B4 - ENERGY PROBE INTERROGATORY - 050

Reference:
Exhibit B-4-1, GSP Section 4.6, Page 2

Preamble:

> *Hydro One has committed to transforming a portion of its fleet to plug-in electric or hybrid electric vehicles by 2030. Fleet Management Services has begun a gradual adoption of EVs, devoting 5% of its capital budget for EV purchases in 2021 and 50% by 2030 (including but not limited to the purchase of pickup trucks, vans and heavy power take-off units, provided their procurement is feasible based on market availability and conditions). This gradual approach will balance the need to transition to a green fleet, while also minimizing potential business and operational risks associated with rapid changes in EV technology and infrastructure.*

Interrogatory:
a) Please provide a projection of the number of electric vehicles added to the Fleet from 2020-2030. If possible, divide between Light Duty, Heavy Duty and Other. Please provide the percentage for each class/group and the Total percentage.

b) Please provide the estimated Costs for the Infrastructure and the Incremental Cost for Electric vs Conventional vehicles.

c) How much fuel cost will be saved in 2030?

d) Provide an estimate of the Cost/Benefit of partial electrification of the Fleet, with and without the GHG reduction based on projected 2030 Carbon costs.

Response:
Please refer to interrogatory B4-Staff-157 for a clarification to GSP Section 4.1, Page 16, lines 19 to 22.

a) The following table shows the addition of fully electric and hybrid vehicles for the current planning period of 2020 to 2027.

Vehicle Type	Fully Electric & Hybrid	% of EV
Heavy Duty Vehicles	62	4%
Light Duty Vehicles	906	33%
Total for On-Road	968	23%

b) The total cost of ownership of an electric vehicle versus a conventional fuel-based vehicle has no significant incremental cost. The number of electric vehicle chargers installed by Hydro One Facilities in any given year primarily depends on the adoption rate of electric vehicles within the Hydro One fleet, and within a certain geographic region or location. Based on the need for infrastructure over the past years, the expected annual estimated costs for electric vehicle charger installations is $0.7M across 10 sites for the current planning period of 2023-2027.

c) Please refer to interrogatory A-DRC-002 part d).

d) The projected 2027 carbon cost is estimated to be $125 per tonne. Using this assumption, the estimated savings based on projected carbon costs in 2027 will be $0.7M. The estimated incremental costs for partial electrification of the fleet in 2027 will be $5M without any estimated carbon savings factored in. Other operational savings have not been included in this calculation. Please note that over the planning period there may be new government regulations, incentives and policies changes that may incentivise manufactures to change the pricing model on electric vehicles and/or combustion engine vehicles, which would change the projection.

C - ENERGY PROBE INTERROGATORY - 051

Reference:

Exhibit C-2-2, Page 5

Preamble:

> *The main drivers of this overage compared to the approved category plan was increased complexity of New Load Connections, Service Upgrades, Cancellations and Metering (ISD SA-04 as part of EB-2017-0049) work as well as the influx in demand of Joint Use and Line Relocations Program (ISD SA-01 as part of EB-2017-0049) requests and Distribution Lines Trouble Call and Storm Damage Response Program (ISD SR-07 as part of EB-2017-0049) requirements.*

Interrogatory:

a) Does Hydro One require customers with complex new load connections to pay a contribution? If the answer is no, why not? If the answer is yes, what was the amount collected in 2019?

b) Does Hydro One require parties requesting a line relocation to share in the cost of the relocation? If the answer is no, why not. If the answer is yes, what was the amount collected in 2019 and what was the cost sharing formula?

Response:

a) The requirement for customer contribution towards connection costs is described in ISD D-SA-02, page 6, lines 10-18. This applies to all connecting load customers, regardless of complexity.

   Hydro One does not track capital contribution amounts based on complexity of the connection. In 2019 Hydro One collected $24.8M in capital contribution associated with new load connections (excluding acquired LDC areas).

b) As per lines 1-8 of ISD D-SA-01 Page 4 of 8, Hydro One does require cost sharing to be completed when a relocation is requested, and such arrangements are based on the principle that Hydro One would recover applicable costs from the requesting party. For the amount collected in 2019, refer to D-Staff-185 part (d).

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C - ENERGY PROBE INTERROGATORY - 052

Reference:

Exhibit C2-2-2, Page 7

Preamble:

> *System Access ISAs are forecasted to average $225.1M annually from 2023 to 2027, a 19% increase compared to years 2018 through 2022 which is primarily due to increased investment within Metering Sustainment (DSP Section 3.11, D-SA-04) and alignment of anticipated demand within New Load Connections, Upgrades, Cancellations (DSP Section 3.11, D-SA-02) based on historical trends.*

Interrogatory:

Please explain how the 19% increase figure was derived showing all calculations.

Response:

Please refer to System Access expenditures in Table 1 on page 2 of Exhibit C, Tab 2, Schedule 2.

	Average		**Increase**	
OEB Category	**2018-2022 ($M)**	**2023-2027 ($M)**	**($M)**	**%**
System Access	$ 189.6	$ 225.1	$ 35.5	19%

2018-2022 Average (196.9, 189.9, 197.5, 182.7, 181.2) = 189.6

2023-2027 Average (239.6, 241.8, 227.5, 212.5, 204.1) = 225.1

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D - ENERGY PROBE INTERROGATORY - 053

Reference:

Exhibit D2-2-3, Page 3, Table 1
Exhibit D2-2-3, Page 5, Table 3

Interrogatory:

a) Please explain the differences between the General Counsel services provided by Hydro One Networks Inc. to Hydro One Limited and the Chief Legal Officer services provided by Hydro One Limited to Hydro One Networks Inc.

b) Does the General Counsel of Hydro One Networks Inc. report to the Chief Legal Officer of Hydro One Limited? Please explain your answer.

Response:

a) The differences between the General Counsel services provided by Hydro One Networks to Hydro One Ltd., as compared with the Chief Legal Officer services provided by Hydro One Ltd. to Hydro One Networks Inc., are explained further within Exhibit E-04-02, pages 24, 25 and 8, respectively.

b) Yes, the General Counsel of Hydro One Networks reports to the Chief Legal Officer of Hydro One Ltd.

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D - ENERGY PROBE INTERROGATORY - 054

Reference:

Exhibit D-2-3, Page 5, Table 2

Interrogatory:

a) Please provide more detail about the "grant by Hydro One Networks Inc. to Hydro One Telecom Inc. on an indefeasible right of use basis, certain dark optical fibre."

b) Does the use of the word grant mean that the use of the fibre is free of charge?

c) Please explain the term "indefeasible right of use basis".

Response:

a) Hydro One Networks Inc. (HONI) owns and operates a telecommunications network which includes optical fibre facilities (collectively, the "Network"), which Network is utilized among other things for the protection and control of the electricity transmission and distribution system. Pursuant to the Dark Fibre IRU Agreement, HONI agreed to grant to Hydro One Telecom Inc., and Hydro One Telecom Inc. agreed to acquire from HONI on an IRU basis, that portion of the Network which constitutes dark optical fibre that is excess to HONI's teleprotection, control and communication needs. Pursuant to the agreement and among other terms and conditions,

   i. Hydro One Telecom Inc. is entitled to connect its equipment to the dark fibre and to light the dark fibre for its purposes or to provide telecommunications services to third parties;

   ii. ownership of the dark fibre remains at all times with HONI;

   iii. HONI has the right to terminate the IRU interest in and to any or all dark fibre if the dark fibre is needed by HONI for the transmission and/or distribution of electricity.

b) No. The term "grant" is just a conveyance term that is used in the context of an indefeasible right of use. The fibre is not being granted free of charge. Fees are payable for Hydro One Telecom Inc.'s use of the surplus dark fibre.

c) "Indefeasible right of use" is a right to use an asset such as dark fibre typically for a long period of time.

Witness: JODOIN Joel

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D - ENERGY PROBE INTERROGATORY - 055

Reference:

Exhibit D2-2-3, Page 7

Interrogatory:

a) How often are the Affiliate SLA's audited?

b) Please file a copy of the most recent audit of Affiliate SLA's.

Response:

a) The Affiliate SLAs have not been audited by Hydro One's external or internal auditor.

b) Not applicable.

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D - ENERGY PROBE INTERROGATORY - 056

Reference:

Exhibit D-3-3, Page 1

Interrogatory:

Please reconcile the Distribution Load Forecast with Distribution capital projects justified by load growth such as ISD D-SA-02, New Load Connections, and ISD D-SS-01, System Upgrades Driven by Load Growth. Specifically, how much load growth is provided by each capital project that is justified by load growth.

Response:

The load growth associated with capital projects is implicitly included in Hydro One's load forecast because the equipment, station and local area forecasts provided to Hydro One's planning department for the purpose of identifying capital project needs are based on the same forward-looking economic trends and consensus forecasts of economic/demographic factors which are used to develop the overall load forecast for the purposes of this application.

Additionally, in some special cases, local load growth may be greater than that suggested by economic/demographic factors due to specific local circumstances, such as government directives related to certain developments. In such cases, the load forecast is increased, using a manual adjustment, to include such additional load. In this Application, load growth related to capital projects in Leamington and surrounding areas was added to the load forecast implied by the forecasting models as detailed in Hydro One's response to VECC-43.

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D - ENERGY PROBE INTERROGATORY - 057

Reference:

Exhibit D-4-1, Page 6

Interrogatory:

a) Does the forecast of embedded generation include both injecting and non-injecting load displacement generation?

b) Is a forecast of large-scale energy storage included in the embedded generation forecast or anywhere else in the evidence? If the answer is no, please explain why not. If the answer is yes, please provide the forecast.

Response:

a) The forecast of embedded generation only includes injecting load displacement generation, not non-injecting load displacement generation.

b) The load impact of large-scale energy storage is included in the load forecast. Regarding its inclusion in the embedded generation forecast, it is included as long as it meets the following definition in the Distribution System Code: "embedded retail generator" means a customer that: (a) is not a wholesale market participant or a net metered generator (b) owns or operates an embedded generation facility, other than an emergency backup generation facility; and (c) sells output from the embedded generation facility to the Ontario Power Authority under contract or to a distributor".

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D - ENERGY PROBE INTERROGATORY - 058

Reference:

Exhibit D-5-1, Page 28, Appendix C

Interrogatory:

Does the end use model include EV charging, heat pumps, and residential storage batteries? If the answer is yes, please explain how. If the answer is no, please explain why not.

Response:

Yes. For residential customers, heat pumps would be reflected in the heating and cooling categories and EV charging and residential storage are captured implicitly in the base load category of the end-use model.

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E - ENERGY PROBE INTERROGATORY - 059

Reference:

Exhibit E-2-2, Page 2, Table 1
Exhibit E-3-2, Table 1

Interrogatory:

a) Please provide two tables in the same format as the referenced Exhibits, one for Transmission one for Distribution, with a calculated summary line showing for each year the Total for each category (e,g. Sustainment) of OM&A, using the OEB inflation factors.

b) For each category for Transmission and Distribution indicate if the 2023 Budget is at, below, or above, the 2020 actual amount inflated.

c) Please provide the answer in Excel format.

d) Discuss the drivers that resulted in material above inflation-adjusted amounts in the 2023 Budget.

Response:

a) Please see Excel Attachment 'I-08-E-Energy Probe-059-01' of this interrogatory response.

b) Please see Exhibit E-02-02 pages 2, 6, 48 and 67 for Transmission Sustainment OM&A and Exhibit E-03-02 pages 3-4, 6-51 for Distribution Sustainment OM&A.

c) Please refer to a)

d) No 2023 forecast values are materially above the 2018 amounts (inflated to 2023 dollars), Please refer to b).

Witness: JABLONSKY Donna, FALTAOUS Peter

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Distribution Sustainment OM&A E-03-02 Table 1	**Historical**							**Bridge Year**		**Test Year**	
	2018	**2019[1]**		**2020**		**2021**		**2022**		**2023**	
	Actual	**Actual**	**Inflated**	**Actual**	**Inflated**	**Forecast**	**Inflated**	**Forecast**	**Inflated**	**Forecast**	**Inflated**
Inflation, %			1.50%		2.00%		2.20%		2.20%		2.20%
Stations	21.8	20.1	22.1	22.2	22.6	21.2	23.1	20.5	23.6	20.2	24.1
Lines	133.3	149.0	135.3	149.9	138.0	121.2	141.0	125.3	144.1	132.0	147.3
Meters, Telecom & Control	17.7	15.5	18.0	14.9	18.3	17.5	18.8	17.5	19.2	19.8	19.6
Vegetation Management	139.5	162.4	141.6	137.9	144.4	139.6	147.6	140.3	150.8	139.4	154.2
Total Sustainment OM&A	**312.3**	**347.1**	**317.0**	**324.9**	**323.3**	**299.6**	**330.4**	**303.6**	**337.7**	**311.4**	**345.1**
Variance 2023 Forecast to Actual, $	**-0.9**			**-13.5**		**11.8**		**7.7**			
Variance 2023 Forecast to Actual Average 2018-2021, $	**-9.6**										

1: Hydro One Distribution's last rebasing year was 2018 and as such, forms the basis for the variance explanations and calculations.

Transmission Sustainment OM&A E-02-02 Table 1	**Historical**					**Bridge Year**		**Test Year**	
	2018	**2019**	**2020[2]**	**2021**		**2022**		**2023**	
	Actual	**Actual**	**Actual**	**Forecast**	**Inflated**	**Forecast**	**Inflated**	**Forecast**	**Inflated**
Inflation, %					2.00%		2.00%		2.00%
Stations	161.4	144.1	141.3	148.6	144.1	151.7	147.0	159.5	149.9
Lines	63.8	55.8	54.2	52	55.3	51.9	56.4	55.2	57.5
Engineering & Environmental Support	4.1	7.9	5.4	4.7	5.5	4.7	5.6	5	5.7
Total Sustainment	**229.4**	**207.8**	**200.9**	**205.2**	**204.9**	**208.3**	**209.0**	**219.6**	**213.2**
Variance 2023 Forecast to Actual, $			**18.7**	**14.4**		**11.3**			
Variance 2023 Forecast to Actual Average 2018-2021, $	**8.8**								

2: Hydro One Transmission's last rebasing year was 2020 and as such, forms the basis for the variance explanations and calculations.

E - ENERGY PROBE INTERROGATORY - 060

Reference:

Exhibit E-3-2, Page 24, Table 8

Preamble:

> *"Table 88(sic) provides a summary of various expenditures and programs within Hydro One's Distribution Sustainment Lines OM&A expenditures."*

Interrogatory:

a) Please provide the total km of overhead and underground lines in 2020.

b) Indicate if this includes or excludes transformers maintenance for each. If transformer maintenance is under a different category please provide the OM&A related to UG and Overhead lines.

c) Please provide an estimate of the 2023 Sustainment costs for each of underground and overhead lines.

d) Specifically provide costs related to trouble calls in 2020 for UG and Overhead lines.

e) Please provide the unit maintenance costs for each of UG and Overhead lines.

f) In the DSP is Hydro One planning to increase (or decrease) the km of UG and overhead lines in 2023-2027?

g) Discuss directionally, how this will impact future OM&A?

Response:

a)

	Circuit Length (km)
Overhead	113,478
Underground including Submarine	10,011

b) Hydro One does not perform preventive maintenance on overhead or underground distribution line transformers. OM&A expenditures for line transformers are limited to minor repairs, inspections and PCB related costs.

c) Hydro One does not differentiate OM&A for underground and overhead line costs across all maintenance activities.

d) OM&A Trouble Call costs in 2020 were $76.4M. Hydro One does not differentiate OM&A for underground and overhead line costs.

e) See part c.

f) Hydro One expects an increase in the number of overhead and underground kms of line to meet system load growth and connect new customers.

g) In general, as Hydro One's system expands, OM&A costs to maintain inspection cycles and forestry clearing cycles will increase. Over the course of the plan, this change is not anticipated to be material on a system level. Please see DSP Section 3.8.3.2 for capital investments effect on Line Maintenance costs.

E - ENERGY PROBE INTERROGATORY - 061

Reference:

Exhibit E-3-2, Page 44

Preamble:

> *The 2023 forecast expenditures for Defect Correction (OCP) are $122.2M which is $18.3M or 13% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($140.5M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast is $10.7M lower.*

Interrogatory:

a) Please provide a copy of the 2017 ClearPath report, "Hydro One – Forestry Survey Assessment".

b) Please provide a Table with the 2014-2020 data for tree contacts in total and as a % of total outages.

c) Compare the data before and after the OCP.

d) Discuss if the OCP has/has not resulted in less tree contacts and has improved system reliability.

e) What does the OCP correspond to in annual tree-trimming cycle?

Response:

a) The 2017 ClearPath report, "Hydro One – Forestry Survey Assessment", can be found in the previous rate application, see reference EB-2017-0049 Exhibit Q Tab 1 Schedule 1.

b) The following are the recorded tree caused outages and tree caused outages as a percentage of the total system outages excluding the LOS and FM events:

	2014	2015	2016	2017	2018	2019	2020
TCO	6533	6942	7439	7800	7044	7561	8670
%	22%	22%	24%	26%	23%	23%	25%

c) See part B. OCP began in 2018.

d) OCP has had a positive impact on the reliability of Hydro One's system. An analysis of Tree Caused Outages (TCOs) comparing non-OCP feeders with feeders on which OCP work has been executed demonstrated an improvement of between 23% and 41%. See Exhibit B-3-1, Section 3.3, Attachment 3, ClearPath OCP First Cycle Performance Assessment, Section 3.2 of the report.

e) Hydro One is expected to have an average cycle length of 4.1 years for its first cycle.

E - ENERGY PROBE INTERROGATORY - 062

Reference:

Exhibit E-3-2, Page 48, Table 21

Preamble:

"Between 2018-2020, Hydro One has seen a nearly 50% reduction in the vegetation management cost per km."

Interrogatory:

a) Please support the above statement by providing numerical evidence on which it is based.

b) Has Hydro One compared its unit cost per km to other similar utilities such as Hydro Quebec similar to the 2016 Study? If so, please provide the comparison.

c) Show how the unit costs vary between the four vegetation areas and discuss if acquisition of southern Ontario Utilities will increase/decrease future costs.

Response:

a) The statement referenced above is incorrect. The following is the corrected statement:

> "Hydro One has seen over a 50% reduction in the vegetation management cost per km when comparing the 2018-2020 average to the 2016 cost per km."

Please see DSP Section 3.3, Attachment 2 Figure 13 for the numerical evidence.

b) Hydro One engaged CNUC to perform a benchmarking study of Hydro One's vegetation management program against its peers. Table 2, in the CNUC benchmarking study (B-03-01_3.3 Attachment 2) lists Hydro Quebec as one of the peers in the Peer 2019 group. The unit cost comparisons in terms of cost per managed distribution pole km can be reviewed in figure 12 of the CNUC report.

	Regional Unit costs		
Regions	**2018**	**2019**	**2020**
Southern Region	$ 5,272	$ 6,567	$ 5,186
Central Region	$ 6,765	$ 7,026	$ 8,636
Eastern Region	$ 4,141	$ 5,560	$ 5,789
Northern Region	$ 3,421	$ 3,240	$ 3,835

Witness: FALTAOUS Peter, FRENCH Teri

c) Southern Region unit costs are inline with the provincial average, however the impact of adding southern utilities would have to be assessed on a case by case basis as the specific vegetation management needs of the acquired utility would need to be examined.

E - ENERGY PROBE INTERROGATORY - 063

Reference:

Exhibit E-4-1, Page 1
Exhibit E-4-1, Attachment 1, Pages 1 and 6

Preamble:

> *The provision of these [CCF&S] services is centralized to enable them to be delivered to affiliates and business segments efficiently. Hydro One allocates Common OM&A Costs to affiliates and business segments through a cost allocation methodology which is described in Exhibit E-04-08.*

Interrogatory:

a) Please provide a comparison table showing Shared Services by category for 2018 (Rebasing) and 2023 Test year. Indicate the $ change and % change in each category over the 5 years.

b) Provide explanations for any increases.

Response:

a)

Service Offered	2018 ($k)	2023 ($k)	$ Change ($k)	% Change (CAGR)
Supply Chain Services	276	276	-	-
Lease of IT Assets	768	2,077	1,309	22.0%
Utility Operation Services	1,546	1,474	(72)	-0.9%
Network Operations	1,177	-	(1,177)	-100%
Managing Director	120	233	113	14.2%
Meter and Lines and Training Work	404	363	(41)	-2.1%
Business and Power System Operations	19,585	22,033	2,448	2.4%

b) Explanations for the increases:

- Lease of IT Assets: The increase in 2023 is to support additional allocations to other segments. This is the result of the detailed review of the shared assets methodology as outlined in Exhibits C-03-01 and E-04-08, Attachment 1.
- Managing Director: Increases are primarily due to the inclusion of the Niagara Reinforcement Limited Partnership, as well as inflationary increases.

- Business and Power System Operations: Increases are primarily due to annual contractual changes in the Telecom Services Agreement with Hydro One Telecom.

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E - ENERGY PROBE INTERROGATORY - 064

Reference:

Exhibit E-4-2, Appendix 2 JA, Appendix 2 JB

Preamble:

Compared to 2020 OEB-approved expenses, Hydro One’s 2020 actual OM&A expenses were $13.5M or 7.6% higher, largely due to unplanned expenses related to COVID-19 of approximately $18M, as further described in Exhibit E Tab4 Schedule 2.

Interrogatory:

a) Please show line by line in the Appendices where the increase was due to Covid-19 Expenses and the Totals

b) How much is HONI proposing to recover from ratepayers? Provide Totals and amounts for Tx and Dx.

Response:

a) Within Appendix 2-JA, incremental COVID-19 costs for 2020 are shown within the Miscellaneous (Other OM&A, Recovery) line. Within Appendix 2-JB, 2-JC, they are included within “Other Recovery”.

b) Please refer to Interrogatory Response **G-Staff-309** part c).

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E - ENERGY PROBE INTERROGATORY - 065

Reference:

Exhibit E-4-4, Page 2, Table 1

Interrogatory:

a) Please provide the Total annual percentage increases.

b) Please provide a line showing the Total Cost each year escalated by inflation for each year from 2018 (rebasing distribution).

c) Are the allocations to Transmission and Distribution consistent with the B&V recommendations? Please compare the allocation percentages.

Response:

a) Please see the revision to the referenced Table 1 below under part b) with the added row for “Year over Year Change”.

b) Please see the revision to the referenced Table 1 below with the added row for “2018 Costs with Inflation”. A 2% annual inflation was assumed for Transmission and Other allocated costs, and a 2.2% annual inflation was assumed for Distribution allocated costs.

Table 1 - Summary of Total Information Solutions OM&A ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
IT Sustainment	73.9	92.1	85.7	86.8	86.2	88.9
Business Telecom	18.2	18.5	18.5	17.8	17.8	18.0
IT Development	15.2	8.8	9.6	16.4	12.7	14.4
Security	3.9	4.8	4.6	6.8	7.5	8.5
IT Management and Project Control	14.3	11.9	12.8	9.6	10.9	12.0
Total	**125.5**	**136.2**	**131.2**	**137.4**	**134.9**	**141.8**
Year over Year Change		**8.5%**	**-3.7%**	**4.7%**	**-1.8%**	**5.1%**
Allocated to Transmission	50.4	53.7	51.2	51.4	51.2	53.7
Allocated to Distribution	73.8	81.1	78.4	83.8	81.5	85.9
Allocated to Other[1]	1.4	1.4	1.6	2.2	2.2	2.3
2018 Actuals with Inflation	**125.5**	**128.3**	**131.0**	**133.7**	**136.6**	**139.5**

c) As described in exhibit E-04-08, the Black & Veatch allocation methodology applies to common corporate costs. The allocation recommendations contained in Attachment 1 to that exhibit impact only common corporate costs, which make up a portion of Information Solutions OM&A costs within exhibit E-04-04 Table 1, specifically captured under the "IT Management and Project Control" item. The common corporate costs and their allocations are consistent with the Black & Veatch allocation methodology.

Table 2 – Common Corporate Costs Associated with Information Solutions

Common Corporate Costs Associated with Information Solutions	2018	2019	2020	2021	2022	2023
Allocated to Transmission	55%	55%	54%	46%	46%	46%
Allocated to Distribution	45%	45%	46%	54%	54%	54%

[1] As discussed in Exhibit E-04-08, Section 3.0, the amounts allocated to "Other" in Table 1 above reflect costs allocated to Hydro One Network's affiliates.

E - ENERGY PROBE INTERROGATORY - 066

Reference:

Exhibit E-4-8, Attachment 1, Table 10

Preamble:

> *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 60.6% to Dx as shown on Table 10; compared to the 38.3% to Tx and 61.7% to Dx provided in the summary Table within Black & Veatch's Transmission report filed in EB-2019-082.*

Interrogatory:

a) Please confirm 1.04 % is allocated to Other%. What was the Other % in 2018?

b) Please confirm the updated Shared Asset Allocation has been applied to the 2022 Test year OM&A.

c) Please provide a comparison Table based on Table 10 that shows the 2018 B&V Report Cost Allocations to Tx%, Dx% and Other %.

d) Please discuss any material changes between 2018 and 2023 and the reasons for each.

Response:

a) Response from Black & Veatch:
Not confirmed. As shown in the last column of Table 10 on p. 43 of the Black & Veatch report, the allocations to Hydro One's Other affiliated businesses represent a total of 1.01% of all Hydro One shared assets. In the 2018 report that was filed by Hydro One in EB-2019-0082, the Other percentage was 1.17% as shown in Table 4 of that report.

b) Response from Hydro One:
Not confirmed. The Shared Asset Allocation will be applied to 2023.

c) Response from Black & Veatch:
Please see Table 1 below which is developed from Table 10 in the current Black & Veatch report and Table 3 and Table 4 within Black & Veatch's Transmission report filed in EB-2019-0082.

1 **Table 1 - Comparison of 2018 B&V Report and Current Black & Veatch Report**[1]

	Tx		Dx		Other [1]	
Category	**2018**	**Current**	**2018**	**Current**	**2018**	**Current**
Major Assets	41.5%	41.59%	58.5%	56.73%	1.40%	1.68%
Minor Assets	34.2%	33.86%	65.8%	66.07%	0.89%	0.07%
Total-All Shared Assets	38.3%	38.39%	61.7%	60.60%	1.17%	1.01%

Note 1: *It appears the Black & Veatch report in 2018 contained an error in Table 4 – where the Minor Fixed Assets are listed as 1.17%; however, this is the total of all shared assets. The correct number is 0.89% for Minor Fixed Assets.*

2 d) Response from Black & Veatch:
3 Please see the Interrogatory Response **E-Staff-247**.

[1] The 2018 Black & Veatch report provided summary details for assets that were allocated to Dx and Tx totaling 100% and then provided separately the allocation of assets to Other affiliates. As such, the totals for the 2018 report sum to above 100%. In contrast, the current Black & Veatch report provides Tx, Dx, and Other in the same table so those three components sum to 100%.

E - ENERGY PROBE INTERROGATORY - 067

Reference:

Exhibit E-6-1, Attachment 1

Preamble:

> *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"). 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 (on Average) is positioned 4% above this defined competitive range; down from 7% above the competitive range in the 2017 Study.*

Interrogatory:

a) Please indicate the Total number of Incumbents in Hydro One, including positions not reviewed for each of the 3 main categories:
   i. Non-Represented
   ii. Energy Professionals
   iii. Trades and Technical

b) Please calculate the 2020 Total Compensation for each group (incumbents x average TC). Reconcile to Exhibit E Tab 6 Schedule 1 Attachment 2A Appendix 2K and E Tab 6 Schedule 1 Attachment 2B Table 1.

c) Please calculate the above median total compensation for each group and the Hydro One Total Compensation above median.

d) For the Professional Group, how does Hydro One Compare to OPG, IESO? Please discuss.

Response:

a) Hydro One has assumed the data requested is for 2020, the study year

Non-Represented	647
Energy Professionals	1449
Trades and Technical	3603

b) Response from Mercer

We understand this request to involve combining data from Hydro One's Total Compensation Tables and findings from the Mercer Study. There are significant and meaningful differences in methodological approach between these two sources which would make the requested analysis inconclusive and inaccurate. For example, the Hydro One Total Compensation Tables include actual overtime costs which are not included in the Mercer Study, as well as payroll burden costs such as Cananda Pension Plan and Employment Insurance contributions.

c) Response from Mercer

Please refer to the response provided in E-SEC-212.

d) Response from Mercer

Due to confidentiality standards, Mercer cannot comment on the competitiveness of individual organizations.

E - ENERGY PROBE INTERROGATORY - 068

Reference:

Exhibit E-6-1, Attachment 2A
Exhibit E-6-1, Attachment 2B

Interrogatory:

a) Please provide Exhibit E Tab 6 Schedule 1 Attachment 2A Appendix 2K in Excel format

b) Please provide Exhibit E Tab 6 Schedule 1 Attachment 2B Table 1 in Excel format

c) Please provide a Summary of Executive Compensation - Positions (FTE), Salaries, Benefits, STI and LTI.

d) Has Executive Compensation been Benchmarked? If so please provide the report, If not why was this not done?

Response:

a) Exhibit E-06-01 Attachment 2A (Appendix 2K) was provided in excel format in Hydro One's application filed on August 5, 2021.

b) Please see Excel Attachment 1 (I-08-E-Energy Probe-068-01) to this response.

c) Information regarding compensation for executive positions is summarized in Section 3.4.1 (Executive Compensation) of Exhibit E-06-01 (page 29 – 30). Further information regarding Hydro One's executive compensation is publicly disclosed in the Compensation Discussion & Analysis section of the 2021 Management Information Circular (a requirement for all publicly traded organizations). As noted in Section 3.4.1, Hydro One is not seeking recovery for the compensation costs of the noted executive positions. Therefore, further details on executive compensation are not relevant to the proceeding as they do not pertain to the matters at issue on the application.

d) As noted in part c) above, since Hydro One is not seeking recovery of compensation costs related to executive positions, any additional executive benchmarking information would not be relevant to the proceeding as it would not pertain to matters at issue on the application.

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E - ENERGY PROBE INTERROGATORY - 069

Reference:

Exhibit E-6-1, Attachment 3, Page 1

Interrogatory:

a) Please provide the Last 5 year's Values for each metric.

b) Please indicate how the Threshold, Target and Exceed levels were set relative to historic values

c) Are these fixed at 2021 Levels or change over the IRM period? If the latter, please provide projected values.

d) Please Indicate how the Scorecard is related to total compensation, STI and LTI or Non-Represented, Professionals and (if applicable) Trades and Technical

e) Is there a different scorecard for Executive positions? If so, please provide this.

f) For Executive positions, do incumbents have a different STI? Please discuss provide details.

Response:

a) Please see Interrogatory Response A-SEC-004 for the historical Team Scorecards.

b) The threshold, target, and exceeds are set based on the methodology specific to each measure and are approved by the Board of Directors.

c) The 2021 levels have been approved by the Board of Directors. The Team Scorecard is set annually for a given year and approved by the Board of Directors. Future scorecards will be informed by the outcome of this application, as appropriate for each measure.

d) The Team Scorecard represents the performance measures for STIP. MGT/ Non-Represented compensation is directly impacted by STIP. Professional, and Trades and Technical employees' efforts impact the outcomes of the Team Scorecard, however compensation for these representations is not directly impacted by the Team Scorecard.

e) No, Executive STIP compensation is based on the same scorecard.

f) Please see Interrogatory Response E-Energy Probe-068 part c).

Witness: LILA Sabrin

E - ENERGY PROBE INTERROGATORY - 070

Reference:

Exhibit E-8-1, Page 3, Attachment 1, Appendix A-1, Table BU 210
EB-2019-0082, Exhibit F-6-1, Attachment 1

Preamble:

Energy Probe wishes to understand Hydro One's progress regarding the Pension Contribution Ratio (PCR) for the 3 groups of Hydro One employees.

Interrogatory:

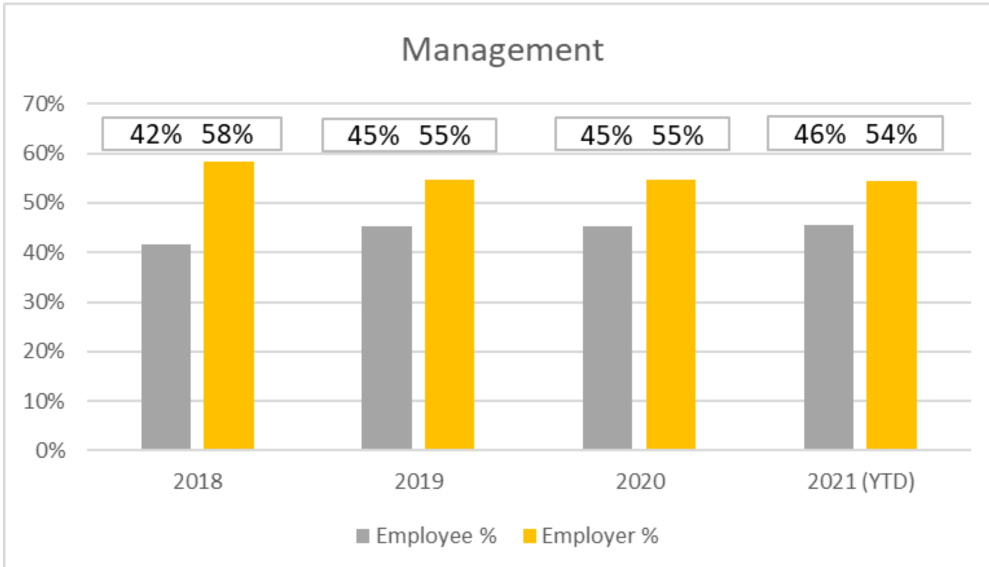
a) Please provide Charts that show for the DB Pension Plan the Employer and Employee Contributions for Non-Represented, Professionals and Trades Technical employees for 2015-2021 period.

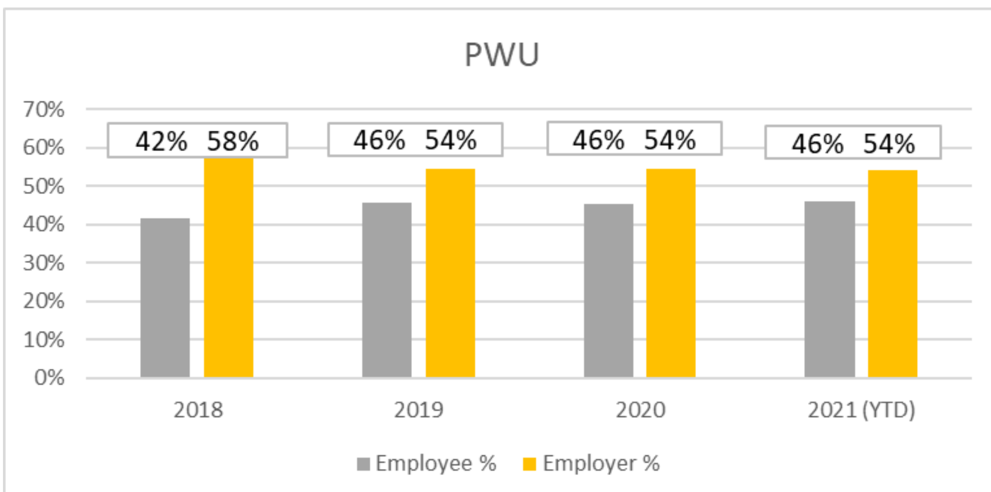
b) Discuss the trends relative to target 50:50 contributions (Leach Report).

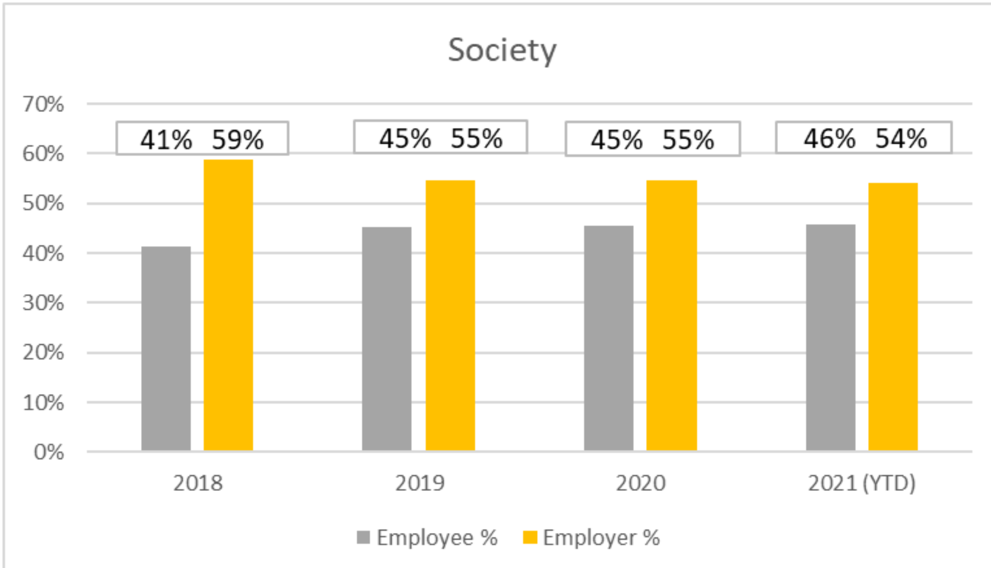
c) What are the forecasts for the 2022 Test Year?

Response:

a) The following charts summarize the Defined Benefit Pension Plan Employer and Employee contributions for Management, Society of Energy Professional and Power Workers Union plans from 2018 to 2021. The costs reflected from 2019 – 2021 are based on the valuation filed on September 30, 2019 (Exhibit E-07-01 Attachment 1). Information regarding 2015 to 2017 is available in the EB-2019-008 proceeding.


Management
70%
60%
50%
40%
30%
20%
10%
0%
42% 58%
45% 55%
45% 55%
46% 54%
2018
2019
2020
2021 (YTD)
Employee %
Employer %


PWU
70%
60%
50%
40%
30%
20%
10%
0%
42% 58%
46% 54%
46% 54%
46% 54%
2018
2019
2020
2021 (YTD)
Employee %
Employer %



b) The Leech Report referenced was conducted in 2014 by Jim Leech, Special Advisor to the Minister of Finance to provide advice to the government on potential changes to the energy sector pension plans that would result in pension plans that are "affordable for employers and ratepayers, and sustainable for members who rely on them for their retirements".[1] The Leech Report was issued at the time that Hydro one was under sole ownership of the province of Ontario (prior to initial public offering).

Hydro One's pension plan is a Single-Employer Pension Plan (SEPP), which means it is composed of members that work for the same employer. SEPPs can be contributory (as is the case for Hydro One) or non-contributory. Moreover, the employer in this type of plan is the sole sponsor. As the sole sponsor, Hydro One is responsible for ensuring the plan is fully funded and bears all the funding risk including any funding shortfalls, as required by the Ontario Pension Benefits Act (PBA).

Equal cost-sharing or 50-50 cost-sharing refers to equal cost-sharing of pension plan costs. When considering a target of 50-50 cost-sharing it is important to understand i) how pension plan costs are established, and ii) employee contributions:

i. Pension costs are determined based on the results of funding valuations performed periodically on the Plan in accordance with the PBA. The employer is responsible for

[1] Jim Leech, Special Advisor, *Report on the Sustainability of Electricity Sector Pension Plans to the Minister of Finance.* 18 March 2014 at page 1.

paying the pension costs defined in the valuation results, net of any employee contributions. Pension costs (as a percent of payroll) are "locked in" until the next valuation is prepared.

The total cost contributions are determined each time an actuarial valuation is filed. The total cost contribution requirement is dependent on many assumptions, most notably the discount rate used in the valuation. The discount rate assumption is set based on the actuary's expectations of future returns, which can fluctuate. The employee's portion of the total cost contributions is fixed as a percentage of their earnings and is-not impacted by the valuation or any of the assumptions. Therefore, the employer required contribution amount reflects the full impact of any change to the valuation assumptions, notably the discount rate.

Hydro One's most recent valuation had an effective date of December 31, 2018, which established Hydro One's pension costs from 2019 to 2021. A forecast, as at February, 2021, was prepared by the plan actuary (which assumes that a new valuation will have an effective date of December 31, 2021) and has been used to establish the pension costs from 2022 to 2027.

ii. Hydro One understands the concern regarding equal cost sharing and has made progress over the past decade by increasing employee contributions, plan design changes aimed at reducing employee benefits (which reduce employer costs thereby making the plan more sustainable) and other cost management efforts over the past decade.

Employee contributions are established through the collective bargaining process. Over the past decade and specifically, since 2014, Hydro One has prioritized managing pension costs through its collective bargaining processes with a focus on increasing employee contributions, changes to the pension plan formula and managing base wage increases (which have a direct impact, based on the plan formula on pension costs). Further detail is available in Section 4.1 Addressing the Hydro One Pension Plan (HOPP) of Exhibit E-06-01 (page 31-36).

Specifically, since 2014 (the year of the Leech Report), through collective bargaining, employee contribution rates have increased by nearly 3% of base pay for both SUP and PWU as indicated in Exhibit E-06-01 at page 35 (Table 7). These increases in contribution rates were negotiated over successive rounds of collective bargaining by offering equity compensation in the form of share grants. Employee contributions overall have increased by 60% from 2014 to 2021.

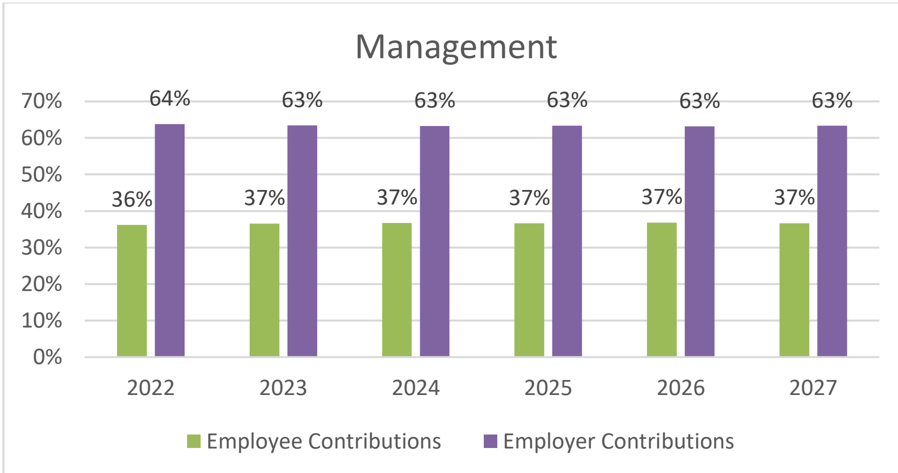
The introduction of equity compensation in collective bargaining has provided Hydro One a means to negotiate increases to compensation that do not simultaneously increase its longer term pension obligations (as they do not impact base wages). Employees' contribution levels currently represent, on average, over 10% of their pay, which is a reasonable and sustainable level that will continue to be monitored over time. The Leech report concludes there should be a ceiling on contributions. "A suggested appropriate range would be 9 per cent to 12 per cent."[2] Hydro One is within this recommended range.

Based on the 2019 valuation, Hydro One is near 50:50 cost sharing levels (see charts from part a) above. Based on the independent actuarial forecast referred to above, overall pension costs are projected to increase based on the most recent forecast. The forecast of the upcoming valuation suggests that Hydro One's pension costs will need to increase in response to various factors including the discount rate mentioned above. Based on this forecast, the ratio is expected to move to 63:37 beginning in 2022. Employee contribution levels will continue to represent a significant portion of the overall contributions to the fund in 2022 and beyond, and an appropriate percentage of their pay. The forecast also includes years where negotiated plan formula changes will take effect (i.e. 2025) – there is a notable decrease in Hydro One's required contributions to the fund in 2025 to reflect the earning of a less valuable benefit by employees in that year and beyond.

Hydro One has made important strides towards increasing employee contributions and managing pension costs through the collective bargaining process and intends to continue to do so.

c) The following charts summarize the Defined Benefit Plan Employer and Employee contributions for Management, Society of Energy Professionals, and Power Workers Union plans from 2022 to 2027. The costs reflected from 2022 onwards are taken from the previous forecast created in February 2021. The next formal valuation must be filed by September 30, 2022 (Exhibit E-07-01, section 2.2, page 3).

[2] *Ibid* at pg. 25.


Management
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10%
0%
36%
64%
37%
63%
37%
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63%
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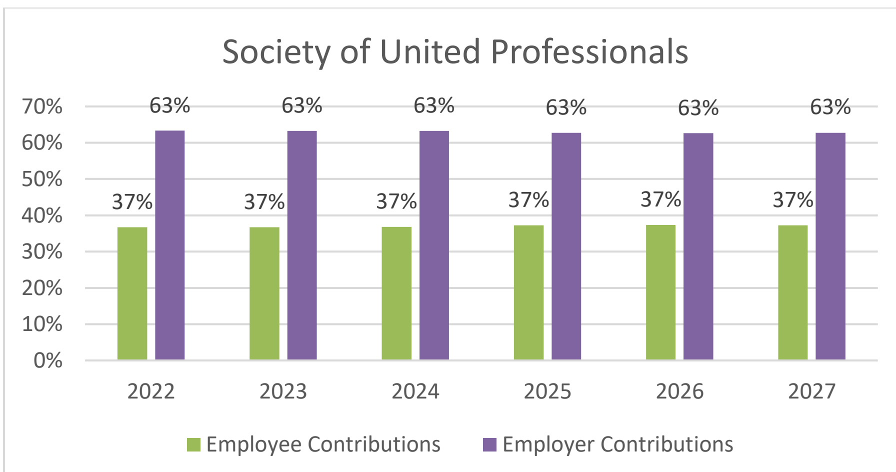
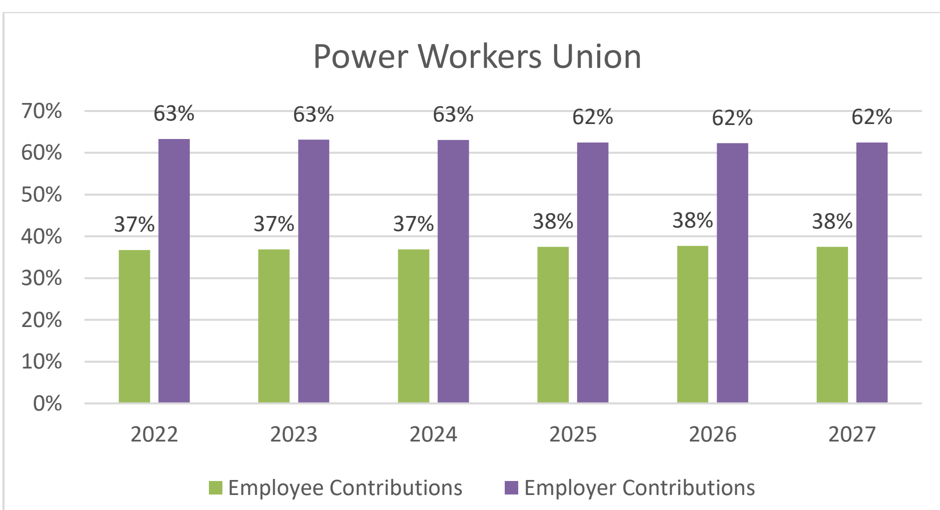
63%
2022
2023
2024
2025
2026
2027
Employee Contributions
Employer Contributions


Society of United Professionals
70%
60%
50%
40%
30%
20%
10%
0%
37%
63%
37%
63%
37%
63%
37%
63%
37%
63%
37%
63%
2022
2023
2024
2025
2026
2027
Employee Contributions
Employer Contributions


Power Workers Union
70%
60%
50%
40%
30%
20%
10%
0%
37%
63%
37%
63%
37%
63%
38%
62%
38%
62%
38%
62%
2022
2023
2024
2025
2026
2027
Employee Contributions
Employer Contributions

E - ENERGY PROBE INTERROGATORY - 071

Reference:

Exhibit E-08-01-01, E-08-01

Preamble:

Hydro One (through counsel) issued a request for proposal and selected Alliance Consulting Group (Alliance) to prepare a new depreciation study covering Hydro One Networks' transmission, distribution and common assets for the 2023 to 2027 test years. Alliance has applied the average life group, broad group depreciation methodology (BG) to group the assets within each account. This is in contrast to the approach historically used by Hydro One based on the depreciation studies prepared by Foster. The Foster studies used the straight line, vintage group, remaining life (SL-VG-RL) depreciation methodology. Alliance has used the BG methodology instead of the vintage group (VG) methodology because the BG methodology is more widely used.

Interrogatory:

a) Please provide a comparison Table that shows the prior Foster Depreciation Rates and recommended Alliance Rates for Transmission.

b) Confirm that the "Existing Accrual" in Alliance Table BU 210 Transmission Operations is consistent with the Foster Associates Study. If not explain how depreciation rates have been set from 2016-2021.

c) What is the percentage difference in 2022 annual Depreciation Expense for
   i. Transmission. and (based on prior Foster Associates studies),
   ii. Common costs,
   iii. Distribution operations?

d) What are the implications for 2022 Depreciation Expense, of adopting the broad group depreciation methodology (BG) to group the assets within each account rather than the vintage (VG) method?

e) What other utilities in Ontario use the BG methodology? Does the change in methodology have widespread distribution sector implications?

f) Do US Transmission companies in reporting to FERC, use broad group depreciation methodology (BG) to group the assets within each account or the vintage (VG) method?

Response:

Responses below provided by Alliance:

a) Please see Exhibit E-08-01-01, Appendix B-1 for the requested information. The current accrual rate is the depreciation accrual rate developed using the Foster Depreciation rates. The proposed accrual rate represents the rates developed from the Alliance Depreciation Study.

b) Confirmed.

c) The rates during the 2022 time period will be the same as the existing rates, so there will be no percentage difference in each category propounded in the question.

d) There are no implications for 2022 Depreciation Expense because Hydro One will not be implementing the BG depreciation methodology for 2022. However, generally speaking, the theoretical implications of adopting broad group depreciation as proposed, as opposed to vintage group depreciation, are that broad group depreciation will produce lower depreciation rates than vintage group depreciation in situations where the plant balance is growing, which is the case for Hydro One. The difference between the two methodologies is discussed in the Alliance Consulting Group Deprecation Study, Exhibit E-08-01-01, pages 18-20.

e) Alliance Consulting Group has not performed an exhaustive study of all entities regulated by the Ontario Energy Board. To the best of our determination, no other entities except HONI subsidiaries have used the VG methodology as supported by Foster. HONI affiliates, HORCI and B2M, have used the VG methodology as supported by Foster in existing rates. In addition, by adopting HONI's existing depreciation rates (developed by Foster Associates), we understand that Upper Canada Transmission (known as NextBridge) used the VG methodology in its recent rate application, but without engaging Foster Associates as a consultant.

Within Alliance Consulting Group's experience across North America, Foster Associates is the only major depreciation consulting company that normally uses the vintage group procedure. The change in methodology has the implication that BG rates will be lower than VG rates if a utility's plant balance is growing.

f) In the US, all of the companies that Alliance Consulting Group is aware of (which are the majority of companies within the US) use the BG methodology unless Foster Associates prepares their depreciation studies. See response to part e) above.

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E - ENERGY PROBE INTERROGATORY - 072

Reference:

Exhibit E-10-1, Tables 1 and 2

Interrogatory:

a) Please provide a Comparison Table, including the last 2 Transmission and Distribution Applications, to EB-2021-0110.

b) Provide a variance report and discussion.

Response:

a) Direct Application Costs for Past Distribution and Transmission Applications ($M)

Description	**EB-2013-0416 (Dx)**	**EB-2016-0160 (Tx)**	**EB-2017-0049 (Dx)**	**EB-2019-0082 (Tx)**	**EB-2021-0110 (F) (Tx and Dx)**
Studies and Consultants	1.0	0.7	1.2	2.5	6.9
Legal	0.3	2.6	2.5	2.5	6.4
Intervenors and Hearings	0.7	1.1	1.9	1.1	1.7
Total	**2.0**	**4.4**	**5.6**	**6.1**	**15.0**

b) Key drivers of the variances are as follows:

1. As described in Exhibit E-10-1, for EB-2021-0110 Hydro One's application costs, including costs for studies and consultants, are incurred and funded by the Regulatory Affairs Division (with the exception of legal costs which are included in the budget of the General Counsel Department). These amounts, inclusive of legal costs, are reflected in the last column of the table above.

   In contrast, in each of the four prior proceedings presented in the above table, Hydro One's costs for studies and consultants in relation to its applications were typically funded from the budgets of specific lines of business corresponding with the nature of the study or consulting services. As such, while Hydro One has made best efforts to capture all of the costs of previous proceedings for purposes of preparing the comparison table in part (a), above, it is likely that not all costs have been captured for the prior proceedings and that those amounts are therefore understated.

2. Stakeholder expectations and the complexity of hearings has increased. One indicator of this is the number of OEB directives that Hydro One has been required to address in each application based on relevant prior proceedings. Another indicator is the number of studies or reports that Hydro One has been required to obtain from third party consultants in response to those directives. The table below, which is based on Hydro One's reviews of relevant prior decisions and evidence, provides a strong indication of the overall trend with respect to OEB directives and requirements for third party studies in recent proceedings. These elements contribute significantly to the complexity, scope and cost of Hydro One preparing for and participating in rate applications.

Description	**EB-2013-0416[1] (Dx)**	**EB-2016-0160[2] (Tx)**	**EB-2017-0049[3] (Dx)**	**EB-2019-0082[4] (Tx)**	**EB-2021-0110[5] (Tx / Dx)**
Number of OEB Directives	6	5	13	14	42
Number of Supporting Studies Ordered or Required	0	1	6	7	22

3. This application is Hydro One's first joint application for both transmission and distribution rates. Hydro One's preparation of the application and participation in the hearing process on a combined basis has required additional resources to address the novel challenges associated with the application, as well as to provide the capacity to concurrently lead and support the development of both Transmission and Distribution evidence, as well as interrogatory responses and other elements of the application process.

[1] Numbers of directives and supporting studies based on summaries of EB-2009-0096, EB-2010-0228, EB-2012-0136 and EB-2013-0141 from Exhibit A-21-1 from EB-2013-0416.
[2] Numbers of directives and supporting studies based on summary of EB-2014-0140 and EB-2012-0031 from Exhibit A-4-2 of EB-2016-0160.
[3] Numbers of directives and supporting studies based on summary of directions in Appendix 2 of OEB decision in EB-2013-0416.
[4] Numbers of directives and supporting studies based on summary of EB-2016-0160 from Exhibit A-2-4 of EB-2019-0082.
[5] Numbers of directives and supporting studies based on summaries of EB-2017-0049 and EB-2019-0082 from Exhibit A-2-4 of the current application.

F - ENERGY PROBE INTERROGATORY - 073

Reference:

Exhibit F-1-2, Page 7, Tables 5 and 6

Preamble:

Treasury OM&A costs for Transmission are provided in the long-1 term debt schedules for the 2021, 2022 and 2023 in Exhibit F-01-04 and are summarized in Table 5: Treasury OM&A costs for Distribution are provided in the long-term debt schedules for the 2021, 2022 and 2023 in Exhibit F-01-04 and are summarized in Table 6:

Interrogatory:

a) Why are Forecast Transmission Treasury OM&A Costs higher than Distribution since all debt is issued by Hydro One and allocated to Transmission and Distribution? Is this an allocation based on the amount of debt? Please explain.

b) Please provide the Treasury OM&A for Transmission and Distribution for the historic years 2016-2020.

c) Please provide a variance report.

Response:

a) This allocation is based on the amount of debt. Forecasted Transmission Treasury OM&A Costs are higher than Distribution Treasury OM&A Costs due to a higher amount of long-term Transmission debt relative to Distribution long-term debt.

b) Please see table below for Treasury OM&A actuals for Transmission and Distribution for the historical years 2016-2020.

	2016 ($M)	2017 ($M)	2018 ($M)	2019 ($M)	2020 ($M)
Transmission	1.7	1.5	1.7	1.8	1.9
Distribution	1.1	0.9	0.9	1.0	1.0

Reference: 2018-2022 Dx Application (EB-2017-0049) and 2020-2022 Tx Application (EB-2019-0082)

Witness: PAOLUCCI William

c) As discussed in part a) of this interrogatory, the amount of Treasury OM&A Costs allocated to Transmission and Distribution is driven by the relative total amount of long-term debt outstanding for each business. The forecasted Transmission and Distribution Treasury OM&A costs discussed in Exhibit F-01-02 pages 6-7 are materially consistent with the historical data shown in part b) of this interrogatory.

G - ENERGY PROBE INTERROGATORY - 074

Reference:

Exhibit G-1-1, Page 19

Interrogatory:

Does the Capital in Service Variance Account (Account 2405) provide any incentives for productivity improvements for the management of capital expenditures? Please explain your answer.

Response:

As described in Exhibit A-04-01, the Capital in Service Variance Account (CISVA) provides additional elements of protection for customers. The account itself does not provide incentives for productivity improvements for the management of capital expenditures but it is designed so as to not undermine the efforts being made through Hydro One's Productivity Framework. More particularly, the CISVA calculation excludes variances associated with in-service additions resulting from verifiable productivity gains. In this way, the CISVA is designed to ensure that Hydro One is not penalized for achieving productivity improvements that may result in capital costs that are less than 98% of the approved funding envelopes, thereby aligning Hydro One's objectives with those of its ratepayers and ensuring that true productivity savings are incented through the term of the Custom IR application.

With respect to the Productivity Framework, customers benefit as a result of Hydro One having a lower rate base over the long-term. This is further described in SPF Section 1.4, Page 2, which states: "For capital, once the in-service additions and the rate base are approved as part of this Application, holding everything else constant, any incremental productivity can reduce in-service additions relative to OEB approved levels forecasted. Customers are already obtaining the upfront benefit of this productivity via the above-described stretch factors, and could also benefit in the long-term via a lower than planned rate base."

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H - ENERGY PROBE INTERROGATORY - 075

Reference:

Exhibit H-9-1, Attachment 1

Preamble:

> *The May 2014 methodology was based on how the transmission system is designed and since exports needs are not considered in the planning of the transmission system, exports would not be allocated a portion of Shared Network Assets._The methodologies identified in this report account for how exports are being treated by the IESO. Exports use the transmission system almost as much as domestic customers_use the system, including at peak times, therefore, exports could be allocated a portion of Shared Network Asset-related costs. If exports are to be allocated a portion of Shared Network Asset-related costs, Elenchus is of the view that exports should also then be allocated a portion of External Transmission Revenues received by HONI.*

Interrogatory:

a) Based on 100% cost causality and the HONI Transmission projected annual exports for 2023 what would be:
   i. the revenue generated from Export Transmission Service,
   ii. the allocation portion of External Transmission Revenues,
   iii. the net benefit to domestic transmission customers$/MWh and Total, and
   iv. the net cost to Export Transmission service customers$/MWh?

b) Based on 50% cost causality and the HONI Transmission projected annual exports for 2023 what would be:
   i. the revenue generated from Export Transmission Service,
   ii. the allocation portion of External Transmission Revenues,
   iii. the net benefit to domestic transmission customers in $/MWh and Total, and
   iv. the net cost to Export Transmission service customers in $/MWh?

c) Based on 50% cost causality and the HONI Tx projected annual exports for 2023 what would be:
   i. the revenue generated from Export Transmission Service,
   ii. the allocation portion of External Transmission Revenues,
   iii. the net benefit to domestic transmission customers in $/MWh and Total, and
   iv. the net cost to Export Transmission service customers in $/MWh?

d) If Exports had been priced under one of the current proposed 3 options, what would have been the revenue to Hydro One TX and Domestic Customers in each year from 2015 to 2022 based on Actual Export Volumes. Please provide a schedule.

Response:

As per the OEB's Procedural Order #1 issued on September 17, 2021, the OEB has decided to commence a separate, generic proceeding on its own motion to review a number of UTR-related issues and the Export Transmission Service (ETS) Rate in that generic proceeding (EB-2021-0243).

This interrogatory is related to ETS Rate, which is one of the issues that will be addressed in the OEB generic UTR proceeding. As such, this interrogatory is considered beyond the scope of this Application.

H - ENERGY PROBE INTERROGATORY - 076

Reference:

Exhibit H-9-1, Attachment 2, Appendix A

Interrogatory:

a) Please clarify why TransEnergie is listed on the same basis as ISOs (it is a Tx company/exporter not an ISO).

b) Please provide a schedule that shows the $/MW day and $/MWh ranges for Firm and Non-firm On-peak and Off-peak ETS for the 6 US ISOs and for the Canadian ISOs (Alberta and Ontario) and TransEnergie (Quebec).

c) What ETS rates are charged in British Columbia?

d) Does CRA have a recommendation for an Ontario ETS rate? If so, please provide this, with whatever caveats that may apply.

Response:

As per the OEB's Procedural Order #1 issued on September 17, 2021, the OEB has decided to commence a separate, generic proceeding on its own motion to review a number of UTR-related issues and the Export Transmission Service (ETS) Rate in that generic proceeding (EB-2021-0243).

This interrogatory is related to ETS Rate, which is one of the issues that will be addressed in the OEB generic UTR proceeding. As such, this interrogatory is considered beyond the scope of this Application.

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H - ENERGY PROBE INTERROGATORY - 077

Reference:

Exhibit H-9-1, Attachment 3

Preamble:

> *Exporters contribute to the cost of the Ontario transmission system through two mechanisms. The first mechanism is through the fixed ETS rate and the second mechanism is through the dynamic ICP mechanism. When considered together, exporters not only contribute approximately $30-40 million per year towards the transmission system through the ETS rate but have also paid an average of $160 million per year towards the cost of the transmission system from the ICP mechanism.*

Interrogatory:

a) Please provide a schedule that shows how much ETS and ICP revenues flowed to Ontario Domestic customers from 2015-2020.

b) Please show how much revenue flowed to Transmission Rights Holders over the same period.

c) When was the ICP revenue allocation changed and what was/is the basis for this? Please provide details and the change in revenue allocated to domestic customers.

d) Why is/is not the Current Ontario ETS rate appropriate? Please discuss.

e) The Elenchus Report suggests three cost-based ETS rates. Which does the IESO believe to be most appropriate (or does IESO prefer the status quo)?

Response:

As per the OEB's Procedural Order #1 issued on September 17, 2021, the OEB has decided to commence a separate, generic proceeding on its own motion to review a number of UTR-related issues and the Export Transmission Service (ETS) Rate in that generic proceeding (EB-2021-0243).

This interrogatory is related to ETS Rate, which is one of the issues that will be addressed in the OEB generic UTR proceeding. As such, this interrogatory is considered beyond the scope of this Application.

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H - ENERGY PROBE INTERROGATORY - 078

Reference:
Exhibit H-10-1, Attachment 1

Interrogatory:

a) Please provide bar charts showing:
   i. Network Rates/MWh for each province, for Alberta use the nearest proxy, and
   ii. PTP rates.

b) Provide the range for Network Rates and the average.

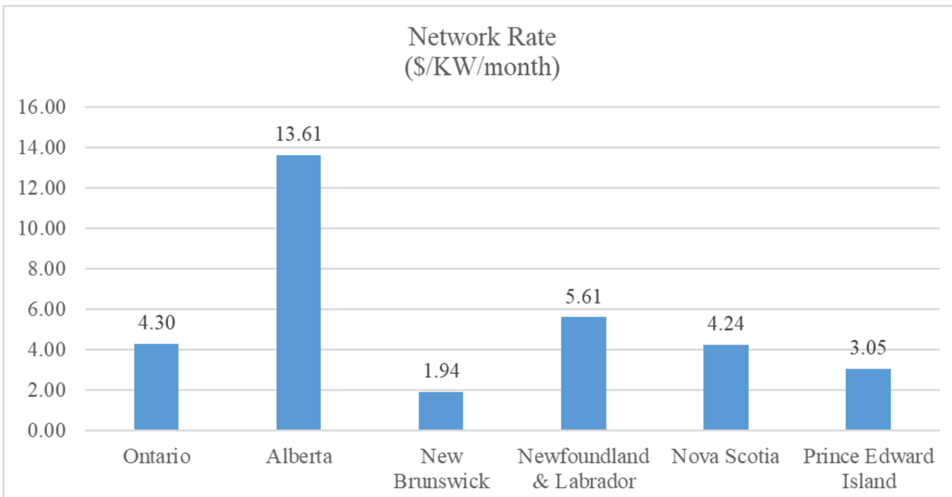
c) Please comment on Ontario's position in the Provincial Cohort.

Response:

a)
   i. Hydro One is unable to provide a bar chart showing Network Rates ($) per MWh as no jurisdiction listed in Table 2 of Exhibit H-10-01 Attachment 1 expresses their Network Rate in MWh. As shown in I-01-H-Staff-319(b), there are only six provinces (including Ontario) for which there are network rates (or proxy) that can be expressed in $/kW/month. Those are shown in Chart 1 below. Provinces whose network rates could not be converted to $/kW/month (e.g. expressed in $/month) have been excluded.

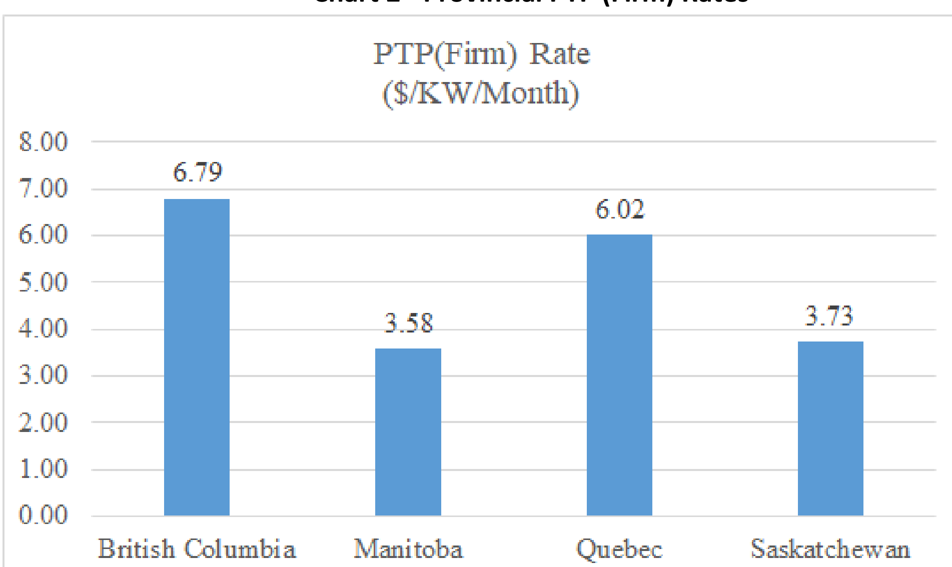
   Hydro One notes that it is not appropriate nor helpful to compare the Network Rate charged under Ontario's Uniform Transmission Rates (UTRs) to the Network Rate charged under Open Access Transmission Tariff (OATT) or the transmission pricing regime in Alberta. As further explained in section 2.1 of Exhibit H-10-01, UTRs are derived and applied on the basis of customer usage of transmission assets. If a customer's facilities are directly connected to a transmitter's network facilities, the customer pays only a UTR's Network charge to compensate the transmitter for providing service using the transmitter's network assets. In contrast, under OATTs, a customer that chooses to receive Network Service will pay a Network charge that includes the costs associated with all transmission assets, including network, line connection and transformation connection facilities. The closest proxy to a network rate in Alberta is the sum of the Demand Transmission Service ("DTS") Bulk and DTS Regional rate as shown in Table 2 of Exhibit H-10-01 Attachment 1. However, the transmission pricing regime in Alberta is driven by statutory obligations assigned to the Alberta Electric System Operator (AESO). The AESO then calculates a complex mix of fixed and variable charges that apply to transmission customers in Alberta. As such, the Network rates under OATT and the proxy for Alberta shown in Chart 1 below do not provide a reasonable comparison of Ontario's UTRs Network rate.

Chart 1 - Provincial Network (and Proxy) Rates



ii. The PTP (Firm) rates are shown in the chart below expressed as $/kW-month.

Chart 2 - Provincial PTP (Firm) Rates



b) The Network (and proxy) Rates shown in Chart 1 range between $1.94 and $13.61 per kW per month. The average rate is $5.46 per kW per month.

c) As described in part (a), it is not appropriate nor helpful to compare Ontario UTR's Network rate to Network rates under OATT or Alberta's transmission pricing regime.

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L - ENERGY PROBE INTERROGATORY - 079

Reference:

Exhibit L-2-1, Pages 7-9, Table 6

Preamble:

The revenue to cost ratio for the UR class is increasing over the 2023 to 2027 period which indicates that customers in this rate class are increasingly subsidizing customers in other rate classes, including customers in certain classes of Acquired Utilities which have low revenue to cost ratios.

Interrogatory:

What could be done to bring the revenue to cost ratios in the UR class closer to 1.0? Please discuss.

Response:

As discussed in its March 31, 2011 Cost Allocation Report (EB-2010-0219), the OEB established 85% to 115% as an acceptable range of revenue to cost (R/C) ratios for residential customers. In this Application, the UR R/C ratios range from 1.04 to 1.07 during the 2023-2027 period, which is well within the OEB acceptable range of 85% to 115%. As such, Hydro One submits that it is not necessary to bring the UR class R/C ratios closer to 1 during the 2023-2027 period.

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L - ENERGY PROBE INTERROGATORY - 080

Reference:

Exhibit L-3-1, Page 14, Table 9

Interrogatory:

Please explain the reasons for the large difference between the NPDI Status Quo Capital Forecast and the Hydro One Actual Capital for 2014-2018.

Response:

The NPDI actual capital savings from 2016[1] forward reflect the synergy savings that were attained as a result of being integrated into Hydro One's distribution business. Savings were achieved from the elimination of capital expenditures for support functions that were made redundant as a result of the consolidation. In addition, operational capital savings were able to be achieved due to elimination of the artificial border and economies of scale as described in Exhibit L-3-1 page 13, lines 11-14.

[1] Note: In 2014 and 2015, NPDI was not integrated into Hydro One.

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L - ENERGY PROBE INTERROGATORY - 081

Reference:

Exhibit L-3-1, Page 15, Table 10

Interrogatory:

Please explain the reasons for the large difference between the HCHI Status Quo Capital Forecast and the Hydro One Actual Capital for 2015-2019.

Response:

The HCHI actual capital savings from 2016[1] forward reflect the synergy savings that were attained as a result of the being integrated into Hydro One's distribution business. Savings were achieved from the elimination of capital expenditures for support functions that were made redundant as a result of the consolidation. In addition, operational capital savings were able to be achieved due to elimination of the artificial border and economies of scale as described in Exhibit L-3-1 page 13, lines 11-14.

[1] Note: In 2014 and 2015, HCHI was not integrated into Hydro One.

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