefits (OPEBs), in Attachment 1, OPEB expenses are added, OPEB payments are deducted, and capitalized pension costs are deducted.

Questions:

a) Regarding the treatment of pensions for regulatory tax purposes, please confirm that pension expense is reflected on a cash basis in net income before taxes, and therefore, the deduction of capitalized pension from net income before taxes ultimately results in only the amount of pension contributions paid being deducted for regulatory tax purposes.

b) It states that for tax purposes, only the portion of annual OPEB costs paid are deductible. It further states that even though total tax deductions from annual OPEB costs remain unchanged, irrespective of capital or expense treatment, regulatory taxes would be lower in years where more OPEB costs are capitalized and higher in years where more OPEB costs are expensed. Please further explain why this would be the case, when any OPEB accrual cost included in net income before taxes should be reversed and only the OPEB costs paid are deductible for regulatory tax purposes.

Black & Veatch's REPORT ON CORPORATE COST ALLOCATION REVIEW

E-Staff-288
Exhibit E/Tab 4/Schedule 8/Attachment 1/p.6

Preamble:

Black & Veatch's Report on Corporate Cost Allocation Review states that:

> The focus of this review was to ensure that the Corporate & Shared Cost Allocation Methodology distributes costs in an accurate manner that is consistent with Ontario Energy Board ("OEB") precedent as well as generally acceptable regulatory practices for cost allocation.

Question(s):

a) Please elaborate on the criteria used in Black & Veatch's Report, including:

   i) Any OEB precedent (specific decisions and orders and how these decisions are relevant to Hydro One's circumstances)

   ii) Specific generally accepted regulatory practices for cost allocation.

b) Please explain whether Black & Veatch has considered differences in cost allocation between IFRS and USGAAP in its review of Hydro One's cost allocation methodology.

   i) If not, why not.

Black & Veatch's REPORT ON CORPORATE COST ALLOCATION REVIEW

E-Staff-289

Exhibit E/Tab 4/Schedule 8/Attachment 1/p.9
Exhibit E/Tab 4/Schedule 8/Attachment 1/p.34

Preamble:

Regarding the capitalization methodology for corporate common costs for Hydro One Transmission and Distribution, Black & Veatch's Report on Corporate Cost Allocation Review states that:

> The general methodology employed is first to review Shared Service activities to ascertain if the activity directly supports OM&A, directly supports capital, or supports both capital and OM&A. Second, to split the costs that support both capital and OM&A between (a) costs that remain OM&A, and (b) costs that will be included in the Overhead Capitalization Rate calculation and thereby capitalized (by applying a 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio). Third, the total Capitalized Common Corporate Costs are calculated by adding (1) the portion of overhead costs directly relating to capital and (2) the Shared Service activities relating to capital - the result of splitting costs that support both capital and OM&A. The total Capitalized Common Corporate Costs is then divided by the total Capital Expenditures to determine the Overhead Capitalization Rate.

In reference 2, Black & Veatch elaborated further on how to split the cost supporting both OM&A and overhead capitalization:

> The method employed to do this is to split Total Applicable Overhead Costs between (a) and (b) by multiplying the Total Applicable Overhead Costs by a ratio developed using a 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

Question(s):

a) Please elaborate on the second step, i.e., to split the costs that support both capital and OM&A between (a) costs that remain OM&A, and (b) costs that will be included in the Overhead Capitalization Rate calculation and thereby Capitalized. Specifically, what are the criteria for the costs that remain OM&A versus the amounts to be included in the overhead capitalization rate calculation, given these costs are not identified as those that directly support OM&A initially.

b) Please use an example of an activity that support both capital and OM&A to illustrate this process, including the calculation of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

Black & Veatch's REPORT ON CORPORATE COST ALLOCATION REVIEW

E-Staff-290

Exhibit E/Tab 4/Schedule 8/Attachment 1/p.43

Preamble:

Regarding the allocation of shared assets to business units, Black & Veatch's Report provided the allocation % of the assets in table 10, as reproduced below:

Table 10 - Allocation of Shared Assets to Tx and Dx Businesses

Type	Asset Value	Transmission	Distribution	Other	Tx %	Dx %	Other %
Major Assets							
Buildings and Fixtures	$ 44.60	$ 19.96	$ 24.29	$ 0.35	44.75%	54.46%	0.79%
Communication equipm	$ 12.72	$ 6.41	$ 6.20	$ 0.11	50.38%	48.77%	0.85%
Computer Equip Major	$ 19.37	$ 7.48	$ 11.72	$ 0.16	38.63%	60.53%	0.83%
Computer Software	$ 144.25	$ 63.20	$ 76.12	$ 4.93	43.81%	52.77%	3.42%
Intangible-ContCap	$ 12.01	$ 11.16	$ 0.85	$ -	92.95%	7.05%	0.00%
Intangibles Software	$ 92.37	$ 23.80	$ 67.57	$ 1.00	25.76%	73.16%	1.08%
Land	$ 61.97	$ 29.41	$ 32.56	$ -	47.46%	52.54%	0.00%
Leasehold improvemnt	$ 3.18	$ 1.10	$ 2.08	$ -	34.61%	65.39%	0.00%
Syst supervisry equp	$ 0.36	$ 0.02	$ 0.34	$ 0.00	6.04%	93.65%	0.32%
Subtotal - Major Assets	$ 390.82	$ 162.54	$ 221.73	$ 6.55	41.59%	56.73%	1.68%
Minor Assets							
Transportation equip	$ 167.39	$ 54.15	$ 113.24	$ -	32.35%	67.65%	0.00%
Power operated equip	$ 88.97	$ 28.78	$ 60.19	$ -	32.35%	67.65%	0.00%
Aircraft & Railway	$ 5.48	$ 4.12	$ 1.36	$ -	75.18%	24.82%	0.00%
Comp Equip / Telecom	$ 8.07	$ 3.81	$ 4.06	$ 0.20	47.23%	50.30%	2.47%
Tools,shop,garag equ	$ 2.39	$ 1.29	$ 1.10	$ -	54.09%	45.91%	0.00%
Office furnitre Equp	$ 2.62	$ 1.27	$ 1.35	$ -	48.42%	51.58%	0.00%
Measurement & testin	$ 1.19	$ -	$ 1.19	$ -	0.00%	100.00%	0.00%
Misc. service equipm	$ 0.15	$ 0.08	$ 0.07	$ -	54.09%	45.91%	0.00%
Stores equipment	$ 0.18	$ 0.10	$ 0.08	$ 0.00	53.87%	45.72%	0.41%
Subtotal - Minor Assets	$ 276.45	$ 93.61	$ 182.64	$ 0.20	33.86%	66.07%	0.07%
Total - All Shared Assets	**$ 667.27**	**$ 256.15**	**$ 404.37**	**$ 6.75**	**38.39%**	**60.60%**	**1.01%**

In Reference 2, Black & Veatch states that:

> There are no material changes to the outcome of the Shared Asset allocations to the Transmission and Distribution businesses. The current analysis is resulting in 38.39% to Tx and 60.60% to Dx as shown on **Table 10**; compared to the 38.3% to Tx and 61.7% to Dx provided in the summary Table 3 within Black & Veatch's Transmission report filed in EB-2019-082.

Question(s):

a) Please provide the allocation % of Hydro One’s major assets only in Black & Veatch’s last report and compare to the allocation % in table 3.

b) Please explain the reason for any large differences (i.e., difference greater than 5%).

Black & Veatch’s REPORT ON CORPORATE COST ALLOCATION REVIEW

E-Staff-291
Exhibit E/Tab 4/Schedule 8/Attachment 1/p.32

Preamble:

With respect to one of the guiding principles for the overhead capitalization methodology, Black & Veatch states that:

> The methodology should accommodate changes in organizational structure, availability of data, business processes, and information systems with reasonable ease. Where possible, the method should automatically adjust for changes in circumstances.

Question(s):

a) Please elaborate on how Hydro One’s updated overhead allocation methodology meets this principle.

Black & Veatch’s REPORT ON CORPORATE COST ALLOCATION REVIEW

E-Staff-292
Ref 1: Exhibit E/Tab 4/Schedule 8/Attachment 1/p.40

Preamble:

With respect to the allocation methodology for shared assets, Black & Veatch states that:

Buildings and Telecommunications Equipment - Each asset included in Buildings and Telecommunications Shared Assets was allocated using one of the following methods:

- **Specific estimation for a building** - For example, the Sudbury Service Centre has estimated usage of Transmission-20% and Distribution-80%.
- **Direct assignment based on type of usage** - For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2014-1st quarter 2020 and determined that Fleet usage was Transmission- 32% and Distribution- 67%

Question(s):

a) Please explain how Hydro One estimated usage for the Sudbury Service Centre at 20% for Transmission and 80% for Distribution.

b) Please explain why Hydro One chose the years 2014 to the first quarter of 2020 to review the fleet time charges.

E-Staff-293
Exhibit E / Tab 9 / Schedule 1 / pp.8-9
Exhibit E / Tab 9 / Schedule 2 / Attachment 1

Preamble:

Regarding the tax treatment of Pension and Other Post Employment Benefits (OPEBs), in Attachment 1, OPEB expenses are added, OPEB payments are deducted, and capitalized pension costs are deducted.

Questions:

a) Regarding the treatment of pensions for regulatory tax purposes, please confirm that pension expense is reflected on a cash basis in net income before taxes, and therefore, the deduction of capitalized pension from net income before taxes ultimately results in only the amount of pension contributions paid being deducted for regulatory tax purposes.

b) It states that for tax purposes, only the portion of annual OPEB costs paid are deductible. It further states that even though total tax deductions from annual OPEB costs remain unchanged, irrespective of capital or expense treatment, regulatory taxes would be lower in years where more OPEB costs are capitalized and higher in years where more OPEB costs are expensed. Please further explain why this would be the case, when any OPEB accrual cost included in net income before taxes should be reversed and only the OPEB costs paid are deductible for regulatory tax purposes.

E-Staff-294

Exhibit E / Tab 9 / Schedule 1 / pp.10-15, 17
Exhibit G / Tab 1 / Schedule 2 / pp. 10-15 and Attachments 1, 5

Preamble:

Regarding tax deductible capitalized overhead for tax purposes,

Question:

a) In the first reference, it states that tax deductible capitalized overhead costs are distinct from the capitalized overhead for financial reporting purposes, and they are not dependent on the accounting treatment under applicable accounting standards. Please provide examples of capitalized overhead for tax purposes.

b) Hydro One has filed an amendment to its 2016 tax return relating to the change in approach for tax deductible capitalized overheads. The amendment is expected to be completed before the end of 2021. Please provide an update to the status of the amendment, if available. Please update the evidence as necessary.

c) Is Hydro One aware of other utilities that use the Updated Approach for tax deductible capitalized overheads? If so, please discuss.

d) Hydro One is requesting a new variance Account 1508, Sub-account Capitalized Overhead Tax Variance Account related to tax deductible capitalized overheads. The account is proposed to capture amounts potentially related to 2016 to 2022. In the second reference, Hydro One noted that it wishes to provide any such benefits arising from the 2016 to 2022 updated treatment of tax deductible capital overheads despite the general prohibition against retroactive ratemaking. Please explain whether Hydro One is aware of any similar OEB precedents on retroactivity that would provide additional support for Hydro One’s proposal.

e) Page 14 of the second reference provides an example calculation of the amount that would be recorded in the proposed Account 1508, Sub-account Capitalized Overhead Tax Variance Account.

i. Please clarify whether the amounts for “Capitalized overhead deductions as filed” represents actual capitalized overhead deductions, Hydro One’s tax returns, or the amounts embedded in rates.

ii. Please clarify whether the amounts for “capitalized overhead with Updated Approach” represents capitalized overheard deductions with the Updated approach based on actual amounts in Hydro One’s tax returns, or based on amounts embedded in rates.

iii. Based on the responses to i and ii above, please explain Hydro One’s rationale for the approach taken for the basis of capitalized overheads.

iv. Footnote 7 states that the associated CCA impact is from 2016 to 2027. However, page 17 of reference 1 states that capital additions in the UCC schedules do not agree with rate base in the historical, bridge and test years, primarily due to tax deductible capitalized overheads. This seems to imply that for the 2023 to 2027 test period, a lower opening 2023 UCC due to the Updated Approach has been reflected in the UCC relating to the increased capitalized overhead deductions pertaining to the 2016 to 2022 period. Please confirm whether this understanding is correct. If so, it appears that there would be double counting of the CCA impact related to tax deductible capitalized overheads from the 2016 to 2022 period in both the proposed DVA (by including the CCA impact from 2023 to 2027) and the 2023 to 2027 regulatory taxes (by using a lower UCC reflecting the Updated Approach. Please explain whether there would be any double counting of these impacts based on the understanding articulated above.

E-Staff-295

Exhibit E / Tab 9 / Schedule 2 / Attachments 1, 2a and 3
Exhibit E / Tab 8 / Schedule 1/ pp. 5-6

Preamble:

Asset removal costs are included in total depreciation expense as shown in Tables 1 and 2 of Exhibit E / Tab 8 / Schedule 1. For 2021 to 2027, total depreciation expense (excluding other regulatory amortization from Table 6 of Exhibit E / Tab 8 / Schedule 1 for Distribution) is added to regulatory net income before taxes in line 5 of the calculation of utility income taxes (Attachment 1). Removal costs are deducted from regulatory net income before taxes in line 8. In the reconciliation of accounting to tax additions (Attachment 2a), asset removal is added to fixed assets for the purpose of calculating CCA.

Questions:

a) Please explain the regulatory tax treatment of removal costs, (e.g. amounts included in UCC, amounts that are deductible).

    i. Please explain why the removal costs amounts shown in line 8 of the calculation of utility income taxes differ from the asset removal costs shown in total depreciation expense.

    ii. Please explain why the removal costs amounts shown in the accounting to fixed asset additions differ from the asset removal costs shown in total depreciation expense.

b) In the 2018 to 2020 calculation of utility income taxes (Attachment 3), the depreciation and amortization added back to net income before taxes in line 3 do not agree to the total depreciation expense as shown in Tables 1 and 2 of Exhibit E / Tab 8 / Schedule 1 (excluding other regulatory amortization from Table 6 of Exhibit E / Tab 8 / Schedule 1 for Distribution). Please reconcile the depreciation and amortization added back to net income before taxes to Tables 1 and 2.

    i. Please also explain why the methodology of determining the depreciation and amortization expense added back to income before taxes is different for the periods of 2018 to 2020 and 2021 to 2027.

E-Staff-296

Exhibit E / Tab 9 / Schedule 2 / Attachments 2 and 2A

Preamble:

Regarding capital cost allowance (CCA),

Questions:

a) Total Transmission and Distribution CCA is reduced by an amount of CCA “not in rates” annually from 2021 to 2027. Please explain what this reduction represents.

b) Total Distribution CCA is reduced by CCA relating to Acquired Utilities for 2021 and 2022. The 2021 and 2022 net additions specifically added additions for Acquired Utilities. Please explain why total CCA is reduced by CCA relating to Acquired Utilities.

c) For Transmission and Distribution, 2022 to 2027 reflects the CCA rule in place in accordance with Bill C-97. However, for the calculation of 2021 CCA, it appears that CCA is calculated at less than three times the legacy unaccelerated CCA. Please explain how 2021 CCA was calculated and why it is not calculated at three times the legacy unaccelerated CCA.

d) Please provide a reconciliation of accounting to tax additions for 2018 to 2020 in the same format as that in Attachment 2a.

E-Staff-297
Exhibit E / Tab 9 / Schedule 2 / Attachments 1 and 3
Exhibit E / Tab 9 / Schedule 1 / p.17

Preamble:

In the calculation of utility income taxes for 2018 to 2020 (Attachment 3),

Question:

a) Line 14 shows an adjustment for capital contributions. Please explain this adjustment and why no similar adjustment is needed in the calculation of utility income taxes for 2021 to 2027.

b) There are adjustments for “items not in business plan detail”, whereby the impacts are immaterial in total. Please clarify the relevance of these items not being in the business plan detail and why they are adjustments to net income before taxes.

    i. Total annual adjustments for items not in the business plan detail are up to $28 million. Please clarify why these adjustments would not be considered material.

E-Staff-298
Exhibit E / Tab 9 / Schedule 4 / pp.1, 6

Preamble:

Regarding the property taxes, it states that 2019 Transmission and Distribution property taxes includes property tax provision adjustment of ($4.6 million) and ($0.3 million), respectively and 2020 Transmission property taxes includes a tax credit of ($1.1 million) for refunds received as a result of successful property tax appeals.

Questions:

a) Please explain how frequently these property tax adjustments/appeals occur, and how often they result in refunds to Hydro One.

b) Does Hydro One take into account these refunds for regulatory purposes? Please explain why or why not.

Exhibit F – Cost of Capital and Capital Structure

No interrogatories on this section.

Exhibit G - Deferral and Variance Accounts

Deferral and Variance Accounts - Transmission

ACCOUNT 1508 OPEB COST DEFERRAL ACCOUNT
G-Staff-299

Ref 1: Exhibit G/Tab 1/Schedule 1/p.9-11, p.42-43
Ref 2: Exhibit G/Tab 1/Schedule 2/p.4 & p.28
Ref 3: Hydro One Transmission's DVA continuity schedule G-01-05-01
Ref 4: Hydro One Distribution's DVA continuity schedule G-01-05-02

Preamble:

Hydro One is requesting to recover $29.5M from customers for Transmission's Account 1508 OPEB cost deferral account and $69.1M for Distribution's Account 1508 OPEB cost deferral account, representing the non-service cost of OPEB costs and associated tax impacts for transmission and distribution, respectively. Based on a review of the DVA continuity schedules for transmission and distribution, OEB staff notes that the claims associated with Account 1508 OPEB deferral cost are comprised of the following:

	Account 1508 OPEB Deferral Cost	
in $	**Transmission**	**Distribution**
2018 Principal	n/a	16,410,051
2019 Principal	20,978,329	16,066,688
2020 Principal	7,563,615	34,683,554
Total Interest	912,328	1,916,763
Total Claim	**29,454,272**	**69,077,055**

Hydro One Transmission proposes to continue the OPEB cost deferral account for the interest accumulation during the approved disposition period.

Hydro One Distribution proposes to continue the OPEB cost deferral account "so that the residual balance for 2021 and 2022 can be brought for disposition in the next rebasing application".

Question(s):

a) Please provide a breakdown of the 2018 to 2020 principal amounts into non-service cost of OPEB and associated tax impact for transmission and distribution.

b) Please reconcile the non-service cost of OPEB of each year to the relevant actuarial report.

c) For Hydro One Transmission, please provide the estimated quantum of the accumulated interest during the disposition period and explain whether the total estimated interest is material.

    i) If the total estimated interest is not material, please provide Hydro One's position on the notion of discontinuing the account.

Account 1522 OPEB Asymmetric Carrying Charge Account

G-Staff-300
Exhibit G/Tab 1/Schedule 2/pp.24-25
EB-2019-0082/OEB staff submission/p.132

Preamble:

In Hydro One Transmission’s last Custom IR application, OEB staff submitted the following with respect to the OPEB asymmetric carrying charge account:

> OEB staff submits that if Hydro One is permitted to use an alternate methodology for purposes of tracking amounts in the variance account, it should be based on the sum of the following components:
> a) The portion of the annual OPEB costs that is expensed to OM&A
> b) The annual depreciation associated with the cumulative undepreciated capitalized OPEB costs in rate base
> c) The annual amortization of costs recorded in the OPEB Cost deferral account

In this application, Hydro One proposed an updated methodology for this account. Hydro One stated that:

> With respect to the determination of the accrual amount in rates, Hydro One obtained the 2018-2020 OPEB amounts recovered through OM&A for both transmission and distribution businesses from the respective rate applications. The 2018-2020 OPEB amounts recovered through depreciation were obtained from the historical OPEB capitalization file.

Question(s):

a) Please confirm that Hydro One’s updated methodology for the OPEB asymmetric carrying charge account includes the three components in OEB staff’s submission from Hydro One Transmission’s last Custom IR application.

    i. If not, please elaborate further.

Account 2405 Pension Cost Differential Account

G-Staff-301
Exhibit G/Tab 1/Schedule 1/pp.17-18 and pp.47-48
Hydro One Transmission’s DVA continuity schedule G-01-05-01
Hydro One Distribution’s DVA continuity schedule G-01-05-02

Preamble:

Hydro One uses this account to track the difference between the OM&A portion of pension cost estimates based on actuarial assessments used for the application and the actual OM&A portion of pension contributions for transmission and distribution.

Hydro One Transmission stated that:

> The OM&A portion of the pension cost estimates approved by the OEB in the EB-2019-0082 Decision was $9.3M for 2020, and $9.5M for 2021.The actual OM&A portion of pension costs was $9.6M for 2020.

Hydro One Distribution stated that:

> The OM&A portion of pension cost estimates approved by the OEB in the EB-2017-0049 Decision was $17.5M for 2020, and $17.8M for 2021. The actual OM&A portion of pension costs were $16.2M for 2020.

Based on a review of the DVA continuity schedules for transmission and distribution, OEB staff notes that the total claims in Account 2405 Pension Cost Differential Account are comprised of the following:

	Account 2405 Pension Cost Differential Account	
in $	**Transmission**	**Distribution**
2017 Principal	n/a	-$21,071,861
2018 Principal	n/a	-$24,474,110
2019 Principal	-$4,518,354	$24,474,110
2020 Principal	$287,704	-$1,372,461
Total Interest	-$276,157	-$1,504,860
Total Claim	-$4,506,807	-$23,949,182

Question(s):

a) Please provide the variance calculation between the approved and the actual OM&A portion of pension cost for the 2019 principal amounts for Hydro One transmission and the 2017 to 2019 principal amounts for Hydro One distribution.

b) Please clarify whether the actual OM&A percentages of pension cost for transmission and distribution are different than the approved OM&A percentages of pension costs.

c) Please explain why the 2019 principal amounts for transmission is a credit of $4.5M while the 2019 principal amount for distribution is a debit of $24M.

Account 1522 Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance (Tracking Account)

G-Staff-302

OEB's Report on Regulatory Treatment of Pension and OPEB Cost
Exhibit G/Tab 1/Schedule 1/pp.27-28 and p. 57

Preamble:

Appendix C Accounting Guidance, for the generic Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential variance account, within the OEB's Report on Regulatory Treatment of Pension and OPEB cost states that:

> The account is to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis. Therefore, pension and/or OPEB entries will not need to be posted to the account if the OEB approves the cash method to recover these costs in a utility's rates.

The appendix also states that three sub-accounts are to be established for the cost differential: a primary sub-account for the cost differential; a contra sub-account; and a sub-account for carrying charges. The journal entries in the contra sub-account offset the entries in the primary sub-account.

In Reference 2 and Reference 3, Hydro One stated that this variance account tracks the difference between the forecasted accrual amount in rates and actual cash payment(s) made, with an asymmetric carrying charge in favor of ratepayers applied to the differential.

Hydro One also stated that as of December 31, 2020, the tracking account for Hydro One Transmission has a balance of $22.1M and for Hydro One Distribution has a balance of $35.9M.

OEB staff notes that Hydro One transmission and distribution also have an OPEB asymmetric carrying charge account for the carrying charges on the OPEB cost differential between the accrual basis and cash basis.

Question(s):

a) Please confirm that this tracking account is used to track the cost difference for OPEB costs, given Hydro One's pension costs are presented on a cash basis.

b) Please confirm that this tracking account corresponds to the primary sub-account as stated in the OEB's Report of pension and OPEB costs.

c) Please confirm that there should also be a contra sub-account for the OPEB cost differential. If confirmed, please update the relevant evidence.

d) Please confirm that the OPEB asymmetric carrying charge account corresponds to the carrying charge sub-account of this account.

ACCOUNT 2405 Integrated System Operating Center (ISOC) Asymmetric Variance

G-Staff-303
Exhibit G/Tab 1/Schedule 1/pp.28-29 and pp.55-56
Exhibit B/Tab 4/Schedule 1/p.6

Preamble:

Hydro One states that it is not requesting disposition of Account 2405 ISOC Asymmetric Variance for transmission and distribution because no entries have been made in the account for transmission and distribution in 2020. Hydro One states that the earliest entry into this account would be in 2021 (the expected in-service year).

In Reference 2, Hydro One states that the ISOC is still on track to be substantially completed by September 2021.

Hydro One states that it plans to update all transmission and distribution DVA balances for which disposition is being requested in this application to reflect 2021 actuals once they become available.

Question(s):

a) Please explain whether the ISOC project has been completed.

i) If the project has been completed, please provide the following information:
- The actual cost for the project
- The variance between the actual cost and the cost included in 2021 historical year in the application
- Hydro One's position on the notion of updating the application for the costs included in this application
- The calculated 2021 and 2022 balance in the ISOC variance account
- Hydro One's position on the notion of disposing the 2021 and 2022 balances in the ISOC variance account as part of this proceeding

ii) If the project has not been completed, please explain why and provide the estimated time of the completion.
- If the estimated time of completion is in 2022, please explain Hydro One's position on how to treat the ISOC-related approved 2021 revenue requirement with respect to the sub-account.

New Accounts - Externally Driven Transmission/Distribution Projects Variance Accounts

G-Staff-304

Exhibit G/Tab 1/Schedule 2/pp.16-20, pp.33-37
Exhibit G / Tab 1 / Schedule 2 / Attachment 2
Exhibit G / Tab 1 / Schedule 2 / Attachment 6

Preamble:

Hydro One Transmission is requesting a new symmetric variance account under Account 1508 for externally driven transmission projects. Hydro One states that:

> In developing its investment plans, Hydro One Transmission uses the best information available to forecast investment needs including for Externally Driven Work. Those forecasts are based on reasonably anticipated customer and system requirements developed through detailed engineering analysis, integrated system and customer studies, and third-party requests.
> However, due to Externally Driven Work being mandatory, significant in scale and outside of Hydro One's control, there are significant risks in relation to cost and schedule for this work. Projects may be announced or cancelled, and their timing may be advanced or delayed, all at the discretion of the relevant third-

party…. Moreover, there is a risk that over the rate period Hydro One receives additional directions or orders to undertake externally driven projects not currently contemplated.

Hydro One Transmission further states that:

> Pursuant to various legislative and regulatory mechanisms, Hydro One Transmission may receive directions from the IESO, Orders in Council from the Province or directions from the Minister of Energy, Northern Development and Mines (the Ministry), to undertake certain work.
>
> Alternatively, the Ministry or Province may direct the OEB to require Hydro One to undertake certain work as a condition of its Electricity Transmission Licence or as a result of a policy change. In addition, Hydro One Transmission may be required to relocate existing transmission facilities to accommodate infrastructure projects on roads. In these circumstances, the work is typically complex and large in scale, externally driven by third party authorities and it is mandatory for Hydro One to perform the work.

Hydro One Transmission also states that this new account is a symmetrical account recording the revenue requirement and associated tax impacts of any variation in externally driven work that is included in the capital plan (with the revenue requirement related impact of the underspending returned to ratepayers and the revenue requirement related impact of increased spending recorded in the account for future recovery) and the revenue requirement and associated tax impacts of any new externally driven work that is not included in the capital plan.

In addition, Hydro One Distribution is requesting a new symmetrical variance account (Account 1508 – Other Regulatory Assets, Sub-Account Externally Driven Distribution Projects Variance Account) to record the revenue requirement impact, including tax, of overspending or underspending relative to Hydro One's distribution capital investment plan which underlies the proposed revenue requirement for the 2023-2027 period, where such overspending or underspending is for work related to third-party initiated relocation, Distributed Energy Resource (DER) connections, or service upgrades, which Hydro One is required to undertake. Hydro One distribution states that:

> During the course of the of the 2018-2022 approved term, externally driven System Access investments are forecasted to exceed approved amounts by close to 20%, contributing to an approximate 2% overage on a five-year envelope basis.

In Reference 2 and Reference 3, Hydro One has provided a draft accounting order for Transmission and Distribution's new account respectively.

Question(s):

a) For Transmission's last approved term of 2020 to 2022, please provide the comparison of the externally driven work between the actual amount and the approved amount on a total basis.

   i) Please explain how Hydro One Transmission dealt with the externally driven work that was not included in the revenue requirement.

   ii) Please explain what kind of communication Hydro One Transmission received from external authorities (e.g. Ministry) for the externally driven work.

b) For Hydro One Distribution, please provide the approved and actual externally driven system access net expenditures for each year of 2018, 2019 and 2020, as well as the approved and forecast externally driven system access net expenditures for 2021 and 2022.

   i) Please explain how Hydro One Distribution dealt with the externally driven work that was not included in the revenue requirement.

   ii) Please explain what communication Hydro One Distribution received from external authorities (e.g. Ministry) for the externally driven work.

c) For Hydro One Transmission, please clarify whether the proposed account includes station work as well as line work.

   i) For station work, please provide Hydro One Transmission's plan for how it intends to demonstrate prudence of the costs incurred when it ultimately seeks disposition.

d) For line work, please provide Hydro One Transmission's plan for how it intends to demonstrate prudence of the costs incurred when it ultimately seeks disposition. For Hydro One Transmission, please clarify the following:

i) The “mandatory” nature of the externally driven work - Does Hydro One have discretion over how Externally Drive Work is carried out?

ii) What is the IESO’s ability to “direct” Hydro One to do externally driven work?

iii) Please provide a copy of any relevant previous IESO communications regarding externally driven work

iv) Please specify the governmental authorities, agencies, Crown corporations, or similar parties that may initiate externally driven work

v) Please provide the specific criteria for identifying an externally driven project to be included in the proposed account and explain why these criteria are appropriate

e) For Hydro One Distribution, please clarify the following:

i) The “mandatory” nature of the externally driven work - Does Hydro One have discretion over how externally drive work is carried out?

ii) Please specify the governmental authorities, agencies, Crown corporations, or similar parties that may initiate externally driven work

iii) Please provide the specific criteria for identifying an externally driven project to be included in the proposed account and explain why these criteria are appropriate.

f) For Hydro One Transmission and Distribution, please provide the following with respect to reporting and recording in the account requested:

i. Please confirm that any externally driven work is subject to Black & Veatch’s updated capitalization methodology.

ii. Please explain whether and how the externally driven work is to be recorded in the account by project (and for transmission, whether the line work and station work will be separated). If not, why not.

iii. Please confirm that the new account comprises of two components: 1) variance for the revenue requirement impact of over/under-spending of existing forecasted externally driven work included in the revenue requirements and 2) the revenue requirement impact of any new external driven work not included in the revenue requirements.

a. If confirmed, please explain why the customers should absorb the overspending by Hydro One for the external driven projects that are currently forecasted and included in the revenue requirements.

g) Please discuss Hydro One's position on using the Z-factor mechanism during the Custom IR period to deal with any material externally driven work rather than the request of a new variance account.

h) Under the OEB's ratemaking framework for Custom IR applications, the Incremental Capital Module (which would otherwise be available to applicants) is not an option. Please discuss whether Hydro One believes externally driven capital projects, such as the ones contemplated to be recorded in these proposed accounts, would otherwise be eligible for ICM treatment under a Price Cap rate-setting framework.

<u>Account 2405 Capital in-service Variance Account - Modification</u>

<u>G-Staff-305</u>

Ref 1: Exhibit G/Tab 1/Schedule 2/pp.20-22
Ref 2: Exhibit G/Tab 1/Schedule 2/Attachment 10
Ref 3: Hydro One Transmission's Decision and Order EB-2019-0082/pp.172-173
Ref 4: Hydro One Transmission's DVA continuity schedule G-01-05-01
Ref 5: Hydro One Distribution's DVA continuity schedule G-01-05-02

Preamble:

In Reference 3, the OEB states that:

> The OEB accepts the modifications proposed by Hydro One to the [Capital In-service Variance Account] CISVA. The account was established to protect customers from potential underspending of Hydro One's capital plan. The OEB finds it reasonable to have a threshold at 98% to allow Hydro One to manage its operations without a potential penalty from underspending. The OEB also finds it acceptable during this three-year term to allow Hydro One to adjust the account for identifiable productivity improvements, in order to encourage continuous improvement. The OEB agrees with Hydro One that the OEB panel for its next

rebasing application can review these adjustments to determine whether they were true productivity savings and reasonable. The OEB panel for that proceeding can also determine whether the CISVA account should continue, and if so, whether these productivity adjustments add too much complexity to the account and should be discontinued.

In this application, Hydro One transmission has proposed the continuation of the CISVA and proposed a modification to the account. Based on a review of Transmission and Distribution's DVA continuity schedules, OEB staff notes that no entries have been made in the CISVA for transmission and distribution as at December 31, 2020 because the actual in-service additions exceeded 98% of the OEB approved amounts on a yearly basis.

Hydro One Transmission requests that the CISVA be modified to enable the balance in the account to be calculated yearly using the cumulative in-service additions over the Custom IR term so as to provide an opportunity for Hydro One to "catch-up" in later years within the term on any shortfalls in in-service additions that may occur in earlier years, and thereby to reverse the applicable impact recorded in a prior year of under in-servicing to the extent it makes up for such a shortfall.

Hydro One Transmission states that this modification would remove the incentive to complete projects in December of any given year when it would be more appropriate and cost-effective to instead complete such projects in January of the following year, which is an issue that is particularly significant for the Transmission business where projects are large in scale and multi-year in nature. Hydro One transmission also states that this modification ensures that if there are projects that are delayed outside of Hydro One's control, Hydro One is not unfairly penalized.

In Reference 2, Hydro One has provided an illustrative example for Hydro One Transmission for the modified methodology on page 1 and an illustrative example for Hydro One Distribution on page 2. OEB staff notes that the two examples use the same data and assumptions. However, Hydro One Transmission's account will have a nil balance as at the end of 2027 while Hydro One Distribution's account will have a credit balance of $5.3M refunding to the customers as at the end of 2027.

Question(s):

a) Please provide Hydro One's rationale for the continuation of the account for both Transmission and Distribution, given that no entries have been made in the last Custom IR period.

b) Please confirm that Hydro One is proposing to continue to adjust the account for identifiable productivity improvements.

c) Please confirm that Hydro One Distribution's illustrative example represents the current methodology for Hydro One Transmission.

   i) If so, please explain why the current methodology results in a refund of $5M as at end of 2027 while the modified methodology will result in a nil balance in the account.

   ii) If not, please use the same data and assumptions used in attachment 10 to provide an illustrative example for Hydro One Transmission's current methodology. Please also compare the account balances between the current methodology and proposed modified methodology.

d) Please confirm that under the modified methodology, the CISVA will only have a balance refunding to the customers when the cumulative in-service additions for the period of 2023 to 2027 is less than 98% of the cumulative five-year approved amounts.

G1-Staff-306
Exhibit G / Tab 1 / Schedule 1 / p. 54
Exhibit G / Tab 1 / Schedule 1 / p. 58

Preamble:

In its application for 2010 and 2011 rates (EB-2009-0096), Hydro One requested funding of $34.7 million for construction of six express feeders to support renewable generation as well as other costs. In its decision on this matter, the OEB:

- Approved provincial renewable generation connection rate protection payments[8].
- Required Hydro One to inform the OEB when it had sufficient information regarding requests for connection underpinning the need for each feeder and the location of each feeder and to use a variance account for the

[8] EB-2009-0096 / Decision with Reasons / April 29, 2010 / p. 34

purpose of tracking the difference between the forecast and actual expenditures for future disposition, among other requirements[9].

- Required Hydro One to capture other renewable generation actual expenditures in deferral accounts which were to be subject to a prudence review and cleared as part of Hydro One's next distribution rate case.[10]
- Directed Hydro One to use 3 accounts:
  - 1531 for capital costs
  - 1532 for OM&A cost
  - 1533 to record amounts collected through the funding adder, split into sub-accounts to separate collection from Hydro One ratepayers and provincial ratepayers (i.e. payments from the IESO)

The evidence provided in this application and in Hydro One's 2014 rate application EB-2013-0416 shows balances in 1533 sub accounts but does not show balances in account 1531 or 1532.

In the OEB's decision and order for 2018 renewable generation connection rate protection compensation amount (EB-2017-0370), the OEB approved the discontinuation of the provincial funding for eligible investments for Haldimand. In this proceeding, Hydro One stated consistent with the approach approved for Hydro One in the OEB's decision in EB-2013-0416, Hydro One would record costs for the provincial portion of the eligible investments in the former Haldimand County service area in Account 1553 until such time as the credit in the account is expected to be fully depleted. At that time, Hydro One will apply to the OEB to re-instate funding for the provincial portion of the remaining revenue requirement of eligible investments made under O. Reg. 330/09 in Hydro One's overall service territory, including Haldimand County.

Question(s):

With respect to the express feeders, please provide the following information:

a) Please state whether or not Hydro One implemented the use of accounts 1531 and 1532, or whether it has recorded all costs in sub accounts for account 1533, in accordance with the OEB's March 2015 Accounting Procedures Handbook Guidance #9? Please explain the use of the accounts.

[9] *Ibid*, p. 38
[10] *Ibid*, p. 38

b) Please explain how Hydro One has informed, or plans to inform, the OEB of the sufficient information referenced above regarding requests for the express feeders that have been constructed with funding through the adder?

c) How many feeders have been constructed?

d) What are Hydro One's plans for the disposition of the variance account?

e) Have expenditures allocated for the express feeders been added to fixed assets?

With respect to Other costs, please provide the following information:

f) Did Hydro One implement use of accounts 1531 and 1532, or has it recorded all costs in sub accounts for account 1533, in accordance with the OEB's March 2015 Accounting Procedures Handbook Guidance #9? Please explain the use of the accounts

g) What is Hydro One's plan for the prudence review of the other costs and disposition of the amounts?

h) Have the other costs expenditures been added to fixed assets?

With respect to Account 1533 for Haldimand, please provide the following information:

i) Did Hydro One implement use of accounts 1531 and 1532, or has it recorded all costs in sub accounts for account 1533, in accordance with the OEB's March 2015 Accounting Procedures Handbook Guidance #9? Please explain the use of the accounts

j) Account 1533 has not been requested for disposition in Hydro One's Acquired's 2022 rate application. What is Hydro One's plan for the prudence review of the other costs and disposition of the amounts?

k) Have the costs expenditures relating to Account 1533 been added to fixed assets?

G1-Staff-307

Exhibit G1 / Tab 1 / Schedule 2 / p. 31

EB-2011-0207 / Decision and Order / March 22, 2012 / pp. 13-20

Preamble:

The OEB approved Woodstock Hydro's request to recover incremental capital costs for the Commerce Way Transmission Station through a rate rider effective May 1, 2012.[11]

Question(s):

a) Please state whether or not the assets for which costs are being recovered through the rate rider for incremental capital have been transferred to fixed assets for 2023? If not, explain how the assets are being accounted for.

b) In the Incremental Capital Model (ICM) decision referenced above, the OEB decided that the half-year rule did not apply to the incremental revenue requirement for the ICM. Please confirm that a full year's depreciation was recorded in the first-year the ICM assets were in service. If not confirmed, please explain the basis under which depreciation was recorded and explain why a full year's depreciation was not recorded.

c) Please confirm that collection of the rate rider will cease, as of January 1, 2023.

d) Please confirm that there is no request in this proceeding to dispose of balances in account 1508 - Incremental Capital Module Deferral Account, as audited balances as of December 31, 2020 are being requested for disposition in the 2022 Acquired Utilities' rate application.

<u>G-Staff-308</u>
Exhibit G / Tab 1 / Schedule 1 / Attachment 5

Preamble:

Regarding Account 1592, Sub-account CCA Changes

Questions:

a) The methodology in Attachment 5 states that the 2018 Transmission CCA schedules have been used to approximate the accelerated CCA impact for 2019.

[11] EB-2011-0207 Woodstock Hydro Services Inc., Decision and Order, March 22, 2012

Please clarify whether approved additions embedded in rates have been used to calculate the balance in Account 1592 for Transmission and Distribution.

i. If not confirmed, please further explain the above statement.

b) Please provide the calculation for the Account 1592 annual entries from 2018 to 2020 for Transmission and Distribution (as applicable) on both of the following bases:

i. The difference in CCA between the calculations embedded in Hydro One's rates and what that calculation would have been had the Accelerated Investment Incentive Program (AIIP) rules been applied in its last rebasing application (i.e. based on approved capital additions)

ii. The difference in CCA between the amounts claimed from 2018 to 2020 and what the claims would have been had the AIIP program not been introduced (i.e. based on actual capital additions in the year).

c) In the calculation of the amounts in Account 1592, note 1 indicates that the additions have been multiplied by a percentage to determine the proportion of total annual in-service additions that are eligible for AIIP. Please explain why a percentage has been used instead of using actual additions that are eligible for AIIP.

d) In each of the tables showing the calculation of the amounts in Account 1592, please confirm that the formula for the columns Incremental CCA Under Accelerated CCA should not be divided by 2 (e.g. for Distribution, the formula should be E=D*C*D), except for CCA class 12 with 100% CCA rate.

e) In the DVA Continuity Schedule, Account 1592 shows a principal balance of $47,653,393 as at December 31, 2021. Per the calculation of Account 1592, Sub-account CCA Changes in Attachment 5, the total principal balance from 2018 to 2022 would be $48.8 million. It appears that the Account 1592 line in the DVA Continuity Schedule includes another sub-account besides the CCA Changes sub-account and that there are $1,165,424 of transactions in 2017 relating to this other sub-account. Please confirm and explain what the 2017 transactions pertain to.

G-Staff-309
Exhibit G / Tab 1 / Schedule 1 / pp. 1, 26, 58
Exhibit G / Tab 1 / Schedule 2 / pp. 8, 29

Preamble:

Hydro One indicated that it will reflect the Report of the OEB, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency[12] (COVID-19 Report) in its 2021 Transmission and Distribution audited balances. Hydro One has indicated that it has presented 2020 audited balances in this application and will update the balances for 2021 audited balances, once available. In the interim, Hydro One proposes to continue this account.

Questions:

a) Please confirm that Hydro One intends to seek disposition of audited 2021 balances once available.
   i. Please indicate when Hydro One expects to have the audited 2021 balances available and comment on whether there will be sufficient opportunity for discovery on these balances in this proceeding.

b) Please clarify if Hydro One intends to seek disposition of Account 1509 balances (2020 or 2021), as updated to reflect the OEB's COVID-19 Report.

   i. If so, please provide the updated Account 1509 balances for 2020, with supporting calculations of the annual sub-account balances, broken down into categories, as appropriate, and the amount for disposition after applying the applicable recovery rate

   ii. Please also provide discussion on applicable aspects of the Report, such as interim/final disposition and rationale for it, causation, materiality, prudence, incremental savings, continuation/discontinuation of sub-accounts after rebasing, etc.

c) Please explain whether Hydro One has reflected COVID-19 related impacts in the revenue requirements in this application. If so, please provide a summary of the impacts reflected in revenue requirement.

[12] EB-2020-0133, June 17, 2021

G-Staff-310
Exhibit G / Tab 1 / Schedule 1 / pp. 29, 48-50

Preamble:

Regarding Account 2435 - Earnings Sharing Mechanism (ESM) Deferral Account

Questions:

a) Please provide the 2020 ESM calculation for Transmission using the Reporting and Record Keeping Requirements (RRR) 2.1.5.6 filing format for electricity distributors,

b) Please provide the 2018, 2019 2020 RRR 2.1.5.6 ROE filings for Distribution and the 2020 RRR ROE filing for Transmission.

c) Table 8 provides the ESM calculation for Distribution, where the 2020 regulated net income is $348.9M. Using the below table, please provide a further breakdown of the regulated net income for the Distribution and Transmission ESM, comparing adjustments in the ROE filing and adjustments in the ESM calculation.

In M$	**2020**	**Explanation for adjustment**
Adjusted Regulated Net Income per ROE filing		
Quantify and explain each adjustment made for ESM purposes		
Adjusted Regulated Net Income for ESM		

d) For the 2020 ESM calculations for both Transmission and Distribution, how have any COVID-19 related impacts have been accounted for (i.e. if the ESM was calculated before or after entries are made to Account 1509).

   i. Please explain Hydro One’s rationale for this treatment of COVID-19 related impacts in the ESM calculations

   ii. If COVID-19 related impacts have been reflected in the ESM calculation, please explain whether there is double counting with any amounts recorded in Account 1509

e) For Hydro One Distribution and Transmission, the non-service cost of OPEB is recorded in OPEB cost deferral account in 2020 (Transmission: $7.6M; Distribution: $34.7M).

    i) Please explain how Hydro One has treated these costs for the 2020 RRR 2.1.5.6 ROE filing and 2020 ESM calculation.

    ii) Please explain how Hydro One recognized the rate rider revenues collected for the OPEB cost deferral disposed in prior applications.

f) OEB staff notes that in the OEB's decision for 2021 UTRs[13], the OEB approved a two-year disposition of the accumulated 2020 foregone revenue for Hydro One Transmission.

    i) Please explain whether and how Hydro One has adjusted the regulated net income for the collection of the foregone revenues.

    ii) In the 2020 ESM for Transmission, please confirm that Hydro One has increased regulated net income by including the approved foregone revenues for 2020. If confirmed, please quantify the amount included. If not confirmed, please explain why not and revise the ESM calculation for to increase regulated income by the foregone revenues.

g) In the Hydro One Distribution 2021 Custom IR Update proceeding,[14] Hydro One's reply argument responded to OEB staff's inquiry on the $14.1 million deferred tax asset adjustment made to the current tax provision for the "2018 DTA Sharing Adjustment" in Hydro One's RRR filing of its 2019 ROE. Hydro One indicated that the adjustment was net income neutral and the offset is embedded in the foregone revenue normalization adjustment. Hydro One also confirmed that results of the Remittal of Future Tax Savings Issue proceeding[15] does not impact the ESM deferral account calculations as the deferred tax asset sharing amounts are net income neutral.

    In the 2020 RRR 2.1.5.6. ROE filing for Distribution, there is a similar adjustment of $2.3M to the current tax provision for "DTA Sharing". In the 2020 ROE filing for Transmission, there is a similar adjustment of ($12.1M) for "DTA Sharing (June to December) + Excluded OPEB".

[13] EB-2020-0251, Decision and Rate Order, December 17, 2020
[14] EB-2020-0030
[15] EB-2020-0194

i. Please explain what the initial treatment of the deferred tax asset in regulated net income was, prior to any adjustments for each of the 2019 and 2020 Distribution and 2020 Transmission ROEs.

ii. Please explain why the adjustments for DTA Sharing are appropriate for each of the 2019 and 2020 Distribution and 2020 Transmission ROEs.

iii. Please clarify what Hydro One meant by the adjustment being "net income neutral"

iv. Please explain how the results from the Remittal of Future Tax Savings proceeding have been reflected in the ROE and ESM calculations.

v. In the adjustment for 2020 Transmission noted above, please quantify and explain what the adjustment pertaining to "Excluded OPEB" represents and why it is an appropriate adjustment.

h) In the Hydro One Distribution 2021 Custom IR Update proceeding, Hydro One's reply argument responded to OEB staff's requested clarity in respect of how the 2018 ESM was calculated compared to the OEB's typical RRR 2.1.5.6 ROE calculation. However, Hydro One did not address utility-specific adjustments that were made to the RRR ROE calculation. In the 2018 RRR 2.1.5.6 ROE filing, there are adjustments of $3.1M for "Loss Carry-forward + Contingent Liability", and $800k for "Tax Credits + Other Provisions" made to the current tax provision. Please explain what these adjustments are for and why they are appropriate.

i) In Hydro One Distribution's 2018 to 2022 Custom IR proceeding, Hydro One was approved to collect foregone base rate revenue pertaining to the period of May 1, 2018 to June 30, 2019 over the 18 month period from July 1, 2019 to December 31, 2020. In the 2018 ESM calculation and 2019 RRR 2.1.5.6 ROE calculation, it appears that Hydro One has adjusted 2018 and 2019 regulated net income to reflect the impact of foregone revenues. In the 2020 RRR 2.1.5.6 ROE calculation, there does not appear to be a similar adjustment to remove the 2018/2019 foregone revenues that was collected in 2020. Please confirm if this understanding is correct.

i. If so, please explain why the 2020 regulated net income was not adjusted.

ii. Please quantify the 2018/2019 foregone revenues collected in 2020 and revise the ESM calculation to remove this amount from regulated net income.

j) Please confirm that Hydro One Distribution's 2018, 2019 and 2020 ESM calculations excludes the results of the Acquired Utilities.

i. If not confirmed, please explain why.

ii. Please also provide the 2018, 2019 and 2020 ESMs excluding the Acquired Utilities' results.

G-Staff-311
Exhibit G / Tab 1 / Schedule 1 / pp. 29-31

Preamble:

Hydro One is proposing not to dispose of 2020 Group 1 balances for Distribution and Acquired Utilities in their respective 2022 rate applications, but to seek disposition of consolidated Distribution and Acquired Utilities Group 1 balances in this proceeding. Hydro One will request disposition of Acquired Utilities Group 2 2020 balances in the Acquired Utilities' 2022 rate application.

Questions:

a) Hydro One indicated that this proceeding is the first application for both Hydro One Distribution and the Acquired Utilities, which introduces the opportunity to dispose Group 1 balances on a consolidated basis, without performing an allocation to Distribution and each of the Acquired Utilities. Please provide a high level approximate comparison of the 2020 Group 1 disposition related bill impacts to Distribution and each of Acquired Utilities using the consolidated approach and using an allocation approach.

b) Hydro One indicated that it intends to update this application for audited 2021 Group 1 balances during the course of this proceeding. Hydro One further stated that in the event that Group 1 balances change based on 2021 audited transactions from a credit balance to a debit balance or a smaller credit balance, the combined disposition based on 2020 and 2021 audited balances would result in less volatility to rate payers.

i. Given that there are 9 months of data for 2021 available, please confirm that net 2021 transactions to date have been debit transactions which would reduce the 2020 credit Group 1 balances. If not confirmed, please explain the basis for Hydro One's statement above.

c) Hydro One indicated that it receives one consolidated invoice for settlement of commodity, bulk transmission and wholesale settlements for all service territories. Please explain when Hydro One started to receive one consolidated bill for Hydro One Distribution and the Acquired Utilities.

d) The Acquired Utilities' Group 2 accounts are expected to remain effective until the Acquired Utilities rebase in 2023. If the 2020 Group 2 balances are approved for disposition, there will still be 2021 and 2022 balances remaining to be disposed in the future.

i. Please explain Hydro One's plan for the disposition of the 2021 and 2022 Group 2 balances remaining for the Acquired Utilities, including when it would be requested for disposition, and whether it would be disposed to the legacy ratepayers from the Acquired Utilities or all of Hydro One's ratepayers.

ii. Please confirm that the Group 2 accounts for the Acquired Utilities would be discontinued effective January 1, 2023. If not confirmed, please explain why not.

e) Hydro One has acquired the former Orillia Power Distribution Corporation and Peterborough Distribution Inc. In the related 2022 rate application, Hydro One has not requested disposition of Group 1 balances or Group 2 balances (excluding Accounts 1575 and 1576).

i. Please explain Hydro One's plan for consolidating Orillia and Peterborough's Group 1 accounts with the rest of Hydro One's deferral and variance accounts (e.g. when Hydro One expects to consolidate balances). Please also explain when Hydro One plans on requesting consolidated balances for disposition.

ii. Regarding Group 1 accounts, please explain when Hydro One expects to have one invoice for settlement of commodity, bulk transmission and wholesale settlements for all service territories consolidated for the Orillia and Peterborough service territories, as well as the rest of Hydro One.

iii. Please explain Hydro One's planned disposition approach for Group 2 accounts, excluding Accounts 1575 and 1576, including discussion on when disposition will be requested, impacts to intergenerational inequity as balances continue to accumulate during the deferred rebasing period, and the continuation of the accounts during the deferred rebasing period.

iv. Please confirm that Hydro One is able to continue recording transactions for Group 2 accounts specifically for Orillia and Peterborough going forward.

a. If not, please explain why not and indicate which accounts Hydro One proposes to consolidate with the rest of Hydro One.

G-Staff-312

Exhibit G / Tab 1 / Schedule 1 / Attachment 1

Preamble:

In the GA Analysis Workform,

Questions:

a) The reconciling item for Impacts of the GA Deferral has not been completed. Please explain why there is no reconciling item for this and quantify the reconciling item.

b) There is a reconciling item of $926,044 on line eight with no associated description. On line six, there is a description for "charging LDC Class B customers at actual GA rate instead of the first estimate" with no associated amount quantified. For each of these lines, please clarify the associated description and amount.

c) Please explain why there is no expected volume variance calculated in the Workform. Please quantify the expected volume variance.

d) In the 2020 GA tab, under note 3, regarding whether the same GA rate is used to bill all customers, "no" was selected. Please confirm this is referring to the "LDC Class B customers" that are charged the actual GA rate. If not confirmed, please explain which customers are billed a different GA rate and how this has been accounted for in the GA Analysis Workform.

e) In the 2020 GA tab, under note 3, regarding whether the GA rate used for unbilled revenues is the same as the rate used to billed revenues, “no” was selected. Please confirm that the implications of this are accounted for in the reconciling item 2a/2b for unbilled to actual revenue differences. If not, please explain how the implication from the use of a different GA rate for unbilled revenues (versus billed revenues) has been accounted for in the GA Analysis Workform.

G-Staff-313
Exhibit G / Tab 1 / Schedule 2 / pp. 2, 27
Exhibit G / Tab 1 / Schedule 1 / p. 42
Exhibit G / Tab 1 / Schedule 5 / Attachment 2
OEB’s Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Customer Choice Initiative
Ontario Energy Board File No. EB-2020-0152

Preamble:

Hydro One is requesting the Account 1508, Sub-account Long Term Load Transfer (LTLT) Rate Impact Mitigation Deferral Account and Account 1508, Sub-account Customer Choice Initiative Costs for disposition,

Questions:

a) Based on the DVA Continuity Schedule for Distribution, annual transactions for Account 1508, Sub-account Long Term Load Transfer (LTLT) Rate Impact Mitigation Deferral Account from 2017 to 2020 have been under $250k per year. It also appears that there was a minimal balance recorded in this account in 2016, as this sub-account was not listed for disposition in Hydro One’s 2018 Custom IR rate proceeding.[16] In Table 2, Hydro One has requested this sub-account be continued. Please explain why Hydro One is requesting this sub-account for disposition, given the balance of $776k is immaterial, giving due consideration to the OEB’s criteria for materiality.

    i. Given the magnitude of transactions in the account from 2016 to 2020, please explain how this account will meet the OEB’s materiality criteria for DVAs in the future and why the account should continue.

[16] EB-2017-0049, Draft Rate Order – Exhibit 7.0

b) In the Accounting Order for Account 1508, Sub-account Customer Choice Initiative Costs, it states that the OEB will assess any claimed costs recorded in the sub-account at the time the sub-account is requested for disposition, subject to the causation, materiality and prudence criteria. Please explain why Hydro One is requesting this sub-account for disposition when the amount of debit $855k in the sub-account is immaterial.

G-Staff-314

Exhibit G / Tab 1 / Schedule 1 / pp. 43 and p.15 of Attachment 4
Exhibit G / Tab 1 / Schedule 2 / pp. 32
EB-2016-0201 / Decision and Order / September 28, 2017 / p.2

Preamble:

Hydro One is requesting disposition of a debit amount of $2.3 million in Account 1508, Sub-account Smart Grid Fund (SGF) Pilot Deferral Account. Per the accounting order of this account, Hydro One should also record rebates to customers and maintenance costs associated with the extension of the SGF program. In the decision and order referenced above, the OEB indicated that its review of this sub-account will include a consideration of the quantum of the avoided recruitment costs that the maintenance of the existing customer group was intended to achieve. The OEB further noted that the onus will remain on Hydro One to demonstrate that the cited benefits in its original request for the sub-account outweigh the incurred costs.

Questions:

a) It was indicated that the sub-account balance is comprised of costs associated with pilot design. Please confirm whether these are maintenance costs of extending the SGF program, or whether they are the initial SGF pilot design costs. If the latter, please explain why these costs are recorded in the sub-account.
b) Please explain whether there have been any rebates to customers that have been recorded in the sub-account. If so, please quantify the amount.
c) Please discuss whether there were any avoided recruitment costs, as noted above.
d) Please discuss whether the cited benefits in its original request for the sub-account outweighed the incurred costs.

G-Staff-315
Exhibit G / Tab 1 / Schedule 2 / p. 2, 28
Exhibit G / Tab 1 / Schedule 1 / pp. 54-55
Exhibit G / Tab 1 / Schedule 5 / Attachment 2

Preamble:

Hydro One has listed Account 1533 – Distributed Generation – Other Costs – Provincial Deferral Account to be continued in Table 2. It further states that Hydro One Distribution proposes to continue this account to record funding relating to renewable distributed generation connection investments, as Hydro One Distribution continues to incur costs eligible for direct benefit treatment as per Ontario Regulation 330/09.

The DVA Continuity Schedule shows three Account 1533 sub-accounts:

i. Distribution Generation – Hydro One – Other Costs – Deferral Account
ii. Distribution Generation – Provincial - Other Feeders – Deferral Account
iii. Distribution Generation – Provincial - Express Feeders – Deferral Account

Page 55 of the second reference indicates that the Distribution Generation – Hydro One – Other Costs – Deferral Account has been discontinued in 2015.

Question(s):

a) Please confirm that the Distribution Generation – Hydro One – Other Costs – Deferral Account has been discontinued in 2015 and Hydro One is not proposing to continue this sub-account.

b) Please confirm that Hydro One is requesting that the second and third sub-accounts noted above be continued. If not confirmed, please clarify Hydro One's proposal

G-Staff-316
Exhibit G / Tab 1 / Schedule 1 / pp. 44-46

Preamble:

Hydro One is proposing the disposition of the 2020 balances Account 1518 – RCVA Retail and Account 1548 – RCVA STR. Hydro One has indicated it will update the balances requested for disposition to reflect audited 2021 balances, when available.

Question:

a) Please indicate if Hydro One is able to forecast the Account 1518 and 1548 balances up to December 31, 2022 with reasonable accuracy. If not, why not?
b) If so, please provide the calculation of the 2021 and forecasted 2022 balances, in the same format as Table 7.
c) Please discuss Hydro One's position on the notion of disposing the forecasted 2022 balance as well, provided it can be forecasted with reasonable accuracy.

G-Staff-317
Exhibit G / Tab 1 / Schedule 2 / pp. 37-39
Exhibit C / Tab 7 / Schedule 1 / pp. 7-10

Preamble:

Hydro One is proposing to establish a new account for Account 1508, Sub-account Distribution Connection Cost Agreement to record the impacts of Distribution revenue requirement of capital contribution true-ups paid by Hydro One Distribution to Transmission, and capital contributions collected by Hydro One Distribution from its embedded distributors and large customers.

As noted in the first reference, this account will not include the impact of the Initial Economic Evaluation (IEE) based upon actual costs, as the capital contributions can be forecasted based on initial customer commitments in their individual contract and will not trigger an immediate tax obligation, as these are collected within the time frame allowed under the Income Tax Act.

As noted in the second reference, this account will also not include the impact of the IEE based upon actual costs as these will be revenue requirement and tax neutral.

Questions:

a) For the 2018 to 2022 period, please provide the annual revenue requirement impact from capital contribution true-ups (i.e. the amount that would have been recorded in the proposed sub-account, had it existed during 2018 to 2022).

b) Please explain whether the initial capital contributions calculated from the IEEs and embedded in the test period revenue requirements could be different than the actual capital contributions calculated from the IEEs.

i. Please further explain why the impact of the IEE based on actual costs will be revenue requirement and tax neutral.

G-Staff-318
Exhibit G / Tab 1 / Schedule 5 / Attachment 2

Preamble:

In the DVA Continuity Schedule, Hydro One has included the "OEB-approved Disposition Amounts during 2021" amounts for Account 1580, Sub-account CBR Class B in the line for Account 1580, Sub-account Wholesale Market Service Charge (WMSC) instead of showing it separately on the CBR Class B line.

Question:

a) Please confirm that the resulting total claim amounts for the CBR Class B and WMSC sub-accounts appropriately reflect the balances pertaining to each of the sub-accounts.

b) If not confirmed, please revise the DVA Continuity Schedule to show the CBR Class B amount for "OEB-approved Disposition Amounts during 2021" in the CBR Class B line, and confirm that the revised total claim amounts for the two sub-accounts are appropriate.

Exhibit H – Cost Allocation and Rate Design for Uniform Transmission Rates

H-Staff-319
Exhibit H / Tab 10 / Schedule 1 / pg. 1 of 8

Preamble:

At the above reference, it is stated in Lines 4 to 15 that:

> The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. For the purpose of determining the impact of the proposed changes to transmission rates on an average customer's bill, the same approach used in the EB-2019-0082 transmission rate application has been adopted. Table 1, below, shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer

The figures from Table 1 have been applied to the proposed increase in transmission rates revenue requirement in 2023 to 2027 to establish average bill impacts as shown in Table 2 [Tables not provided in preamble].

Question(s):

a) Please state, with respect to Table 1, whether or not adjustments were made to make the transmission revenue requirement more comparable between provinces (e.g., to account for the differences in the size of the utilities or total demand served by each utility) evaluated?

    i. If yes, on what basis were these adjustments rejected?

    ii. If no, why not?

b) Please explain why the rates are expressed in different units (e.g., $/kW-month, $/MW/month)?

    i. Please provide an updated version of Table 2 with all volumetric rates expressed in $/kW-month.

<u>H-Staff-320</u>
Exhibit H / Tab 10 / Schedule 1 / pg. 5 to 8 of 8

Preamble:

At the above reference, Hydro One discusses the review which it has undertaken based on reasonably available public information of transmission rate setting in other Canadian provinces.

Question(s):

a) Please state whether or not jurisdictions outside of Canada were evaluated for comparison with Hydro One's proposed transmission revenue requirement and resulting rates?

    i. If yes, please state for what reason these jurisdictions were rejected?

    ii. If no other jurisdictions were considered, please explain why not.

Exhibit L – Distribution Cost Allocation and Rate Design

L1-Staff-321
Exhibit L / Tab 1 / Schedule 1 / p. 2
Exhibit L / Tab 6 / Schedule 1 / p. 18

Preamble:

Hydro One is proposing to merge acquired customers from Norfolk Power, Haldimand Country Hydro and Woodstock Hydro in the Street Lights, Sentinel Lights, USL and Large User classes into Hydro One's existing rate classes. This is resulting in bill impacts that require mitigation in the USL rate classes of all acquired utilities, and the Sentinel Light rate class of Norfolk Power.

Question(s):

a) Please provide any distinguishing characteristics of the Street Light, Sentinel Light, USL and Large User rate classes, or any statements in the EB-2017-0049 Decision, that indicate these rate classes do not require the same treatment as the Residential and General Service rate classes.

b) Please state whether or not Hydro One has consulted with customers of the acquired USL and Sentinel Light rate classes regarding this proposal? If so, please provide details on how this was communicated, and a summary of the feedback obtained.

L1-Staff-322
Exhibit L / Tab 1 / Schedule 2 / p. 3
Exhibit L / Tab 2 / Schedule 1 / pp. 19-20

Preamble:

Hydro One states that it proposes to charge Sub-transmission (ST) customers that rely on a Hydro One supplied transformer a fixed $200 "local transformation charge" and a one-time initial charge.

Table 11 at the second reference provides a derivation of the monthly local transformation charge. Hydro One has estimated costs for each year from 2023 to 2032 ranging from a low of $164,000 in 2025 to a high of $358,000 in 2024. OEB staff has totalled the ten amounts as adding up to $2,328,000.

Hydro One has calculated a monthly cost by dividing a total revenue requirement of $1.2 million for 2023-2032 across 10 years, 51 customers, and 12 months to arrive at a monthly cost of $200.

Hydro One states that it has ensured that the revenue associated with this charge is allocated back to the non-ST rate classes to ensure that the incremental costs of supplying local transformation to ST customers are not borne by non-ST customers.

Question(s):

a) Please confirm that the annual estimated costs relate specifically to the operating and financing costs of transformers owned and maintained by Hydro One and used by ST customers. If this cannot be confirmed, please explain.

b) Please provide the source of the $1.2 million revenue requirement used by Hydro One, and explain why this is not equal to the $2,328,000 calculated by OEB staff.

c) Please provide a cost allocation scenario where both the costs associated with the transformers used by the ST rate class, and the revenues associated with the ST transformers are allocated to the ST rate class.

d) Please provide bill impacts comparing a typical ST customer in 2023 where Hydro One owns the transformer to the corresponding bill in 2022 if the customer were i) a GSd customer and ii) a UGd customer.

L1-Staff-323

Exhibit L / Tab 1 / Schedule 3 / pp. 3

Preamble:

Hydro One states that it has used updated load profiles based on the latest hourly metered data.

Question(s):

a) Please state whether or not the updated load profiles are weather normalized? If so, please explain the methodology used to weather normalize the load profiles.

b) Please state how many years of load and weather data Hydro One used in producing updated load profiles.

c) Please state whether or not a regression methodology was used, and if so, please detail all of the dependent and independent variables used.

d) Please provide any excel worksheets used in the derivation of weather normal load profiles from weather actual, and the derivation of demand allocators.

L1-Staff-324
Exhibit L / Tab 1 / Schedule 3 / pp. 5-7

Preamble:

The billing and collecting weighting factors provided by Hydro One are derived using number of bills for billing and supervision related activities, bad debt for the collecting activity and a weighted average of the two for miscellaneous customer account expense.

Question(s):

a) Please state whether or not the amount of effort and expense involved in collecting directly is related to the amount owed? If not, what causes it?

b) Please discuss whether or not customer bills vary in complexity, and if so, the extent to which this influences customer billing costs?

c) Please state whether or not Hydro One performs periodic validation on customer accounts, and, if so, whether the effort to do so varies with the number of connections per bill – for example street lighting or USL which often have a single bill for multiple connections.

L1-Staff-325
Exhibit L / Tab 1 / Schedule 3 / Attachment 1 / I4 BO Assets
EB-2017-0049 / Draft Rate Order / Exhibit 3.1 / I4 BO Assets

Preamble:

OEB staff has prepared the table below which compares bulk delivery assets between the current application and the previous EB-2017-0049 application. The current application has more assets designated as being for bulk delivery than the previous application.

	Bulk Delivery EB-2017-0049	Bulk Delivery EB-2021-0110
1830 Poles, Towers and Fixtures	25%	42%
1835 – Overhead Conductors and Devices	34%	36%
1840 – Underground Conduit	16%	26%
1845 – Underground Conductors and Devices	16%	26%

Question(s):

a) Please explain the cause of the change in asset proportions designated Bulk, Primary, and Secondary.

b) Please provide the distinguishing characteristics of Bulk vs Primary assets?

L1-Staff-326

Exhibit L / Tab 1 / Schedule 3 / p. 7
Exhibit L / Tab 1 / Schedule 3 / Attachment 1 / I7.2 Meter Reading

Preamble:

Hydro One has used the number of manual meter reads in populating the cost allocation model at the second reference.

The meter reading weighting factors used are 1.0 for all types of urban reads, 2.0 for R2 residential, and 1.25 for all other types of meter reads.

Question(s):

a) Please state which USoA account is used to track the costs associated with automated reads?

b) Please state how much cost is associated with manual meter reading?

c) Please state how much cost is associated with automated meter reading?

d) Please provide the derivation of the meter reading weighting factors, and explain why there doesn't appear to be differential costs for different types of meters.

e) Please provide the proportion of GSe and GSd customers located in an area with density consistent with R1 and the proportion located in an area with density consistent with R2?

L1-Staff-327
Exhibit L / Tab 1 / Schedule 3 / pp. 10-13
Exhibit L / Tab 1 / Schedule 3 / Attachment 3

Preamble:

Hydro One has used allocation factors to allocate costs associated with the acquired utilities.

Question(s):

a) Please confirm that Hydro One has been tracking annual in-service additions for each of the acquired utilities, and that this is reflected in the second reference at sheet 1 in the columns labelled "I/S Adds".

b) If part a) cannot be confirmed, please explain the methodology for arriving at "I/S Adds"

c) Please explain how asset retirements are addressed through this methodology.

d) Please explain the source of the values at the second reference, sheet 6, rows 5 – NFA, 6 – NFA ECC, and 8 GFA.

e) If the answer to part d) indicates that these are allocated across the entire Hydro One asset mix, please comment on the suitability of Hydro One's ratio of NFA to GFA for the acquired utilities which may have a different ratio of NFA to GFA.

f) Please state whether or not Hydro One tracks amortization for the acquired utilities, and if not, whether it can produce a reasonable estimate?

L1-Staff-328
Exhibit D / Tab 5 / Schedule 1 / p. 37
Exhibit L / Tab 1 / Schedule 3 / Attachment 1 / Sheet I6.2 Customer Data
Exhibit L / Tab 2 / Schedule 1 / Attachment 1 / Sheet 2023

Preamble:

The load forecast and rate design worksheet at the first and third references indicate that there will be 5,495 Street Light customers and 19,409 Sentinel Light customers in 2023. The cost allocation model has been populated with 165,226 Street Light devices, 20,653 connections and 65,927 bills. Based on monthly billing, 65,927 bills are consistent with 5495 customers. With respect to sentinel lighting, 9,705 connections have been populated into the cost allocation model, and the 116,457 bills are consistent with 9,705 customers.

The proposed cost allocation model has been configured to apply fixed charge revenue on a per-customer basis for both rate classes.

Question(s):

a) Please explain the sentinel light customer count discrepancy between the load forecast and cost allocation model.

b) Please provide details on the number of customers, connections, and sentinel lighting devices forecasted for 2023.

c) Please confirm that sentinel lights and street lights are billed on a per-customer basis rather than the more common connections or devices.

L1-Staff-329
Exhibit L / Tab 2 / Schedule 1 / pp. 5-8

Preamble:

Hydro One is proposing to adjust revenue-to-cost ratios in every year of the Custom IR term.

Question(s):

a) Please provide a scenario with the rates and revenue-to-cost ratios that would result from adjusting revenue-to-cost ratios in 2023 as proposed, and then applying status quo adjustments only in 2024 to 2027.

L1-Staff-330
Exhibit L / Tab 2 / Schedule 1 / p. 8

Preamble:

Hydro One is proposing to increase the revenue-to-cost ratio for three acquired rate classes, and make offsetting reductions to the USL and Sentinel Light rate classes. The R1 rate class has a higher revenue-to-cost ratio than the Sentinel Light rate class, but Hydro One has chosen to adjust the Sentinel Light rate class due to the materiality of the change to this class. This also has the effect of mitigating the bill impacts to the acquired customers proposed to be merged into Hydro One's USL and Sentinel Light rate classes.

The R1 rate class is a rate protected rate class for most customers.

Question(s):

a) Please confirm that seasonal customers in the R1 rate class are still exposed to the R1 rates.

b) Please provide a scenario with the revenue to cost ratios, rates, and revenue responsibility re-allocations that would result from reducing the revenue-to-cost ratio for the USL rate class first, then the USL and R1 rate classes together.

L1-Staff-331
Exhibit L / Tab 2 / Schedule 1 / pp. 10-12

Preamble:

Hydro One is proposing to maintain the fixed to variable split for non-residential rate classes. The fixed charge is over the minimum system with PLCC adjustment (commonly referred to as the ceiling) from the cost allocation model in several rate classes.

Question(s):

a) Please provide a scenario with the variable charges that would result from leaving the fixed charges constant in the GSe, GSd, UGe, UGd, USL, DGen, ST, AUGe, AUGd, AGSe, and AGSd rate classes.

L1-Staff-332
Exhibit L / Tab 2 / Schedule 1 / pp. 24-28

Preamble:

The transmission charges are proposed to be allocated among non-ST rate classes in proportion to their coincident demand to the transmission system.

Question(s):

a) Please state whether or not it is possible to isolate or allocate transmission charges incurred by the former customers of the acquired utilities?

b) If a) is confirmed, please prepare a scenario where transmission charges are allocated to and recovered from these customers. In doing so, please assume that acquired street lighting, sentinel lighting, ST, and USL would pay the Hydro One legacy rate class RTSRs.

c) Please explain why it is appropriate that the coincident demand contribution of the acquired utilities rate classes be used, but not the actual incurred UTRs.

L1-Staff-333
Exhibit L / Tab 4 / Schedule 1 / pp. 2-3

Preamble:

At the above reference it is stated that customers were randomly selected to be invited to take part in an online survey regarding preferences for recovery of costs through specific service charges or base distribution rates. Residential and small business customers were engaged by way of an e-mail invitation.

Question(s):

a) Please provide the proportion of Hydro One's residential and small business customers that it has an e-mail address for, and permission to contact for the survey.

<u>L1-Staff-334</u>
Exhibit L / Tab 6 / Schedule 2 / pp. 1-8
Exhibit L / Tab 6 / Schedule 2 / Attachment 1
Exhibit L / Tab 1 / Schedule 2 / p. 5

Preamble:

Hydro One is proposing to maintain its current approved loss factors for 2023-2027. Attachment 1 referenced above indicates that actual losses have been stable from 2016-2020. Hydro One notes that its Seasonal rate class has a similar loss factor (10.4%) to R2 (10.5%). OEB staff notes that 63,743 (44.7%) of the Seasonal customers are moving into the R1 rate class, which has a TLF of 7.6%.

OEB staff further notes that the existing and proposed distribution loss factor for the former Norfolk Power customers is 5.0%, which is at the threshold for requiring a loss study, and for the former Haldimand Country Hydro customers is 6.0%, which exceeds the threshold.

Question(s):

a) Please provide total billed losses for the years 2016 – 2020, on a comparable basis to Appendix 2-R such that the billed and observed total loss factors can be compared.

b) Please provide the amount of energy used by the former seasonal rate class customers moving into each of UR, R1 and R2, and the impact this will have on aggregate billed losses

c) Please confirm that if the current approved loss factors remain accurate, the difference identified in part b) for 2023-2027 would ultimately be recovered all customers, not the impacted residential customers.

d) When does Hydro One intend to perform a loss study on the service areas of the former Norfolk Power or Haldimand County Hydro?

e) At what point does Hydro One intend to re-examine its losses and propose updated loss factors?