ROADMAP OF EVIDENCE ADDRESSING TRANSMISSION AND DISTRIBUTION OM&A COSTS

1.0 INTRODUCTION

Given the amount of evidence underpinning this application, which includes multiple witnesses and panels supporting the different categories of Operations, Maintenance and Administration (OM&A) costs, this roadmap of the various OM&A evidence and witnesses associated with it is intended to serve as a reference point for all stakeholders.

2.0 TRANSMISSION OM&A EVIDENCE

The Summary of Transmission OM&A Expenditures is Exhibit E-02-01. That exhibit provides an overview of overall OM&A costs for the Transmission business, including the various categories of expenditures, and summarizes the OM&A envelope level variance explanations. The summary exhibit, in turn, refers to the underlying exhibits which provide further details regarding the OM&A categories – by way of example, details in respect of Transmission Sustainment OM&A are contained in Exhibit E-02-02.

The following are the Transmission OM&A exhibits and associated witnesses:

Exhibit Reference	Exhibit Title	Witness
E-02-01	Summary of Transmission OM&A Expenditures	JODOIN Joel
E-02-02	Transmission Sustainment OM&A	JABLONSKY Donna
E-02-03	Transmission Development OM&A	REINMULLER Robert
E-02-04	Transmission Customer Care OM&A	GILL Spencer
E-02-05	Transmission O&M Work Execution Strategy	SPENCER Andrew

3.0 DISTRIBUTION OM&A EVIDENCE

The Summary of Distribution OM&A Expenditures is Exhibit E-03-01. That exhibit provides an overview of overall OM&A costs for the Distribution business, including the various categories of expenditures, and summarizes the OM&A envelope level variance explanations. The summary exhibit, in turn, refers to the underlying exhibits which provide further details regarding the categories – by way of example, details in respect of Distribution Sustainment OM&A are contained in Exhibit E-03-02.

The following are the Distribution OM&A exhibits and associated witnesses:

Exhibit Reference	Exhibit Title	Witness
E-03-01	Summary of Distribution OM&A Expenditures	JODOIN Joel
E-03-02	Distribution Sustainment OM&A	FALTAOUS Peter
E-03-03	Distribution Development OM&A	FALTAOUS Peter
E-03-04	Distribution Customer Care OM&A	GILL Spencer
E-03-05	Distribution O&M Work Execution Strategy	NG Chong Kiat, FRENCH Teri

4.0 COMMON OM&A EVIDENCE

The Common OM&A exhibits outline the expenditures which are shared between segments of Hydro One and are subsequently allocated to Transmission and Distribution. Those exhibits, including the allocation methodology, and associated witnesses are as follows:

Exhibit Reference	Exhibit Title	Witness
E-04-01	Summary of Common and Other OM&A	JODOIN Joel
E-04-02	Common Corporate Functions and Services (CCF&S) and Other OM&A	JODOIN Joel
E-04-03	Common Corporate OM&A - Planning	JESUS Bruno
E-04-04	Common Corporate OM&A - Information Solutions	MARCOTTE Kevin
E-04-05	Operations OM&A	HOLDER Godfrey
E-04-06	Common Corporate Costs OM&A - Transmission Cost of Sales - External Work	SPENCER Andrew
E-04-07	Common Corporate Costs OM&A - Distribution Cost of Sales - External Work	NG Chong Kiat
E-04-08	Common Corporate Costs & Allocation Methodology	JODOIN Joel
E-09-04	Taxes Other Than Income Taxes	BERARDI Rob

SUMMARY OF TRANSMISSION OM&A EXPENDITURES

1.0 INTRODUCTION

This exhibit provides an overview of Hydro One Transmission's Operations, Maintenance and Administration (OM&A) expenditures over the 2018 to 2023 period, which include the 2018 to 2021 historical period,[1] the 2022 bridge year, and the 2023 test year.

Hydro One's OM&A expenditures are comprised of the work required to meet public and employee safety objectives, maintain transmission system reliability at targeted performance levels, and comply with legislative and regulatory requirements, including those specified by the Transmission System Code, the North American Reliability Corporation (NERC), the Independent Electricity Systems Operator (IESO) and the federal environmental legislation associated with the Polychlorinated Biphenyl (PCB) program.

The OM&A budget has been set in order to deliver outcomes valued by customers, while balancing the needs of the system and customer rate impacts. The forecast OM&A in respect of Sustainment, Development, and Operations has been determined through the Investment Planning process described in SPF Section 1.7. The expenditures are responsive to the outcomes of the Transmission System Plan (TSP Section 2.1) and the Business Plan (attachment 1 to Exhibit A-03-01). This process reflects a risk-based decision making approach to ensure appropriate and cost-effective expenditures.

Hydro One is seeking approval of a total 2023 test year OM&A of $420.5M. This 2023 budget amount represents a little more than an inflationary increase over the 2020 to 2023 period. Specifically, the 2023 test year OM&A is $11.9M (or 2.9%) higher than the amount that would

[1] 2021 is provided on a forecast basis

result from escalating the 2020 OEB approved OM&A[2] by inflation, which is $408.6M, as outlined below in Table 1.

Table 1 - 2023 OM&A Comparison

	($M)	2023
A	2023 Transmission Test Year OM&A	420.5
B	2020 OEB-Approved Transmission OM&A Escalated by Inflation in 2023 Terms[3]	408.6
C=A-B	Variance	11.9
D=C/B	% Change	2.9%

The 2023 OM&A budget should be considered in the context of the years leading up to it and the impacts of prior applications and OEB directives. This includes a temporary, one-time reduction in Transmission OM&A in 2019 as a result of an inflationary adjustment application for that year, where Hydro One was required to manage within the approved revenue requirement (as that application did not rebase for either the required costs or the appropriate load forecast). The subsequent 2020-2022 transmission decision (EB-2019-0082) reduced the OM&A envelope for 2020 by $10.1M[4], which in turn similarly reduced 2021 and 2022 OM&A by virtue of the Custom IR formula. The OM&A for 2021 and 2022 is forecasted to be relatively consistent with the 2020 OEB-approved level, taking into account inflationary pressures.

The total Actual/Forecast OM&A for the period of 2020-2022 is slightly above (by less than 1%) the total OM&A amount included in the OEB-approved revenue requirement for the same period.[5] This reflects Hydro One's cost controls and incremental productivity achievements

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[2] 2020 was the test year of the prior Custom IR period, which was the year approved by the OEB, with 2021 and 2022 then resulting from the Custom IR Framework.
[3] Inflation rate of 2.0% was used annually, which is equal to the OEB approved inflation rate from Hydro One's Transmission annual rate update application in EB-2020-0202.
[4] EB-2019-0082, Decision and Order, April 23, 2020, p. 3
[5] Calculated based on the Custom IR formula. For 2021 this is per the OEB approved formula in *EB-2020-0202.* The 2022 amount was derived by applying the inflation rate less stretch factor equal to the OEB approved rate in *EB-2020-0202.*

notwithstanding unplanned expenditures associated with incremental costs incurred due to COVID-19.

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.

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. This is described further in SPF Section 1.4.

Table 2 provides a summary of OM&A expenditures for the historical, bridge, and test years. The 2020 OEB-approved funding is presented at the total envelope level, consistent with the envelope funding approved by the OEB in the prior Transmission application (EB-2019-0082).

Table 2 - Summary of Recoverable OM&A Expenses ($M)

	Historical					Bridge	Test
	2018	2019	2020		2021	2022	2023
Transmission	Actual	Actual	Actual	OEB-Approved	Forecast	Forecast	Forecast
Sustainment	229.4	207.8	200.9	-	205.2	208.3	219.6
Development	5.2	4.4	6.7	-	8.3	8.9	8.6
Operations	53.4	51.0	47.9	-	48.8	48.6	49.0
Customer Care	11.0	7.2	7.0	-	6.0	6.7	6.9
Common and Other	54.9	26.7	70.5	-	51.6	50.7	65.0
Property Taxes and Rights Payments	65.3	60.8	65.4	-	69.1	70.2	71.4
Total	**419.2**	**357.9**	**398.5**	**385.0**	**389.0**	**393.4**	**420.5**

2024 to 2027 OM&A is established in accordance with the Custom IR framework discussed in Exhibits A-04-01 and A-04-02.

2.0 DESCRIPTION OF OM&A CATEGORIES

The categories that comprise the overall OM&A envelope are the following.

Sustainment: The expenditures in this category are required to maintain existing transmission system equipment and facilities to ensure they continue to function safely and as originally designed. The Sustainment OM&A expenditures allow Hydro One to maintain system reliability and service quality, while satisfying applicable legislative, regulatory, environmental, and safety requirements.

Development: The expenditures in this category fund the costs associated with (i) development of technical standards for transmission power assets, (ii) supporting advancements and adoption of new technologies aimed at improving operational effectiveness, safety, and system reliability, and (iii) addressing and/or mitigating (where possible) issues affecting the reliability and quality of delivered power.

Operations: The expenditures in this category are required to manage the real-time operation of Hydro One's transmission system equipment, including (i) monitoring and controlling transmission assets, (ii) coordinating and scheduling planned outages, (iii) reacting to system contingencies, (iv) provisioning for customer notifications, and (v) reporting on the performance of the transmission system. The 24/7 real time operation of Hydro One's Transmission system is conducted at the Integrated System Operations Centre (ISOC) and the Back-Up Ontario Grid Control Centre (BU-OGCC). Operations OM&A spending also supports Hydro One's environment, health and safety activities.

Customer Care: The expenditures in this category are required to deliver customer care functions to Hydro One's transmission customers, including (i) responding to customer inquiries, (ii) providing proactive outreach and customized advice through account executives, and (iii) performing meter data aggregation, billing and settlement activities. In an effort to improve customer service, Hydro One has placed considerable focus on a renewed commitment to customer advocacy, and operational excellence. Despite the increased focus, the 2023 costs are lower than historical levels.

Common and Other: The expenditures in this category include costs associated with common corporate functions and services (CCF&S), asset management planning, information solutions, the cost of sales for external work, and other costs including those associated with the non-service cost component of Other Post-Employment Benefits (OPEBs). Hydro One allocates common OM&A costs to affiliates and business segments through an updated cost allocation methodology developed by Black & Vetch (described in Exhibit E-04-08), which includes using more direct cost allocation percentages to allocate common corporate costs to the Transmission and Distribution lines of business.

Property Taxes and Rights Payments: In respect of the expenditures in this category, Hydro One is subject to property taxes in accordance with the *Electricity Act 1998*, the *Municipal Act 2001*, and the *Assessment Act 1990*. Hydro One also pays annual fees for the right to cross and/or occupy properties owned by third parties, such as railway companies and/or governmental bodies.

Summary explanations regarding the 2023 amounts requested in these categories compared to prior years are included in the envelope level variance explanations in Section 3 below (to the extent they contribute to the variances). Further details regarding each of these OM&A categories, including detailed variance explanations in respect of them, can be found in the exhibits outlined in Table 3.

Table 3 - Supporting OM&A Exhibits

Cost Category	Exhibit Reference	Exhibit Title	Witness
Sustainment	E-02-02	Transmission Sustainment OM&A	JABLONSKY Donna
Development	E-02-03	Transmission Development OM&A	REINMULLER Robert
Operations	E-04-05	Operations OM&A	HOLDER Godfrey
Customer Care	E-02-04	Transmission Customer Care OM&A	GILL Spencer
Common and Other	E-04-01	Summary of Common and Other OM&A	JODOIN Joel
Property Taxes and Rights Payments	E-09-04	Taxes Other Than Income Taxes	BERARDI Rob

3.0 ENVELOPE LEVEL VARIANCE EXPLANATIONS

This section briefly addresses envelope level variance explanations, which are further described and detailed in the accompanying exhibits that are referred to.

3.1 COMPARISON OF 2023 TEST YEAR OM&A TO 2020 OEB-APPROVED

Compared to the OEB-approved amount for 2020 ($385.0M), Hydro One’s expected 2023 Transmission OM&A expenses are $420.5M (or 9.2%) higher, but when compared to the 2020 approved OM&A escalated by inflation to 2023 dollars, the 2023 OM&A expense is only 2.9% higher.

The small increase in 2023 OM&A (slightly above inflation) is due in large part to the significant pressures and need to (i) address deferred stations maintenance that allowed Hydro One to continue funding PCB remediation work as planned in 2019-2022; and (ii) address security needs related to evolving security threats and NERC CIP standards.

3.2 COMPARISON OF 2023 TEST YEAR OM&A TO 2020 ACTUALS

Compared to actual 2020 OM&A expenses, Hydro One's 2023 expected OM&A expenses are $22.0M (or 5.5%) higher. This increase is necessary in order to fund outstanding and required maintenance activities. The main drivers of these increased costs are primarily due to:

- Increased Sustainment OM&A costs of $18.7M necessary to: (i) address deferred stations maintenance that allowed Hydro One to continue funding PCB remediation work as planned in 2019-2022; and (ii) address security needs related to evolving security threats and NERC CIP standards (detailed in Exhibit E-02-02);
- Increased Property Taxes and Rights Payments of $5.9M primarily due to (i) higher tax rates, (ii) increases in the assessed values of Hydro One properties, and (iii) increasing land values (detailed in Exhibit E-09-04); and
- Increased Development OM&A costs of $1.9M primarily due to expenditures required to support new data capture techniques in the Research Development and Demonstration (RD&D) Program and providing Power Quality assistance to customers (detailed in Exhibit E-02-03);

These increased costs are partially offset by lower Common and Other costs of $5.5M primarily due to incremental COVID-19 related costs in 2020 not forecasted to persist in 2023 (detailed in Exhibit E-04-02).

3.3 COMPARISON OF 2023 TEST YEAR OM&A TO 2021 FORECAST AND 2022 BRIDGE YEARS

Compared to the 2021 forecast and 2022 bridge years, Hydro One's 2023 expected OM&A expenses are $31.5M (or 8.1%) and $27.1M (or 6.9%) higher, respectively. The main drivers of these increased costs are primarily due to:

- Increased Sustainment OM&A costs of $14.4M compared to 2021 and of $11.4M compared to 2022, primarily to (i) address deferred stations maintenance, (ii) address cyber security needs, and iii) fund planned corrective maintenance work on overhead lines. These spending increases have been partially offset by decreasing PCB remediation expenditures in 2023 (detailed in Exhibit E-02-02);
- Increased Common and Other costs of $13.4M compared to 2021 and of $14.3M compared to 2022, primarily due to (i) a reduction of the environmental provision credit due to targeted completion of PCB remediation work by 2025 to meet regulations, (ii) higher real estate and facilities costs associated with fixed operating costs for new facilities as well as lease renewals, (iii) increased human resource costs supporting the development of Hydro One's People Strategy (detailed in Exhibit E-04-02), and (iv) increases associated with technology solution updates, including change management and data migration, and security costs so Hydro One remains appropriately positioned against an evolving security threat landscape (detailed in Exhibit E-04-04);
- Increased Property Taxes and Rights Payments of $2.3M compared to 2021 and of $1.2M compared to 2022, primarily due to (i) higher tax rates, (ii) increases in the assessed values of Hydro One properties, and (iii) increasing land values (detailed in Exhibit E-09-04);

3.4 COMPARISON OF 2020 OM&A ACTUALS TO 2020 OEB-APPROVED

Compared to 2020 OEB-approved expenses, Hydro One's 2020 actual OM&A expenses were $13.5M higher, largely due to unplanned expenses related to COVID-19 of approximately $18M, as further described in Exhibit E-04-02.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

($M)

	2018 Actuals	2019 Actuals	2020 Last Rebasing Year OEB Approved	2020 Actuals	2021 Forecast *	2022 Bridge Year	2023 Test Year
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Sustainment	$ 229.4	$ 207.8		$ 200.9	$ 205.2	$ 208.3	$ 219.6
Development	$ 5.2	$ 4.4		$ 6.7	$ 8.3	$ 8.9	$ 8.6
Operating	$ 53.4	$ 51.0		$ 47.9	$ 48.8	$ 48.6	$ 49.0
Asset Management (Planning) costs	$ 31.0	$ 26.7		$ 25.3	$ 25.2	$ 26.6	$ 27.4
SubTotal	**$ 319.0**	**$ 289.9**		**$ 280.8**	**$ 287.5**	**$ 292.4**	**$ 304.7**
%Change (year over year)		-9.1%		-3.1%	2.4%	1.7%	4.2%
%Change (Test Year vs Last Rebasing Year - Actual)							8.5%
Customer Service (Billing, Collecting, Bad Debt, Misc)	$ 11.0	$ 7.2		$ 7.0	$ 6.0	$ 6.7	$ 6.9
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	$ 4.6	$ 4.5		$ 4.4	$ 7.2	$ 7.3	$ 7.6
Common Functions and Services	$ 87.9	$ 83.7		$ 84.1	$ 83.6	$ 87.6	$ 89.3
Information Technology	$ 50.4	$ 53.7		$ 51.2	$ 51.4	$ 51.2	$ 53.7
Property taxes and rights payments	$ 65.3	$ 60.8		$ 65.4	$ 69.1	$ 70.2	$ 71.4
SubTotal	**$ 219.2**	**$ 209.8**		**$ 212.3**	**$ 217.2**	**$ 223.0**	**$ 228.8**
%Change (year over year)		-4.3%		1.2%	2.3%	2.7%	2.6%
%Change (Test Year vs Last Rebasing Year - Actual)							7.8%
Miscellaneous (Other OM&A, Recovery)	-$ 119.0	-$ 141.9		-$ 94.6	-$ 115.7	-$ 122.0	-$ 113.0
Total	**$ 419.2**	**$ 357.9**	**$ 385.0**	**$ 398.5**	**$ 389.0**	**$ 393.4**	**$ 420.5**
%Change (year over year)		-14.6%	7.6%	11.4%	-2.4%	1.1%	6.9%

	2018 Actuals	2019 Actuals	2020 Last Rebasing Year OEB Approved	2020 Actuals	2021 Forecast *	2022 Bridge Year	2023 Test Year
Sustainment	$ 229.4	$ 207.8		$ 200.9	$ 205.2	$ 208.3	$ 219.6
Development	$ 5.2	$ 4.4		$ 6.7	$ 8.3	$ 8.9	$ 8.6
Operating	$ 53.4	$ 51.0		$ 47.9	$ 48.8	$ 48.6	$ 49.0
Asset Management (Planning) costs	$ 31.0	$ 26.7		$ 25.3	$ 25.2	$ 26.6	$ 27.4
Customer Service (Billing, Collecting, Bad Debt, Misc)	$ 11.0	$ 7.2		$ 7.0	$ 6.0	$ 6.7	$ 6.9
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	$ 4.6	$ 4.5		$ 4.4	$ 7.2	$ 7.3	$ 7.6
Common Functions and Services	$ 87.9	$ 83.7		$ 84.1	$ 83.6	$ 87.6	$ 89.3
Information Technology	$ 50.4	$ 53.7		$ 51.2	$ 51.4	$ 51.2	$ 53.7
Property taxes and rights payments	$ 65.3	$ 60.8		$ 65.4	$ 69.1	$ 70.2	$ 71.4
Miscellaneous (Other OM&A, Recovery)	-$ 119.0	-$ 141.9		-$ 94.6	-$ 115.7	-$ 122.0	-$ 113.0
Total	**$ 419.2**	**$ 357.9**	**$ 385.0**	**$ 398.5**	**$ 389.0**	**$ 393.4**	**$ 420.5**
%Change (year over year)		-14.6%	7.6%	11.4%	-2.4%	1.1%	6.9%

	2018 Actuals	2019 Actuals	2020 Last Rebasing Year OEB Approved	2020 Actuals	Variance 2020 Approved vs. 2020 Actuals	2021 Forecast *	2022 Bridge Year	Variance 2022 Bridge vs. 2020 Actuals	2023 Test Year	Variance 2023 Test vs. 2022 Bridge
Sustainment	$ 229.4	$ 207.8		$ 200.9		$ 205.2	$ 208.3	$ 7.4	$ 219.6	$ 11.4
Development	$ 5.2	$ 4.4		$ 6.7		$ 8.3	$ 8.9	$ 2.2	$ 8.6	-$ 0.4
Operating	$ 53.4	$ 51.0		$ 47.9		$ 48.8	$ 48.6	$ 0.7	$ 49.0	$ 0.4
Asset Management (Planning) costs	$ 31.0	$ 26.7		$ 25.3		$ 25.2	$ 26.6	$ 1.3	$ 27.4	$ 0.8
Customer Service (Billing, Collecting, Bad Debt, Misc)	$ 11.0	$ 7.2		$ 7.0		$ 6.0	$ 6.7	-$ 0.3	$ 6.9	$ 0.2
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	$ 4.6	$ 4.5		$ 4.4		$ 7.2	$ 7.3	$ 2.9	$ 7.6	$ 0.2
Common Functions and Services	$ 87.9	$ 83.7		$ 84.1		$ 83.6	$ 87.6	$ 3.4	$ 89.3	$ 1.7
Information Technology	$ 50.4	$ 53.7		$ 51.2		$ 51.4	$ 51.2	-$ 0.1	$ 53.7	$ 2.5
Property taxes and rights payments	$ 65.3	$ 60.8		$ 65.4		$ 69.1	$ 70.2	$ 4.8	$ 71.4	$ 1.2
Miscellaneous (Other OM&A, Recovery)	-$ 119.0	-$ 141.9		-$ 94.6		-$ 115.7	-$ 122.0	-$ 27.3	-$ 113.0	$ 9.0
Total OM&A Expenses	**$ 419.2**	**$ 357.9**	**$ 385.0**	**$ 398.5**	**$ 13.47**	**$ 389.0**	**$ 393.4**	**-$ 5.1**	**$ 420.5**	**$ 27.1**
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB) [3]										
Total Recoverable OM&A Expenses	$ 419.2	$ 357.9	$ 385.0	$ 398.5	$ 13.5	$ 389.0	$ 393.4	-$ 5.1	$ 420.5	$ 27.1
Variance from previous year		-$ 61		$ 41		-$ 10	$ 4		$ 27	
Percent change (year over year)		-14.6%		11.4%		-2.4%	1.1%		6.9%	
Percent Change: Test year (2023) vs. Most Current Actual (2020)									5.5%	
Simple average of % variance for all years									0.5%	
Compound Annual Growth Rate for all years										0.1%
Compound Growth Rate (2020 Actuals vs. 2018 Actuals)										-2.5%

CAGR from 2020 actual to 2023 1.8%

Note:

* Will be updated with actuals when data is available

1 Historical actuals going back to the last cost of service application are required to be entered by the applicant.
2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.
3 For unrecoverable OM&A Expenses see Section 2.4.3.7

Appendix 2-JB
Recoverable OM&A Cost Driver Table [1,3]

($M)

OM&A	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast *	2022 Bridge Year	2023 Test Year
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Opening Balance [2]	$ -	$ 419.2	$ 357.9	$ 398.5	$ 389.0	$ 393.4
Land Assessment and Remediation		-$ 0.3	-$ 0.4	$ 0.3	-$ 0.0	$ 0.1
Environment Management		-$ 1.5	$ 3.5	$ 6.2	$ 0.8	-$ 7.9
Power Equipment		-$ 9.3	-$ 7.7	$ 1.9	-$ 0.3	$ 8.0
Ancillary System Maintenance		$ 0.8	-$ 1.1	-$ 0.5	-$ 0.1	$ 1.9
Protection, Control, Monitoring, Metering and Telecommunications (including cybersecurity)		-$ 3.9	$ 1.8	-$ 0.7	$ 2.3	$ 4.2
Site Infrastructure Maintenance		-$ 3.2	$ 1.1	$ 0.2	$ 0.5	$ 1.5
Rights of Way		-$ 5.4	$ 0.7	-$ 0.2	-$ 0.1	$ 0.7
Overhead Lines		-$ 0.6	-$ 1.1	-$ 1.6	$ 0.2	$ 2.4
Underground Cables		-$ 2.0	-$ 1.2	-$ 0.4	-$ 0.2	$ 0.3
Engineering & Environmental Support		$ 3.8	-$ 2.6	-$ 0.7	-$ 0.0	$ 0.3
Transmission Standards Program		-$ 0.3	$ 1.6	-$ 0.2	$ 0.1	$ 0.2
Research Development and Demonstration		-$ 0.4	$ 0.5	$ 1.0	$ 0.6	-$ 0.6
Customer Power Quality Program		-$ 0.2	$ 0.2	$ 0.7	$ 0.0	$ 0.0
Operations Contracts		$ 0.6	-$ 0.6	$ 2.8	-$ 1.5	$ 1.8
Environmental, Health and Safety		$ 0.6	-$ 1.0	$ 0.4	-$ 0.0	$ 0.0
Operators		-$ 3.6	-$ 1.5	-$ 2.3	$ 1.3	-$ 1.4
Customer Service OM&A		-$ 3.8	-$ 0.1	-$ 1.0	$ 0.7	$ 0.2
Corporate Management		-$ 1.5	$ 0.3	-$ 0.8	$ 0.0	$ 0.1
Finance		-$ 3.4	-$ 1.6	-$ 1.3	$ 0.3	-$ 0.5
Human Resources		$ 0.5	$ 1.5	-$ 2.2	$ 0.8	$ 1.4
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		-$ 0.1	-$ 0.0	$ 2.7	$ 0.2	$ 0.2
General Counsel		-$ 0.7	$ 0.9	-$ 0.7	$ 0.2	$ 0.1
Regulatory Affairs		-$ 0.3	$ 0.6	$ 1.0	$ 1.0	-$ 1.0
Security Management		-$ 0.8	-$ 0.5	$ 1.0	$ 0.4	$ 0.1
Internal Audit		-$ 0.1	-$ 0.5	$ 0.6	$ 0.2	$ 0.2
Facilities and Real Estate		$ 2.0	-$ 0.4	$ 1.9	$ 1.1	$ 1.4
Asset Management (Planning) costs		-$ 4.3	-$ 1.4	-$ 0.1	$ 1.4	$ 0.8
Information Technology		$ 3.3	-$ 2.4	$ 0.2	-$ 0.2	$ 2.5
Cost of Sales		-$ 4.7	$ 3.9	-$ 1.3	-$ 1.5	$ 0.8
Other Recovery		-$ 18.2	$ 43.3	-$ 19.8	-$ 4.7	$ 8.2
Property Taxes & Rights Payments		-$ 4.5	$ 4.6	$ 3.7	$ 1.1	$ 1.2
Closing Balance	$ 419.2	$ 357.9	$ 398.5	$ 389.0	$ 393.4	$ 420 5

Notes:

* Will be updated with actuals when data is available

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the OEB-Approved amount. For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

Appendix 2-JC
OM&A Programs Table

($M)

Programs	2018 Actuals	2019 Actuals	2020 Board Approved	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year	Variance (Test Year vs. 2020 Actuals)	Variance (Test Year vs. 2020 Approved)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Sustainment									
Land Assessment and Remediation	1.3	1.0		0.7	0.9	0.9	0.9	0.3	
Environment Management	13.9	12.5		15.9	22.1	23.0	15.1	-0.8	
Power Equipment	60.1	50.8		43.1	45.0	44.7	52.6	9.5	
Ancillary System Maintenance	8.3	9.1		8.0	7.5	7.4	9.3	1.3	
Telecommunications (including cybersecurity)	55.1	51.2		52.9	52.2	54.5	58.7	5.7	
Site Infrastructure Maintenance	22.7	19.5		20.7	20.9	21.3	22.8	2.1	
Rights of Way	37.3	31.9		32.6	32.4	32.3	33.0	0.4	
Overhead Lines	18.9	18.3		17.2	15.6	15.8	18.2	0.9	
Underground Cables	7.6	5.6		4.3	4.0	3.7	4.0	-0.3	
Engineering & Environmental Support	4.1	7.9		5.4	4.7	4.7	5.0	-0.4	
Sub-Total	229.4	207.8		200.9	205.2	208.3	219.6	18.7	
Development									
Transmission Standards Program	2.8	2.5		4.1	4.0	4.0	4.3	0.1	
Research Development and Demonstration	2.2	1.8		2.3	3.4	3.9	3.3	1.0	
Customer Power Quality Program	0.2	0.1		0.2	0.9	1.0	1.0	0.8	
Sub-Total	5.2	4.4		6.7	8.3	8.9	8.6	1.9	
Operating									
Operations Contracts	19.5	20.2		19.5	22.3	20.8	22.6	3.1	
Environmental, Health and Safety	1.4	2.0		1.1	1.5	1.4	1.4	0.4	
Operators	32.5	28.8		27.3	25.0	26.4	25.0	-2.3	
Sub-Total	53.4	51.0		47.9	48.8	48.6	49.0	1.1	
Customer									
Customer Service OM&A	11.0	7.2		7.0	6.0	6.7	6.9	-0.2	
Sub-Total	11.0	7.2		7.0	6.0	6.7	6.9	-0.2	
Common Functions and Services									
Corporate Management	3.9	2.4		2.7	1.9	2.0	2.1	-0.7	
Finance	20.8	17.5		15.8	14.5	14.8	14.4	-1.5	
Human Resources	10.4	10.9		12.4	10.2	11.0	12.4	0.0	
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	4.6	4.5		4.4	7.2	7.3	7.6	3.1	
General Counsel	5.0	4.3		5.2	4.5	4.7	4.8	-0.4	
Regulatory Affairs	9.2	9.0		9.6	10.6	11.6	10.6	1.0	
Security Management	2.9	2.1		1.6	2.6	3.0	3.1	1.5	
Internal Audit	3.0	2.9		2.4	3.0	3.2	3.3	0.9	
Facilities and Real Estate	32.7	34.7		34.3	36.2	37.3	38.7	4.3	
Sub-Total	92.5	88.2		88.6	90.7	94.9	96.9	8.3	
Asset Management (Planning) costs									
Sub-Total	31.0	26.7		25.3	25.2	26.6	27.4	2.1	
Information Technology									
Information Technology	50.4	53.7		51.2	51.4	51.2	53.7	2.5	
Sub-Total	50.4	53.7		51.2	51.4	51.2	53.7	2.5	
Miscellaneous									
Cost of Sales	8.4	3.7		7.7	6.4	4.9	5.7	-2.0	
Other Recovery	-127.4	-145.6		-102.3	-122.1	-126.8	-118.7	-16.4	
Property Taxes & Rights Payments	65.3	60.8		65.4	69.1	70.2	71.4	5.9	
								0.0	
								0.0	
								0.0	
								0.0	
Sub-Total	-53.7	-81.1		-29.2	-46.6	-51.8	-41.6	-12.4	
Total	**419.2**	**357.9**	**385.0**	**398.5**	**389.0**	**393.4**	**420.5**	**22.0**	**35.5**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	2018 Actual	2019 Actuals	2020 Board Approved	2020 Actuals	2021 Forecast*	2022 Bridge Year	2023 Test Year
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
OM&A Costs							
O&M	$ 326,678,725	$ 269,685,406		$ 309,923,392	$ 298,275,876	$ 298,535,907	$ 323,665,611
Admin Expenses (CCFS)	$ 92,493,986	$ 88,190,273		$ 88,583,877	$ 90,718,464	$ 94,910,488	$ 96,864,059
Total Recoverable OM&A from Appendix 2-JB [5]	$ 419,172,711	$ 357,875,679	$ 385,040,207	$ 398,507,268	$ 388,994,339.9	$ 393,446,394	$ 420,529,670
Number of Delivery Points [2,4]	668	675		676	680	684	688
Number of FTEs [3,4]	4,247	4,028		3,983	4,149	4,218	4,285
Customers/FTEs	0.16	0.17		0.17	0.16	0.16	0.16
OM&A cost per delivery point							
O&M per delivery point	$ 489,040	$ 399,534		$ 458,467	$ 438,641	$ 436,456	$ 470,444
Admin per delivery point	$ 138,464	$ 130,652		$ 131,041	$ 133,410	$ 138,758	$ 140,791
Total OM&A per delivery point	$ 627,504	$ 530,186		$ 589,508	$ 572,050	$ 575,214	$ 611,235
OM&A cost per FTE							
O&M per FTE	$ 76,920	$ 66,957		$ 77,809	$ 71,893	$ 70,784	$ 75,535
Admin per FTE	$ 21,779	$ 21,896		$ 22,240	$ 21,866	$ 22,503	$ 22,605
Total OM&A per FTE	$ 98,699	$ 88,853		$ 100,049	$ 93,759	$ 93,287	$ 98,140

Total OM&A/delivery pt	3.7%	change from 2020
	-2.6%	change from 2018
	1.2%	CAGR 2020 to 2023
Total OM&A/FTE	-1.9%	change from 2020
	-0.6%	change from 2018
	-0.6%	CAGR 2020 to 2023

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB.
Number of delivery points are used for Hydro One Transmission, and thus number of customers is not provided consistent with 2020-22 Tx Application.

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K.
Per Attachment E-06-01-02A, the FTE portion for transmission is based on the average FTEs by month-end

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

OM&A COST DRIVER TABLES FOR TRANSMISSION OM&A EXPENDITURES – EXPLANATORY NOTES

1.0 INTRODUCTION

Hydro One completed Appendix 2-JA, 2-JB, 2-JC and 2-L at Attachment 1A of Exhibit E-02-01. The tables cover Hydro One Transmission's OM&A costs over the 2018 to 2023 period and provide a breakdown of the Transmission OM&A cost drivers by year and program.

1.1 SUMMARY OF RECOVERABLE OM&A EXPENSES (APPENDIX 2-JA)

Appendix 2-JA includes the detailed breakdown of Transmission OM&A expenditures by major category and the year-over-year variances. As noted in Exhibit E-02-01, the 2023 OM&A expenditure ($420.5M) is 9.2% higher than the 2020 approved OM&A ($385.0M) and 5.5% higher than 2020 actuals ($398.5M). The compound annual average growth rate in OM&A is 1.8% per year from 2020 to 2023, and 0.1% per year from 2018 to 2023, as shown in Appendix 2-JA. Relative to the bridge year, the 2023 test year OM&A is 6.9% higher than the 2022 OM&A ($393.4M) with high level variance explanations provided in Exhibit E-02-01.

1.2 RECOVERABLE OM&A COST DRIVER TABLE (APPENDIX 2-JB)

Appendix 2-JB shows the year-over-year changes in the major cost drivers for Hydro One's Transmission OM&A expenses.

1.3 OM&A PROGRAMS (APPENDIX 2-JC)

Appendix 2-JC provides the variance in test year OM&A to 2020 actuals by program. The full analysis and detailed variance explanations for activities that are within and not within the company's control are provided at the following exhibits:

Cost Category	Exhibit Reference	Exhibit Title
Sustainment	E-02-02	Transmission Sustainment OM&A
Development	E-02-03	Transmission Development OM&A
Operations	E-04-05	Operations OM&A
Customer Care	E-02-04	Transmission Customer Care OM&A
Common and Other	E-04-01	Summary of Common and Other OM&A
Property Taxes and Rights Payments	E-09-04	Taxes Other Than Income Taxes

Further details on the decisions and alternatives that were made to manage costs are discussed at these detailed level exhibits.

1.4 RECOVERABLE OM&A COSTS PER DELIVERY POINT AND PER FULL TIME EMPLOYEE (FTE) (APPENDIX 2-L)

Appendix 2-L includes the recoverable OM&A cost per delivery point and per FTE for Hydro One Transmission.

The total OM&A cost per delivery point is $611,235 in 2023, which represents a 3.7% increase from 2020 actuals ($589,508) and a compound annual growth rate of 1.2% per year since 2020.

The total OM&A cost per FTE is $98,140 in 2023, which represents a 1.9% decrease from 2020 ($100,049) and a compound annual growth rate of -0.6% per year since 2020.

TRANSMISSION SUSTAINMENT OM&A

1.0 SUMMARY OF SUSTAINMENT OM&A

Sustainment OM&A consists of expenditures required to maintain existing transmission system equipment and facilities to ensure they continue to function safely and as originally designed. The Sustainment OM&A expenditures allow Hydro One to maintain system reliability and service quality, while satisfying applicable legislative, regulatory, environmental, and safety requirements.

Hydro One's Sustainment OM&A program is organized into three categories of expenditures:

- Stations, which funds the work required to maintain existing assets located within transmission stations, including existing protection, control, and telecommunication facilities;
- Lines, which funds the work required to maintain overhead transmission lines and underground cables, including vegetation management on transmission line rights-of-way; and
- Engineering and Environmental Support, which funds the specialized and administrative support needed to assist with decision-making processes in managing the transmission assets.

Table 1 below sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for each of the three Sustainment OM&A categories.

Table 1 - Summary of Sustainment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Stations	161.4	144.1	141.3	148.6	151.7	159.5
Lines	63.8	55.8	54.2	52.0	51.9	55.2
Engineering & Environmental Support	4.1	7.9	5.4	4.7	4.7	5.0
Total Sustainment	**229.4**	**207.8**	**200.9**	**205.2**	**208.3**	**219.6**

The forecast Transmission Sustainment OM&A expenditure for the 2023 Test Year is $219.6M. This forecast is $6.4M or 3% higher than the amount that would result when adjusting the last rebasing year's actual expenditures (2020) by inflation ($213.2M).[1]

The 2023 Test Year forecast is $8.8M higher than the historical average (2018-2021), $14.4M higher than the 2021 forecast, and $11.3M higher than the 2022 Bridge Year forecast. Notwithstanding inflationary pressures, the proposed 2023 Test Year increase relative to 2021 and 2022 is primarily driven by increased expenditures for preventive maintenance on stations power equipment, cyber security needs, and overhead lines maintenance, partially offset by decreased expenditures on polychlorinated biphenyl (PCB) remediation work and productivity savings in the Lines programs. These drivers are summarized below.

Power Equipment Maintenance OM&A – Hydro One plans to resume preventive maintenance on transmission power equipment that was deferred in 2019-2022, returning this work to historical levels. These deferrals allowed Hydro One to continue funding PCB remediation work

[1] 2020 actual expenditures adjusted by inflation for 3 years = = $200.9M x (1+2%)^3 = $213.2M. ($219.6M/$213.2M - 1)% = 3%. Inflation is as presented in Exhibit E-03-01.

as planned. This remediation work is required by the federal *PCB Regulations*, which provide that PCB-contaminated equipment meeting applicable thresholds must be removed from service by December 31, 2025.

From 2018 to 2022, total sustainment OM&A funding declined by 9% (from $229.4M to $208.3M). To accommodate the reprioritization of maintenance activities while remaining within the OM&A funding envelope and completing necessary PCB remediation work (PCB expenditures increased from 3% of the budget in 2018 to 8% of the budget in 2022), Hydro One had to defer certain preventive maintenance activities and condition assessments on stations power equipment, as well as certain planned transformer refurbishments. Hydro One selected these deferrals by using updated asset condition data to determine which maintenance activities could be deferred for a short period of time without unduly jeopardizing the performance of Hydro One’s transmission system. This deferred work must now be completed, as Hydro One’s asset management approach relies on sustaining asset performance to maintain transmission system safety and reliability. Thus, Hydro One must resume the previously planned level of preventive maintenance to ensure that necessary maintenance activities are completed in a timely manner and that new capital replacement candidates are identified before they malfunction or fail. This, in turn, will reduce the risk of unplanned equipment failure impacting the reliability of the transmission system.

Cyber Security – Hydro One plans to increase funding for cyber security requirements to maintain compliance with regulatory obligations – including security needs related to evolving security threats and North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards – and to insource key aspects of its security operations through a new in-house Joint Security Operations Centre (JSOC), a 24/7 centre for monitoring cyber and physical security. The JSOC will allow Hydro One to appropriately manage evolving security risks, including new risks created by the growth of digitally-connected devices and cloud-based services, by enabling improved incident monitoring, triage assessment, proactive security and response capabilities, and regulatory compliance oversight. This, in turn, will improve the resilience of the transmission system in the face of physical and cyber security threats. Hydro One anticipates completing the JSOC in 2022 and fully assuming all primary cyber and physical security monitoring and system operations functions from its existing managed service providers by the end of 2023.

Overhead Lines Maintenance - 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.

PCB Remediation Expenditures - Hydro One plans to partially offset the expenditure increases described above by decreasing its PCB remediation expenditures in 2023 to a level that will allow Hydro One to complete all remaining PCB remediation work according to the federal *PCB Regulations* by December 31, 2025. The decrease is primarily driven by the completion of some PCB remediation work during the 2021-2022 period at Hydro One’s critical customers’ plants (such as generators, OPG, Bruce Power, and manufacturing plants) as well as at certain stations assets that are more expensive to remediate.

2.0 SUSTAINMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide further details regarding Stations, Lines, and Engineering and Environmental Support Sustainment categories; their respective programs and sub-programs; and Test Year expenditures and variance analysis.

2.1 STATIONS

Transmission stations are used for the delivery of power, voltage transformation, and switching. They serve as connection points for both load customers and generator customers. Transmission stations contain power system equipment further described in TSP Section 2.2.

The Stations Sustainment OM&A covers expenditures that maintain the performance of assets located within Hydro One's transmission stations. The Stations Sustainment OM&A program is divided into the following seven program categories: (i) Land Assessment and Remediation; (ii) Environmental Management; (iii) Power Equipment Maintenance; (iv) Ancillary Systems Maintenance; (v) Protection, Automation and Telecom Maintenance; (vi) Cyber Security; and (vii) Site Infrastructure Maintenance.

Table 2 below sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for each of the seven Stations categories.

Table 2 - Stations Sustainment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Land Assessment and Remediation	1.3	1.0	0.7	0.9	0.9	0.9
Environmental Management	13.9	12.5	15.9	22.1	23.0	15.1
Power Equipment Maintenance	60.1	50.8	43.1	45.0	44.7	52.6
Ancillary Systems Maintenance	8.3	9.1	8.0	7.5	7.4	9.3
Protection, Automation and Telecom Maintenance	40.6	39.5	39.3	36.7	36.1	37.1
Cyber Security	14.6	11.8	13.7	15.5	18.4	21.5
Site Infrastructure Maintenance	22.7	19.5	20.7	20.9	21.3	22.8
Total	**161.4**	**144.1**	**141.3**	**148.6**	**151.7**	**159.5**

The proposed Stations Sustainment OM&A for the Test Year is $159.5M. This budget is $9.5M or approximately 6% higher than the amount that would result from adjusting the last rebasing year's actual expenditures (2020) by inflation ($150M).[2]

The 2023 Test Year forecast expenditure is $10M higher than the historical average (2018-2022), $10.9M higher than the 2021 forecast, and $7.7M higher than the 2022 Bridge Year forecast. Notwithstanding inflationary pressures, the increase is primarily driven by the following programs:

- Power Equipment Maintenance – to accommodate the reprioritization of maintenance activities in order to remain within the OM&A funding envelope and support the PCB remediation program, Hydro One deferred certain preventive maintenance activities for transformers, circuit breakers, and switches. Using asset condition and maintenance data, Hydro One identified areas where specific time-based preventive maintenance activities could be deferred for a short period of time only. As the PCB remediation program winds down, Hydro One plans to return to the pre-2019 historical level of spending by resuming the deferred maintenance activities in 2023. As a result of the foregoing, the Power Equipment Maintenance expenditures in 2023 Test Year are increasing compared to the 2019-2022 period.

- Cyber Security – as discussed above, Hydro One plans to increase funding for cyber security requirements to maintain compliance with regulatory obligations, including NERC CIP standards, and to establish the Joint Security Operations Centre (JSOC), which will allow Hydro One to streamline its security operations and appropriately manage new and evolving security threats that pose risks to the operation of the transmission system.

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[2] 2020 actual expenditures adjusted by inflation for 3 years = $141.3M x (1+2%)^3 = $150M. ($159.5M/$150M - 1)% = 6.3%. Inflation is as presented in Exhibit E-03-01.

- Other – slight increases in Ancillary Systems Maintenance and Site Infrastructure Maintenance programs are the result of the need to address deficiencies in the stations grounding system and building infrastructure.

The increased spending in Stations expenditure is partially offset by the decrease in the Environmental Management program. The variance is mainly driven by the completion of the PCB remediation work at critical customer stations, such as nuclear generators and manufacturing plants that require extensive outage and resource planning in order to execute the required work.

Further details on the aforementioned drivers, along with descriptions of the Stations programs and their respective Test Year expenditures, are provided in the sections below.

2.1.1 LAND ASSESSMENT AND REMEDIATION

Through the Land Assessment and Remediation (LAR) program, Hydro One assesses the level of contamination on its properties. This program is focused on the mitigation and remediation of historical off-property contamination from transmission station sites and real estate facilities that may pose a risk to the public and/or Hydro One staff. Where appropriate, LAR work is coordinated with refurbishment and capital work.

The LAR program follows a process to prioritize and select sites for environmental assessment and remediation work based on two factors: (i) the type and level of contamination that exceeds Ministry of Environment, Conservation and Parks (MOECP) standards; and (ii) the potential for the contaminants to cause adverse effects on human health and/or the environment

The LAR program consists of the following components: site assessment, site remediation, and site management work. Site assessments involve information-gathering and soil and groundwater testing to identify and prioritize the remediation work. Site remediation is performed where contamination is identified, and includes the development of a remediation plan. This plan typically includes the treatment, removal, or management of the identified contamination. Site management work begins once a site has been assessed and remediated, and includes the monitoring and management of any residual on-site contamination, as well as the management of installed controls (e.g., barriers and long-term treatment systems).

Table 3 below sets out Hydro One's planned expenditures for LAR program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 3 - Land Assessment and Remediation OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Land Assessment and Remediation	1.3	1.0	0.7	0.9	0.9	0.9

The forecast expenditures for the 2023 Test Year are $0.9M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing year's actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The expenditure in a given year depends on the number of sites identified for remediation and the extent of the remediation work required.

2.1.2 ENVIRONMENTAL MANAGEMENT

The Environmental Management program is an ongoing program that focuses on mitigating and remediating contamination located both within and beyond the station fence. It involves managing, testing, and disposing of PCB and other regulated waste that develops as part of Hydro One's normal business operations. This program ensures that Hydro One is able to satisfy its obligations related to environmental regulations and policies associated with its transmission station equipment.

The Environmental Management program consists of the following four activities: (i) PCB Retirement and Waste Management, (ii) Transformer Oil Leak Reduction, (iii) Preventive and

Corrective Maintenance, and (iv) Environmental Compliance and Emergency Response Plan Updates. Proposed funding for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, is set out in Table 4 below.

Table 4 - Environmental Management OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
PCB Retirement and Waste Management	6.9	7.5	9.9	17.0	17.7	9.3
Transformer Oil Leak Reduction	3.0	1.5	2.7	2.3	2.4	2.6
Preventive and Corrective Maintenance	2.6	2.4	2.1	1.8	1.8	1.8
Environmental Compliance and Emergency Response Plan Updates	1.4	1.0	1.1	1.0	1.1	1.4
Total	**13.9**	**12.5**	**15.9**	**22.1**	**23.0**	**15.1**

The proposed 2023 Test Year expenditures are $15.1M. This is slightly lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), in line with the historical average (2018-2021), and lower compared to the 2021-2022 forecast period. The decrease relative to 2020 and the 2021-2022 forecast period is primarily driven by the completion of some PCB remediation work at (i) critical customer stations such as nuclear generators and manufacturing plants that require extensive outage and resource planning in order to execute the required work, and (ii) transformer bushings and auto-transformer bushings that are more expensive to remediate due to outage planning and scheduling and the lead time required to procure materials. Further details are provided below.

2.1.2.1 PCB Retirement and Waste Management

The PCB Retirement and Waste Management program aims to identify and phase out PCB-contaminated inventory to comply with the *PCB Regulations*. In accordance with the *PCB Regulations*, oil-filled power equipment located at Hydro One's transmission stations (such as transformers, breakers, instrument transformers, and associated capacitors, bushings, and reclosers) containing concentrations of PCB greater than 50 ppm are required to be retro-filled or replaced by year-end 2025.[3] In addition to inspecting, testing, and retro-filling PCB-contaminated equipment, the program also funds activities that manage regulated waste, including but not limited to lead, cadmium, and mercury, which are the subject of provincial and federal regulatory requirements applicable to Hydro One.[4]

Table 5 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 5 - PCB Retirement and Waste Management OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
PCB Retirement and Waste Management	6.9	7.5	9.9	17.0	17.7	9.3

The proposed expenditures in the 2023 Test Year are $9.3M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and lower than the historical average (2018-2021) and 2021-2022 forecast period. The decrease is primarily driven by the completion of some PCB remediation work at Hydro One's critical customers' plants (such as generators, OPG, Bruce Power, and manufacturing plants) as well as at certain stations assets that are very expensive to remediate.

Hydro One identified more than 25,000 components of equipment (i.e., bushings, instrument transformers, etc.) that require sampling and, where indicated, either retro-filling or replacement. This remediation work largely spans the 2019-2022 period and will be scaling down from 2023 to 2025. If the identified PCB content is high, this equipment needs to be retro-filled or replaced. To date, Hydro One has identified more than 2,235 assets (including

[3] Based on an amendment to the regulation by Environment Canada in 2014, which took effect in 2015.
[4] O. Reg. 362: *Waste Management – PCB's*; O. Reg. 347: *General – Waste Management*; and *PCB Regulations*, SOR/2008-273.

approximately 1800 breaker bushings, 350 transformer bushings and 75 instrument transformers) that require replacement or OM&A retro-filling to remediate high PCB content. Many of these assets are located at critical customer stations such as nuclear generators and manufacturing plants that require extensive outage and resource planning in order to execute the require work. This work is currently scheduled during the 2021-2022 period.

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. Following the completion of this work in 2022, the proposed 2023 Test Year expenditure is decreasing and has been set to complete the PCB remediation work through to the 2025 deadline.

2.1.2.2 Transformer Oil Leak Reduction

Hydro One repairs transformer oil leaks through the Transformer Oil Leak Reduction program. As transformers age, they become susceptible to leaks due to the effects of thermal cycling and the gradual deterioration of sealing gaskets. Oil leaks are one of the most common deficiencies found in transformers, and are a significant contributor to transformer forced outages. Active leaks also provide a path of moisture ingress into a transformer's internal winding, which, in Hydro One's experience, has been one of the major causes of transformer Class 1 failures[5] (e.g., the Richview TS T8 transformer, which caught fire due to an internal failure caused by moisture).

When first discovered, transformer oil leaks are repaired on a temporary basis under the corrective program to mitigate any immediate environmental concerns. These repairs are usually a short-term solution that uses an exterior application of sealant until a more permanent solution can be implemented. The permanent solution involves disassembling the transformer

[5] A Class 1 failure is a transformer failure that cannot be fixed at the site.

and changing the gaskets, which requires an outage, staff with a specific skill set, and specialized equipment.

Table 6 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 6 - Transformer Oil Leak Reduction OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Transformer Oil Leak Reduction	3.0	1.5	2.7	2.3	2.4	2.6

The proposed 2023 Test Year expenditures are $2.6M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing year's actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast expenditures.

2.1.2.3 Preventive and Corrective Maintenance

The preventive maintenance component of the Preventive and Corrective Maintenance Program ensures that spill containment systems are inspected and operate as designed. The program also ensures that non-functioning mechanical components (such as pumps, sensors, and relays) used in oil/water separators to control effluent from the transformer spill containment pits are repaired or replaced, as required.

The corrective maintenance component of the program includes repairing spill containment systems identified as requiring mitigation. The program also maintains spill containment capacity for non-functioning spill containment systems by removing and disposing of the rainwater, containing and cleaning up insulating fluid spills as they occur, and undertaking all other actions necessary to mitigate environmental risks posed by transmission equipment problems and failures.

The Preventive and Corrective Maintenance program allows Hydro One to meet its corporate Environmental Policy objectives, maintain compliance with MOECP requirements, minimize risks to human health and the environment, and mitigate Hydro One's exposure to legal and reputational risks.

Table 7 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 7 - Preventive and Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive and Corrective Maintenance	2.6	2.4	2.1	1.8	1.8	1.8

The proposed 2023 Test Year expenditures are $1.8M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing year's actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast expenditures.

2.1.2.4 Environmental Compliance and Emergency Response Plan Updates

The Environmental Compliance category encompasses (i) activities associated with greenhouse gas management, and (ii) activities required to comply with MOECP Environmental Compliance Approvals (ECAs),[6] which include a number of common and site-specific requirements (e.g., regular testing of effluent).

[6] Formerly known as Certificates of Approval.

Hydro One's climate adaptation and mitigation program includes compliance requirements related to legislation and regulations for greenhouse gases. Compliance activities include program management, emission reporting, third-party verification, and related initiatives.

Emergency Response Plans (ERPs) are station-specific emergency response and evacuation plan documents that are kept at each transmission station. They are an effective tool for planning, preparing for, and responding to emergencies. The ERPs ensure that the risk of harm to employees, contractors, the public, the environment, and the physical assets of Hydro One in the event of an emergency is minimized. Funding under this program ensures that all ERPs contain up-to-date and accurate site-specific information.

Table 8 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 8 - Environmental Compliance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Environmental Compliance and Emergency Response Plan Updates	1.4	1.0	1.1	1.0	1.1	1.4

The proposed 2023 Test Year expenditures are $1.4M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing year's actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast expenditures.

2.1.3 POWER EQUIPMENT MAINTENANCE

Hydro One's transmission power equipment includes 721 transformers, 4,756 circuit breakers, as well as switches, insulators, bus work, instrument transformers, capacitor banks, and reactors installed in 291 transmission stations. Maintenance of these assets is required to sustain power equipment performance and to maintain transmission system safety and reliability, refurbish power equipment to preserve the equipment's expected service life and reliability, and assess poor-equipment condition warranting replacement under Hydro One's capital renewal expenditure plan.

The Power Equipment Maintenance program is divided into the following five categories: (i) Preventive Maintenance, (ii) Corrective Maintenance, (iii) Transformer Refurbishments, (iv) Breaker Refurbishments, and (v) Other Maintenance and Inspection Programs. Table 9 below sets out Hydro One's planned expenditures for the 2023 Test year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each category.

Table 9 - Power Equipment Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance	19.4	15.4	13.1	12.3	12.9	18.5
Corrective Maintenance	30.0	27.2	26.7	24.8	23.5	25.6
Transformer Refurbishments	4.9	3.7	0.5	3.3	3.5	3.5
Breaker Refurbishment	3.9	2.2	0.4	1.9	2.0	2.1
Other Maintenance and Inspection Programs	1.9	2.3	2.4	2.7	2.7	2.9
Total	**60.1**	**50.8**	**43.1**	**45.0**	**44.7**	**52.7**

The proposed expenditure for Power Equipment Maintenance in the 2023 Test Year is $52.7M. This budget is $9.6M or 22% higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure). The 2023 Test Year forecast expenditure is $9.6M higher than the historical average (2018-2021) and approximately $8.0M higher compared to the 2021-2022 forecast period.

The Test Year increase is primarily due to the need to resume certain preventive maintenance activities that were deferred in 2019-2022, returning this work to historical levels. These deferrals allowed Hydro One to (i) maintain the required levels of PCB remediation work to comply with the *PCB Regulations*, and (ii) accommodate increasing Cyber Security expenditures while remaining within the funding envelope for OM&A expenditures for the 2020-2022 period.

To allow Hydro One to maintain the levels of PCB remediation work (discussed in the Environmental Management section above) required to meet the legislative deadline and remain within the funding envelope for OM&A expenditures, Hydro One deferred specific preventive maintenance activities over 2019-2022 on power equipment such as transformers, circuit breakers, and switches, as well as transformer mid-life refurbishments. Hydro One selected these deferrals by using updated asset condition data to identify assets for which certain preventive maintenance activities, such as intrusive internal inspections and some diagnostics, could be deferred for a short period of time at comparatively lower risk to transmission system performance and reliability.

These preventive maintenance activities are necessary to comply with manufacturer guidelines and industry standards and to test the equipment and verify its performance. Hydro One relies on condition data collected during preventive maintenance to assess the need for, prioritize, and execute capital replacements and other preventive and corrective maintenance. Thus, Hydro One must resume the proposed level of preventive maintenance to ensure that the necessary maintenance activities are completed in a timely manner and new capital replacements candidates are identified. This, in turn, will reduce the risk of unplanned equipment failure impacting the reliability of the transmission system.

Furthermore, Hydro One expects to add five new transformer stations to the total number of stations during the 2023-2027 period. The power equipment in these new stations, as well as the newly in-serviced equipment in existing stations, require regular preventive maintenance. This includes condition and diagnostic testing to ensure proper operation and performance in the “infancy” stages of their deployment.

As a result of the deferrals described above in 2019-2022, Hydro One has a backlog of preventive maintenance activities that need to be addressed through increased expenditures starting in the 2023 Test Year. These expenditures are in line with pre-2019 spending levels, notwithstanding the accumulated backlog that must be addressed.

2.1.3.1 Preventive Maintenance

Hydro One performs preventive maintenance to ensure the safe and reliable operation of its transmission system. The preventive maintenance activities are also undertaken to meet obligations under section 7.1.1 of the Transmission System Code, which requires Hydro One to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments."

Hydro One's preventive maintenance program places priority on condition assessment activities – including visual inspections, oil analysis, function testing, and equipment performance monitoring – rather than more intrusive time-based repairs. The different types of power equipment have varying maintenance activities. The following are examples of maintenance activities for transformers, breakers, and switches that Hydro One performs:

- Regular visual inspections to identify and record defects;
- Recording of pressures and temperatures to ensure that equipment is operating within appropriate specifications and to identify oil leaks;
- Testing the function of various equipment elements and alarms to ensure continued operation and reliability, and topping up oil as required;
- Diagnostic testing such as circuit breaker trip timing, contact resistance, oil analysis for dissolved gas, moisture content, and dielectric strength; and
- Selective intrusive maintenance to assess equipment condition, check contacts, clean and lubricate, replace seals, and complete minor repairs as required.

The frequencies of these activities vary depending upon the make, model type, and condition of the subject power equipment. The Preventive Maintenance program expenditures are based on the volume and type of maintenance work required to be completed during the calendar year.

Table 10 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 10 - Preventive Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance	19.4	15.4	13.1	12.3	12.9	18.5

The proposed 2023 Test Year expenditure is $18.5M. This is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the 2021-2022 forecast period. The variance is primarily driven by the need to (i) resume certain preventive maintenance activities that were deferred to manage within the OM&A funding envelope in 2019 due to the one-year inflationary rate application, (ii) maintain the required levels of PCB remediation work to comply with the *PCB Regulations*, and (iii) accommodate increasing Cyber Security expenditures while remaining within the funding envelope for OM&A expenditures during the 2020-2022 period.

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. The preventive maintenance activities that were deferred during 2019-2022 (e.g., breaker and transformer intrusive maintenance) need to be resumed to repair equipment deficiencies, and because the ongoing condition data from these activities is necessary to properly assess the need for, prioritize, and execute capital replacements. Thus, to mitigate the risk of unplanned equipment failure impacting the reliability of the transmission system, Hydro One must resume the proposed level of preventive maintenance to ensure that the necessary maintenance activities are completed in a timely manner and new capital replacements candidates are identified.

The data obtained through preventive maintenance is required to determine whether major overhaul maintenance, intrusive repairs, or refurbishments are necessary, and the extent to which any maintenance activities may be deferred. For example, in order to determine whether it is appropriate to defer time-based intrusive repair or refurbishment of a breaker, Hydro One must have data on the condition and performance of the breaker. This data is obtained through some time-based preventive inspections such as visual inspections, thermography, and diagnostic testing. The same applies in respect of other power equipment such as transformers, switches, and reclosers. The data from these time-based inspections allows Hydro One to make appropriate, risk-based decisions regarding which equipment needs major overhaul maintenance and which maintenance activities can be deferred for a short period of time, where necessary, without unduly jeopardizing the performance of the transmission system. Expenditures on time-based preventive maintenance are required regardless of asset age or condition. For example, preventive inspections and diagnostic testing are required to ensure the proper operation and performance of assets in the early stages of their deployment. Such testing is typically recommended by the manufacturer to qualify for warranties, as well.

In light of the foregoing, Hydro One’s Preventive Maintenance expenditures are forecast to increase in the 2023 Test Year relative to the 2020 expenditure and Historical Years in order to resume deferred maintenance activities that can no longer be deferred without compromising system performance and reliability.

2.1.3.2 Corrective Maintenance

Corrective maintenance work is required to repair power equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned repairs based on condition assessments and unplanned (i.e., demand) work, including emergency response. Planned corrective maintenance addresses issues outside regular preventive maintenance activities, including defects identified during normal condition assessments. Where possible, planned corrective maintenance is bundled or coordinated with other work to achieve efficiencies.

Unplanned corrective maintenance includes all unscheduled, non-programmed maintenance necessitated by unforeseen problems and/or equipment failures. Emergency response may include a preliminary investigation and minor repairs following equipment failure. Typically, the emergency work is required to address the risk of harm and/or damage to employee safety, public safety, system reliability, or the environment.

Table 11 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 11 - Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Corrective Maintenance	30.0	27.2	26.7	24.8	23.5	25.6

The proposed 2023 Test Year expenditures are $25.6M. This is lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the historical average (2018-2021), and slightly higher than the 2021-2022 forecast period. Given that this work is reactive in nature, the number and severity of corrective maintenance issues addressed each year is variable.

2.1.3.3 Transformer Refurbishments

Refurbishment of Hydro One's transformer fleet is required to preserve the transformer's expected service life and reliability and to mitigate the need for premature replacement. Refurbishment includes addressing deteriorating transformer parts and components (such as radiators, gaskets, gauges, bushings, fans, pumps, and instrumentation) through major refurbishment or replacement prior to the end of the expected service life of the transformer. The Transformer Refurbishment program targets transformers that have not been scheduled for capital replacement programs.

The scope of the refurbishments is comprehensive and includes activities such as changing gaskets, refurbishment or replacement of transformer components, adding pressure relief devices, adding and upgrading transducers and monitoring devices, painting, and oil processing. Some refurbishments also include low-frequency heating (LFH) dry-out treatment, to reduce moisture in the transformer's internal paper insulation in order to preserve its useful life. These refurbishments are completed where it is cost-effective to do so. They allow the transformer to remain in-service through its expected service life while maintaining reliability.

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. Examples of these activities include upgrading fall-arrest safety systems, proactive on-line dry-outs, installation of maintenance-free self-regenerating breathers, installation of under-load tap changer (ULTC) filtration systems, and the planned implementation of manufacturer recommended modifications to ULTCs.

Table 12 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 12 - Transformer Refurbishment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Transformer Refurbishment	4.9	3.7	0.5	3.3	3.5	3.5

The proposed Test Year expenditure is $3.5M, which is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) but in line with the 2021-2022 forecast period and the overall historical trend (2018-2021). The increase compared to the most recent actual expenditure is primarily driven by a one-year deferral of certain maintenance work in 2020 to accommodate the PCB remediation program, as further described above.

2.1.3.4 Breaker Refurbishments

Breaker refurbishments are required to address specific issues with some circuit breaker models (e.g., air blast, oil, gas-insulated switchgear, and sulfur hexafluoride (SF_6) circuit breakers) so as to allow those circuit breakers to reach their expected service lives. A significant portion of this program encompasses breaker refurbishment activities that resulted from past failures and corrective action plans developed during failure investigations. The majority of expenditures in this category are related to modifications and upgrades targeting air blast (predominantly at Bruce A and B TS), oil, and SF_6 breakers as well as gas-insulated switchgear (GIS). Planned work focuses on mitigating reliability risks by performing time-based condition monitoring to track asset condition and then, based on asset condition, undertaking the necessary actions to ensure reliability for customers and the BES. The Breaker Refurbishment program also focuses on refurbishing GIS breakers and high-voltage breaker hydraulic drive mechanisms.

Table 13 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 13 - Breaker Refurbishment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Breaker Refurbishment	3.9	2.2	0.4	1.9	2.0	2.1

The proposed Test Year expenditures are $2.1M. This is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) but in line with the 2021-2022 forecast period and the overall historical trend (2018-2021). The Test Year variance relative to 2020 is primarily driven by a one-year deferral of certain refurbishment work in 2020 in order to remain within the funding envelope for OM&A expenditures. The Test Year refurbishment expenditures are necessary to continue refurbishing poor-condition breakers to preserve their expected service life and reliability, as well as to mitigate the need for premature replacement.

2.1.3.5 Other Maintenance and Inspection Programs

Maintenance activities under this category include nuisance wildlife control, maintenance required for strategic spares, and miscellaneous maintenance as outlined below.

Nuisance wildlife control programs are in place to address the issues associated with equipment interruptions and customer outages resulting from wildlife entering Hydro One's transmission stations. The program involves installation of animal controls (such as cover-ups) and barriers (such as perimeter fence dig barriers) to limit the likelihood of an animal coming into contact with power equipment. Hydro One has found this program to be effective in mitigating delivery point interruptions caused by animal contact.

Strategic spares maintenance programs are in place to maintain the inventory of spare parts or components for circuit breakers and transformers that support the in-service fleet. The program includes the maintenance required to ensure that these components are available to enable timely response to system component failures and are maintained in a manner that does not void manufacturer warranties.

Other miscellaneous maintenance programs for power equipment include capacitor bank maintenance, insulator contamination monitoring and power washing, and station asset assessment activities. These activities are important for ensuring equipment and customer reliability, as well as for managing equipment in a prudent and sustainable manner.

Table 14 below sets out Hydro One's planned expenditures for this program for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 14 - Other Maintenance and Inspection Programs OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Other Maintenance and Inspection Programs	1.9	2.3	2.4	2.7	2.7	2.9

The proposed 2023 Test Year expenditures are $2.9M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the historical average (2018-2021), primarily due to additional programs such as nuisance wildlife and other attributed programs that are necessary for reliable power system operations.

2.1.4 ANCILLARY SYSTEMS MAINTENANCE

Ancillary systems are comprised of station service systems, high-pressure air systems, grounding systems, DC battery and charger systems, backup generators, and oil-processing facilities. These systems provide key services and operating support to various station components and protection systems and are required at all Hydro One transmission stations.

This program focuses on sustaining the performance of ancillary systems by dividing the work into the following three categories: (i) Preventive Maintenance; (ii) Corrective Maintenance; and (iii) Other Maintenance Programs. Table 15 shows Hydro One’s planned expenditures for this program in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each category.

Table 15 - Ancillary Systems Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance	4.1	4.5	4.0	4.1	4.0	4.3
Corrective Maintenance	3.6	3.6	2.9	2.3	2.3	2.9
Other Maintenance Programs	0.6	1.0	1.1	1.1	1.1	2.1
Total	**8.3**	**9.1**	**8.0**	**7.5**	**7.4**	**9.3**

Hydro One's proposed 2023 Test Year expenditures for the Ancillary Systems Maintenance program are $9.3M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The increase in 2023 is primarily driven by the need to repair deficiencies in station grounding systems, which are essential components of transmission stations that ensure public and employee safety.

2.1.4.1 Preventive Maintenance

The Preventive Maintenance program for Ancillary Systems is required to sustain the performance of ancillary equipment that supports the operation of protection systems and critical power equipment. Preventive maintenance activities include periodic testing and inspections to ensure that the equipment is in satisfactory condition and will operate reliability.

Oversight bodies, such as the Technical Standards and Safety Authority, IESO, Northeast Power Coordinating Council (NPCC), NERC, Ministry of Health, and the MOECP, impose various regulatory requirements and in some cases mandate specific inspection and testing cycles to which Hydro One must adhere.

Table 16 shows Hydro One's planned expenditures for this program in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical years.

Table 16 - Preventive Maintenance OM&A ($M)

Description	Historical Years				BridgeYear	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance	4.1	4.5	4.0	4.1	4.0	4.3

The proposed 2023 Test Year expenditure is $4.3M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the overall historical trend (2018-2021). The 2023 Test Year expenditures are necessary to continue preventive maintenance activities on batteries, chargers, and backup power generators at mandated intervals to comply with NERC PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance) and NPCC Directory 8 (System Restoration). The slight variances in expenditures from year to year are due variances in the maintenance activities that are required to be carried out each year, with some years requiring more frequent or more costly maintenance plans.

2.1.4.2 Corrective Maintenance

The Corrective Maintenance program for Ancillary Systems is required to repair ancillary equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and unplanned work, including emergency response. Corrective maintenance is required to address the risk of harm and/or damage to employee safety, public safety, system reliability, or the environment.

Table 17 shows Hydro One's planned expenditures for this program in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 17 - Corrective Maintenance OM&A ($M)

Description	Historical Years				BridgeYear	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Corrective Maintenance	3.6	3.6	2.9	2.3	2.3	2.9

The proposed 2023 Test Year expenditure is $2.9M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and slightly higher compared to the 2021-2022 forecast period. The proposed expenditures are in line with the overall historical trend (2018-2021).

2.1.4.3 Other Maintenance Programs

Other maintenance program activities include grounding studies and repairs, maintenance of Hydro One's oil storage and processing operation at its Central Maintenance Services facility, and upgrades to backup diesel generators.

This program also funds the payments for services at facilities shared with OPG and Bruce Power. Hydro One has a number of sites located within or adjacent to generating stations (hydraulic, thermal, and nuclear) that are owned and operated by OPG or Bruce Power and where services are purchased directly from the plant in order to maintain switchyard operations. These services include AC/DC station service and water and snow removal.

Table 18 sets out Hydro One's planned expenditures for this program in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 18 - Other Maintenance Programs OM&A ($M)

Description	Historical Years				BridgeYear	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Other Maintenance Programs	0.6	1.0	1.1	1.1	1.1	2.1

The proposed 2023 Test Year expenditure is $2.1M. This is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical trend, and the 2021-2022 forecast period. 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.

2.1.5 PROTECTION, AUTOMATION AND TELECOM MAINTENANCE

Protection and automation assets are required to protect, control, and operate the transmission system. They also provide real-time operational data, control remote equipment, and capture detailed event records for post-event analysis. Power system telecom systems provide high-reliability and high-speed communications required for the protection, monitoring, and control of Hydro One's transmission system.

Table 19 below sets out Hydro One's planned OM&A expenditures for protection, automation and telecom assets for the 2023 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for each category of expenditures.

Table 19 - Protection, Automation and Telecom OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Protection and Automation	16.4	14.8	13.9	15.0	15.6	16.1
Telecom	24.2	24.7	25.4	21.7	20.5	21.0
Total	**40.6**	**39.5**	**39.3**	**36.7**	**36.1**	**37.1**

The proposed 2023 Test Year expenditure is $37.1M. This is $4.6M or 11.0% lower than the amount that would result from escalating the last rebasing actual expenditures (2020) by inflation ($41.7M).[7] The 2023 Test Year forecast expenditure is slightly lower than the historical average (2018-2021) but in line with the 2021-2022 forecast period. The decrease in this program is due to higher expenditures for Protection and Automation that are required to meet new and updated NERC and NPCC requirements, offset by lower expenditures in Telecom (Operation of Power System Telecom Services) as a result of continuing efforts to reduce the scope of telecom operational services expenditures.

2.1.5.1 PROTECTION AND AUTOMATION

Protection and automation assets are required to protect, control, and operate the transmission system. The maintenance of these assets is required to sustain equipment performance and to comply with applicable NERC standards.

The protection and automation maintenance program is divided into three categories, discussed further below: (i) Preventive Maintenance, (ii) Corrective Maintenance, and (iii) Support Processes and Systems. Table 20 below sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for each of the three categories.

Table 20 - Protection and Automation OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance	2.7	3.2	2.9	4.3	5.1	4.1
Corrective Maintenance	7.0	6.3	5.9	5.5	5.5	6.6
Support Processes and Systems	6.7	5.3	5.1	5.2	5.0	5.4
Total	**16.4**	**14.8**	**13.9**	**15.0**	**15.6**	**16.1**

[7] 2020 actual expenditures adjusted by inflation for 3 years = $39.3M x (1+2%)^3 = $41.7M. ($37.1M/$41.7M - 1)% = -11.0%. Inflation is as presented in Exhibit E-03-01.

The proposed expenditures for the 2023 Test Year are $16.1M. This is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast expenditures. The increase is primarily due to an increase in planned spending on preventive maintenance to meet applicable NPCC and NERC requirements (PRC-005 and PRC-012), carrying out scheduled maintenance, and the need to perform planned corrective maintenance on defective or failed equipment.

Further details of the forecasted costs for each of the three Protection and Automation OM&A programs are discussed below.

2.1.5.1.1 Preventive Maintenance

Preventive Maintenance involves routine testing of protection systems and revenue meters. Examples of such activities include relay re-verification, zone test trip, breaker trip coil testing, and special protection system trip testing. Further details relating to the prescribed maintenance for protection system activities is in provided in TSP Section 2.2.

Protection systems spend most of their service life in a stand-by or monitoring state, yet they must be relied upon to perform flawlessly within milliseconds of a fault inception or other abnormal system condition. Routine, preventive testing is the only means to maintain a high degree of certainty that the system will operate correctly when called upon.

Maintenance performed on the majority of Hydro One’s protection-related assets is governed by NERC standards. The maintenance activities and testing frequencies for protection systems that are part of the BES are mandated by NERC reliability standard PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance). For the remaining portions of the system, the scope of testing and testing frequencies are determined in accordance with a risk evaluation for reliability, safety, and environmental impact, as per Hydro One standards.

Hydro One's planned expenditures for Preventive Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 21 below.

Table 21 - Preventive Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance	2.7	3.2	2.9	4.3	5.1	4.1

The proposed expenditure for the 2023 Test Year is $4.1M. This is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and slightly higher than the historical average (2018-2021). The increase is primarily due to (i) new Remedial Action Scheme (RAS) maintenance plans to meet the maintenance requirements of NERC PRC-012-2.[8] PRC-012-2 came into effect on January 1, 2021, and requires maintenance plans to include full functional tests on RAS assets according to the latest RAS list issued by the IESO; (ii) transitioning maintenance plans to follow NERC PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance) cycles, increasing the scheduled maintenance that must be done in and from the year 2022. PRC-005-6 came into effect in 2016 and allows a maximum maintenance cycle of 6 years and 12 years depending on the protection device technology; and (iii) increasing preventive maintenance for Special Protection Systems as per NPCC Directories D4 (Bulk Power System Protection Criteria) and D7 (Special Protection Systems), and due to Hydro One's continued installation of new station assets.

[8] These are automatic protection systems designed to detect abnormal or predetermined system conditions and take corrective actions to maintain system reliability, other than or in addition to isolating faulted components from the system.

2.1.5.1.1 Corrective Maintenance

All Protection and Automation assets experience a certain rate of failure during their normal operating life. Increased failure rates cause a reduction in overall system reliability. The Corrective Maintenance program allows Hydro One to restore system reliability by performing timely emergency repairs and remedying systemic protection equipment issues. These issues are usually discovered during the analysis of protection system misoperations and typically relate to design or manufacturing defects. If not corrected on time, these issues can impact other similar installations.

Once the failure of any portion of the protection system is detected, Operating Centre staff dispatch field personnel to resolve the issue and restore system reliability. If the problem is discovered during a preventive maintenance test, corrective action must be taken immediately to avoid adverse impacts to system reliability. The corrective action can be as minor as calibrating a relay or as major as replacing an existing relay with a new or refurbished one. The costs of these corrective actions are covered by this program.

As part of its obligation to comply with NERC requirements, Hydro One must analyse every BES protection system operation and correct those which are characterized as misoperations. When Hydro One determines that a misoperation is not an isolated case (e.g., it is a manufacturer defect that applies to multiple relays), Hydro One proactively replaces or repairs protection system components in order to prevent widespread system issues. The costs of these planned corrective actions are also covered by this program.

Hydro One's planned expenditures for Corrective Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 22 below.

Table 22 - Corrective Maintenance OM&A ($M)

Description	Historical				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Corrective Maintenance	7.0	6.3	5.9	5.5	5.5	6.6

The proposed expenditures for the 2023 Test Year are $6.6M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), but in line with the historical average (2018-2021). The Test Year expenditures are required to perform (i) emergency corrective maintenance activities, (ii) corrective maintenance activities associated with those assets that are most critical to system reliability, safety, and environment, and (iii) corrective maintenance activities that are of higher priority due to compliance requirements under applicable NERC standards.

2.1.5.1.1 Support Processes and Systems

Hydro One maintains a set of support processes and systems that are needed to maintain protection and automation system assets. These systems are in place to manage relay settings, to control changes to relay settings and configurations, to keep records of system events, and to manage the inventory and re-seal schedule for revenue meters. The Support Processes and Systems program covers the costs associated with maintaining these systems.

In addition, this program provides funding for multiple activities that directly support system reliability and maintain Hydro One’s compliance with mandatory NERC requirements. These activities include:

- Analyses of protection system operations;
- Tracking vendor advisories;
- Root-cause analysis of protection system component failures and mitigation actions;
- Managing protection and automation spare parts;
- Maintaining transmission metering assets; and
- Maintaining protection and automation asset data and information.

The proposed funding for these activities is necessary to ensure that Hydro One maintains its safety and reliability performance and complies with applicable NERC requirements.

Hydro One's planned expenditures for Support Processes and Systems OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 23 below.

Table 23 - Support Processes and Systems OM&A ($M)

Description	Historical				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Support Processes and Systems	6.7	5.3	5.1	5.2	5.0	5.4

The proposed expenditures for the 2023 Test Year are $5.4M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period.

2.1.5.2 POWER SYSTEM TELECOM

Power System Telecom Services (PSTS) provide high-reliability, high-speed communications required for the protection, monitoring, control, and operation of Hydro One's transmission system in Ontario. Hydro One's Power System Telecom system consists of a fibre optic-based synchronous optical networking (SONET) transport network, power-line carrier (PLC) systems, teleprotection terminal devices, microwave radio systems, high voltage protection (HVP) systems, provincial mobile radio system (PMRS), and associated auxiliary telecommunication equipment and infrastructure.

The Power System Telecom program is divided into three categories, discussed further below: (i) Preventive and Corrective Maintenance; (ii) Leased Telecommunication Circuits for PSTS; and (iii) Operation of PSTS. Table 24 below sets out Hydro One's planned expenditures for Power

System Telecom OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each of these three categories.

Table 24 - Power System Telecom OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive and Corrective Maintenance	4.3	4.3	4.7	4.5	4.5	4.8
Leased Telecommunication Circuits for Power System Services	10.6	11.1	11.8	11.0	10.4	10.5
Operation of Power System Telecom Services	9.3	9.3	9.1	6.2	5.6	5.7
Total	**24.2**	**24.7**	**25.5**	**21.7**	**20.5**	**21.0**

Hydro One’s proposed expenditure for the 2023 Test Year is $21.0M. This is lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the historical average (2018-2021), and in line with the 2021-2022 forecast period. The reduction in planned expenditures for the 2023 Test Year relative to 2020 and the historical average is due to the reduction in Operation of Power Telecom System Services expenditures. 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

In addition, the planned 2023 Test Year expenditures for Leased Telecommunication Circuits for Power System Telecom Services are lower than the most recent actual in 2020. This program includes the cost of additional leased circuits and circuit capacity that are required for ongoing deployment of new protection, control, and monitoring equipment to support Hydro One’s power system. Although leased circuit costs generally increase due to new services, cost of leasing, and inflation, the 2023 Test Year expenditure reflects cost savings expected from investment in optical ground wire (OPGW) fibre-optic infrastructure development projects.

Further details of the forecasted costs for each of the three Power System Telecom OM&A programs are discussed below.

2.1.5.2.1 Preventive and Corrective Maintenance

The Preventive and Corrective Maintenance program is required to sustain Hydro One's Power System Telecom systems for the safe and reliable operation of Hydro One's transmission system. Routine telecom maintenance requires field testing of telecom schemes and equipment to ensure that they are operating within expected parameters.

Telecom preventive maintenance involves the following activities:

1. Routine maintenance/re-verification;
2. Signal adequacy tests (SATs);
3. Radio communication tower visual/structural inspections;
4. Telecom battery/charger maintenance;
5. Auxiliary telecommunication equipment inspections; and
6. OPGW and all-dielectric self-supporting (ADSS) cable maintenance and inspections.

Timing intervals for telecom preventive maintenance are dependent on the technology and/or equipment used in the communications scheme, and on whether the telecom equipment directly interfaces with protection schemes included in the BES. Maintenance of telecom devices that are an integral part of protection schemes classified as BES elements is non-discretionary and requires annual compliance reporting, as per the NERC PRC-005 and NPCC Directory 8 standards.

The overall strategy for the preventive maintenance component of the program is to reduce replacement costs, corrective maintenance costs, and interruption of services while complying with regulatory and Hydro One maintenance requirements. Preventive maintenance is used to gauge the condition of the assets and to aid in the planning of asset replacements and technology upgrades.

Corrective maintenance performed on Power System Telecom assets consists of (i) planned corrective maintenance to rectify issues that were identified during preventive maintenance or to address failure events that do not have an immediate system impact, and (ii) emergency corrective maintenance to rectify issues that have already impacted system stability or will have an immediate impact on system stability if left unresolved.

The overall program strategy for the corrective maintenance component of the program is to ensure that Power System Telecom issues are corrected in a timely manner based on severity of the issue. Planned corrective maintenance prioritizes corrective actions based on the available budget and on identified issues to ensure that future system impacts are mitigated, while reducing future corrective maintenance costs. Emergency corrective maintenance ensures that the affected telecom components and services are restored to normal operating conditions as soon as possible.

As part of the overall Preventive and Corrective Maintenance program, Hydro One also maintains an adequate level of operational spare equipment in order to respond to corrective maintenance requirements and restore communication systems to normal operation within a timely manner, thereby minimizing potential reliability impact on the transmission system.

Hydro One's planned expenditures for Preventive and Corrective Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 25 below.

Table 25 - Preventive and Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive and Corrective Maintenance	4.3	4.3	4.7	4.5	4.5	4.8

The proposed expenditures for the 2023 Test Year are $4.8M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period.

2.1.5.2.2 Leased Telecommunication Circuits for Power System Telecom Services

Hydro One leases carrier-based telecommunication circuits from third-party providers in order to support the telecommunication requirements for protection and control of the power system. This program covers the costs associated with leasing telecommunication services for power system protection and control, the provincial mobile radio system, and sites/space for provincial mobile radio base stations. In order to contain leasing costs for telecom circuits, Hydro One enters into long-term contracts where feasible to secure competitive pricing from third-party telecom service providers. Some telecommunications services covered by this program are tariffed, meaning the rates for those services are approved and regulated by the Canadian Radio-television Telecommunications Commission (CRTC).

Some of the protection systems at transmission stations depend on remote backup, automated electrical grounding, and sometimes operator intervention due to a lack of telecommunication facilities. To improve system reliability, new leased circuits are incorporated into protection schemes to help clear a fault within appropriate time frames.

Hydro One’s planned expenditures for Leased Telecommunication Circuits for Power System Telecom Services OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 26 below.

Table 26 - Leased Telecommunication Circuits OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Leased Telecommunication Circuits for Power System	10.6	11.1	11.8	11.0	10.4	10.5

The proposed expenditure for the 2023 Test Year is $10.5M. This is lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the historical average (2018-2021), and in line with the 2021-2022 forecast period. The lower expenditure in the 2023 Test Year relative to 2020 and the historical average is due to cost savings expected from investment in OPGW fibre-optic infrastructure development projects.

2.1.5.2.3 Operation of Power System Telecom Services

This program covers the cost of labour for the monitoring, management, and operation of the telecom infrastructure and engineering technical support for Power System Telecom Services. These services are provided by the Integrated Telecom Management Center (ITMC) at Hydro One Telecom Inc. (HOT), under contract with Hydro One.

HOT provides Hydro One with coordinated network management, vendor management, real-time alarm-based monitoring, and system analysis services. HOT also provides services related to maintaining and upgrading the Operating Support Systems, which consist of the inventory management, network management, and other software systems used in the operation and management of Hydro One’s telecommunication assets and services. The Operating Support Systems are vital to supporting the day-to-day ITMC operational functions, including the updating of the inventory of the fibre-optic network, the management and updating of network alarms, the management of incidents (trouble tickets), and outage and change requests.

While Operating Support Systems upgrades will be addressed though capital programs, Operation of Power Telecom Services OM&A will include spending to support enhancements to telecommunication systems in order to address key Operating Support Systems that no longer have adequate vendor support and are at the end of service life.

Hydro One's planned expenditures for Operation of Power Telecom Services OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 27 below.

Table 27 - Operation of Power Telecom Services OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Operation of Power System Telecom Services	9.3	9.3	9.1	6.2	5.6	5.7

The proposed expenditures for the 2023 Test Year are $5.7M. This is lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the historical average (2018-2021), but in line with the 2021-2022 forecast period. The overall trend is expected to decline as components of services retained for project-related work are allocated to capital projects.

2.1.6 CYBER SECURITY

Hydro One must comply with cyber security standards that are intended to ensure the integrity of the Ontario BES and all of the interconnected BESs across North America. NERC has developed mandatory CIP standards to ensure regular testing and updating of the security systems and procedures affecting transmission assets and utility personnel. These standards are designed to mitigate cyber security risks to BES facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cyber-security incident, would affect the reliable operation of the BES.

NERC Cyber Security involves maintenance activities that are required to sustain systems and facilities so as to maintain compliance with NERC CIP Standards. A more detailed description of this program is located in Exhibit E-04-04. Hydro One's planned expenditures for NERC Cyber Security OM&A for the 2023 Test Year, along with its forecast and actual spending levels for the Bridge and Historical Years, are set out in Table 28 below.

Table 28 - NERC Cyber Security OM&A ($M)

Description	Historical				Bridge Year	Test Year
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
NERC Cyber Security	14.6	11.8	13.7	15.5	18.4	21.5

The proposed 2023 Test Year expenditure is $21.5M. This is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021 forecast, and slightly higher than the 2022 Bridge Year forecast. The increase is due to compliance with regulatory obligations – including security needs related to evolving security threats and NERC CIP standards – and the establishment of a new, in-house Joint Security Operations Centre (JSOC), a 24/7 centre for monitoring cyber and physical security. 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.

Hydro One currently outsources key aspects of its security operations for physical, personnel and cyber security but has revisited this approach in light of evolving security needs. In its 2020 National Cyber Threat Assessment, the Canadian Center for Cyber Security (part of the Government of Canada's Communications Security Establishment) found that there are heightened cyber security risks to Canada's electricity sector.[9] In light of such risks, and to maintain the appropriate level of response to physical security threats, Hydro One is moving to insource key operational components of physical, personnel and cyber security monitoring. This will ensure better alignment with Hydro One's security strategy, emergency response processes, quality expectations, and security risk management programs. This is especially important given the increasing shift away from analog to digitally connected devices and cloud-based services, which require Hydro One to monitor and defend a larger surface than ever before.

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.

Exhibit E-04-04 contains further discussion and analysis of OM&A expenditures for NERC Cyber Security (along with General Cyber Security) in the context of Hydro One's unified security strategy.

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[9] Canadian Centre for Cyber Security, *National Cyber Threat Assessment 2020* - online: https://cyber.gc.ca/sites/default/files/publications/ncta-2020-e-web.pdf

2.1.7 SITE INFRASTRUCTURE MAINTENANCE

Hydro One's site facilities and infrastructure systems are comprised of yard drainage, fire protection and detection, structural footings, station buildings, cranes, elevators, HVAC systems, access roads, water supplies, sewage management, and fences at transmission stations. These systems provide infrastructure and support services to all other station components, prevent unauthorized access, and make the station site functional for equipment and staff. The Site Infrastructure Maintenance program is focused on the planned and corrective maintenance at transmission stations to ensure that these site facilities and infrastructure systems remain in a safe condition and in compliance with the regulatory requirements.

The program is extensively driven by the assessment of data collected, unplanned work, corporate standards, and regulatory requirements such as the Building Code, Fire Code, *Occupational Health and Safety Act*, municipal by-laws, and requirements of the Ministry of the Environment, Conservation and Parks. The program is divided into the following three categories: (i) Facilities/Infrastructure Maintenance, (ii) Grounds Maintenance, and (iii) Site Perimeter Maintenance.

Table 29 below sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 29 - Site Infrastructure Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Facilities/ Infrastructure Maintenance	20.5	17.2	18.4	19.1	19.4	20.8
Grounds Maintenance	0.6	0.8	0.5	0.5	0.6	0.7
Site Perimeter Maintenance	1.6	1.5	1.7	1.3	1.3	1.4
Total	**22.7**	**19.5**	**20.7**	**20.9**	**21.3**	**22.9**

The 2023 proposed expenditure is $22.9M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The slight increase is primarily due to spending that will enable Hydro One to continue to address deficiencies with 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.

2.1.7.1 Facilities and Infrastructure Maintenance

This program is focused on the preventive and corrective maintenance of transmission station facilities and associated infrastructure. Information on the condition of station sites and buildings is collected through regular inspections, as well as during maintenance work and trouble-call responses. Contracted inspections and asset surveys are also conducted.

The preventive maintenance program for site facilities and infrastructure addresses a wide variety of activities, such as building maintenance and facility improvements, HVAC maintenance, inspections, janitorial services, water system maintenance and testing, station civil geotechnical inspections and maintenance, asset assessments, and roads, bridges, and railway maintenance.

Hydro One's planned expenditures for Facilities and Infrastructure Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 30 below.

Table 30 - Facilities and Infrastructure Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Facilities/ Infrastructure Maintenance	20.5	17.2	18.4	19.1	19.4	20.8

The proposed expenditures for the 2023 test year are $20.8M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The increase is primarily due to preventive maintenance spending that will enable Hydro One to continue to address deficiencies with its building infrastructure that pose a risk to reliability if not remedied (e.g., leaking roofs, basement sump pumps and backflow, etc.).

2.1.7.2 Grounds Maintenance

The Grounds Maintenance program funds a number of activities, including the application of herbicides to control weeds and vegetation inside Hydro One's transmission stations. Weed and vegetation control is required to keep step and touch voltages at safe levels for workers who enter the station. Grounds maintenance also includes snow removal, grass cutting, clean-up, and general maintenance that may be required for site drainage and grading.

Hydro One's planned expenditures for Grounds Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 31 below.

Table 31 - Grounds Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Grounds Maintenance	0.6	0.8	0.5	0.5	0.6	0.7

The proposed expenditures for the 2023 Test Year are $0.7M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period.

2.1.7.3 Site Perimeter Maintenance

The Site Perimeter Maintenance program includes preventive and corrective maintenance at station perimeters, with measures taken to keep animals out of stations and reduce the likelihood of power interruptions due to animal contacts. The activities under this program complement Hydro One's broader corporate security initiatives aimed at safeguarding transmission assets to ensure public and employee safety and to maintain equipment and system reliability.

Hydro One's planned expenditures for Site Perimeter Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 32 below.

Table 32 - Site Perimeter Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Site Perimeter Maintenance	1.6	1.5	1.7	1.3	1.3	1.4

The proposed expenditures for the 2023 Test Year are $1.4M. This is slightly lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) but in line with the historical average (2018-2021) and the 2021-2022 forecast period.

2.2 LINES

The high-voltage power lines in Hydro One's transmission network are categorized as either lines that form part the BES or area supply lines. Power lines which form part of the BES typically connect major generation facilities with transmission stations and often cover long distances, while area supply lines serve a local region. Hydro One's transmission lines primarily operate at voltages of 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV. Hydro One's transmission system consists of approximately 29,000 circuit km of overhead transmission lines located on about 81,500 hectares of rights-of-way and 273 circuit-km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shield wire, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems, and grounding systems. The underground transmission lines are generally located in large urban centres.

Lines Sustainment OM&A funding covers expenditures required to maintain existing overhead and underground transmission lines assets. Hydro One manages its Lines Sustainment OM&A program by dividing the program into the following three categories:

1. Vegetation Management, which ensures that vegetation clearances to energized equipment are maintained. This includes brush control, line clearing, condition patrol, property owner notifications, annual vegetation patrol, demand (unplanned) maintenance, and grounds maintenance.

2. Overhead Lines Maintenance, which focuses on inspections and condition assessments of overhead lines components to identify defects and poor-condition assets, planned corrective work to replace and repair minor component, and demand (unplanned) maintenance to respond to emergency situations.

3. Underground Cable Maintenance, which focuses on condition assessment through inspection, testing, analysis, and diagnostics of the main cable and ancillary equipment (accessories) used to support cable operation, and associated corrective maintenance.

Hydro One's planned expenditures for Lines Sustainment OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 33 below for each of the categories discussed above.

Table 33 - Lines Sustainment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Vegetation Management	37.3	31.9	32.6	32.4	32.3	33.0
Overhead Lines Maintenance	18.9	18.3	17.2	15.6	15.8	18.2
Underground Cable Maintenance	7.6	5.6	4.3	4.0	3.7	4.0
Total	**63.8**	**55.8**	**54.2**	**52.0**	**51.9**	**55.2**

The proposed Lines Sustainment OM&A is forecast to be $55.2M in the 2023 Test Year. This is $2.3M or 4% lower than the amount that would result from adjusting the last rebasing year's actual expenditures (2020) by inflation ($57.5M).[10] The 2023 Test Year forecast expenditure is $1.3M lower than the historical average (2018-2021), $3.2M higher than the 2021 forecast, and $3.4M higher than the 2022 Bridge Year forecast.

Despite the increased pacing of Lines maintenance activities, the proposed Test Year spending is slightly lower than the inflation-adjusted 2020 actual and the overall historical trend, primarily due to the offsets from productivity initiatives, described further below. The increase in Test

[10] 2020 actual expenditures adjusted by inflation for 3 years = $54.2M x (1+2%)^3 = $57.5M. ($55.2M/$57.5M - 1)% = -4.0%. Inflation is as presented in Exhibit E-03-01.

Year expenditures compared to the 2021-2022 forecast period is primarily driven by (i) the increased pace of asset condition assessments required to partially address the growing quantity of assets that require condition assessment and (ii) an increase in demand and planned defect corrective work, each of which forms part of the Overhead Lines Maintenance program.

This work is necessary as part of Hydro One's asset management approach and to maintain compliance with applicable NERC and NPCC reliability standards. Hydro One does not run its transmission assets to failure given their criticality to the integrity of the transmission system and the reliability, safety, and environmental impacts associated with their failure. Instead, Hydro One's asset management approach relies on sustaining assets based on condition, and maintenance and condition assessments must performed on time in order to identify potential defects and poor-condition assets. Failure to do so increases the risk of outages caused by component failures that might have been identified during these activities. In addition, Hydro One's transmission system is subject to NERC and NPCC reliability standards, discussed further below, which require maintenance and condition assessments to be performed at certain intervals and in certain circumstances.

The sections below provide more detailed program descriptions along with the planned Test Year expenditures (and variances where applicable) for each of the Lines OM&A programs.

2.2.1 VEGETATION MANAGEMENT

The strip of land that is occupied by a transmission line is referred to as a right-of-way (ROW) or a corridor. Hydro One's in-service ROWs cover an area of approximately 81,500 hectares and support Hydro One's 115 kV, 230 kV, 345 kV, and 500 kV circuits. Hydro One's 230kV, 345kv, and 500kV circuits form part of the Bulk Electric System and are therefore subject to NERC's FAC-003 Transmission Vegetation Management standards. These require Hydro One to improve the reliability of its transmission systems by preventing outages from vegetation located on transmission ROWs, minimizing outages from vegetation located adjacent to ROWs, and maintaining clearances between transmission lines and vegetation on and along transmission

ROWs. To ensure system reliability and compliance with NERC's FAC-003, the Vegetation Management program is responsible for maintaining the clearance distance between the energized equipment and the vegetation located on and adjacent to all of these ROWs.

The Vegetation Management program consists of the following seven categories: (i) brush control, (ii) line clearing, (iii) condition patrol, (iv) property owner notifications, (v) annual vegetation patrol, (vi) demand maintenance, and (vii) grounds maintenance. Table 34 below sets out Hydro One's planned expenditures for Vegetation Management OM&A in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each of these seven categories.

Table 34 - Vegetation Management OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Brush Control	20.1	15.0	19.2	19.0	17.5	18.6
Line Clearing	8.7	8.5	5.5	5.6	5.6	5.9
Condition Patrol	1.3	1.9	1.2	1.6	1.6	1.7
Property Owner Notifications	2.4	2.9	2.0	2.2	2.5	2.3
Annual Vegetation Patrol	1.0	0.8	0.5	0.7	0.7	1.0
Demand Maintenance	2.0	1.4	2.5	1.3	2.5	1.4
Grounds Maintenance	1.9	1.4	1.6	1.9	1.9	2.1
Total	**37.3**	**31.9**	**32.6**	**32.4**	**32.3**	**33.0**

Hydro One's forecast vegetation management expenditures in the 2023 Test Year are $33M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The Test Year expenditures are required to maintain compliance with the NERC FAC-003 regulatory requirements and to perform more vegetation maintenance on critical 115 kV ROWs.

2.2.1.1 Brush Control

Brush Control maintenance involves managing vegetation growth to ensure adequate standing clearance to overhead conductors necessary to preserve system performance and reliability. This is accomplished through selective application of herbicides and manual and mechanical brush-cutting.

Table 35 below sets out Hydro One's planned expenditures for Brush Control OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 35 - Brush Control OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Brush Control	20.1	15.0	19.2	19.0	17.5	18.6

Planned expenditures for Brush Control in the 2023 Test Year are $18.6M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021 forecast, and slightly higher than the 2022 Bridge Year forecast. Hydro One has lowered the Bridge Year forecast for Brush Control work to fund more Demand Maintenance work (discussed below). The Test Year expenditures are in line with prior levels and enables Hydro One to complete higher unit-cost work in urban areas and some of the deferred Brush Control work (which may require additional patrols and Demand Maintenance work), while supporting compliance with NERC FAC-003 regulatory requirements.

Brush Control unit costs for urban areas are higher as a result of complexities associated with public consultations in advance of urban vegetation management. To successfully perform maintenance in these areas, property owner and community consultations begin a year in advance, and techniques such as stump grinding, wood removal, off-ROW vegetation replanting, pollinator seed, and community beautification funds are used. These activities are necessary as a form of social license to operate in urban areas to prevent work stoppage.

2.2.1.2 Line Clearing

Line Clearing maintenance involves the trimming and removal of trees, including danger trees, that do not meet Hydro One's standards along the edge of or adjacent to transmission ROWs. This work is necessary to maintain Hydro One's standing and falling clearances to the energized conductor and other transmission line equipment.

Table 36 below sets out Hydro One's planned expenditures for Line Clearing OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 36 - Line Clearing OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Line Clearing	8.7	8.5	5.5	5.6	5.6	5.9

Planned expenditures for Line Clearing in the 2023 Test Year are $5.9M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), lower than the historical average (2018-2021), and in line with the 2021 and 2022 Bridge Year forecasts. The Test Year expenditures are required to continue clearing vegetation defects such as danger trees (which may fall onto overhead lines and impact system reliability), address some of the deferred Line Clearing work (which may require additional patrols and Demand Maintenance work), and to continue supporting compliance with NERC FAC-003 regulatory requirements. Where possible, Hydro One conducts line clearing and brush control along the same or adjacent ROWs in the same year, thereby achieving efficiencies.

2.2.1.3 Condition Patrol

Condition Patrol is a mid-cycle inspection to identify and mitigate any danger trees or vegetation that will encroach upon Hydro One's standing and falling clearances before the next scheduled line clearing or brush control maintenance. Table 37 below sets out Hydro One's planned expenditures for Condition Patrol OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 37 - Condition Patrol OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Condition Patrol	1.3	1.9	1.2	1.6	1.6	1.7

Planned expenditures for Condition Patrols in the 2023 Test Year are $1.7M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) but in line with the historical average (2018-2021) and the 2021-2022 forecast period.

2.2.1.4 Property Owner Notifications

Property owner notifications are required before the execution of ROW vegetation maintenance. They consist of Hydro One contacting all required adjacent property owners to communicate maintenance plans, obtain approval for access onto private property, and acquire permission for the use of any herbicides to be applied during maintenance. Hydro One also engages with other external stakeholders, such as government agencies, municipal officials, and special interest groups as needed. Notifications are particularly important in urban areas where a significant number of vegetation encroachments require removal. Over the past years, Property Owner Notification expenditures have been increasing primarily due to the complexities of public consultations.

Hydro One's planned expenditures for Property Owner Notifications OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 38 below.

Table 38 - Property Owner Notifications OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Property Owner Notifications	2.4	2.9	2.0	2.2	2.5	2.3

Planned expenditures for Property Owner Notifications in the 2023 Test Year are $2.3M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021) and the 2021-2022 forecast period.

2.2.1.5 Annual Vegetation Patrol

An annual vegetation patrol is conducted by air or ground and is used to identify vegetation that is encroaching upon Hydro One's standing and falling clearance distances. In accordance with NERC FAC-003, Hydro One is required to annually inspect all of its circuits operating at 230 kV or more. This patrol is conducted for NERC-applicable circuits not receiving Line Clearing or Condition Patrol maintenance in the current calendar year.

Hydro One's planned expenditures for Annual Vegetation Patrol OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 39 below.

Table 39 - Annual Vegetation Patrol OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Annual Vegetation Patrol	1.0	0.8	0.5	0.7	0.7	1.0

Planned expenditures for Annual Vegetation Patrol in the 2023 Test Year are $1.0M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The increase is primarily due to the need to increase vegetation patrols to ensure that Hydro One's remains compliant with NERC FAC-003, and inflationary increases for helicopter costs to conduct air patrols.

2.2.1.6 Demand Maintenance

Demand Maintenance is an unplanned and corrective program which addresses vegetation issues that cannot wait until the next Line Clearing or Brush Control maintenance. Encroachments mitigated as part of this program are typically identified through Condition Patrols or Annual Vegetation Patrols, but can also be initiated by other Hydro One business units, members of the public, municipalities, government agencies, etc.

Hydro One's planned expenditures for Vegetation Management Demand Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 40 below.

Table 40 - Demand Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Demand Maintenance	2.0	1.4	2.5	1.3	2.5	1.4

The proposed Test Year expenditures are $1.4M. This is lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2022 Bridge Year forecast, but in line with the 2021 forecast. The primary reason for the variance is that Demand Maintenance expenditures are reactive by nature and fluctuate year over year.

Deferral of Line Clearing and Brush Control maintenance may result in an increase of vegetation defects over time that need to be addressed by Demand Maintenance. Hydro One will prioritize and address vegetation defects that are more likely to impact system reliability.

2.2.1.7 Grounds Maintenance

Grounds Maintenance includes grass cutting, snow removal, garbage clean-up, and repair of access barriers and fences on Hydro One's urban ROWs. The work is required to comply with local by-laws. It comprises both planned and demand components: planned work includes grass cutting and snow removal, which remains steady, while demand work fluctuates depending on clean-up or repair work that arises.

Hydro One's planned expenditures for Grounds Maintenance OM&A for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided Table 41 below.

Table 41 - Grounds Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Grounds Maintenance	1.9	1.4	1.6	1.9	1.9	2.1

Planned expenditures in the 2023 Test Year are $2.1M. This is slightly higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The proposed funding will allow Hydro One to address ground maintenance work required to ensure the management of the environment and public safety on urban ROWs.

2.2.2 OVERHEAD LINES MAINTENANCE

The Overhead Lines Maintenance program is required to maintain the reliability of transmission lines, address safety issues, and ensure the long-term economic viability of the overhead lines system. The program includes activities such as overhead lines inspections to identify defects, component condition assessments to identify poor-condition assets that will require replacement, planned corrective maintenance to replace and repair minor components, and demand maintenance to respond to emergency situations. The gathering of asset condition information enables Hydro One to allocate funding based on priority to maximize the life of the lines assets and to maintain asset performance. The program also provides for repair or replacement of defective equipment and components.

The Overhead Lines Maintenance program is divided into the following three activities: (i) Preventive Maintenance and Asset Assessment, (ii) Demand Maintenance, and (iii) Planned Corrective Maintenance. Table 42 below sets out Hydro One's planned Overhead Lines Maintenance expenditures in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each category of activities.

Table 42 - Overhead Lines Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance and Asset Assessment	8.0	6.1	6.6	6.6	5.8	5.9
Demand Maintenance	8.5	9.9	5.9	4.0	4.1	5.2
Planned Corrective Maintenance	2.4	2.3	4.8	5.0	5.9	7.0
Total	**18.9**	**18.3**	**17.2**	**15.6**	**15.8**	**18.2**

Hydro One's planned expenditures in the 2023 Test Year are $18.2M. This is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. This increase is primarily driven by the need to address hardware defects as part of the Planned Corrective Maintenance work program. 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 planned expenditures has been partially offset by sustained productivity savings in the following two areas: (i) optimizing preventive maintenance and condition assessment patrol cycles, and (ii) reducing insulator washing costs due to the installation of new hydrophobic insulators. Hydro One's approach on productivity, and performance relative to prior applications, is further described in SPF Section 1.4. Those improvements are further discussed below.

2.2.2.1 Preventive Maintenance and Asset Condition Assessment

The Overhead Lines Maintenance program encompasses cyclical and non-cyclical maintenance activities. Cyclical maintenance activities include helicopter patrols and foot patrols to identify major defects on transmission line components, thermographic patrols to identify defective transmission line components using infrared cameras, switch maintenance to inspect and maintain switch components, and insulator washing to address salt contamination on selected transmission structures near urban highway and road crossings.

Non-cyclical activities are mainly asset condition assessments, which include detailed helicopter inspections (DHIs) to inspect structure hardware and tops of wood poles; climbing inspections to inspect structures in no-fly regions; conductor and shield-wire assessments using the Kinectrics LineVue tool, typically on aluminum conductor steel-reinforced (ACSR) conductors greater than 50 years of age and galvanized steel shield wires greater than 25 years of age; polymer insulator testing to detect internal conductive defects; wood pole assessments to inspect the condition of the pole, typically on wood poles greater than 25 years of age; and steel structure assessments to evaluate the remaining protective zinc layer in heavy corrosion zones. Further information on these activities can be found in TSP Section 2.2.

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. In 2020, Hydro One undertook a review of these activities and implemented several changes to address the following objectives:

- Improving patrol cycles to more efficiently discover defects and to support proactive asset management;
- Reducing overlap of the various patrols and condition assessment activities, allowing for efficient data collection (e.g., executing steel tower condition assessments as part of other patrols, instead of executing them separately); and
- Focusing Preventive Maintenance and Asset Condition Assessment activities on higher risk (i.e., older) assets.

Hydro One performs testing to empirically establish the condition of its conductors, in particular through Kinectrics LineVue scans, laboratory testing, or a combination of both. This allows Hydro One to operate verified good-condition conductors well beyond their expected service life, thus avoiding the replacement of conductors that do not need replacement.

LineVue scans and short sample testing provide an initial assessment of a line's condition, which in most cases is sufficient to categorize a conductor as being in good, fair, or poor condition and to determine whether condition-based replacement is required. Based on test results, the conductor will be scheduled for follow-up assessments in 5 to 15 years depending on the determined level of deterioration, or it will be planned for replacement if it is clearly identified as being in poor condition. Where signs of deterioration are found but poor condition is not clearly established based on test results, a more comprehensive assessment through a short- or long-conductor sample test is performed to ensure that only poor-condition conductors are targeted for replacement.

Table 43 below sets out Hydro One's planned Preventive Maintenance and Asset Condition Assessment OM&A expenditures for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 43 - Preventive Maintenance and Asset Assessment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance and Asset Assessment	8.0	6.1	6.6	6.6	5.8	5.9

The proposed 2023 Test Year expenditure is $5.9M. This is slightly lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021 forecast, but in line with the 2022 Bridge Year forecast. The overall trend is decreasing compared to the historical average primarily due to the enhancements described above. The planned expenditure in 2023 for asset condition assessments is required to mitigate safety and reliability risks due to the unknown condition of transmission lines components such as U-bolt hardware, insulators, wood poles, steel structures, conductors, and shield wires.

2.2.2.2 Demand Maintenance

Demand maintenance is needed to respond to emergencies and to restore power as soon as possible. This program includes activities such as unplanned data collection, emergency component repair, and trouble-call response. This program also addresses problems identified during line patrols that need a near-term response to prevent a potential outage or to address a serious safety issue.

Table 44 sets out Hydro One's planned overhead lines Demand Maintenance OM&A expenditures for the 2023 Test year, along with its forecast and actual spending levels for the Bridge and Historical Years.

Table 44 - Demand Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Demand Maintenance	8.5	9.9	5.9	4.0	4.1	5.2

The Demand Maintenance expenditure of $5.2M in the 2023 Test Year is lower than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the historical average (2018-2021), but higher than the 2021-2022 forecast period. 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. The planned increase in expenditures in the 2023 Test Year reflects the reactive nature of Demand Maintenance work. To account for this, Hydro One determined its 2023 Test Year expenditures for this program based on historical actual expenditures, excluding unusual events such as those mentioned above.

2.2.2.3 Planned Corrective Maintenance

Planned corrective maintenance and projects include minor corrective work and technical support to resolve reliability and safety problems with transmission line assets. The planned corrective maintenance activities and projects are developed using the data collected during patrols and asset assessment activities, as well as information about equipment reliability performance.

Planned corrective maintenance addresses multiple line components, including defective ground wire connections, missing or broken safety signs and nomenclature signs, U-bolt hardware that supports the insulator strings and conductors, and the replacement of dampers that limit conductor vibration.

Table 45 sets out Hydro One's proposed overhead lines Planned Corrective Maintenance OM&A expenditures for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 45 - Planned Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Planned Corrective Maintenance	2.4	2.3	4.8	5.0	5.9	7.0

The proposed Test Year expenditure of $7.0M is higher than the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period. The increasing trend over the 2020-2023 period is primarily due to increased planned corrective maintenance to address tower re-torqueing and tensioning defects on several 500 kV circuits, replacing faulty vibration dampers on several circuits, and shifting low-priority demand work from the Demand Maintenance program to the Planned Corrective Maintenance Program.

2.2.3 UNDERGROUND CABLE MAINTENANCE

Underground transmission cable systems are used to transmit electrical power and typically connect portions of the overhead network and substations. They are commonly installed in areas where it is impossible or impractical to construct overhead transmission lines due to urban density or legal, environmental, or safety reasons.

Underground cable maintenance programs are implemented to monitor cable condition and identify and repair deteriorated components. Hydro One's cable maintenance programs include:

(i) preventive maintenance, consisting of condition assessment and testing activities;
(ii) corrective maintenance, consisting of activities undertaken to investigate and repair equipment deficiencies; and
(iii) cable locates.

A key aspect of Hydro One's cable asset strategy to maximize service life. Accordingly, cable testing and maintenance reduce the risk of cable equipment failure, which, as discussed in TSP Section 2.2, can seriously impact the environment (through oil leaks) and reliability (through loss of service and redundancy).

Table 46 sets out Hydro One's planned Underground Cable Maintenance OM&A expenditures for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each activity.

Table 46 - Underground Cable Maintenance OM&A ($M)

Description	**Historical Years**				**Bridge Year**	**Test Year**
	2018 Actual	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**
Preventive Maintenance	0.8	1.2	1.0	1.1	1.0	1.0
Corrective Maintenance	5.7	3.0	1.7	1.4	1.3	1.5
Cable Locates	1.1	1.4	1.6	1.5	1.4	1.5
Total	**7.6**	**5.6**	**4.3**	**4.0**	**3.7**	**4.0**

The proposed expenditures in the 2023 Test Year are $4.0M. This is in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the 2021-2022 forecast period, and slightly lower than the historical average

(2018-2021). These expenditures are required to continue performing condition assessments and testing activities, as well as to investigate and repair equipment where necessary.

2.2.3.1 Preventive Maintenance

Preventive maintenance reduces the likelihood of premature cable degradation and failure, customer interruptions (loss of supply), and oil leaks. The intent of the preventive maintenance program is to determine the condition of cable and ancillary equipment through inspection, assessment, testing, and diagnostics in order to enable repairs (as part of the Corrective Maintenance program) or replacement prior to experiencing failures affecting the environment, reliability, and customers. Activities performed under the Preventive Maintenance program include condition assessment patrols, vault inspections, oil tests and analysis, and jacket tests. These activities are done cyclically. Condition and test data collected by this program is used to determine the optimal timeframe for repair or capital replacement.

Table 47 below sets out Hydro One's planned Preventive Maintenance OM&A expenditures in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 47 - Preventive Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Preventive Maintenance	0.8	1.2	1.0	1.1	1.0	1.0

Preventive maintenance activities are cyclical in nature. As such, the proposed expenditures in the 2023 Test Year ($1.0M) are in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period.

2.2.3.2 Corrective Maintenance

Corrective maintenance activities are undertaken to investigate and repair cable and ancillary equipment deficiencies with the intent of returning assets to their normal operating state. Deficiencies are typically noted during preventive maintenance condition assessments or trouble-call responses. Demand corrective maintenance addresses repairs requiring immediate attention (i.e., emergencies) while planned corrective maintenance addresses deficiencies not requiring immediate repair. Corrective maintenance activities include excavating and repairing cable components, locating, repairing and clean-up of oil leaks, etc.

In addition, supplemental non-routine tests are done on a demand basis to verify repairs and obtain detailed condition data if routine testing results show abnormalities. These non-routine tests are typically more intrusive (sometimes destructive), costly, require specialized equipment, and often cannot be done with internal resources (i.e., contractors are required). This data is used to facilitate the selection and prioritization of replacement candidates.

Table 48 below sets out Hydro One’s planned Corrective Maintenance OM&A expenditures in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 48 - Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Corrective Maintenance	5.7	3.0	1.7	1.4	1.3	1.5

The proposed expenditures in the 2023 Test Year ($1.5M) are in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure) and the 2021-2022 forecast period, and slightly lower than the historical average (2018-2021). The decrease relative to the historical average is primarily because corrective maintenance includes both planned and demand work and is a function of labour, equipment, and material requirements that vary by repair.

2.2.3.3 Cable Locates

Upon request, Hydro One is required by provincial legislation[11] to provide locate services for its underground infrastructure. The locate program covers the cost of field stakeouts and site representation of Hydro One's underground transmission system. Hydro One receives more than 10,000 locate requests per year. This investment reduces the probability of underground transmission cable damage caused by dig-ins, and the associated public safety risk and outages to perform repairs.

Table 49 below sets out Hydro One's planned Cable Locates OM&A expenditures in the 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 49 - Cable Locates OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Cable Locates	1.1	1.4	1.6	1.5	1.4	1.5

Cable locates are driven by external demand, and funding is based on the historical number of locate requests. The proposed expenditures in the 2023 Test Year ($1.5M) are in line with the 2020 actual expenditure (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average (2018-2021), and the 2021-2022 forecast period.

[11] *Ontario Underground Infrastructure Notification System Act, 2012*, S.O. 2012, c. 4

2.3 ENGINEERING AND ENVIRONMENTAL SUPPORT

The Engineering and Environmental Support program supports a wide range of activities, including management of records and drawings, database management and provision of specific technical information, technical support including specialized studies, outage assessments conducted by the IESO, event investigation and incidents response, and funding of external technical expertise when needed.

This program is primarily demand-driven, in that it is driven by the level of work required to support the transmission capital work programs. The technical support and specialized studies are completed on an *ad hoc* basis to aid in the decision-making process and justification for capital investments. Table 50 below sets out Hydro One's planned OM&A expenditures for this program in 2023 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 50 - Engineering and Environmental Support OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Engineering and Environmental Support	4.1	7.9	5.4	4.7	4.7	5.0

The proposed 2023 Test Year expenditures are $5.0M. This is $0.7M or 12.7% lower than the amount that would result from adjusting the last rebasing actual expenditures (2020) by inflation ($5.7M).[12] The 2023 Test Year forecast expenditure is $0.5M lower than the historical average (2018-2021) and in line with the 2021-2022 forecast period.

[12] 2020 actual expenditures adjusted by inflation for 3 years = $5.4M x (1+2%)^3 = $5.7M. ($5.0M/$5.7M - 1)% = -12.7%. Inflation is as presented in Exhibit E-03-01.

This program is reviewed annually to assess the level of engineering and environmental support needs. Based on the latest review, the Engineering and Environmental Support expenditures have been decreased to a level in line with the prior five-year average as a result of streamlining certain design and engineering processes and reassigning teams to other departments.

TRANSMISSION DEVELOPMENT OM&A

1.0 OVERVIEW

Transmission Development OM&A (Development OM&A) consists of expenditures required to (i) develop and/or update the required technical standards for transmission power assets, (ii) support advancements and adoption of new technologies aimed at improving operational effectiveness, safety, and system reliability, and (iii) address and/or mitigate (where possible) issues affecting the reliability and quality of delivered power. These activities benefit customers by helping to ensure safe and reliable operation of the transmission system and by addressing issues that are important to the day-to-day operations of customer facilities.

The Development OM&A expenditures fund the following three programs:

- Transmission Standards Program;
- Research Development and Demonstration (RD&D) Program; and
- Customer Power Quality (PQ) Program.

A summary of the Development OM&A expenditures is provided in Table 1 below.

Table 1 - Summary of Development OM&A ($ Million)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Transmission Standards Program	2.8	2.5	4.1	4.0	4.0	4.3
RD&D Program	2.2	1.8	2.3	3.4	3.9	3.3
Customer PQ Program	0.2	0.1	0.2	0.9	1.0	1.0
Total Development	**5.2**	**4.4**	**6.7**	**8.3**	**8.9**	**8.6**

The proposed 2023 Test Year budget of $8.6M is higher than the last rebasing actual expenditures in 2020[1] and higher than the prior five-year average (2018-2022: $6.7M). The proposed 2023 budget is in line with the 2021 and 2022 forecast. The increase compared to the most recent actuals is primarily due to:

- As part of the Transmission Standards Program, Hydro One is reviewing and updating technical standards that are more complex and require more detailed analysis compared to those that were reviewed and updated in the past;
- The RD&D Program has an increased focus in the advancement of new data capture techniques and assessment of opportunities for improvement in operational performance in comparison with current data gathering techniques and methodologies.
- Through the Customer PQ Program, Hydro One continues to engage with its customers to offer assistance in reducing the sensitivity of plant equipment and processes to momentary disturbances that are inherent in large-scale power systems, and includes co-funding of PQ audits to provide specific guidance on mitigation measures. This program now also includes the management of PQ monitoring systems.

2.0 PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below summarize the Test year costs for each of the three Hydro One Development OM&A programs.

2.1 TRANSMISSION STANDARDS PROGRAM

The Transmission Standards Program supports the planning, design, installation, operations, and maintenance of Hydro One's transmission system by maintaining, updating and/or developing new transmission technical standards for power system assets such as: stations, transformers, lines, protection and control equipment and other transmission equipment. Technical standards

[1] And higher than the 2023 amount that would result when adjusting the 2020 actuals for inflation: 2020 Actual adjusted by inflation for 3 years: $6.7M x (1+2%)^3 = $7.1M; ($8.6M/$7.1M - 1)% = 21%; Inflation as presented in Exhibit E-03-01.

are continuously evolving and new standards are being introduced by external bodies and equipment manufacturers. It is of paramount importance that Hydro One fully investigates these increasingly complex standards, documents them thoroughly, communicates them throughout the organization and integrates them into its investment planning process.
Hydro One's technical standards provides a framework for consistent application of engineering principles resulting in design and maintenance approaches, which improve efficiency, maintainability and operational performance.

Technical standards ensure clear direction and work procedures are in place to safe-guard employees and the public where electrical equipment is installed, operated and maintained. Through repeatable and consistent designs, maintenance practices are standardized and bulk purchasing is enabled, which are expected to lower total asset lifecycle costs.

Standards also incorporated into internal policies and requirements to ensure compliance with new and existing industry standards and codes. This program supports the development of standards triggered by changes to reliability standards from organizations such as the North American Electric Reliability Corporation (NERC) and/or the Northeast Power Coordinating Council (NPCC), as well as any revisions to wide-scale, externally-developed industry standards such as the Transmission System Code (TSC). As new technologies are introduced, Hydro One will continue to update its standards and develop new standards to facilitate the integration of these technologies with its legacy systems.

Furthermore, the Transmission Standards Program manages Hydro One's external standards subscriptions and service-level agreements with Standards Development Organizations such as the Institute of Electrical and Electronic Engineers (IEEE), the Canadian Standards Association (CSA), and the Information Handling Services (IHS) Global standards. This function provides employees across the company with access to up-to-date industry standards.

Hydro One participates in industry standards groups to better understand emerging standards and influence their development. With the many factors increasingly impacting the provision of transmission service, including climate change and cyber security, it is important that Hydro One stay abreast of the latest developments. Adding its experience and expertise to influence developing standards through participation in these forums helps Hydro One to remain an industry leader

Hydro One reviews its existing technical standards in accordance with its revision cycles that are based on the specific asset or equipment type as well as various compliance requirements. The development of new standards may be necessitated by the adoption of new equipment and technologies and/or to address compliance requirements. For example, in recent years considerable effort has focused on updating standards related to critical infrastructure protection.

Table 2 below sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for Transmission Standards Program.

Table 2 - Transmission Standards Program OM&A ($ Million)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Transmission Standards Program	2.8	2.5	4.1	4.0	4.0	4.3

The planned Transmission Standards program expenditure in 2023 Test Year is $4.3M, which will ensure that a continued focus on the development and revision of technical standards is maintained in order to: (i) address scheduled updates of existing standards for lines and stations, (ii) prepare new standards that will be needed as new technologies are adopted, and (iii) comply with mandatory standards for safety and reliability. The proposed expenditures are slightly increasing compared to the most recent actuals but are in line with the expenditures expected over the 2021-2022 period. The slight increase is attributable to the complexities of technical standards that are scheduled to be reviewed and updated.

2.2 RESEARCH DEVELOPMENT AND DEMONSTRATION PROGRAM

The RD&D program supports Hydro One's adoption of new technologies to improve operational effectiveness, safety, and system reliability. This program addresses: (i) operational needs by resolving technical challenges experienced by Hydro One to improve the management of existing transmission facilities to deliver safe and reliable supply to customers, (ii) strategic needs by engaging in research on and demonstration of emerging technologies, and (iii) other electricity industry changes arising from innovation and policy initiatives (e.g. OEB's Advisory Committee on Innovation, IESO's Innovation Roadmap and Market Renewal, etc.).

The following transmission related initiatives are some examples of the work that the RD&D program supports:

i. Emerging Technologies

Investing in the development of applications for emerging technologies present opportunities to improve information gathering and operational performance. The main areas of emerging technologies that Hydro One RD&D is focused on are:

- <u>Beyond Visual Line of Sight (BVLOS) Unmanned Aircraft Systems (UAS) Operations</u>

  The RD&D Program has an increased focus on the impacts of emerging data capture technologies that may provide opportunities for improvement in operational performance. The use of UAS is currently limited to line-of-sight applications, however further value could be obtained through BVLOS operations. The goal of this research, through BVLOS pilot demonstrations, is to assess current performance and opportunities for improvement which will inform functional specifications to further the safe and effective adoption of UAS technology to improve operational performance.

- Emerging Technology

  The goal of this research, through collaborative demonstration projects, is to evaluate and assess the impact of emerging technologies, such as energy storage, larger scale micro-grids, advanced real-time sensors and monitoring applications, on the transmission system, in order to inform new approaches to meet changing customer needs.

ii. Innovative Practices and Technologies

Investigating better ways of doing current work, with the potential to improve efficiency, health, and safety for ongoing work and maintain the reliability of the transmission system. The innovative technologies that are a focus of current RD&D efforts can be grouped into the following four areas:

- Overhead Transmission Practices and Technologies

  The goal of this research is to improve safety and reliability in the operation and maintenance of transmission lines, and identify approaches to cost-effectively maintain or increase transmission capacity. This research focuses on overhead transmission line issues, including: corrosion of structures and components; lightning and grounding; line hardening; emerging designs; polymer, composite, porcelain, and glass transmission insulators; and practices for construction and maintenance.

- Underground Transmission Practices and Technologies

  The goal of this research is to improve the operation and maintenance of existing underground cable facilities, and to ensure effective design and implementation of new facilities to meet anticipated system needs. This research focuses on underground cable issues, including: cable ratings; inspection technologies; thermo-mechanical performance; advanced sensing and monitoring; and buried steel pipe corrosion.

- Transmission Substations Practices and Technologies
  The goal of this research is to improve the lifecycle management of substation assets, by examining issues relating to new materials; component aging; and monitoring techniques for assets such as transformers, ground grids, circuit breakers, protection and control equipment.

- Transmission Environmental Practices and Technologies
  The goal of this research is to examine a broad range of subjects including: transmission-line siting; spill prevention, containment, management and remediation; prevention of animal interactions; sensitive species protection; and selecting and managing dielectric fluids.

Much of the research undertaken as part of the RD&D is conducted through industry associations, including the Electric Power Research Institute (EPRI) and the Centre for Energy Advancement through Technological Innovation (CEATI), on a subscription basis. This participation model is a cost-effective approach that allows Hydro One to leverage joint funding with other utilities, risk sharing, and access to the broader expertise of companies with similar interests and challenges.

Table 3 below sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for RD&D Program.

Table 3 - RD&D Program OM&A ($ Million)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
RD&D Program	2.2	1.8	2.3	3.4	3.9	3.3

The planned RD&D program expenditure for 2023 is $3.3M, which will allow Hydro One to continue its focus on improving the management of existing transmission facilities, and staying abreast of advances in emerging technologies that could impact Hydro One's existing transmission business operations. The proposed Test Year expenditures are higher than the most recent actuals, but slightly lower than the expenditures expected over the 2021-2022 period. The increase over recent year actual expenditures is mainly attributable to the increased focus on the assessment of the following: (i) impacts on the system of emerging technologies, such as transmission level energy storage and grid modernization; (ii) data capture technologies and methodologies; and (iii) opportunities for improvement in operational performance with the development and adoption of new data capture techniques.

2.3 CUSTOMER POWER QUALITY PROGRAM

The Customer Power Quality (PQ) Program is designed to address the quality of delivered power, which can materially impact customers' operations and satisfaction. The exact impact of PQ issues on customers depends on their individual circumstances and are functions of:

1. The nature, severity and frequency of the PQ issue; and
2. The sensitivity of customer equipment or processes to PQ disturbances.

Voltage sags due to faults occurring on power systems are a principal cause for a large number of equipment and process disruptions experienced by industrial customers, such as automotive plants, manufacturing facilities, and material processing plants. This causal relationship has been well established by the power industry as well as by industry groups, and it is universally accepted that PQ issues are more practical and cost-efficient to manage closer to the end-use equipment (within the customer facilities) that has the potential to be disrupted.

Through the Customer PQ Program, Hydro One assists its customers in understanding and investigating the sensitivity of plant equipment to power quality disturbances that are inherent in electricity supply systems. In particular, Hydro One undertakes the following activities through the Customer PQ Program:

- Expanding power quality monitoring capabilities by enabling PQ monitoring features in existing Hydro One and customer revenue meters;
- Managing PQ related database software and monitoring systems;

- Investigating PQ disturbances and ensuring compliance with internal and industry PQ standards;
- Co-funding third party customer PQ audits to identify power quality resiliency weak links, analyze available power quality data, and make specific recommendations to improve equipment's resiliency to such future events; and
- Collecting and archiving historical lightning activity data (spatial location and intensity), as gathered from a lightning detection system hosted by an external service provider. The information gleaned from this database allows monitoring and identifying transmission lines experiencing undue lightning outage rates, so that consideration may be given to possible upgrades or mitigation. It is also needed for investigating customer PQ complaints to establish the cause of particular disturbances and to identify effective response strategies.

The Customer PQ Program also allows Hydro One to work on PQ issues with customers. The program provides customers with detailed information about the "PQ environment" – a term defined to include characterization of unwanted deviations of the supply voltage from its intended ideal character, including the frequency of such occurrences. This information about the PQ environment facilitates a coordinated approach to managing PQ performance while recognizing the inherent limitations on the power delivery system to address individual customer issues within customer facilities. As part of this initiative, Hydro One is continuing to expand its PQ monitoring ability across the network, helping to achieve better visibility into events and causes, which enhances the company's ability to resolve PQ issues with customers.

Table 4 below sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for Customer PQ Program.

Table 4 - Customer PQ Program OM&A ($ Million)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Customer PQ Program	0.2	0.1	0.2	0.9	1.0	1.0

The planned Customer PQ Program expenditure for 2023 Test Year is $1.0M, required to focus on meeting demand for customer enrolment in the PQ meter integration initiative program and third party audit activities, and managing PQ monitoring software. The proposed 2023 expenditures are increasing compared to the most recent actuals and in line with the 2021-2022 forecast period. The increase is primarily driven by the realignment of the expenditures for the management of PQ monitoring systems, which was previously captured under a different maintenance program.

TRANSMISSION CUSTOMER CARE OM&A

1.0 SUMMARY OF CUSTOMER CARE OM&A

Hydro One's transmission system effectively serves the entire province—about 97% of electricity customers in Ontario. Most electricity customers are served by a local distribution system and, thus, are indirectly connected to Hydro One's transmission system. Transmission-connected customers (LTX) include about 255 customers of three types, Local Distribution Companies (LDCs), Generators and large End-users, connect directly to the transmission system.

LTX customers represent large electricity consumers and important companies for Ontario's economy whose energy needs are critical inputs for the long-term planning of the transmission system. Hydro One's Account Executives serve a key function as the main point of contact between these customers and the grid, and Hydro One's Customer Care team is committed to meeting the evolving needs of LTX customers through active and engaged relationships with each customer. The department focuses on positively influencing customer relationships and providing transparent, responsive, and cost conscious customer service. More specifically, the Large Customer Account Management Group provides customers with a single point of contact at Hydro One. This group communicates with customers on matters that include customer connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality. Table 1 summarizes Hydro One's Transmission Customer Care OM&A expenditures for the historical (2018-2020), forecast (2021), Bridge (2022), and Test (2023) years.

Table 1 - Summary of Customer Care OM&A Allocated to Transmission ($M)

	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Customer Care	11.0	7.2	7.0	6.0	6.7	6.9
Total	11.0	7.2	7.0	6.0	6.7	6.9

The proposed 2023 Test Year budget is $6.9M. This forecast is $0.5M or 7.1% lower than the amount that would result when adjusting the last rebasing year's actual expenditures (2020) by inflation ($7.4M).[1]

The proposed 2023 budget is lower than the historical average (2018-2021), but is higher than the 2021 forecast due to lower expenditures that materialized in 2020 and continued in 2021 because activities were paused due to the COVID-19 Pandemic. The proposed 2023 budget is in line with the 2022 Bridge Year reflecting spending levels with the reactivation of customer service activities that were paused in the prior year.

The customer care plan aims to strike a balance between improved customer service and managing operational expenditures. Specifically, over the term of the Application, Hydro One plans to exceed its historical average for overall customer satisfaction targeting 88% as set out in the Transmission Scorecard (see TSP Section 2.5).

Hydro One is committed to improving customer service through a focus on customer experience. Customers expect Hydro One to keep commitments, be responsive to the needs of their business, and provide transparent and cost conscious service. Over the past three years, the department's commitment to striking a balance between improved customer service and

[1] 2020 actual expenditures adjusted by inflation for 3 years = $7M x (1+2%)^3 = $7.4M. ($6.9M/$7.4M - 1)% = 7.1%. Inflation is as presented in Exhibit E-03-01.

managing operational expenditures has been successful, and Customer Care OM&A costs have declined since 2018 (as outlined in Table 1).

2.0 CUSTOMER CARE OM&A PROGRAM DESCRIPTION AND VARIANCE DISCUSSION

The Customer Care team provides a range of services to LTX customers, including (i) responding to customer inquiries, (ii) providing proactive outreach and customized advice through Account Executives, and (iii) performing meter data aggregation, billing, and settlement activities.

Hydro One is committed to providing consistently high levels of overall customer satisfaction for all customer segments and to demonstrating operational excellence. Hydro One's average performance among LTX customers over the past five years (2016 to 2020) was 85%.

Hydro One’s dedicated Account Executives play an important role in achieving this goal. They are the single point of contact for LTX customers, acting as their advocate and providing education on issues that matter. Account Executives meet with transmission customers on a regular basis to ensure that the needs of those customers are identified and discussed, and that action plans are developed to address these needs. Hydro One’s Account Executives proactively and directly engage with transmission customers to review and coordinate plans for the company’s assets in order to minimize impacts on customers and optimize opportunities for both Hydro One and its customers to plan and execute work on their respective facilities.

The customer care team also performs billing and settlements functions to ensure the integrity of financial transactions between Hydro One, the Independent Electricity System Operator (IESO), and applicable LTX customers. Settlement activities include: calculating gross load-billed quantities at specific delivery points; reviewing and approving transmission totalization tables; reviewing and approving IESO transmission delivery point site registration reports and meter connectivity; reconciling transmission delivery point quantities and charges; and identifying anomalies and exceptions in metering data used by the IESO to bill Hydro One LTX customers.

The COVID-19 Pandemic was the main reason for the lower than planned Customer Care OM&A expenditures in 2020. Because of the outbreak of the Pandemic in March 2020, the Customer Care team was forced to limit or suspend some of its customer service activities for the remainder of the year. Most notably, Hydro One was unable to host its annual Large Customer Conference (LCC) resulting in fewer direct customer contacts and lower spending. Furthermore, Account Executives limited travel activities to customer sites for most of the year. In addition, the insourcing of the Settlements function in the later half of 2020 resulted in further efficiencies. Lastly, the Key Account Management team had vacancies throughout 2020, which remained open because of the Pandemic. Over the same period, Customer Satisfaction among LTX customers declined marginally (from 87 to 83%).

Hydro One expects the impacts of the Pandemic to continue in 2021, manifesting in similar restrictions and associated lower OM&A spending described above, as well as reflecting the full-year efficiencies attributed to insourcing of the Settlement function. However, the Customer Care team will work on reversing the slight downward trend in customer satisfaction, while maintaining a focus on cost optimization and productivity.

Forecast costs in the 2022 Bridge Year increase compared to 2021 but remain below 2020 actuals, based on the assumption that the Customer Care team will be able to reactivate the customer service activities that were paused due to the Pandemic. Specifically, Hydro One plans to host its annual LCC and reinstate regular customer site visits for Account Executives.

TRANSMISSION O&M WORK EXECUTION STRATEGY

1.0 INTRODUCTION

This exhibit describes the approach Hydro One uses to efficiently deliver its large and complex Transmission Operations and Maintenance (O&M) work program while meeting approved expenditure levels. The company aims to complete its annual O&M work program with a work execution plan that is aligned with the business objectives described in the TSP, ensures system reliability, addresses customer needs, meets regulatory requirements, and, above all, ensures a safe environment for workers and customers.

This exhibit details Hydro One's approach to O&M work and the associated initiatives in place to effectively execute required maintenance work. It begins by describing the process by which the work program is executed and a description of the O&M work program. This is followed by a discussion of Hydro One's safety culture and initiatives, continuous improvement model, and productivity initiatives.

2.0 PROGRAM DELIVERY PROCESS

The program delivery process comprises three key phases: (i) Planning; (ii) Program Development, which includes the Work Program Planning, and Work Initiation and Scheduling sub-phases; and (iii) Execution. Each of these phases and sub-phases are discussed in the sections that follow. Below is a diagram that depicts the process in Transmission O&M starting from initial Planning through to Program Execution.

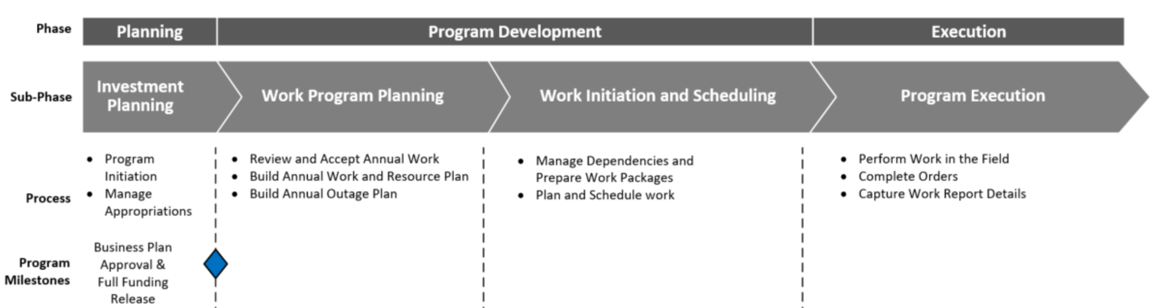

Figure 1: Transmission O&M Program Delivery Model

2.1 PLANNING

The Investment Planning Process determines the frequency and nature of maintenance activities that are optimized to make best use of the Transmission O&M funding, as discussed in Section 1.7 of the System Plan Framework (SPF). Hydro One's program delivery process, illustrated in Figure 1 above, is used to develop and execute the programs necessary to meet the Investment Plan.

Programs are approved and released on an annual basis, which enables the work management and execution lines of business to plan accordingly with respect to resources, training, and material purchases.

2.2 WORK PROGRAM PLANNING

Once the programs are released to the executing lines of business the Work Management function starts to plan the work. This typically starts in advance of the calendar year. Work Management seeks to further optimize the work program, looking at enablers such as resources and system outages across the entire portfolio of transmission and distribution work.

2.3 WORK INITIATION AND SCHEDULING

Detailed work packages are prepared for the executing workgroups capturing material, equipment, and standards required to complete the work safely. Maintenance work is scheduled for execution taking into account the criticality of work, resource availability and utilization, staff and public safety, as well as the requirement for system outages. Work is bundled when scheduling to make best use of outages and resources.

Much of Hydro One's Transmission O&M work requires an outage to safely and efficiently execute. Given the number and variety of capital and O&M work programs that Hydro One is executing, outage planning is a significant effort and is done initially through an annual planning process and refined through a continually rolling outage planning process. Hydro One limits the number of planned bulk electric system outages required through the bundling of work to make the best possible use of available outages while executing a growing work program. Some of the approaches taken to minimize the impact of outages include: work-bundling initiatives; and improved planning through better communication within the company, and with customers and the IESO.

2.4 PROGRAM EXECUTION

The workgroups are responsible for safely and efficiently executing the O&M work program as planned and are responsible to report any variances to the plan as they relate to scope, schedule or cost. The execution work groups work closely with program managers to identify and report any unforeseen issues requiring additional time or resources so that work can be reprioritized effectively. They are also responsible to provide meaningful input on the condition of assets and any potential risks or opportunities that may impact the Hydro One system.

3.0 PROGRAM OVERSIGHT AND GOVERNANCE

As part of the program delivery process, Hydro One has established the mechanisms below to enable appropriate tracking and reporting of work program performance.

3.1 TRACKING AND REPORTING

Hydro One reviews its program status on a monthly basis. Hydro One uses a combination of standard reporting requirements, key performance indicators, and unit reporting metrics to monitor the execution of work at program and portfolio levels to provide assurance that its O&M work program is well-managed and executed to plan.

This review occurs at multiple levels of leadership from the leader of the Work Management function to the executive level. Programs are reviewed against their plans for expenditures and work accomplishment, monitoring any changes in cost throughout the year and against previous year’s performance. Work programs required to comply with regulatory requirements related to maintenance or inspection activities are tracked, reported on and measured to ensure compliance is achieved. Hydro One works to incorporate these requirements into the efficient scheduling and execution of the work program, specifically highlighting regulatory requirements in the management of applicable programs, and reviewing the status and outlook of required work monthly with multiple levels of management and executive leadership review.

At the portfolio level, Hydro One reviews its overall transmission O&M work program spending and completion. The goal of the review is to establish a comprehensive view of work delivery, to ensure that planned work is being completed and resources are redirected as required for optimal efficiency.

3.2 GOVERNANCE

On a quarterly basis, material variances against plan are reviewed by the appropriate expenditure authority[1] and redirection opportunities or offsets are identified and brought forward to the Redirection Committee for approval. As discussed in SPF Section 1.7, redirection refers to the process by which changes are made to the programs included in Hydro One's annual budget. Within the O&M work program, approved programs expenditures and accomplishments may be increased or decreased to address material variances or other emergent issues or factors that require the postponement of program work such as outage availability.

4.0 WORK PROGRAM

Transmission O&M work is primarily executed by internal staff, in the areas of Stations, Lines, and Forestry.

The stations maintenance work program is underpinned by preventive maintenance programs designed to monitor and ensure the health of power system equipment. Preventive maintenance activities are based on frequency cycles specific to the type and make of the

[1] The appropriate expenditure authority is defined by the Expenditure Authority Register, which establishes the spending and investment limits associated with each organizational level from the Board of Directors to the manager level.

equipment, or in some cases the number of operations a device has experienced or other condition-based triggers. These activities include visual inspections and selective intrusive inspections of the internal working components of power equipment such as transformers and circuit breakers. Diagnostic and operating tests are performed to assess the condition of power system, auxiliary equipment, as well as protection, control and telecom systems. The frequency by which maintenance activities are performed is reviewed in conjunction with asset health assessments to maximize the effective use of planned maintenance funding, power system reliability and useful equipment life.

Corrective maintenance in stations can result from inspection findings, trouble calls in response to automated equipment monitoring alarms, and dispatch from the Ontario Grid Control Centre (OGCC). Inspection results requiring attention are logged as defect reports, which are prioritized, either as requiring urgent attention or to be planned for remediation. Non-urgent maintenance and repairs are planned and scheduled to make the most efficient use of resources and outages. The common types of corrective activities performed are switch repairs, breaker repairs, oil leaks, transformer fan/cooling repairs and right of way maintenance.

The lines preventive maintenance work program includes condition assessment of equipment including conductor, shieldwire, insulators, steel and wood structures, high-voltage underground cables (HVUG). Inspections and assessments on these transmission system assets allow for the proactive identification of conditions which, if not addressed, could result in reliability or safety concerns. Data collected from assessments on asset condition also informs the capital refurbishment and replacement programs.

Corrective maintenance on transmission lines, as in stations, is identified through inspections and foot patrols, and during trouble calls. Defect reports are prioritized, and either addressed as urgent repairs, or scheduled for remediation. Scheduled repairs are prioritized, and planned for the most efficient utilization of resources, material and outages. The common types of activities performed are repairs on insulator structures, towers, pole structures and shieldwire component repairs. Defects requiring asset replacement are addressed under the transmission capital work program.

The Forestry work program is focused on safely managing vegetation on Hydro One's Transmission right-of-way corridors and at Hydro One Transmission facilities to maintain system reliability. Preventive maintenance activities include transmission vegetation notification, annual vegetation patrols, line clearing, brush control, condition patrol and station spray. The brush control program involves managing vegetation growth to satisfy standing and falling clearance distances to overhead conductors while the line clearing program is focused on removing or selectively trimming vegetation and danger trees on the edge of or adjacent to the right-of-way that have the potential to exceed clearances.

The line clearing and brush control programs are cyclical in nature. The associated cycle lengths are taken into consideration when annual programs are planned and feeder selection occurs, which is particularly important to ensure compliance with NERC regulations.

A portion of the overall work program involves unplanned maintenance to address vegetation deficiencies that require treatment prior to the next scheduled cyclical maintenance activity. Trouble Call Response and Storm Restoration efforts also require Forestry support as many weather events result in tree-related incidents that require the expertise of forestry crews to clear downed trees and other unwanted vegetation.

5.0 EXECUTION RESOURCES

Hydro One relies on the expertise of a high-performing, skilled workforce to complete its work program. The yearly Vegetation work program is accomplished using a fairly balanced combination of Regular (Regional Maintainers, Area Forestry Technicians and students) and Casual (Apprentices, PWU HH Technicians, Labourers, and Mechanical Operators) resources.

The company also realizes economies of scale and efficiencies by integrating its transmission and distribution workforces, and capital and O&M work where it is advantageous to do so. The mix of full-time and temporary staff provides the needed flexibility to support the fluctuations in the work program, which result from the seasonal nature of some work, the need to react to emergent situations and evolving asset requirements. (See Exhibit E-06-01).

6.0 SAFETY CULTURE

Hydro One believes that a safe utility is an efficient utility, and that a healthy safety culture fosters accountability and discipline across all aspects of our business. As a result, a Chief Safety Officer (CSO) role was established in 2020 to lead the transformation of our safety culture, and the health, safety and environment function was recently redesigned to provide a more effective focus on our health and safety management systems, training and development, operations field support and learning, analytics and reporting as discussed below. Furthermore, a Safety Improvement Team was created from a diverse cross section of the organization to identify areas of improvement to prevent serious injuries and fatalities.

Hydro One also continues to improve workplace health and safety by ensuring effective job planning through its Human Success program. The overall goal of Human Success is to ensure that frontline workers and supervisors are well informed of potential risks, and are actively engaged in safe work planning. Weekly safety bulletins are distributed and shared with staff at Monday morning tailboard sessions to ensure planning discussions are relevant. Onsite planning meetings are carried out at the start of each day and after breaks to refocus staff and reinforce safe work practices. The use of open-ended questions is encouraged to generate good discussion and to ensure that everyone's viewpoints are heard. Additional discussion of safety in work execution can be found in TSP Section 2.10.

7.0 CONTINUOUS IMPROVEMENT

Hydro One has implemented a Continuous Improvement Model (CIM) in relation to the management and execution of the Transmission Stations O&M work program. The Continuous Improvement Model provides processes, controls and tools to improve the planning, scheduling, execution and reporting of work. This structured approach is designed to promote a change in work culture by empowering staff. CIM has successfully enhanced the management and execution of O&M work by improving both planning and execution as discussed below. Based on the positive results observed within the O&M work program, a CIM initiative is now underway for the Transmission capital and Transmission Lines O&M work programs. Further information of the capital program initiative may be found in TSP Section 2.10.

CIM provides a framework to address three fundamental areas:

- Providing a structured methodology and tools for more effective planning, work execution and reporting.
- A province-wide problem resolution program that facilitates the identification, prioritization and tracking of continuous improvement opportunities in execution.
- Alignment of roles, responsibilities and accountabilities.

Improved work planning processes from CIM have reduced the cancellations and extension of maintenance activities beyond planned durations. The addition of new standardized work management tools and reporting have improved scheduling and work tracking.

Based on the CIM, Hydro One has implemented systematic processes to quantify, categorize and escalate issues that arise during work execution. Issues are analyzed and addressed through a resolution process, using a consistent escalation framework with levels corresponding to the importance of the issue, to drive the implementation of permanent solutions. This eliminates the frustration caused by the same problem recurring, and has proven to increase engagement as staff are stakeholders in the development of solutions.

Structured processes articulate clear expectations for each role in the work. These include the roles of managers, supervisors, as well as workers. Consistent, timely communication and coaching are a key component of CIM, with a focus on increasing active supervision.

This CIM toolset has enabled an improvement in field workforce utilization on O&M work and more efficient use of available equipment outages. This is reflected in an increase in the O&M work program productivity savings discussed in the following section.

Wrench-Time Studies were performed to provide insight into work practices for preventive maintenance and other repeatable, standardized work. The studies led to the identification of best practices and areas of opportunity for improvement. This insight has informed improvements in work execution for greater efficiency. Having been incorporated into work practices, the results of the studies continue to provide improved utilization of resources and as a result lower costs.

8.0 PRODUCTIVITY

Hydro One has placed a significant focus on improving the efficiency of its work program delivery over the last several years. Productivity initiatives have improved the utilization of resources, and, as a result, have reduced the cost of delivering the O&M work program. Hydro One anticipates that the improvements and efficiencies described in this exhibit will contribute to identifying incremental productivity savings as described in SPF Section 1.4.

The use of overtime to complete work has been reduced significantly in recent years. This has been made possible by the improvements in the planning and scheduling of work. Work is monitored during execution to assess progress and reprioritized as necessary to enable the most efficient utilization of available resources and equipment outages.

A framework of reporting to support regular monitoring of performance of maintenance work is in place, providing visibility to work groups exhibiting best practices. When identified, these practices are adopted through the Continuous Improvement Model (see Section 7.0). Estimates and work schedules are updated and revised to reflect these best practices as improved plans are implemented.

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. Hydro One has established Temporary Work Headquarters (TWHQ) for employees who are required to work outside of their residence headquarters for extended periods of time. The benefits of this initiative include increased wrench time, fleet savings, decreased travel expenses, scheduling efficiencies and safety improvements (e.g. less driving time).

Corrective maintenance costs have been reduced not only through the reduction in overtime, but also due to incremental savings from the improved work planning, prioritization and a issue resolution process, as explained in the Continuous Improvement section above. Weekly status reporting provides field supervisors with improved visibility into the performance of their crews.

9.0 SUMMARY

Hydro One delivers a large and complex maintenance work program within approved expenditure levels, while maintaining the necessary flexibility to meet demands of a changing environment in a safe and effective manner. Asset needs, system reliability, and meeting regulatory requirements are achieved through the robust oversight over the transmission maintenance portfolio. A key focus of the company remains the safe, efficient and cost-effective execution of work.

SUMMARY OF DISTRIBUTION OM&A EXPENDITURES

1.0 INTRODUCTION

This exhibit provides an overview of Hydro One Distribution's Operations, Maintenance and Administration (OM&A) expenditures over the 2018 to 2023 period, which include the 2018 to 2021 historical period[1], the 2022 bridge year, and the 2023 test year.

Hydro One's OM&A expenditures are comprised of work required to meet public and employee safety objectives, maintain distribution system reliability at targeted performance levels, and comply with regulatory requirements, including those specified within the Distribution System Code, and the federal environmental legislation associated with the Polychlorinated Biphenyl (PCB) program.

The OM&A budget has been set in order to deliver outcomes valued by customers, while ensuring responsible stewardship of the Company's distribution assets and balancing customer rate impacts. The forecast OM&A expenditures in respect of Sustainment, Development, and Operations have been determined through the Investment Planning process described in SPF Section 1.7. The expenditures are responsive to the outcomes of the Distribution System Plan (DSP Section 3.1) and the Business Plan (Attachment 1 to Exhibit A-03-01). This process reflects a risk-based decision making approach to ensure appropriate and cost-effective expenditures.

Hydro One is seeking approval of a 2023 test year OM&A budget of $597.5M (including OM&A related to the Acquired Utilities). This 2023 budget represents a less than inflationary increase over the period from 2018 to 2023. Specifically, the 2023 test year OM&A is $4.1M (or 0.7%) lower than the amount that would result from escalating the 2018 OEB approved OM&A[2] by

[1] 2021 is provided on a forecast basis
[2] 2018 is the test year of the prior Custom IR period, which was the year approved by the OEB, with 2019 to 2022 then resulting from the Custom IR Framework.

inflation, which is $601.6M. Further, when the 2023 test year OM&A amount is normalized[3] on the same basis as the amounts approved in the prior application, the equivalent 2023 OM&A is in fact approximately $36.4M (or 6.1%) lower than the 2018 approved OM&A escalated by inflation, as outlined in Table 1.

Table 1 - 2023 OM&A Comparison

	($M)	**2023**
A	2023 Distribution Test Year OM&A	597.5
B	Less: 2023 non-service costs component of OPEBs[4]	(20.1)
C	Less: 2023 Acquired Utilities' OM&A	(12.2)
D=A-B-C	2023 Equivalent Distribution Test Year OM&A	565.2
E	2018 OEB-Approved Distribution OM&A Escalated by Inflation in 2023 Terms[5]	601.6
F=D-E	Variance	(36.4)
G=F/E	% Change	(6.1%)

It is through successful implementation of cost control initiatives and achievement of productivity that Hydro One is able to keep Distribution OM&A costs below the rate of inflation. That is the case even though the 2023 test year OM&A reflects the impacts of implementing the OEB's decisions in the 2018-2022 Distribution application and the 2020-2022 Transmission application, specifically in respect of the non-service cost component of Other Post-Employment Benefits (OPEBs).

Relative to amounts forecasted in the 2018-2022 Distribution application, there is higher achieved productivity, primarily due to: (i) accelerated savings in the Cable Locate Outsourcing initiative; (ii) accelerated saving in the In-Sourcing of the IT contract initiative; (iii) savings

[3] For non-service costs component of OPEBs and Acquired Utilities' OM&A
[4] To equate the 2023 OM&A to 2018 levels for comparison purposes, a normalization for non-service cost component of OPEBs of $20.1M was applied to 2023, as it was not previously included in the 2018 approved OM&A and consistent with the Transmission decision in EB-2019-0082.
[5] 2019 Inflation rate is equal to the OEB approved rate in in EB-2017-0049. 2020 Inflation rate is equal to the OEB approved rate in EB-2019-0043. 2021 to 2023 Inflation rate is equal to the OEB approved rate in EB-2020-0030.

realized due to Customer Call Centre Insourcing initiative, (iv) Forestry Line Patrols cost reductions as a result of bundling overhead asset inspections with vegetation management defect patrols, and (v) implementation of the corporate costing initiative which significantly reduced vacancies and limited contract spending to critical functions. This productivity benefit continues into 2023 by having these OM&A efficiencies become part of regular business planning and thus reducing upward pressure on future OM&A expenditures. This is described further in SPF Section 1.4.

The total Actual/Forecast OM&A for the period of 2018-2022 is in fact lower by $54M than the total OM&A amount included in the OEB-approved revenue requirement for the same period,[6] further reflecting Hydro One's cost controls and incremental productivity achievements that more than offset unplanned expenditures such as incremental costs associated with COVID-19.

Table 2 provides a summary of OM&A expenditures for the historical, bridge, and test years. The 2018 OEB-approved funding is presented at the total envelope level, consistent with the envelope funding approved by the OEB in Hydro One's prior Distribution application (EB-2017-0049).

[6] Calculated based on the Custom IR formula. For 2019-2021, this is per the OEB approved formula in *EB-2017-0049, EB-2019-0043, and EB-2020-0030.* The 2022 amount was derived by applying the inflation rate less stretch factor equal to the OEB approved rate in *EB-2020-0030.*

Table 2 - Summary of Recoverable OM&A Expenses ($M)

Distribution	Historical					Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
	OEB-Approved	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment	-	312.3	347.1	324.9	299.6	303.6	311.4
Development	-	7.5	7.1	6.0	10.0	10.2	11.0
Operations	-	37.3	36.6	33.0	39.7	41.3	40.8
Customer Care	-	111.7	97.8	111.2	108.6	107.9	118.3
Common and Other	-	84.9	66.3	79.7	68.0	67.0	110.0
Property Taxes and Rights Payments	-	5.1	4.6	5.4	5.6	5.8	6.0
Total	**544.4**	**558.8**	**559.6**	**560.2**	**531.4**	**535.8**	**597.5**

2024 to 2027 OM&A is established in accordance with the Custom IR framework discussed in Exhibits A-04-01 and A-04-03.

2.0 DESCRIPTION OF OM&A CATEGORIES

The categories that comprise the overall OM&A envelope are the following.

Sustainment: The expenditures in this category are required to maintain existing components of the distribution system to ensure they continue to function as designed. The expenditures allow Hydro One to ensure operational effectiveness by maintaining an acceptable level of reliability, to deliver on commitments to customers, and to respond to public policy by complying with all legislative, regulatory, safety and environmental requirements. Hydro One manages its Sustainment OM&A by way of the following categories: (a) stations, (b) lines, (c) meters, telecom, and control, and (d) vegetation management.

Development: The expenditures in this category are required to (i) perform technical studies and develop construction standards for the connection of load and generation customers to the distribution system, (ii) support research into new technologies and the development of power quality solutions, and (iii) ensure that the existing and forecast customer load and generation demands are met, system reliability is maintained, regulatory requirements are satisfied, and the impact of distributed generation connected to the system is effectively monitored. Hydro One manages its Development OM&A by the way of the following categories: (a) engineering and technical studies, (b) distributed generation connections, (c) distribution standards programs, (d) research development and demonstration, and (e) customer power quality programs.

Operations: The expenditures in this category are required to (i) monitor and control distribution assets, including newly integrated smart devices on the distribution system, (ii) manage customer outage information, (iii) coordinate and dispatch crews as required, (iv) plan for and react to system contingencies, (v) schedule and coordinate planned outages, (vi) provide customer notifications, and (vii) monitor and report on the performance of the distribution electricity systems. The 24/7 real time operation of Hydro One's distribution system is conducted at the Integrated System Operations Centre (ISOC) and the Back-Up Ontario Grid Control Centre (BU-OGCC). Operations OM&A spending also supports Hydro One's environment, health and safety activities and the Smart Grid.

Customer Care: The expenditures in this category are required to provide services to residential, small business, commercial, and industrial customers. The key functions of Customer Care are: (i) responding to customer inquiries when they contact the call center, (ii) obtaining meter readings, (iii) issuing timely and accurate bills, (iv) processing customer payments, (v) collections program management, and (vi) providing financial assistance to low-income customers through the OEB's Low-Income Energy Assistance Program (LEAP).

Common and Other: The expenditures in this category include costs associated with common corporate functions and services (CCF&S), asset management planning, information solutions, the cost of sales for external work, and other costs including those associated with the non-service component of OPEBs. Hydro One allocates Common OM&A Costs to affiliates and business segments through an updated cost allocation methodology developed by Black & Vetch (described in Exhibit E-04-08), which includes using more direct cost allocation percentages to allocate common corporate costs to the Transmission and Distribution lines of business.

Property Taxes and Rights Payments: In respect of the expenditures in this category, Hydro One is subject to property taxes in accordance with the *Electricity Act 1998*, the *Municipal Act 2001*, and the *Assessment Act 1990*. Hydro One also pays annual fees for the right to cross and/or occupy properties owned by third parties, such as railway companies and/or governmental bodies.

Summary explanations regarding the 2023 amounts requested in these categories compared to prior years are included in the envelope level variance explanations in Section 3 below (to the extent they contribute to the variances). Additional details regarding each of these OM&A categories, including detailed variance explanations in respect of them, can be found in the exhibits outlined in Table 3.

Table 3 - Supporting OM&A Exhibits

Cost Category	Exhibit Reference	Exhibit Title	Witness
Sustainment	E-03-02	Distribution Sustainment OM&A	FALTAOUS Peter
Development	E-03-03	Distribution Development OM&A	FALTAOUS Peter
Operations	E-04-05	Operations OM&A	HOLDER Godfrey
Customer Care	E-03-04	Distribution Customer Care OM&A	GILL Spencer
Common and Other	E-04-01	Summary of Common and Other OM&A	JODOIN Joel
Property Taxes and Rights Payments	E-09-04	Taxes Other Than Income Taxes	BERARDI Rob

3.0 ENVELOPE LEVEL VARIANCE EXPLANATIONS

This section briefly addresses envelope level variance explanations, which are further described and detailed in the accompanying exhibits that are referred to.

3.1 COMPARISON OF 2023 TEST YEAR OM&A TO 2018 OEB-APPROVED

Compared to the OEB-approved amount for 2018 ($544.4M), Hydro One’s expected 2023 Distribution OM&A expenses ($597.5M) are 9.7% higher. However, as previously outlined in Table 1 above, when the 2023 OM&A of $597.5M is normalized on the same basis as the amounts approved for 2018, the equivalent 2023 OM&A budget ($565.2M) is actually 6.1% lower than the 2018 approved amount escalated by inflation to 2023 dollars ($601.6M). Even without normalization, the 2023 budget is 0.7% lower than the 2018 OEB approved amount escalated by inflation. As previously explained, the 2023 budget is significantly lower than previously approved levels, when normalized on the same basis, due to the sustained impact of productivity savings.

3.2 COMPARISON OF 2023 TEST YEAR OM&A COSTS TO 2020 ACTUALS

Compared to actual 2020 OM&A expenses, Hydro One’s 2023 expected OM&A expenses are $37.3M (or 6.7%) higher.[7] The main drivers of these increased costs are:

- Increased Common and Other costs of $30.3M primarily due to (i) OPEB non-service costs of approximately $20.1M, (ii) higher real estate and facilities costs associated with fixed operating costs for new facilities as well as lease renewals, (iii) increased human resource costs supporting the development of Hydro One’s People Strategy (detailed in Exhibit E-04-02), and (iv) increases associated with technology solution updates, including change management and data migration, and security costs so Hydro One remains appropriately positioned against an evolving security threat landscape (detailed in Exhibit E-04-04);
- Increased Operations costs of $7.8M primarily due to the reshuffling of staff between the Transmission Operations and Distribution Operations organization. Staff were moved from Transmission Operations into Distribution Operations in 2021 to support the increased deployment of modernized distribution system technology, including

[7] Similar to the adjustments noted in Table 1, when the 2023 OM&A of $597.5M is normalized on the same basis as actuals for 2020, the equivalent 2023 OM&A budget ($565.2M) is $5M higher than 2020 actual results.

automated devices, switches, and fault indicator devices, which help reduce the number of customers impacted by outages and improve outage restoration times (detailed in Exhibit E-04-05);

- Increased Customer Care costs of $7.1M due to an increase in Third Party Support costs required for Customer Service Operations including postage services, e-billing services using Canada Post's ePost solution, toll-free phone numbers for the call center, payment processing services, customer communication, the collection of customer feedback and surveys, and collection agency costs for outstanding final-billed accounts and additionally, an increase in call centre operations expenses (detailed in Exhibit E-03-04); and,
- Increased Development costs of $5.1M primarily due to Research Development & Demonstration (RD&D) attributable to further study and assessment of new technologies and practices as well as an increase in Engineering and Technical Studies to focus on new and/or updated standards associated with smart devices and integration of new technologies (detailed in Exhibit E-03-03).

These increased costs are partially offset by an overall decrease in Sustainment OM&A costs of $13.5M. This decrease is primarily due to decreases in Lines due to lower forecast volumes of trouble calls primarily resulting from Hydro One continuing through the Optimal Cycle Protocol (OCP) program and PCB equipment and waste storage costs based on the targeted completion year of 2025 to meet regulations partially offset by increases in Meters, Telecom and Control primarily due to retail revenue meters based on forecasts of the regulatory requirements for statistical sampling and failed meter replacements (detailed in Exhibit E-03-02).[8]

[8] In 2020, the Company had higher than normal levels of storm activity which contributed to higher trouble call levels.

3.3 COMPARISON OF 2023 TEST YEAR OM&A COSTS TO 2021 FORECAST AND 2022 BRIDGE YEARS

Compared to the 2021 forecast and 2022 bridge years, Hydro One's expected 2023 OM&A expenses are $66.1M (or 12.4%) and $61.7M (or 11.5%) higher, respectively.[9] The main drivers of the increases are:

- Increased Common and Other costs of $42.0M compared to 2021 and of $43.0M compared to 2022, primarily due to (i) OPEB non-service costs of approximately $20.1M, (ii) a reduction of the environmental provision credit due to targeted completion by 2025 to meet regulations, (iii) higher CCF&S noted above (detailed in Exhibit E-04-02), and (iv) increases in costs to update technology solutions and Hydro One's security posture (detailed in Exhibit E-04-04);
- Increased Sustainment OM&A of $11.8M compared to 2021 and of $7.7M compared to 2022 are primarily due to Line Maintenance and Trouble Calls, including increased forecast expenditures in the Line Maintenance program due to inclusion of the Acquired Utilities (Norfolk, Woodstock, and Haldimand) into the Hydro One plan (detailed in Exhibit E-03-02); and,
- Increased Customer Care expenses of $9.7M compared to 2021 and of $10.4M compared to 2022 primarily due to an increase in Third Party Support costs required for Customer Service Operations including for the services previously described in Section 3.2 above and an increase in call centre operations expenses (detailed in Exhibit E-03-04).

3.4 COMPARISON OF 2018 OM&A ACTUALS TO 2018 OEB-APPROVED

Hydro One did not receive the OEB's approval for 2018-2022 revenue requirement, including 2018 OM&A, until 2019. As such, a comparison between 2018 OEB approved and 2018 actuals

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[9] Similar to the adjustments noted in Table 1, when the 2023 OM&A of $597.5M is normalized on the same basis as forecast for 2021 and 2022, the equivalent 2023 OM&A budget ($565.2M) is $33.8M and $29.4M higher than the 2021 and 2022 forecast, respectively.

would not be a meaningful comparison.[10] Hydro One also notes that the OEB-approved OM&A was set at an overall envelope level and so a more detailed comparison (beyond the envelope level) would not be feasible.

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[10] $14.4M higher than OEB-approved

Appendix 2-JA
Summary of Recoverable OM&A Expenses

($M)

	2018 Last Rebasing Year OEB Approved	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year	
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	
Sustainment		$ 312.3	$ 347.1	$ 324.9	$ 299.6	$ 303.6	$ 311.4	
Development		$ 7.5	$ 7.1	$ 6.0		$ 10.2	$ 11.0	
Operating		$ 37.3	$ 36.6	$ 33.0		$ 41.3	$ 40.8	
Asset Management (Planning) costs		$ 15.7		$ 14.2	$ 13.6	$ 14.4	$ 14.9	
SubTotal		**$ 372.8**	**$ 404.3**	**$ 378.0**	**$ 362.9**	**$ 369.6**	**$ 378.0**	
%Change (year over year)			8.5%	-6.5%	-4.0%	1.8%	2.3%	
%Change (Test Year vs Last Rebasing Year - Actual)							0.02%	
Customer Service (Billing, Collecting, Bad Debt, Misc)		$ 111.7		$ 111.2		$ 107.9	$ 118.3	
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		$ 7.5		$ 7.2	$ 6.9	$ 7.1	$ 7.3	
Common Functions and Services		$ 72.5	$ 69.4	$ 69.2	$ 76.9	$ 80.1	$ 81.8	
Information Technology		$ 73.8	$ 81.1	$ 78.4		$ 81.5	$ 85.9	
Property taxes and rights payment		$ 5.1		$ 5.4	$ 5.6	$ 5.8	$ 6.0	
SubTotal		**$ 270.6**	**$ 260.4**	**$ 271.4**	**$ 281.7**	**$ 282.4**	**$ 299.3**	
%Change (year over year)			-3.8%	4.2%	3.8%	0.2%	6.0%	
%Change (Test Year vs Last Rebasing Year - Actual)							10.3%	
Miscellaneous (Other OM&A, Recovery)		-$ 84.7	-$ 105.2	-$ 89.2	-$ 113.2	-$ 116.1	-$ 79.9	
Total	**$ 544.4**	**$ 558.8**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	**$ 597.5**	**6.7%**
%Change (year over year)			0.1%	0.1%	-5.1%	0.8%	11.5%	

	2018 Last Rebasing Year OEB Approved	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year
Sustainment		$ 312.3	$ 347.1	$ 324.9	$ 299.6	$ 303.6	$ 311.4
Development		$ 7.5	$ 7.1	$ 6.0	$ 10.0	$ 10.2	$ 11.0
Operating		$ 37.3	$ 36.6	$ 33.0	$ 39.7	$ 41.3	$ 40.8
Asset Management (Planning) costs		$ 15.7	$ 13.5	$ 14.2	$ 13.6	$ 14.4	$ 14.9
Customer Service (Billing, Collecting, Bad Debt, Misc)		$ 111.7	$ 97.8	$ 111.2	$ 108.6	$ 107.9	$ 118.3
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		$ 7.5	$ 7.5	$ 7.2	$ 6.9	$ 7.1	$ 7.3
Common Functions and Services		$ 72.5	$ 69.4	$ 69.2	$ 76.9	$ 80.1	$ 81.8
Information Technology		$ 73.8	$ 81.1	$ 78.4	$ 83.8	$ 81.5	$ 85.9
Property taxes and rights payment		$ 5.1	$ 4.6	$ 5.4	$ 5.6	$ 5.8	$ 6.0
Miscellaneous (Other OM&A, Recovery)		-$ 84.7	-$ 105.2	-$ 89.2	-$ 113.2	-$ 116.1	-$ 79.9
Total		**$ 558.8**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	**$ 597.5**
%Change (year over year)			0.1%	0.1%	-5.1%	0.8%	11.5%

	2018 Last Rebasing Year OEB Approved	2018 Actuals	Variance 2018 Approved vs. 2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	Variance 2022 Bridge vs. 2020 Actuals	2023 Test Year	Variance 2023 Test vs. 2022 Bridge
Sustainment		$ 312.3		$ 347.1	$ 324.9	$ 299.6	$ 303.6	-$ 21.2	$ 311.4	$ 7.7
Development		$ 7.5		$ 7.1	$ 6.0	$ 10.0	$ 10.2	$ 4.2	$ 11.0	$ 0.8
Operating		$ 37.3		$ 36.6	$ 33.0	$ 39.7	$ 41.3	$ 8.4	$ 40.8	-$ 0.6
Asset Management (Planning) costs		$ 15.7		$ 13.5	$ 14.2	$ 13.6	$ 14.4	$ 0.2	$ 14.9	$ 0.5
Customer Service (Billing, Collecting, Bad Debt, Misc)		$ 111.7		$ 97.8	$ 111.2	$ 108.6	$ 107.9	-$ 3.4	$ 118.3	$ 10.4
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		$ 7.5		$ 7.5	$ 7.2	$ 6.9	$ 7.1	-$ 0.2	$ 7.3	$ 0.2
Common Functions and Services		$ 72.5		$ 69.4	$ 69.2	$ 76.9	$ 80.1	$ 10.9	$ 81.8	$ 1.7
Information Technology		$ 73.8		$ 81.1	$ 78.4	$ 83.8	$ 81.5	$ 3.2	$ 85.9	$ 4.3
Property taxes and rights payment		$ 5.1		$ 4.6	$ 5.4	$ 5.6	$ 5.8	$ 0.4	$ 6.0	$ 0.2
Miscellaneous (Other OM&A, Recovery)		-$ 84.7		-$ 105.2	-$ 89.2	-$ 113.2	-$ 116.1	-$ 26.9	-$ 79.9	$ 36.2
Total OM&A Expenses	**$ 544.4**	**$ 558.8**	**$ 14.38**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	-$ 24.3	**$ 597.5**	**$ 61.6**
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB) [3]										
Total Recoverable OM&A Expenses	**$ 544.4**	**$ 558.8**	**$ 14.38**	**$ 559.6**	**$ 560.2**	**$ 531.4**	**$ 535.8**	**-$ 24.3**	**$ 597.5**	**$ 61.6**
Variance from previous year				$ 0.8	$ 0.6	-$ 28.8	$ 4.5		$ 62	
Percent change (year over year)				0.1%	0.1%	-5.1%	0.8%		11.5%	
Percent Change: Test year (2023) vs. Most Current Actual (2020)									6.7%	
Simple average of % variance for all years									1.5%	
Compound Annual Growth Rate for all years										1.3%
Compound Growth Rate (2020 Actuals vs. 2018 Actuals)										0.1%

Note:

1 Historical actuals going back to the last cost of service application are required to be entered by the applicant.
2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.
3 For unrecoverable OM&A Expenses see Section 2.4.3.7

$	**597.5**	**Total**
	20.1	Non-service OPEB
	12.2	LDC Acquired
$	**565.2**	**Normalized to 2018**
	0.2%	**CAGR**

Appendix 2-JB
Recoverable OM&A Cost Driver Table [1,3]

($M)

OM&A	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Opening Balance [2]	$ -	$ 558.8	$ 559.6	$ 560.2	$ 531.4	$ 535.8
Stations		-$ 1.7	$ 2.1	-$ 1.0	-$ 0.7	-$ 0.3
Lines		$ 15.8	$ 0.9	-$ 28.7	$ 4.1	$ 6.7
Meters, Telecom & Control		-$ 2.2	-$ 0.6	$ 2.6	-$ 0.0	$ 2.3
Vegetation Management		$ 22.9	-$ 24.6	$ 1.8	$ 0.7	-$ 1.0
Engineering & Technical Studies		-$ 0.1	-$ 0.3	$ 0.6	$ 0.0	-$ 0.1
Distribution Generation Connections		$ 0.7	-$ 0.9	-$ 0.0	-$ 0.0	$ 0.0
Distribution Standards Program		-$ 0.4	$ 0.3	$ 0.7	$ 0.2	$ 0.1
Research Development & Demonstration		-$ 0.6	-$ 0.3	$ 2.7	$ 0.0	$ 0.9
Customer Power Quality Program		$ 0.0	-$ 0.1	$ 0.1	$ 0.0	$ 0.0
Operations Support		$ 9.4	-$ 0.9	$ 1.2	$ 0.6	-$ 1.8
Operations		-$ 2.4	$ 0.1	$ 5.4	$ 2.0	$ 1.2
Health, Safety & Environment		$ 0.1	-$ 0.9	$ 0.4	-$ 0.0	$ 0.0
Smart Grid		-$ 7.8	-$ 1.9	-$ 0.2	-$ 1.0	$ 0.1
Customer Service		-$ 13.9	$ 13.4	-$ 2.7	-$ 0.7	$ 10.4
Asset Management (Planning) costs		-$ 2.2	$ 0.7	-$ 0.5	$ 0.8	$ 0.5
Corporate Management		-$ 1.1	-$ 0.4	$ 0.1	$ 0.0	$ 0.1
Finance		-$ 2.0	-$ 0.1	$ 2.9	$ 0.3	-$ 0.5
People and Culture		-$ 0.7	$ 0.7	$ 0.2	$ 0.8	$ 1.4
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		-$ 0.0	-$ 0.3	-$ 0.3	$ 0.2	$ 0.2
General Counsel		$ 0.2	$ 0.8	-$ 0.3	$ 0.2	$ 0.1
Regulatory Affairs		-$ 0.1	$ 0.5	-$ 0.8	$ 0.7	-$ 0.7
Security Management		-$ 0.6	-$ 0.3	$ 0.8	$ 0.4	$ 0.1
Internal Audit		$ 0.3	-$ 0.5	$ 1.0	$ 0.2	$ 0.2
Real Estate and Facilities		$ 0.9	-$ 0.9	$ 3.8	$ 0.7	$ 1.1
Information Technology		$ 7.3	-$ 2.7	$ 5.4	-$ 2.2	$ 4.3
Cost of Sales		-$ 5.1	-$ 1.1	-$ 0.1	$ 0.4	-$ 0.0
Other Recovery		-$ 15.4	$ 17.1	-$ 23.9	-$ 3.3	$ 36.2
Property Taxes & Rights Payments		-$ 0.5	$ 0.8	$ 0.2	$ 0.2	$ 0.2
Closing Balance	$ 558.8	$ 559.6	$ 560.2	$ 531.4	$ 535.8	$ 597.5

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required in Exhibit 4.

2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the OEB-Approved amount. For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

Appendix 2-JC
OM&A Programs Table

($M)

Programs	2018 Board Approved	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year	Variance (Test Year vs. 2020 Actuals)	Variance (Test Year vs. 2018 Board-Approved)
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Sustainment									
Stations		21.8	20.1	22.2	21.2	20.5	20.2	-2.0	
Lines		133.3	149.0	149.9	121.2	125.3	132.0	-17.9	
Meters, Telecom & Control		17.7	15.5	14.9	17.5	17.5	19.8	4.9	
Vegetation Management		139.5	162.4	137.9	139.6	140.3	139.4	1.5	
Sub-Total		312.3	347.1	324.9	299.6	303.6	311.4	-13.5	
Development									
Engineering & Technical Studies		1.9	1.8	1.5	2.1	2.2	2.0	0.5	
Distribution Generation Connections		1.7	2.4	1.5	1.5	1.5	1.5	-0.1	
Distribution Standards Program		0.6	0.2	0.5	1.2	1.4	1.5	0.9	
Research Development & Demonstration		3.2	2.6	2.3	5.0	5.0	5.9	3.6	
Customer Power Quality Program		0.1	0.1	0.0	0.1	0.1	0.1	0.1	
Sub-Total		7.5	7.1	6.0	10.0	10.2	11.0	5.1	
Operating									
Operations Support		3.6	13.0	12.1	13.2	13.8	12.0	-0.1	
Operations		20.7	18.4	18.4	23.8	25.9	27.0	8.6	
Health, Safety & Environment		1.8	1.9	1.0	1.3	1.3	1.3	0.3	
Smart Grid		11.2	3.4	1.5	1.3	0.4	0.5	-1.1	
Sub-Total		37.3	36.6	33.0	39.7	41.3	40.8	7.8	
Customer									
Customer Service OM&A		111.7	97.8	111.2	108.6	107.9	118.3	7.1	
Sub-Total		111.7	97.8	111.2	108.6	107.9	118.3	7.1	
Common Functions and Services									
Corporate Management		4.0	2.9	2.5	2.7	2.7	2.8	0.3	
Finance		15.0	13.0	12.9	15.8	16.2	15.7	2.8	
Human Resources		9.7	9.0	9.7	10.0	10.8	12.1	2.4	
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services		7.5	7.5	7.2	6.9	7.1	7.3	0.1	
General Counsel		3.2	3.4	4.2	3.9	4.0	4.1	-0.1	
Regulatory Affairs		10.8	10.7	11.2	10.3	11.0	10.3	-0.8	
Security Management		2.3	1.7	1.4	2.2	2.6	2.6	1.3	
Internal Audit		2.3	2.6	2.1	3.0	3.2	3.4	1.3	
Real Estate and Facilities		25.2	26.1	25.2	29.0	29.7	30.8	5.6	
Sub-Total		80.1	76.9	76.4	83.8	87.2	89.1	12.7	
Asset Management (Planning) costs									
Sub-Total		15.7	13.5	14.2	13.6	14.4	14.9	0.7	
Information Technology									
Information Technology		73.8	81.1	78.4	83.8	81.5	85.9	7.5	
Sub-Total		73.8	81.1	78.4	83.8	81.5	85.9	7.5	
Miscellaneous									
Cost of Sales		10.4	5.3	4.1	4.0	4.4	4.4	0.3	
Other Recovery		-95.1	-110.5	-93.4	-117.3	-120.6	-84.3	9.1	
Property Taxes & Rights Payments		5.1	4.6	5.4	5.6	5.8	6.0	0.6	
Sub-Total		-79.6	-100.6	-83.8	-107.7	-110.3	-73.9	9.9	
Total	**544.4**	**558.8**	**559.6**	**560.2**	**531.4**	**535.8**	**597.5**	**37.3**	**53.1**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year 2018 - OEB Approved	Last Rebasing Year - 2018 Actual	2019 Actuals	2020 Actuals	2021 Forecast	2022 Bridge Year	2023 Test Year
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
OM&A Costs							
O&M		$ 478,720,164	$ 482,612,804	$ 483,713,609	$ 447,585,352	$ 448,618,580	$ 508,325,432
Admin Expenses (CCFS)		$ 80,052,569	$ 76,940,973	$ 76,439,659	$ 83,794,574	$ 87,213,757	$ 89,143,594
Total Recoverable OM&A from Appendix 2-JB [5]	$ 544,391,756	$ 558,772,733	$ 559,553,777	$ 560,153,268	$ 531,379,925	$ 535,832,337	$ 597,469,026
Number of Customers [2,4]		1,303,089	1,314,463	1,323,421	1,333,269	1,343,110	1,413,905
Number of FTEs [3,4]		4,182	4,486	4,481	4,787	4,803	4,830
Customers/FTEs		311.6	293.0	295.3	278.5	279.7	292.8
OM&A cost per customer							
O&M per customer		367.4	367.2	365.5	335.7	334.0	359.5
Admin per customer		61.4	58.5	57.8	62.8	64.9	63.0
Total OM&A per customer		428.8	425.7	423.3	398.6	398.9	422.6
OM&A cost per FTE							
O&M per FTE		$ 114,472	$ 107,579	$ 107,944	$ 93,502	$ 93,410	$ 105,250
Admin per FTE		$ 19,142	$ 17,151	$ 17,058	$ 17,505	$ 18,159	$ 18,457
Total OM&A per FTE		$ 133,614	$ 124,730	$ 125,003	$ 111,007	$ 111,570	$ 123,708

-0.2% change since 2020
-1.5% change since 2018
-0.3% CAGR since 2018

-1.0% change since 2020
-7.4% change since 2018
-1.5% CAGR since 2018

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB.

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K.

FTE numbers represent the distribution portion of total FTEs using the average FTE counts by month-end, per Attachment E-06-01-02A

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

Number of customers for the years 2018-2022 exclude Acquired Utilities, and for 2023 include Acquired Utilities

5 For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

OM&A COST DRIVER TABLES FOR DISTRIBUTION OM&A EXPENDITURES – EXPLANATORY NOTES

1.0 INTRODUCTION

Hydro One completed Appendices 2-JA, 2-JB, 2-JC and 2-L at Attachment 1A of Exhibit E-03-01. The tables cover Hydro One Distribution's OM&A costs over the 2018 to 2023 period and provide a breakdown of the Distribution OM&A cost drivers by year and program.

1.1 SUMMARY OF RECOVERABLE OM&A EXPENSES (APPENDIX 2-JA)

Appendix 2-JA includes the detailed breakdown of Distribution OM&A expenditures by major category and the year-over-year variances. As noted in Exhibit E-03-01, the 2023 OM&A expenditure ($597.5M) is 9.7% higher than the 2018 approved OM&A ($544.4M) and 6.7% higher than 2018 actuals ($558.8M). As shown in Appendix 2-JA, the compound annual growth rate is 1.3% per year. When the 2023 OM&A is normalized on the same basis as what was approved in 2018, the 2023 OM&A equivalent is $565.2M and therefore the adjusted compound annual growth rate falls to 0.2% per year.

Relative to the most recent year of actuals, the 2023 test year OM&A is 6.7% higher than 2020 OM&A ($560.2M) but in comparison to the bridge year, the 2023 test year is 11.5% higher than 2022 OM&A ($535.8M), or 5.5% when normalized on the same basis as 2022 expenditures. High level variance explanations are provided in Exhibit E-03-01.

1.2 RECOVERABLE OM&A COST DRIVERS (APPENDIX 2-JB)

Appendix 2-JB shows the year-over-year changes in the major cost drivers for Hydro One's Distribution OM&A expenses.

1.3 OM&A PROGRAMS (APPENDIX 2-JC)

Appendix 2-JC provides the variance in test year OM&A to 2020 actuals by program. The full analysis and detailed variance explanations for activities that are within and not within the company's control are provided at the following exhibits:

Cost Category	Exhibit Reference	Exhibit Title
Sustainment	E-03-02	Distribution Sustainment OM&A
Development	E-03-03	Distribution Development OM&A
Operations	E-04-05	Operations OM&A
Customer Care	E-03-04	Distribution Customer Care OM&A
Common and Other	E-04-01	Summary of Common and Other OM&A
Property Taxes and Rights Payments	E-09-04	Taxes Other Than Income Taxes

Further details on the decisions and alternatives that were made to manage costs are included at these detailed level exhibits.

Hydro One confirms that the Distribution OM&A expenditures do not include the provision of costs to deliver CDM programs. As a result, costs that are directly attributable to CDM programs (e.g. staff labour dedicated to such programs) are not included in the revenue requirement to be recovered through distribution rates.

1.4 RECOVERABLE OM&A COSTS PER CUSTOMER AND PER FULL TIME EMPLOYEE (FTE) (APPENDIX 2-L)

Appendix 2-L includes the recoverable OM&A cost per customer and per FTE for Hydro One Distribution.

The total OM&A cost per customer is $422.6 in 2023, which represents a 1.5% decrease from 2018 actuals ($428.8) and a compound annual growth rate of -0.3% per year (not taking into account the normalization of 2023 levels for the non-service cost component of OPEB which would result in further reduction of costs per customer).

The total OM&A cost per FTE is $123,708 in 2023, which represents a 7.4% decrease from 2018 actuals ($133,614) and a compound annual growth rate of -1.5% per year.

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DISTRIBUTION SUSTAINMENT OM&A

1.0 SUMMARY OF SUSTAINMENT OM&A

Sustaining OM&A represents expenditures required to maintain existing components of the distribution system to ensure they will continue to function as originally designed. Hydro One manages its Sustaining OM&A expenditures into the following four expenditure categories:

1. Stations – Expenditures that 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;
2. Lines – Expenditures that fund the work required to inspect, repair or maintain distribution line sections or individual line components;
3. Meters, Telecom, and Control – Expenditures that fund the work required to inspect, repair and maintain metering and control equipment, perform meter verification, and fund the cost of leasing telecommunication circuits; and
4. Vegetation Management – Expenditures that fund the work required to keep assets clear of unwanted vegetation from both adjacent trees and brush growth below lines.

Within each of the four Distribution Sustainment OM&A expense categories, there are several programs and sub-programs, which are described in detail below, along with variance explanations.

These sustaining OM&A expenditures fund both planned work and unplanned demand work and are intended to ensure operational effectiveness by maintaining an acceptable level of reliability, delivering on customer commitments, and addressing public policy responsiveness by complying with all legislative, regulatory, safety and environmental requirements.

The planned OM&A work involves the inspection, verification, and planned maintenance or repair of existing distribution system assets. Asset inspections are required to identify potentially hazardous conditions in the distribution system and are mandated by the DSC in accordance with Section 4.4 “System Inspection Requirements and Maintenance”. Hydro One utilizes a combination of condition based maintenance and time based maintenance for its assets. An example of a condition based activity would be when a station transformer oil sample determines that the transformer must be taken out of service for corrective maintenance. An example of a time based maintenance activity would be recloser battery replacement, which occurs on a specified time interval. Verification of metering equipment allows for compliance with Federal Measurement Canada requirements on metering device accuracy and seal expiry management. Accurate metering devices are necessary to provide customers with accurate and timely bills. Unplanned demand OM&A work requires an immediate or timely response to customer, public safety or system needs. This work includes responding to service interruptions, resolving public safety hazards, replacing or repairing failed equipment, responding to customer requests, and providing underground cable locating services. More than one third of the Sustaining OM&A expenditures are related to these demand work activities.

The sustainment OM&A forecast expenditures are guided by the investment planning process described in DSP Section 3.7. This process has been completed for all planned and unplanned demand Sustaining OM&A expenditures to ensure that assets are managed prudently so as to meet customer, operational and regulatory requirements.

Table 1 sets out Hydro One’s planned expenditures for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge Year (2022) and Historical Period (2018-2021), for each of the four Sustainment OM&A categories.

The envelope and Test Year forecast variances throughout this exhibit rely on a comparison of the 2018 actual amounts escalated by inflation as detailed in Exhibit E-03-01.

Table 1 - Summary of Sustainment OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Stations	21.8	20.1	22.2	21.2	20.5	20.2
Lines	133.3	149.0	149.9	121.2	125.3	132.0
Meters, Telecom & Control	17.7	15.5	14.9	17.5	17.5	19.8
Vegetation Management	139.5	162.4	137.9	139.6	140.3	139.4
Total Sustainment OM&A	**312.3**	**347.1**	**324.9**	**299.6**	**303.6**	**311.4**

The forecast Distribution Sustainment OM&A expenditure for 2023 is $311.4M, which is $34M, or 10%, lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($345.1M). Hydro One has been able to keep total Distribution Sustainment OM&A expenses at a rate of growth significantly less than inflation.

The 2023 forecast expenditure is lower than the average historical actual and forecast expenditures (2018 to 2021) by about $9.6M. Relative to the 2022 Bridge, the 2023 Test Year forecast is $7.7M higher due to increased forecast expenditures in the Lines category primarily driven by Line Maintenance and Trouble Calls and by increases in the Meters, Telecom, and Control category. The $11.8M increase in the forecast 2023 expenditure relative to the 2021 forecast is primarily due to a $10.8M increase in the Lines and a $2.3M increase in the Meters, Telecom, and Control expense categories. The increase in the Lines category is based on observed historical averages and is required for Line Maintenance and Trouble Calls to ensure customers maintain a level of service that is consistent with customer expectations and allows Hydro One to comply with the service quality requirements set out in Section 7 of DSC; the marginal increase in Meters, Telecom, and Control reflects the need to meet *Electricity Gas and Inspection Act* requirements for meter sampling and to replace AMI 1.0 meters, which are forecasted to experience increased failures. These replacements are necessary for reliable customer billing and to continue to meet related regulatory requirements. The increase is also due to inclusion of the acquired LDCs Norfolk, Woodstock, and Haldimand into the Hydro One plan.

Compared to 2020 and 2018 actuals, the 2023 Test Year forecast expenditure is $13.5M lower and $0.9M lower, respectively. Additional details for explanations for these variances is provided in the sections that follow.

2.0 SUSTAINMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide detailed program and sub-program descriptions and variance explanations for each of the Sustainment OM&A programs: (i) Stations, (ii) Lines, (iii) Meters, Telecoms and Control, and (iv) Vegetation Management.

2.1 STATIONS

Hydro One owns, operates, and maintains 992 distribution and regulating stations. Distribution Stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution to commercial, industrial, year-round residential and seasonal residential customers. Regulating Stations are a special type of station that maintains voltage within the prescribed limits in response to load variations that can cause voltage increases or decreases. Components contained in Distribution Station facilities can include the following:

- station transformers and regulators;
- station reclosers and breakers;
- station switches and fuses;
- station structures;
- station fences;
- station grounding systems;
- station service transformers;
- station insulators;
- station protection relays;
- bus;

- station Intelligent Electronic Devices (IED); and
- station spill containment systems.

Hydro One also owns, operates and maintains a fleet of 35 mobile unit substations (MUSs) that are used to provide emergency power restoration in the event of a transformer or other station component failure, carry station load during maintenance and capital activities, and provide load relief for distribution stations as required.

Stations Sustaining OM&A expenditures are required to maintain assets located within these distribution and regulating stations, as well as to maintain the MUSs. The Stations Sustaining OM&A investments are divided into three programs:

1. Station Inspections and Planned Preventive Maintenance, which funds the OM&A investments to inspect station equipment for monitoring condition, identification of deficiencies and for performing testing on de-energized equipment before they are returned to service. These investments also include Polychlorinated Biphenyl (PCB) Sampling and Retrofill programs to sample station oil filled equipment for PCB content, and remove all PCB content greater than or equal to 50 ppm.
2. Stations Demand and Planned Corrective Maintenance, which funds the OM&A investments to respond to emergency failures and to address equipment deficiencies at distribution and regulating stations; and
3. Land Assessment and Remediation, which funds the OM&A investments to test and carry out remedial work to manage contaminated soil at distribution and regulating stations.

Table 2 - Summary of Stations OM&A ($M)

	Historical				**Bridge Year**	**Test Year**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Stations	21.8	20.1	22.2	21.2	20.5	20.2

The forecast Distribution Sustainment Stations OM&A expenditure (Table 2) for 2023 is $20.2M, which is $3.9M, or 16%, lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($24.1M). Relative to the average of historical actuals and the forecast for 2021 (2018-2021), the 2023 forecast is $1.1M lower than the average of these years, and is $1.6M lower than the 2018 actuals. The 2023 forecast expenditures is also lower than the 2022 bridge and 2021 forecast years, primarily due to the Land Assessment and Remediation program nearing completion. Compared to 2018 to 2020 historical actuals, the 2023 Test Year forecast is $1.6M lower than 2018 actuals and $2.0M lower than 2020 actuals. Hydro One has been able to keep total stations OM&A expenses at a rate of growth significantly less than inflation.

Table 33 provides a summary of the various programs within Hydro One's Distribution Sustainment Stations OM&A expenditures.

Table 3 - Distribution Sustainment Stations OM&A ($M)

Sustainment OM&A - Stations	Historical				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Station Inspections and Planned Preventive Maintenance	6.9	7.6	8.1	7.4	7.4	7.8
Stations Demand and Planned Corrective Maintenance	10.4	9.9	10.2	10.1	10.4	11.5
Land Assessment and Remediation	4.5	2.7	3.9	3.7	2.7	1.0
Total	**21.8**	**20.1**	**22.2**	**21.2**	**20.5**	**20.2**

The 2023 Test Year forecast expenditures in the Stations Inspections and Planned Preventive Maintenance program is $7.8M, which is $0.1M or 1.8% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($7.7M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast expenditure is $0.3M higher. Compared to 2022 and 2021, the 2023 Test Year forecast is marginally higher by $0.4M, and lower by $0.4M compared to 2020 actuals. Relative to 2018 actuals, the 2023 Test Year forecast is marginally higher by $0.9M. Overall, the Test Year forecast expenditures for this program are generally in-line with historical actual and forecast expenditures.

The 2023 Test Year forecast expenditures in the Stations Demand and Planned Corrective Maintenance program is $11.5M, which is $0.02M or 0.2% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($11.5M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast expenditures are $1.3M higher. Compared to the 2022 Bridge and 2021 Forecast, the 2023 Test Year forecast is $1.1M and $1.4M higher respectively, $1.3M higher than 2020 actuals, and $1.1M higher than 2018 Actuals. The marginal increase in the Stations Demand and Planned Corrective program is required to address an expected increase of station transformer related defects as the transformer population continues to age. As discussed in DSP Section 3.2 currently, 30% of the fleet is beyond their expected service life of 50 years, and an additional 20% will reach or exceed their expected service life by 2027 (in the absence of capital investment). Transformers that are in fair condition or poor condition which will not be addressed through capital investments must be addressed through corrective maintenance expenditures. Hydro One has been able to keep Distribution Stations Demand and Planned Corrective Maintenance OM&A expenses at a rate of growth generally in-line with inflation.

The 2023 Test Year forecast expenditures in the Land Assessment and Remediation program is $1.0M, which is $4M or 80% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($5.0M). Relative to the average historical and forecast period (2018-2021), the 2023 Test Year forecast is $2.7M lower, and lower than all actual and forecast expenditures. These reductions are primarily as a result of the reduced number of sites remaining that require remediation. Ongoing monitoring of contaminated sites will continue and may identify further remediation requirements.

Sections 2.1.1 to 2.1.3 provide detailed program descriptions for each of the Sustainment Stations OM&A programs.

2.1.1 STATION INSPECTIONS AND PLANNED PREVENTIVE MAINTENANCE PROGRAM INTRODUCTION

Table 4 - Stations Inspections and Planned Preventive Maintenance OM&A ($M)

Sustainment OM&A - Stations	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Station Inspections and Planned Preventive Maintenance	6.9	7.6	8.1	7.4	7.4	7.8

The station inspections and planned preventive maintenance program addresses the inspection, testing and preventive maintenance of station equipment in line with regulatory requirements and industry-best practices. It also includes PCB oil testing for oil filled equipment.

STATION INSPECTIONS

Station inspections include the following two items:

- Station visual inspection of station assets, as required by the DSC Appendix C – Minimum Inspection Requirements, to identify reliability issues, environmental issues, structural problems, safety hazards, equipment defects and signs of vandalism. Hydro One’s rural stations are inspected twice per year and urban stations are inspected monthly;
- Thermography inspection of all station power equipment to identify hot spots in any of the electrical equipment and components. Hydro One’s distribution station electrical equipment is inspected using thermography every two years.

The proposed spending for the 2023 Test Year is determined based on the completion of 6,590 inspections each year.

PLANNED PREVENTIVE MAINTENANCE

Planned maintenance of station power equipment is performed in order to mitigate the risk of failures by ensuring the safe and reliable operation of the equipment. The preventive maintenance of the station equipment is typically bundled with station corrective maintenance activities in order to minimize the number of planned outages and OM&A expenditure.

This maintenance of station equipment ensures the continued operation of the distribution system which plays an important role in maintaining the level of reliability to customers by reducing the risk of equipment failure.

Details of the preventive maintenance activities performed on the various station asset types are provided in the sections that follow.

TRANSFORMER PREVENTIVE MAINTENANCE

In addition to receiving visual and thermography inspections, station transformers receive the following maintenance activities:

- *General Oil Test* – Annually, an oil sample is taken from the transformer main tank and sent to a third party lab for analysis to obtain industry-standard diagnostic test results including dissolved gas analysis (DGA), Moisture Content and Furan Analysis. If there is an unsatisfactory oil sample result, further diagnostic testing and internal inspection is undertaken.
- *Transformer Diagnostic Test* – Following an unsatisfactory oil sample result, the main tank of the transformer may receive diagnostic testing and an internal inspection. This maintenance activity includes the following: Inspection of current carrying parts, bushing oil level check, insulation resistance tests, turns ratio and phase angle tests, core loss test, dissipation factor and capacitance test, winding resistance test, inspection of oil conservator breather, repair of minor or moderate oil leaks, function test of pressure vacuum device, check and top-up oil levels, function test of gauges and indicators, and application of touch-up painting to mitigate rust.

- *Under-Load Tap-Changer Oil Analysis* – Annually, an oil sample is taken from tap-changer oil-filled compartments and sent to a third party lab for analysis to obtain industry-standard diagnostic test results including DGA and Moisture Content.
- *Tap-Changer Selective Intrusive Inspection* – Internal inspection and maintenance of under-load tap-changers with mechanical moving parts is performed based on unsatisfactory tap changer oil analysis results or unsatisfactory performance. This maintenance activity includes the following: filtration of insulating oil, flush and clean oil compartments, visual check for oil leaks and contact wear, inspection of current carrying parts, checks of insulation condition, collector ring, drive chains, pushrod, reversing switch, oil compartment door gaskets, exercise isolation and grounding switch, function test of operating limit switches, gauges and indicators.
- *Power Factor Test (applicable to HVDS transformers only)* – Distribution station transformers with primary voltages of 115 kV and 230 kV will receive a power factor test to verify the integrity of the transformer insulation material and to ensure they are functioning correctly. This test is performed when the transformers are removed from service for diagnostic testing or *selective intrusive* maintenance.

The proposed spending for the 2023 Test Year is based on the estimated completion of 2,580 transformer oil samples, diagnostic tests, intrusive inspections and power factor tests each year.

RECLOSER PREVENTIVE MAINTENANCE

Distribution Stations are inspected by Stations Electrical Maintenance staff in the spring and fall, during which the station reclosers receive a visual inspection for any visual defects. The recloser counter operations are also checked and recorded to ensure they have not exceeded the manufacturer recommended number of operations from the time when they were last maintained.

Manufacturers of reclosers recommend that maintenance be performed based on the number of operations that they undergo. The rate at which recloser contacts deteriorate is based on the number of operations as well as the type of interrupter (oil versus vacuum).

The controllers for vacuum interrupter electronic reclosers have back-up batteries which require regular battery replacement. These batteries are scheduled for replacement every five years as recommended by manufacturers.

Reclosers also receive infrared thermography scans every two years when the station thermography scan is performed, to identify any reclosers that are overheating, which may indicate a high probability of failure.

The proposed spending for the 2023 Test Year is based on the estimated completion of 450 recloser preventive maintenance activities and electronic controller back-up battery replacements each year.

BREAKER PREVENTIVE MAINTENANCE

The station breaker population consists of metalclad breakers which must be removed from service in order to assess their condition. Because of this, a condition based maintenance strategy is not a favorable approach for these breakers. For station breakers, the maintenance strategy is to remove them from service every 6 years. At that time, the breakers are inspected and maintained.

When these breakers are removed from service for maintenance, they undergo:

- **Diagnostic Test** – The breaker is function tested, manually operated, and undergoes cleaning and lubrication of operating mechanisms; and
- **Selective Intrusive (SI) Inspection on all breakers** – Inspection of all internal components, insulation condition, contacts and rack-in mechanisms where applicable.

The proposed spending for the 2023 Test Year is based on the estimated completion of preventive maintenance on approximately 23 station breakers.

SWITCHES & FUSES PREVENTIVE MAINTENANCE

Station switches and fuses are visually inspected during routine station inspections.

Station switches are test operated when they are removed from service to support transformer maintenance work. Switches that fail to operate are addressed under the corrective maintenance program when they are repairable.

Preventive maintenance for fuses is bundled with transformer maintenance work to minimize planned outages and maintenance costs. When transformers are removed from service for maintenance, fuses are tested and inspected at that time. At that time, fuses which fail testing are replaced under the corrective maintenance program.

The proposed spending for the 2023 Test Year is based on the estimated completion of testing approximately 50 station switches and 50 fuses bundled with transformer corrective maintenance activities.

MOBILE UNIT SUBSTATION (MUS) PREVENTIVE MAINTENANCE

MUS trailers receive a mandated annual inspection by the Ministry of Transportation. They require an Ontario Ministry of Transportation (MTO) annual inspection certificate.

Because the MUSs are such a critical component of the distribution system as they are relied upon for emergency restoration, capital projects and maintenance work, the power equipment on each MUS receives an annual inspection by Hydro One and full maintenance of all electrical components each year. The maintenance activities for the MUS transformers, switches, fuses, reclosers and other electrical components are the same as for those installed in stations, other than the higher (annual) frequency. Each year, the full fleet of 35 MUSs will be inspected and maintained.

OTHER STATION ASSETS PREVENTIVE MAINTENANCE

In addition to the assets previously mentioned, Hydro One distribution station assets also encompass station structures, fences and gates, access roads, foundations, drainage systems grounding systems, station service transformers, insulators and bus. Stations equipped with breakers or vacuum electronic reclosers also have protection relays or IEDs. Stations identified as having high environmental risk can be equipped with spill containment systems.

These additional station assets are generally inspected for defects during routine station visual inspections. The live electrical components will also undergo a thermography inspection when the station thermography scan is performed.

Weed control in station yards and access roads is generally performed two to three times per year based on growth rate to mitigate step and touch potential safety concerns. Stations which have grass surrounding perimeter fences in urban settings will have grass cutting performed up to twice per month based on growth rate and surrounding population density. Each year approximately 3,910 weed control herbicide applications and 4,310 grass cuts around station perimeters will be performed.

STATIONS PCB SAMPLING

The stations PCB sampling program involves the testing of oil-filled power equipment at stations to determine the level of PCB in oil, in accordance with Environment Canada regulations requiring the removal of all insulating oil with PCB contamination levels equal to and above 50 ppm by year end 2025. Hydro One considers all station equipment manufactured prior to year 1985 to potentially be PCB contaminated. Hydro One will obtain approximately 300 outstanding PCB oil samples annually from 2022 - 2023 to complete the testing. The oil filled station equipment remaining to be tested consists of transformer bushings and instrument transformers.

STATIONS PCB RETROFILL

Transformer bushings that are tested and found to have PCB content greater or equal to 50 ppm are either retrofilled or replaced. The retrofill process involves removing the bushing from the transformer, draining the contaminated oil, flushing out the PCB content, and adding new PCB free oil to the bushing. The decision to retrofill or replace is dependent on the availability of spare bushings in inventory, the ability to obtain compatible replacement bushings from manufacturers and PCB contamination levels. The cost to retrofill bushings or to replace them is very similar. All high PCB transformer bushings will be retrofilled or replaced by 2024. It is estimated that approximately 15 transformer bushings will need to be replaced annually from 2022 – 2024, based on the number of bushings known to be contaminated and the PCB test failure rates for station equipment in recent years.

Instrument transformers contaminated with PCB content are planned for replacement under a capital investment.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for the Station Inspections & Planned Preventive Maintenance program based on a combination of time-based inspections, transformer oil sampling, equipment testing bundled with condition-based maintenance, and PCB sampling and retrofill activities.

2.1.2 STATIONS DEMAND AND PLANNED CORRECTIVE MAINTENANCE PROGRAM INTRODUCTION

Table 5 - Stations Demand and Planned Corrective Maintenance OM&A ($M)

Sustainment OM&A - Stations	Historical				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Stations Demand and Planned Corrective Maintenance	10.4	9.9	10.2	10.1	10.4	11.5

The stations demand and planned corrective maintenance programs address both (i) the emergent repair of station equipment identified through trouble calls in relation to a service interruption or through station inspections of equipment that will potentially result in service interruptions if not addressed when identified, and (ii) the planned repair of deficiencies that are identified through station inspections and preventive maintenance, though are not emergent in nature.

A station interruption can impact over 3,000 customers. Hydro One must address station interruptions to maintain reliable service in accordance with good utility practice.

The stations demand and planned corrective maintenance programs achieve the following:

- Respond to equipment failures (such as transformers, regulators, reclosers, switches and fuses) at distribution and regulating stations to ensure timely power restoration;
- Correct situations where equipment failure is imminent that would cause a power interruption if not addressed when identified, allowing for system reliability to be maintained;
- Correct situations which present a safety hazard to public or Hydro One personnel;
- Correct deficiencies discovered during station inspections and planned preventive maintenance activities. Some examples include transformer high DGA results, equipment oil leaks, thermography revealing overheating results or broken insulators;

- Address corrective items at the stations site. Some examples include addressing holes and gaps in fences, damage to breaker buildings, and MUS access roads leading into stations that pose safety or reliability issues to the distribution system; and
- Correct deficiencies to mobile unit substations to ensure the equipment is in operable condition for deployment in case of a failure to ensure timely restoration of power to customers.

When this work involves the repair of a component, it is charged to these corrective OM&A programs. If the resolution involves a capital expenditure such as the replacement of damaged or defective equipment, this replacement is charged to the Distribution Station Demand Capital Program as outlined in DSP Section 3.11, D-SR-01.

TRANSFORMER CORRECTIVE MAINTENANCE

For station transformers, demand corrective maintenance expenditures involve responding to station power transformer related customer outages resulting from failed windings, failed bushings or failed potential transformers (a component of the power transformer). Demand corrective expenditures also involve responding to customer related voltage complaints which can arise from failed under-load tap-changers, which are a component of power transformers that automatically regulate voltage. The demand corrective response involves deploying station maintenance staff to investigate and repair if possible. Depending on the repair time, the equipment may be quickly repaired to restore power. If the repair work is significant, an MUS will be installed to restore load, or load will be transferred to another station where possible.

Planned corrective maintenance expenditures for station power transformers address deficiencies identified during routine station visual inspections and from annual oil samples. The majority of the planned corrective maintenance expenditures for power transformers are related to the following:

- Condition Based Maintenance (CBM) following high risk oil sample results for transformer main tanks or tap-changers. The oil sample results may reveal the following:
    1. High DGA test results which can indicate partial discharge in windings or overheating of paper insulation inside the transformer.
    2. High moisture content test results which indicate water entering the transformer.
- Corrective maintenance on leaking transformers to repair the leaks.

TRANSFORMER PLANNED CORRECTIVE PROGRAM CANDIDATES

Transformers less than 20 years of age normally require minimal planned corrective repair expenditures and in recent years have not needed to be removed from service to address deficiencies. The condition of these younger transformers are monitored through station inspections and oil samples.

Transformer candidates for high DGA and high moisture corrective maintenance have ranged from around 20 to 60 years of age in recent years. The majority of transformer candidates for leak repairs in recent years have ranged from 30 to 60 years of age.

Based on the prioritization of capital projects through the Risk Spend Efficiency (RSE) approach (see DSP Section 3.7), not all transformers with high DGA / moisture content or oil leak defects can be replaced within the filing period. As a result, these transformers which cannot be replaced must undergo corrective repairs to mitigate failure risk and environmental concerns associated with oil leaks.

The proposed spending for the 2023 Test Year is based on the estimated completion of approximately 50 planned transformer corrective maintenance jobs each year, which would require removal of the transformer from service for internal inspection and repair.

RECLOSER CORRECTIVE MAINTENANCE

In general, reclosers receive corrective maintenance based on their condition or ability to open or close when required and when counter readings have exceeded the manufacturer recommended number of operations. Cooper/Kyle model “L” oil hydraulic reclosers are currently the only exception, which Hydro One is replacing with vacuum hydraulic reclosers based on their condition, performance and counter operations.

Hydraulic reclosers are physically removed from the station and sent to a maintenance shop for overhaul where the recloser contacts, oil and other components are replaced based on their condition. The removed hydraulic reclosers are replaced like-for-like with overhauled reclosers.

For oil interrupter electronic controlled reclosers, when counter readings are exceeded, they are removed from service and maintained at the station as it is more cost effective given the small number in the fleet. Worn components are replaced and the reclosers are test operated before being returned to service.

Vacuum interrupter electronic controlled reclosers are visually inspected for deficiencies and controller batteries are replaced on a time cycle. Deficiencies for these reclosers are typically related to failed controller batteries, which maintenance staff will replace, or failure of the recloser to open or close. If they fail to operate they are normally removed and sent to the manufacturer for repair, or are replaced with a spare unit if not repairable.

BREAKER CORRECTIVE MAINTENANCE

The majority of distribution station breakers are metalclad. Common defects observed through normal operation are breakers failing to open when required to clear system faults, failing to close when required to restore power, failure of protection to operate the breaker, or failure to provide the required electrical insulation. When these defects are observed, they are addressed through corrective action.

Defective breakers will be repaired under this program as long as they are repairable and replacement parts can be obtained. Breakers which are obsolete are replaced with reclosers when there is a station refurbishment project planned for the station.

The proposed spending for the 2023 Test Year will fund the completion of approximately 190 station recloser and breaker planned defect corrections and is based on historical actuals defects completed.

SWITCHES & FUSES CORRECTIVE MAINTENANCE

For switches, common defects observed are seized bearings and failure of porcelain support insulators. These failure modes can make the switches not operable when required which can lead to switches stuck in an open or closed position. This will cause unplanned interruptions or extension of interruptions to repair the switches and enable the system to be returned to normal operation. Normally these defects are discovered when the switch needs to be operated. Station switches that have been found to be defective and are repairable will be repaired. These switches are typically repaired by the application of lubrication and manual operation, or replacement of components. In cases where the switches cannot be repaired by application of lubrication or replacement of components, they will be replaced.

Station fuses are installed upstream of the station transformer to protect it from system faults. Normally, a set of spare fuses is stored in the station to replace fuses when they blow. Station fuses that are found to be defective upon inspection or through testing are replaced with new fuses. Common defects observed include fuses that failed air flow testing and broken porcelain support insulators for fuse holders. This program also funds the replacement of fuses that have blown to clear system faults.

The proposed spending for the 2023 Test Year is based on the estimated completion of approximately 60 switch defect corrections and replacement of roughly 60 defective fuses, through planned corrective maintenance activities each year.

MOBILE UNIT SUBSTATION CORRECTIVE MAINTENANCE

For MUSs, the electrical components which include transformers, reclosers, switches and fuses are subject to the same types of defects as station electrical equipment. These defects are addressed when the MUS is not in operation supplying load for a station.

MUSs also have trailers which are subject to defects. These defects include rusting, blown tires, defective breaks, suspension, axels, landing gear/hydraulics and broken cable reels. These defects are also addressed when the MUS is not in operation.

The proposed spending for the 2023 Test Year is based on the estimated completion of 35 MUS defect corrections, through planned corrective maintenance activities each year.

OTHER STATION ASSETS CORRECTIVE MAINTENANCE

For other station assets, some common types of defects that are observed and addressed include the following:

- Station fences with gaps or cut fabric that can allow entry to the public or animals
- Grounding wire that has been tampered with or is missing
- Yards or access roads that have insufficient gravel to prevent step and touch potential safety hazards
- Transformer or structure concrete foundations that are cracked or broken
- Station service transformers that are leaking oil
- Insulators which support bus or other electrical components that are broken
- Protection relays which are defective or require recalibration
- Transformer concrete oil spill containment systems which are cracked

The proposed spending for the 2023 Test Year is based on the estimated completion of approximately 350 deficiencies related to these other station assets through planned corrective maintenance activities.

In regards to demand corrective maintenance activities, the proposed spending for the 2023 Test Year is based on the estimated completion of approximately 1,060 deficiencies across all station assets.

EXPENDITURE FORECAST LEVEL

Due to the variable nature of demand work, Hydro One develops forecast expenditure levels for the stations demand and planned corrective maintenance program based on historical averages.

2.1.3 LAND ASSESSMENT AND REMEDIATION

Table 6 - Land Assessment and Remediation OM&A ($M)

Sustainment OM&A - Stations	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Land Assessment and Remediation	4.5	2.7	3.9	3.7	2.7	1.0

The land assessment and remediation program addresses the environmental risk of soil contamination from distribution stations which over time, either has migrated off-site or has potential to migrate off-site to neighboring lands. There are a number of distribution stations where the level of on-site soil contamination exceeds the applicable soil and groundwater standards under the Environmental Protection Act, R.S.O. 1990, C. E.19. This soil contamination has occurred over time as a result of the application of certain long lasting chemicals; such as arsenic-based herbicides, mineral insulating oil containing PCBs, and miscellaneous other materials. The historical usage of these chemicals met all applicable environment regulations and guidelines at the time they were first used; however, environmental regulations have changed.

These contaminated distribution stations have the potential to cause adverse effects on human health and the environment. Hydro One is assessing its stations and implementing either remedial measures to remove or otherwise manage the contamination found off-site, or on-site management controls to mitigate future off-property impacts where environmental risks are significant.

The land assessment and remediation program consists of sample testing to determine contamination levels, installation of monitoring wells, capping sites in order to prevent off-site contamination, and remediation of off-sites determined to be contaminated through testing.

This program will ensure that Hydro One operates in an environmentally responsible manner that minimizes the risk to human health and the environment and remains in compliance with applicable regulations set by the Ministry of the Environment, Conservation and Parks.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for the land assessment and remediation program based on the number of remaining high risk sites to be assessed for contamination levels, and an estimation informed by historic experience on the percentage of high risk sites that will require remediation upon testing.

2.2 LINES

Hydro One owns, operates and maintains approximately 123,000 circuit kilometers of distribution lines province-wide to deliver power to Hydro One customers. Distribution lines are constructed on road allowances where possible, or on Hydro One’s rights-of-way and consist of:

- poles;
- cross arms;
- conductors;
- line transformers;
- sectionalizing devices; and
- rights of way

Lines Sustaining OM&A funding covers investments required to maintain distribution lines' assets. The Lines Sustaining OM&A investments are divided into four programs:

1. Demand Work, which funds the OM&A investments to respond to (i) Trouble Calls to restore system outages, (ii) Locate Underground Cables, and (iii) Disconnect and Reconnect customers on request;
2. Line Maintenance, which funds the OM&A investments to maintain the lines equipment and patrol the underground and submarine distribution system;
3. PCB Equipment and Waste Management, which funds the OM&A investments to inspect and test equipment for PCB contamination and to manage both PCB and non-PCB waste in compliance with environmental regulations; and
4. Other Services, which funds the OM&A investments to respond to customer inquiries, rent idle transmission lines, track service quality indicators, fund specific community events, and complete joint use audits.

Table 7 - Lines OM&A ($M)

	Historical				**Bridge Year**	**Test Year**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Lines	133.3	149.0	149.9	121.2	125.3	132.0

The forecast Distribution Sustainment Lines OM&A expenditure (Table 7) for 2023 is $132.0M, which is $15.3M, or 10% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($147.3M) Relative to the average historical and forecast period (2018-2021), the 2023 forecast is $6.4M lower. The 2023 forecast expenditure is $10.8M and $6.7M higher than the 2021 forecast and 2022 Bridge years. Relative to 2020, the 2023 Test Year forecast is lower by $17.9M and lower by $1.3M compared to 2018 actuals. The increase relative to 2021 and 2022 is primarily due to increases in the forecast expenditure level for the Line Maintenance program, which represent an average increase of about $5.3M relative to these years, due to inclusion of the acquired LDCs Norfolk, Woodstock, and Haldimand into the Hydro One plan. The increase in the forecast is also attributable to the Trouble Calls program, which represents an average increase of about $4.1M relative to 2021 and 2022. Hydro One has been able to keep the overall Distribution Lines OM&A expenses at a rate of growth significantly lower than inflation.

Table 88 provides a summary of various expenditures and programs within Hydro One's Distribution Sustainment Lines OM&A expenditures.

Table 8 - Distribution Sustainment Lines OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Trouble Calls	64.4	75.4	76.4	59.3	60.4	63.9
Underground Cable Locates	11.5	11.8	12.3	12.0	12.3	13.4
Disconnects/ Reconnects	13.8	17.6	18.7	14.6	14.8	16.4
Line Maintenance	13.5	12.4	13.5	7.6	8.3	13.3
PCB Equipment and Waste Storage	13.4	16.5	14.5	14.1	14.7	9.4
Other Services	16.6	15.3	14.6	13.7	14.7	15.6
Total	**133.3**	**149.0**	**149.9**	**121.2**	**125.3**	**132.0**

The 2023 Test Year forecast expenditures for the Trouble Calls program is $63.9M, which is $7.3M, or 10% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($71.2M), and lower than the average actual and forecast period (2018-2021) by $5M. The $4.6M increase and $3.5M increase in the 2023 forecast expenditures relative to the 2021 forecast and 2022 bridge years respectively is primarily due to inclusion of the acquired LDCs Norfolk, Woodstock, and Haldimand into the Hydro One plan. 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. Hydro One has been able to keep the Trouble Calls OM&A expenses at a rate of growth significantly lower than inflation.

The forecast expenditure in the 2023 Test Year for Underground Cable locates is $13.4M, which is $0.7M, or about 6% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($12.7M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast is $1.5M higher and relative to the 2021 forecast and 2022 bridge years, the forecast expenditures are $1.4M and $1.1M higher respectively. Compared to 2020 and 2018, the Test Year forecast is marginally higher by $1.1M and $1.9M respectively. This increase in the forecast expenditures is primarily due to inclusion of the acquired LDCs Norfolk, Woodstock, and Haldimand into the Hydro One plan.

The Disconnects/Reconnects program 2023 Test Year forecast expenditure is $16.4M, which is $1.1M, or 8% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure escalated by inflation ($15.2M). Compared to the average historical and forecast period (2018-2021), the 2023 Test Year forecast is a marginal increase of $0.2M. Relative to the 2021 forecast and 2022 Bridge years, the 2023 forecast expenditure is $1.5M and $1.8M higher respectively, which is required to address an anticipated increase in demand for this program. Compared to 2020 actuals the 2023 forecast is $2.3M lower, and $2.6M higher relative to 2018 actuals. 2018 actuals were lower than other historical actuals due to normal fluctuations in the volumes for this program.

The Line Maintenance program 2023 Test Year forecast expenditure is $13.3M, which is $1.7M, or 11% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure escalated by inflation ($15.0M). Compared to the average historical and forecast period (2018-2021), the 2023 Test Year forecast is higher by $1.6M. Relative to the 2021 forecast and 2022 Bridge years, the 2023 forecast expenditure is $5.0M and $5.7M higher respectively due to the inclusion of the acquired LDCs Norfolk, Woodstock, and Haldimand into the Hydro One plan. Compared to 2020 and 2018 actuals, the 2023 forecast is $0.2M lower. Hydro One has been able to keep Line Maintenance OM&A expenses at a rate of growth significantly lower than inflation.

The PCB Equipment and Waste Storage program 2023 Test Year forecast expenditure is $9.4M, which is $5.4M, or 36% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($14.9M). The 2023 forecast is lower than the average historical and forecast period (2018-2022) by $5.2M. Relative to the 2021 forecast and 2022 bridge year average, the 2023 forecast is decrease of about $5.0M due to an updated forecast of the remaining obligations and lower than 2020 and 2018 actuals by $5.1M and $4.0M respectively for the same reason

The Other Services program 2023 Test Year forecast expenditure is $15.6M, which is $2.8M or 15% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($18.4M). Compared to the average historical and forecast period (2018-2022), the 2023 forecast is marginally higher by $0.5M. Relative to the forecast (2021) and bridge years (2022), the 2023 forecast is $1.8M and $0.8M higher respectively, primarily due to Community Events being cancelled in 2021 due to COVID lockdowns. The 2023 Test Year forecast is $1.0M higher relative to 2020 actuals and $1.1M lower compared to the 2018 actuals. Hydro One has been able to keep Other Services OM&A expenses at a rate of growth significantly lower than inflation

Sections 2.2.1 to 2.2.6 provide detailed program descriptions for each of the Lines OM&A programs in Table 3.

2.2.1 TROUBLE CALLS

PROGRAM INTRODUCTION

Table 9 - Distribution Sustainment Lines OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Trouble Calls	64.4	75.4	76.4	59.3	60.4	63.9

The trouble call program addresses the restoration of service to customers impacted by an unplanned power interruption. Such unplanned power interruptions on the distribution system are largely due to line component failures or contact with vegetation. Depending on the specific circumstances, these interruptions can vary in size, from impacting a few customers for brief periods of time to impacting thousands of customers for several hours. Trouble calls may also be used to respond to customer complaints or to correct defects on the distribution system that present an imminent safety concern or could result in an imminent service interruption.

Hydro One must address these trouble calls in order to comply with legal and regulatory requirements, to address known public safety hazards and to maintain reliable service in accordance with good utility practice. Hydro One's performance in responding to trouble calls is reflected by service quality indicators specified in section 7 of the DSCas discussed in Exhibit A-05-03.

When the resolution of a trouble call involves the repair of an affected component or the clearing of fallen vegetation, such work is charged to this program. If the resolution involves the replacement of damaged or defective equipment, this replacement is charged to the Trouble Calls and Storm Damage capital program discussed in DSP Section 3.11, D-SR-07.

EXPENDITURE FORECAST LEVEL

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.

2.2.2 UNDERGROUND CABLE LOCATES

PROGRAM INTRODUCTION

Table 10 - Distribution Sustainment Lines OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Underground Cable Locates	11.5	11.8	12.3	12.0	12.3	13.4

The underground cable locates program provides the service of locating and marking Hydro One underground plant for customers and contractors who request this information. Responding to these requests is in everyone's best interest as anyone excavating near a cable may cause damage to these costly assets and cause harm to members of the public. This service is provided in accordance with the Electrical Safety Authority's "Guidelines for Excavating in the Vicinity of Distribution Lines" and in order to comply with legal requirements set out in Ontario Regulation 22/04.

This program minimizes utility equipment damage while providing worker safety to those excavating in proximity to buried utility plant. In order to encourage the use of this service, the program costs are not recovered through end user charges. This approach is consistent with the practice followed by other regulated utilities, including cable TV, telephone service and natural gas utilities.

EXPENDITURE FORECAST LEVEL

Due to the variable nature of demand work, Hydro One develops investment levels based on forecast volumes and costs using observed historical averages with adjustments to this forecast based on projected impact of any changes to the distribution system or to the planned investment programs. The proposed spending for the Test Year is based on an expected volume of 211,500 cable locate requests per year, which is consistent with historical growth in demand since 2018.

2.2.3 DISCONNECTS/RECONNECTS

PROGRAM INTRODUCTION

Table 11 - Distribution Sustainment Lines OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Disconnects/ Reconnects	13.8	17.6	18.7	14.6	14.8	16.4

The service disconnects and reconnects program addresses customer requests for isolation of customer owned assets from the distribution system. This isolation may be requested by the customer to allow for safe conditions to facilitate working on customer owned equipment. Responding to these requests is in everyone's best interest as anyone working without isolation may cause harm to themselves or members of the public.

This program provides customers safe electrical isolation of their service in order for them to conduct work. This service is provided to each customer once per year at no cost, as specified in Hydro One's Conditions of Service, in order to encourage customers to maintain their facilities and to work safely.

Hydro One must address these customer requests in order to meet Hydro One's Conditions of Service. Hydro One's performance in responding to service disconnects and reconnects is reflected by service quality indicators specified in section 7 of the DSC as discussed in Exhibit A-05-03.

EXPENDITURE FORECAST LEVEL

Due to the variable nature of demand work, Hydro One develops investment levels based on forecast volumes and costs using observed historical averages. The number of service disconnection and reconnection requests has increased over the past several years. The proposed spending for the Test Year is based on an expected volume of 18,000 disconnect and reconnect requests per year.

2.2.4 LINE MAINTENANCE

PROGRAM INTRODUCTION

Table 12 - Distribution Sustainment Lines OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Line Maintenance	13.5	12.4	13.5	7.6	8.3	13.3

The line maintenance program addresses the inspection of underground and submarine assets, corrective maintenance on all overhead, underground, and submarine assets, and preventive maintenance on overhead switches and insulators. These activities are in line with regulatory requirements.

INSPECTION

Hydro One inspects all its distribution lines and associated equipment as required by Appendix C – Minimum Inspection Requirements of the DSC. These inspections identify defects on the distribution lines including failing equipment that may become public safety hazards, damaged equipment or any other visual abnormality that may impact the safe and reliable operation of the distribution system. The data collected during the inspections is a key component in the assessment of the condition of line equipment.

Overhead line patrols are now being completed as part of a bundled work activity with the OCP inspections described in Section 2.4 Vegetation Management-of this exhibit.

Underground line patrols inspect Hydro One owned pad-mounted transformers, pad-mounted switches, and the surrounding area to ensure there are no exposed cables. These inspections are performed on a six year cycle in rural locations and on a three year cycle in urban locations. If the inspector identifies a public safety hazard they initiate a trouble call to have the issue fixed. Defects that can be addressed as a planned activity are recorded for later prioritization. Simple defects, such as missing signage, are fixed at the time of patrol. This program will inspect 12,800 locations annually.

Submarine cable patrols inspect the integrity of Hydro One owned underwater cables. These patrols will visually inspect the condition of the cable and the mechanical protection at the load and source side shorelines. Sometimes time domain reflectometry tests are also performed if the cable is not visible to assess any damage. These inspections are performed on a six year cycle. If the inspector identifies a public safety hazard they initiate a trouble call to have the issue fixed. Defects that can be addressed as a planned activity are recorded for later prioritization. Simple defects, such as missing signage, are fixed at the time of patrol. This program will inspect 2,100 cables annually.

MAINTENANCE

Preventive maintenance of line equipment is required in order to mitigate the risk of failures by ensuring the safe and reliable operation of equipment. Hydro One is planning two types of preventive maintenance in the Test Year: Switch Maintenance and Insulator Washing. The air break switch and load break switch maintenance program will maintain an average of 160 three phase switches annually. This time based maintenance program ensures these devices will operate when needed. The insulator washing program is a condition based maintenance program. Pollution and contaminants can build up on insulators over time resulting in a temporary breakdown of the insulation which can cause pole fires and outages for downstream customers. This program will wash an average of 4,300 insulator locations per year.

Corrective maintenance of line equipment is focused on the repair and replacement of minor defective components such as: broken guy wires, damaged insulators, and faulty lightning arresters. All defects are identified and logged during line patrols. The outstanding defects are prioritized as part of the investment planning process. The defects which have a higher impact to safety and reliability risk are addressed in this program. Where possible, defect corrections are combined with other work to improve operational efficiency. The proposed spending for the Test Year is based on an expected average volume of 15,200 defect corrections per year.

The maintenance of these line assets ensures the continued operation of the distribution system which plays an important role in maintaining the level of reliability to customers. The outcomes this program will achieve are as follows: Reduce the risk of equipment failure, which can impact service reliability to customers; and operate in a responsible manner that minimizes the potential of safety risks that the failure of the equipment poses to the public and Hydro One employees.

EXPENDITURE FORECAST LEVEL

Hydro One develops expenditure levels based on known defect volumes, minimum inspection requirements and preventive maintenance cycles. The selection of lines maintenance expenditures is guided by the investment planning process described in DSP Section 3.7.

The forecast lines maintenance Test Year expenditures are based on inspecting Hydro One underground and submarine assets, performing the funded preventive maintenance and correcting 14,900 defects per year with the highest potential impact to reliability or public safety. The forecast and bridge year expenditures represent a reduction relative to historical expenditures and the Test Year, as a result of redirections to higher priority work.

2.2.5 PCB EQUIPMENT AND WASTE STORAGE

PROGRAM INTRODUCTION

Table 13 - Distribution Sustainment Lines OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
PCB Equipment and Waste Storage	13.4	16.5	14.5	14.1	14.7	9.4

The PCB equipment and waste management program includes the inspection and testing of distribution line equipment potentially contaminated with PCBs, along with the management of waste generated during the course of operating and maintaining distribution assets. This program includes:

- Inspection and testing of oil-filled distribution line equipment to determine their PCB contamination level in accordance with Environment Canada PCB regulations requiring the removal of all PCB's in oil-filled equipment greater than 50 ppm by year end 2025. Any equipment with PCB content greater than 50 ppm threshold is replaced under the Lines PCB Equipment Replacements capital program, described in in DSP Section 3.11, D-SR-06; and
- Waste management of all contaminated and non-contaminated waste streams (such as PCB and non- PCB oil, hydraulic oil, lead, cadmium, mercury, etc.) associated with distribution lines day-to-day operations and maintenance. This includes cleanup, notification, documentation, restoration, transportation, storage, containment, security, inventory, inspection and reporting of these wastes as well as the disposal of the waste (i.e. preparation, loading, shipping and destruction) once economical quantities of a particular waste class are gathered.

The outcomes this program will achieve are the following:

- Ensure that Hydro One operates in an environmentally responsible manner that minimizes the risk to human health and the environment; and

- Ensure that Hydro One remains in compliance with applicable regulations.

EXPENDITURE FORECAST LEVEL

Hydro One develops investment levels based on a targeted completion year of 2025 to meet regulations. The proposed spending for the Test Year is based on a forecast of approximately 7,000 PCB tests.

2.2.6 OTHER SERVICES

PROGRAM INTRODUCTION

Table 14 - Distribution Sustainment Lines OM&A ($M)

	Historical				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Other Services	16.6	15.3	14.6	13.7	14.7	15.6

The Other Services program addresses miscellaneous services not funded within other distribution OM&A investments. The specific investments funded are:

- Investigations and Data Collection - This program includes the work required to respond to requests for detailed information on distribution station and line assets. It addresses information requirements related to requests for the condition of select assets, public and employee safety hazards, unacceptable system performance, audits of joint use facilities and data required to support responses to customer reliability concerns.
- Miscellaneous Services - This program includes a number of activities; pole rental payments to Local Distribution Companies (LDCs) where Hydro One wires are supported by these poles, LDC switching requests, collecting and reporting service quality indicators to the Ontario Energy Board on an annual basis, payments to the Electrical Safety Authority for regulatory oversight costs, and miscellaneous engineering and environmental support.

- Transmission Idle Lines Rental - This expenditure is for the annual rental payments to Hydro One Transmission for Hydro One Distribution's use of transmission facilities to supply power to customers at distribution voltages.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast investment levels for the Other Service programs based on historical demand for each investment.

2.3 METERS, TELECOM AND CONTROL

Distribution Sustainment Meters, Telecom and Control expenditures are required to operate and maintain Hydro One's metering assets. These expenditures consist of three programs:

1. Retail Revenue Meters, which funds routine and corrective maintenance on this category of meters;
2. Wholesale Revenue Meters, which funds routine and corrective maintenance on this category of meters, and supports IESO registration or inspection processes; and
3. Telecommunications, Monitoring, Protection & Control, which funds corrective and preventative maintenance of Protection and Control equipment, as well as leases of third-party telecommunication circuits and services. These leased circuits and services enable:
   a) The collection of energy consumption data, and;
   b) The control and operation of sectionalizing switches and electronic reclosers installed on the distribution system.

Table 15 - Meters, Telecom and Control Sustainment OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Retail Revenue Meters	10.4	10.3	8.9	11.2	11.1	12.2
Wholesale Revenue Meters	2.3	1.9	2.1	2.2	2.3	2.4
Telecom, Monitoring and Control	5.0	3.3	3.9	4.1	4.1	5.2
Total	**17.7**	**15.5**	**14.9**	**17.5**	**17.5**	**19.8**

The forecast Meters, Telecom and Control Sustainment Stations OM&A expenditure (Table 15) for 2023 is $19.8M, which is $0.2M, or 0.9% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($19.6M). The 2023 forecast is $3.4M higher that the average historical and forecast actuals (2018-2021), and $2.3M higher than the both the 2022 Bridge and 2021 forecast years primarily due to increasing amount of field work related to AMI 1.0 meters that have begun to reach end-of-life and Measurement Canada regulatory compliance meter sample testing requirements for Retail Revenue Meters (see DSP Section 3.11, D-SA-04). The need for increasing levels of meter compliance sample testing is driven by Measurement Canada guidelines requiring testing be performed at increasing frequency as meters age. 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. Compared to 2018 actuals, the 2023 forecast is $2.0M higher primarily due to the reassignment of staff from other related organizations in 2019 to rationalize meter related functions (telecom, technical standards, asset management, supply chain support) to improve collaboration, productivity and efficiency. Although, the 2023 Test Year forecast is higher compared to previous periods on an absolute basis, overall Hydro One has been able to keep these OM&A expenses at a rate of only marginally higher than inflation.

The 2023 forecast expenditures for Retail Revenue Meters is $12.2M which is $0.6M or 5.5% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($11.5M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast is $2.0M higher primarily due to the 2019 reassignment of staff from other organizations to rationalize meter related functions. The 2023 forecast is $1.1M and $0.9M higher than the 2022 bridge and 2021 forecast respectively, also primarily due to the projected increase in field work associated with AMI 1.0 meter failures and the requirement for increased meter compliance sample testing. Relative to 2020 Actuals, the 2023 Test Year forecast is $3.3M higher due primarily to: 1) the required increase in sample testing based on meter seal expiries almost doubling from 1,550 in 2020 to 2,706 in 2023; and 2) the need to individually replace the increasing number of failing AMI 1.0 meters. Compared to 2018, the 2023 forecast is $1.7M higher due to the same staff reassignments discussed earlier.

The increase in the 2023 Test Year forecast expenditure for Wholesale Revenue Meters is $2.4M which is $0.2M or 7% lower than the last rebasing actual of 2018 escalated by inflation. Relative to the average historical and forecast period (2018-2021) and 2018 and 2020 actuals, the 2023 forecast is marginally higher by $0.3M. Overall, expenses related to Wholesale Revenue Meters are generally lower or in-line with historical expenditures.

The 2023 forecast expenditures for the Telecom, Monitoring and Control program are $5.2M which is $0.3M or 5% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($5.5M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast is $1.2M higher. Compared to the average forecast (2021) and bridge (2022) years, the 2023 forecast is $1.1M higher. Compared to 2020 and 2018 actuals, the 2023 forecast is $1.3M and $0.3M higher respectively. Generally, the fluctuations in these expenditures are primarily due to fluctuations in leased telecom circuit costs. Overall however, Hydro One has been able to keep these OM&A expenses at a rate significantly lower than inflation.

Sections 2.3.1 to 2.3.3 provide detailed program descriptions for each program.

2.3.1 RETAIL REVENUE METERS

PROGRAM INTRODUCTION

Table 16 - Retail Revenue Meters OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Retail Revenue Meters	10.4	10.3	8.9	11.2	11.1	12.2

Hydro One distribution system uses two types of retail revenue meters, with the specific meters determined based on the retail customers' average monthly demand:

- Approximately 1.4 million smart meters measuring energy consumption for residential and other customers whose average monthly demand is 50 kW or less under the residential rate pricing scheme; and
- Approximately 10,300 interval meters for customers with an average monthly electricity demand greater than 50 kW over a 12 month period.

Hydro One's retail revenue meter program is responsible for the inspection, testing and maintenance of retail revenue meters in accordance with regulatory requirements. Retail revenue meters are required to be operated, maintained and verified in accordance with Federal legislation (specifically the Electricity and Gas Inspection Act and Weights and Measures Act), the Ontario Energy Board's Standard Supply Service Code and the DSC, and IESO market rules. This program also manages inventory for Advanced Metering Infrastructure (i.e. meters, collectors, and repeaters), instrument transformers and metering accessories by maintaining adequate stock of equipment to meet the needs for the meter re-verification program, service upgrades, emergencies, and replacement of failed or defective/damaged meters and instrument transformers.

EXPENDITURE FORECAST LEVEL

Hydro One develops expenditure forecasts based on regulatory requirements for statistical meter sampling, and the need to replace failed meters for reliable customer billing.

2.3.2 WHOLESALE REVENUE METERS

PROGRAM INTRODUCTION

Table 17 - Wholesale Revenue Meters OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Wholesale Revenue Meters	2.3	1.9	2.1	2.2	2.3	2.4

The Wholesale Revenue Meters program provides preventative and corrective maintenance, meter re-sealing and verification, trouble call response, IESO registration, and routine maintenance as required by the IESO market rules and the Federal Electricity Gas and Inspection Act. Wholesale revenue meters are also subject to IESO inspections to verify compliance of metering installations with technical specifications contained in the market rules. Any identified deficiencies must be corrected within the prescribed time limits. Hydro One is the metered market participant for 414 wholesale revenue meter installations.

The outcomes this program provide servicing for all wholesale revenue meter installations to comply with IESO market rules and Measurement Canada's Electricity Gas and Inspection Act. Hydro One develops investment levels for the program based on IESO wholesale metering requirements, the number of wholesale metering points, and historical maintenance levels for corrective maintenance.

EXPENDITURE FORECAST LEVEL

The 2023 Test Year forecast expenditure is in line with historical, forecast, and bridge year expenditures and is based on expected load growth with expenditures based on historical costs.

2.3.3 TELECOMMMUNICATIONS, MONITORING, PROTECTION AND CONTROL

PROGRAM INTRODUCTION

Table 18 - Telecom, Monitoring and Control OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Telecom, Monitoring Protection and Control	5.0	3.3	3.9	4.1	4.1	5.2

The telecommunications, monitoring, protection and control program is required to:

- Provide 3rd party leased telecommunications circuits to support retail revenue metering (AMI) and wholesale meter installations.
- Maintain and troubleshoot the telecommunication infrastructure which collects energy consumption data from the retail smart meters.
- Provide 3rd party leased telecom circuits for distribution station communication, monitoring and control of feeder sectionalizing switches and electronic reclosers; and
- Maintain and troubleshoot protection and control assets located on distribution lines and in distribution stations. This work includes the repair, recalibration or replacement of defective protection and control equipment; event record collection for protection event analysis; and planned protection and control device battery replacement.

This program is integral for remote data gathering for reliable customer billing and the reliable operation of the distribution system.

EXPENDITURE FORECAST LEVEL

Hydro One develops expenditure forecasts for telecommunication based on the communication requirements for retail and wholesale metering and monitoring/control requirements and costs are for leased retail circuits from third-party telecom providers. Protection and control maintenance forecasts are based on historical costs and the forecasted number of installed protection and control devices.

2.4 VEGETATION MANAGEMENT

The annual vegetation management program consists of planned and demand maintenance activities, structured within 3 programs:

1. Defect Correction (Planned);
2. Public Safety and Reliability (Planned and Demand); and
3. Quality Assurance and Quality Control (Planned)

In 2018, Hydro One commenced execution of a new approach to managing its right of ways entitled the Optimal Cycle Protocol (OCP). This new approach moves away from full right of way clearing including all trees and brush on the corridor, to a targeted defect driven approach that manages the reliability and safety risk created by incompatible vegetation growing on and along the rights of ways. With the challenge of varying vegetation amounts, species and different climatic regions along the right of ways, the OCP program works towards finding the optimal cycle length for each feeder across Hydro One's service territory.

Hydro One manages approximately 105,000 km of Overhead (O/H) Rights of Way (ROW) that are maintained to keep vegetation away from energized overhead power lines. Hydro One Distribution operates one of the largest North American distribution systems in vast remote and rural areas, dense forests and harsh winters. Hydro One's distribution assets primarily span over three main forest types (see Figure 1): The Boreal forests mainly comprised of conifers; the Great Lakes/St Lawrence Forest Zone is mixed conifer/deciduous forests; and deciduous forests that have the greatest diversity of tree species. The distribution system serves a diversity of customer types ranging from seasonal to large industrial customers. Hydro One's distribution system is divided into four forestry management regions: North, South, Central and East. The Central and East regions have similar vegetation types and densities and require the greatest amount of vegetation intervention. The Northern region has dense remote forests with conifer trees. The southern region is largely cleared for agriculture with scattered forests. Adjacent to Hydro One's distribution right-of-way assets is a potential workload of millions of trees which are a primary cause of distribution outages.

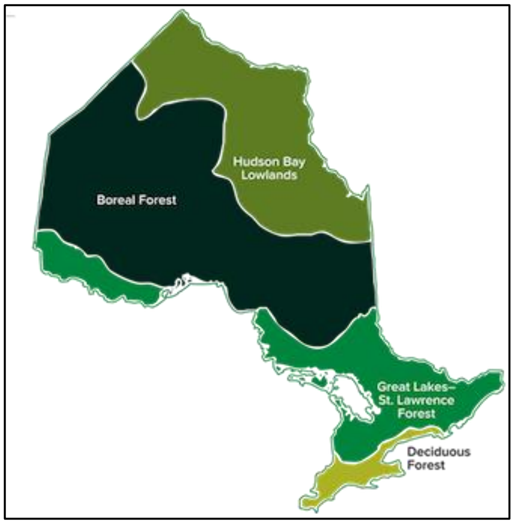

Figure 1: Forest types in Ontario

Prior to OCP, Hydro One treated on average 10,890 right of way kms (for 2006-2016) resulting in an implied maintenance cycle of approximately 9.5 years, which is longer than the industry average. The long maintenance cycles have been identified as a contributor to poor vegetation caused reliability performance. Overgrown vegetation that is in-contact with energized apparatus also presents a safety hazard along Hydro One right-of-ways.

It is important for a vegetation management program to be a sustainable program that addresses defects in a timely manner. Corridor vegetation is a dynamic environment because of tree and vegetation growth. Delays or interruptions in vegetation management on a ROW allows vegetation defects to multiply, resulting in worsening reliability and increased future forestry clearing work at a higher cost.

Hydro One has been able to treat significantly more right of way kilometers under the new vegetation management strategy thereby reducing the backlog of vegetation work and reducing the burden on future vegetation management costs as well as improving reliability and safety on cleared feeders.

Figure 2 below shows the high number of kilometers managed under the defect focused OCP program from 2018 to 2020. The increased number of kms managed every year in the OCP program has contributed to a significant reduction in the backlog of vegetation management.

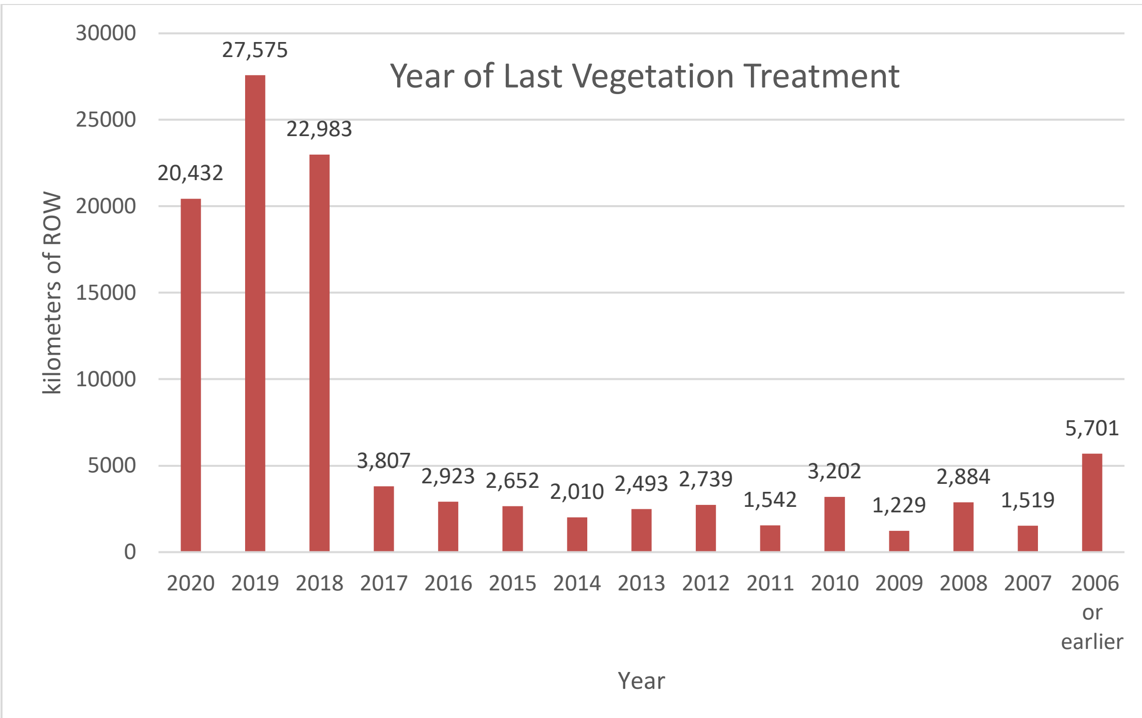

Figure 2: Year of Last Vegetation Treatment

Table 19 below provides a summary of Hydro One's Distribution Sustainment Vegetation Management OM&A expenditures for the Historical Period (2018-2021), Bridge Year (2022), and Test Year (2023).

Table 19 - Vegetation Management Sustaining OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Defect Correction (OCP)	127.1	153.7	127.3	123.4	124.0	122.2
Public Safety and Reliability Demand	10.9	7.2	9.2	15.2	15.3	16.1
QA/QC	1.5	1.5	1.3	1.0	1.1	1.1
Total	**139.5**	**162.4**	**137.9**	**139.6**	**140.3**	**139.4**

The 2023 forecast Distribution Sustainment Vegetation Management OM&A is $139.4M, which is $14.8M, or 10% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($154.2M). Relative to the average of the historical actuals and forecast period (2018-2021), the 2023 forecast is $5.5M lower. Compared to the 2022 bridge and 2021 forecast, the 2023 expenditures are $1.0M and $0.3M lower respectively. Relative to the 2020 actuals, the 2023 forecast is $1.5M higher and lower than the 2018 actuals by $0.1M. Overall, Hydro One has been able to maintain the Distribution Vegetation Management OM&A with no increase in these costs.

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. Compared to the 2022 and 2021 years, the 2023 forecast is $1.8M and $1.2M lower respectively. Relative to 2020 and 2018 actuals, the 2023 Test Year forecast is $5.1M and $4.9M lower respectively. Hydro One has been able to consistently reduce the Distribution Defect Correction (OCP) OM&A expenses.

The 2023 forecast expenditures for the Public Safety and Reliability are $16.1M which is $4.1M or 34% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($12.0M). Relative the average historical and forecast period (2018-2021), the 2023 forecast is $5.5M higher. Compared to the 2022 and 2021 years, the 2023 forecast is $0.8M and $0.9M higher respectively. Relative to 2020 and 2018 actuals, the 2023 forecast is $6.8M and $5.2M higher respectively. The Public Safety and Reliability - Planned Brush control was paused from 2018 through 2020 to accommodate added costs in defect correction due to an increased tree removal rate from 20% to 60% of all defects treated.

The 2023 forecast expenditures for the QA/QC program are $1.1M which is $0.5M or 34% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($1.6M). Relative to the average historical and forecast period (2018-2021), the

2023 forecast is $0.2M lower and flat relative to 2022 and 2021 respectively. Relative to 2020 and 2018 actuals, the 2023 is $0.2M and $0.4M lower respectively. Hydro One has been able to maintain Distribution QA/QC OM&A expenses.

The sections below provide detailed program descriptions for each of the Vegetation Management OM&A programs.

2.4.1 DEFECT CORRECTION

PROGRAM INTRODUCTION

Table 20 - Defect Correction OCP program spending and projection

	Historical				Bridge Year	Test Year
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Defect Correction (OCP)	127.1	153.7	127.3	123.4	124.0	122.2

Hydro One had engaged Clear Path Utility Solutions to perform as assessment of vegetation in Hydro One's distribution territory and provide recommendations on Hydro One's vegetation management practices in 2017. Hydro One has implemented OCP to action the recommendations of the Clear Path Utility Solutions assessment. Line patrol of distribution lines is required by Appendix C – Minimum Inspection Requirements of the DSC and has been integrated into the vegetation management patrols as recommended by the 2016 CNUC report titled "Hydro One Vegetation Management Study".[1]

The OCP treatment is a Defect-focused approach to vegetation management focused on management of high risk trees and incompatible vegetation encroachment into power lines along Hydro One ROWs. Vegetation is assessed by trained arborists and the vegetation that is not expected to encroach into the energized apparatus until the next cycle is managed in a subsequent OCP cycle. The OCP strategy employs time based patrols on Hydro One's rights-of-

[1] EB-2017-0049, Exhibit B1-1-1, Section 1.6, Attachment 2.

ways on an optimized cycle and generates condition based work prescriptions for forestry work execution crew. Defects are an undesirable condition, defined as trees and vegetation growing into power lines and trees with strike potential that exhibit observable conditions such as dead, diseased, decadent, or structurally unsound. Off-ROW trees are also included in the OCP scope of work as the ClearPath report estimated that they were responsible for up to 90% of all vegetation caused outages on Hydro One's distribution system. ROWs with overgrown vegetation accumulate more defects and require higher cost per km to manage and result in worsening system reliability. As Hydro One continues with its vegetation management activities through the OCP strategy, it is using defect data obtained in inspections to develop an optimal cycle length of vegetation management on its rights-of-ways.

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. The feeders that have received the vegetation management treatment under OCP have shown reliability improvement inline with the projections of 20%-40% improvement in the 2017 ClearPath report, "Hydro One – Forestry Survey Assessment". A survey of the rights-of-ways that have undergone the OCP treatment also show very few projected defects for the duration of the first cycle.

The kms of right of way managed through the OCP program has also increased from 11,753 kms in 2016 to an average of 25,695 kms annually over the past three years. Hydro One expects to inspect and clear approximately 95% of its ROWs by end of 2021 at least once. As more defect information is collected, right-of-way clearing cycles are optimized by the amount of defects that exist on the ROWs and past reliability performance.

OCP has also allowed for asset inspections via Distribution Line Patrol to be combined with the planning of vegetation management work performed by Hydro One field technicians. Overhead portion of the Distribution Line Patrol (DLP) program identifies public safety hazards, damaged equipment, or any other defects that may impact the safe and reliable operation of the distribution system.

RELIABILITY PERFORMANCE

One of the benefits of the OCP approach to vegetation management is a marked improvement in system reliability through reduction in corporate tree caused-SAIDI from the ROWs that have undergone the OCP treatment.

The OCP vegetation management program has been successful in reducing the tree caused SAIDI across the feeders that have undergone the OCP vegetation treatment.

As detailed in the Clearpath report (DSP Section 3.3, Attachment 3), the accumulated annual reliability improvement between OCP and non-OCP feeders for tree caused outages ranges from 23% to 41% from 2018-2020. These reliability improvements are identified in Table 7 of the report. Hydro One has seen improved reliability due to OCP across its system including poor weather events.

The differential improvement between pre and post OCP work on the rights-of-ways demonstrate how reducing defects improves the system reliability by reducing vegetation caused outages. The Clearpath report outlines that the reliability improvement projections of 20-40%, from the 2017 assessment, have been achieved for feeders that have been cleared under OCP vs feeders that have not.

UNIT COST PERFORMANCE

OCP has improved unit costs since its implementation. Prior to OCP being rolled out in 2018, the vegetation management program treated 11,753 kms in 2016 at a unit cost of $11,261/km. Since the OCP being introduced in 2018, the average number of kms managed by the Vegetation Management program at Hydro One Distribution has increased to an average of 25,695 kms and the unit cost has reduced to an average of $5,396/km. Between 2018-2020 Hydro One has seen a nearly 50% reduction in the vegetation management cost per km.

Table 21 - OCP Performance - Actuals

Year	2018	2019	2020	Average
Kms cleared (km)	26,070	28,009	23,006	25,695
Unit cost ($/km)	4,910	5,609	5,670	5,396

EXPENDITURE FORECAST LEVEL

Hydro One's Vegetation Management program is expected to treat approximately 95% of all rights-of-ways at least once by the end of year 2021. The forecast expenditure levels for the Defect Correction program was developed based on historical unit costs, projected defect densities and kms of accomplishments required to continue managing feeder rights of ways on an optimal cycle without accumulating a backlog of vegetation defects.

2.4.2 PUBLIC SAFETY AND RELIABLITY (PSR)

PROGRAM INTRODUCTION

Table 22 - PSR Program Spending and Projection

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Public Safety and Reliability Demand	10.9	7.2	9.2	15.2	15.3	16.1

The Public Safety and Reliability (PSR) program provides enhanced performance on sections of the distribution system that are not fully achieving the desired ROW vegetation management benefits. Public safety and reliability maintenance activities may involve responding to customer requests, planned tree pruning and removal, ROW widening, ROW floor clearing, herbicide application or other Vegetation Management treatments outside the OCP. The Public Safety and Reliability program is focused on subsections of Hydro One's distribution network identified through historical reliability, local institutional knowledge, customer feedback and information gained through the QA/QC process. The PSR program is broken down into two subsections; the Demand PSR program and Planned PSR program.

The **Demand** PSR program is setup to respond to customer inquiries and requests around vegetation management in the proximity of Hydro One owned energized apparatus. The program is responsible for managing incoming customer requests, sending out qualified technicians to assess customer concerns and then deploying trained foresters to take action if necessary.

Table 23 - PSR DEMAND Program Spending and Projection

	Distribution Vegetation Management PSR (Demand)					
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Cost ($M)	11.1	7.2	9.2	8.2	8.3	8.5

The **Planned** PSR program is setup to make off-cycle investment in Hydro One's ROWs to improve system reliability. Activities in the program include planned tree pruning and removal for feeders that exhibit worse than expected vegetation related outages, ROW widening, brush control and herbicide application. To fund the high tree removal rate for off-ROW defects, the road side brush control work was paused for years 2018 through 2020. At least two of the four forestry zones will move on to the second cycle of OCP in 2021 and will start to see a reduction in the tree removal rate. The roadside brush control and herbicide application on the rights-of-ways will be reactivated from 2021 onwards.

Table 24 - PSR PLANNED Program Spending and Projection

	Distribution Vegetation Management PSR (Planned)					
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Cost ($M)	-	-	-	7	7	7

EXPENDITURE FORECAST LEVEL

The forecast expenditure levels for the Distribution Sustainment Public Safety and Reliability program was developed based on historical demand for the demand portion of the program. The funding for the PSR Planned program is intended to reactivate the road side brush control program as Hydro One completes the first OCP cycle.

2.4.3 QUALITY ASSURANCE AND QUALITY CONTROL PROGRAM

PROGRAM INTRODUCTION

Table 25 - PSR PLANNED Program Spending and Projection

	Historical				Bridge Year	Test Year
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
QA/QC	1.5	1.5	1.3	1.0	1.1	1.1

QA and QC program assessments are the mechanism by which Hydro One assesses the adherence to its OCP defect specifications. In addition to ongoing program management, there are 3 activities that provide feedback into the continuous improvement process. These 3 activities are; 1) work quality assessments, 2) treatment effectiveness audits, and 3) detailed outage investigations.

The vegetation management program is planned to provide positive outcomes for Hydro One customers. The planned program is executed according to the direction outlined in the distribution vegetation management specifications. Annual program compliance audits provide insight into how well planned operations are working to the prescribed scope and achievement to the standards.

Treatment effectiveness audits help evaluate whether treatments applied are having their desired long-term benefits. The results of the treatment effectiveness assessments can help inform treatment decisions at the time of maintenance, demonstrate a commitment to reducing life-cycle costs and help confirm that program investments are achieving their long-term goals.

Hydro One conducts detailed investigations on tree caused outages on the distribution network. Using qualified forestry staff, data is collected to provide an enriched understanding of the mode of failure and other site characteristics that contribute to tree outages. This information is used to target reliability improvements within feeders, and provides data to drive continuous improvement in Hydro One's tree selection during planned vegetation management operations.

EXPENDITURE FORECAST LEVEL

The expenditure forecast level for the QA/QC program was developed to fund ongoing Quality Assurance and Quality Control work to ensure the UVM work prescriptions meet the OCP Defect Specifications.

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DISTRIBUTION DEVELOPMENT OM&A

1.0 SUMMARY OF DEVELOPMENT OM&A

Distribution Development OM&A consists of expenditures required to (i) perform technical studies and develop construction standards for the distribution connection of load and generation customers, (ii) research and implement new technologies, and (iii) investigate and address customers' power quality concerns. These expenditures are critical to ensuring that Hydro One is able to meet its service commitments and regulatory obligations, including: the connection of load/generation customers, the effective monitoring of the impact of Distributed Energy Resources (DERs), and the overall safe, reliable and efficient operation of the distribution system.

Specifically, Hydro One manages its Distribution Development OM&A expenditures in the following categories:

1. Engineering and Technical Studies – gathering and analyzing system data to identify capability and reinforcement needs
2. DER Connections – studies, coordination, project estimating, and power quality monitoring to support the connection of distributed generation.
3. Distribution Standards Program – maintaining and developing distribution technical standards for power system assets.
4. Research Development and Demonstration – supporting Hydro One Distribution's evaluation and adoption of new technologies.
5. Customer Power Quality Program – addressing customers' power quality concerns through monitoring, audits and investigations.

Hydro One establishes expenditure levels for the Development OM&A work programs based on historical volumes and costs and future anticipated needs.

Table 1 provides a summary of Hydro One's Distribution Development OM&A expenditures for the Historical Period (2018-2021), Bridge Year (2022), and Test Year (2023).

The envelope and Test Year forecast variances throughout this exhibit rely on a comparison of the 2018 actual amounts escalated by inflation as detailed in Exhibit E-03-01.

Table 1 - Summary of Development OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Engineering and Technical Studies	1.9	1.8	1.5	2.1	2.2	2.0
DER Connections	1.7	2.4	1.5	1.5	1.5	1.5
Distribution Standards Program	0.6	0.2	0.5	1.2	1.4	1.5
Research Development & Demonstration	3.2	2.6	2.3	5.0	5.0	5.9
Customer Power Quality Program	0.1	0.1	0.0	0.1	0.1	0.1
Total	**7.5**	**7.1**	**6.0**	**10.0**	**10.2**	**11.0**

The forecast Distribution Development OM&A expenditure for 2023 is $11.0M, which is $2.7M, or 33% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($8.3M)

The 2023 forecast expenditure is higher than the average historical actual and forecast expenditures (2018 to 2021) by $3.4M, primarily due to increased forecast expenditures for Research Development & Demonstration (RD&D). Relative to the 2022 Bridge and 2021 Forecast, the 2023 Test Year forecast is $0.8M and $1M higher respectively. Compared to 2020 and 2018 actuals, the 2023 Forecast is $5M and $3.5M higher respectively. The increase in the 2023 forecast expenditure for these years is primarily due to increases in the same RD&D expenditures already noted.

The establishment of Development OM&A expenditures is guided by the planning process described in DSP Section 3.7 to ensure that expenditures are managed to meet customer, operational and regulatory requirements. Section 2.0 provides detailed program and sub-program descriptions and variance explanations for each of the Development OM&A programs.

2.0 DEVELOPMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

2.1 ENGINEERING AND TECHNICAL STUDIES

Table 2 - Summary of Engineering and Technical Studies OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Engineering and Technical Studies	1.9	1.8	1.5	2.1	2.2	2.0

The forecast Engineering and Technical Studies OM&A expenditure for 2023 is $2.0M, which is $0.1M, or 4%, lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($2.1M), and is in-line with the 2022 Bridge and 2021 Forecast year expenditures. Relative to 2020 actuals, 2023 Test Year expenditure is $0.5M higher due to inclusion of vendor support for the new distribution design tool after vendor support for the current design tool was removed in 2019, and is in-line with 2018 actual expenditures. Hydro One has been able to keep Engineering and Technical Studies OM&A expenses at a rate of growth significantly less than inflation.

PROGRAM INTRODUCTION

The Engineering and Technical Studies program involves the gathering and analysis of system data to identify capability and reinforcement needs. This program also sustains and supports the tools that are used to perform various technical studies.

Engineering and Technical studies are critical to the effective management of the distribution system and are required to support capital investment decisions – both planned (e.g., system modifications, protection coordination) and unplanned (e.g., new connections, power quality complaints) as documented in DSP Section 3.6. These studies also ensure Hydro One can effectively analyze the needs of the system to meet customer's reliability and service quality requirements and ensure continued performance of the distribution system by mitigating the risks of electrically overloading system assets that can result in equipment failure, voltage degradation, and increased frequency and duration of outages.

The Engineering and Technical Studies program also encompasses the ongoing support and maintenance of the Distribution Design Tool, which is being replaced with a new tool to improve the design process for customer- and internally-driven Distribution Lines activities.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for Engineering and Technical Studies program based on historical study volumes, and forward looking estimates of Design Tool support activities.

2.2 DISTRIBUTED ENERGY RESOURCE (DER) CONNECTIONS

Table 3 - Summary of DER OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
DER Connections	1.7	2.4	1.5	1.5	1.5	1.5

The forecast DER Connections OM&A expenditure for 2023 is $1.5M, which is $0.4M, or 19%, lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($1.9M), and is lower or in-line relative to all other historical and bridge years. Hydro One has been able to keep DER Connections OM&A expenses at a rate of growth significantly less than inflation.

PROGRAM INTRODUCTION

The DER Connections program addresses the study, coordination, project estimating, and sustainment of power quality monitoring required for the connection of DERs.

The DER Connections program is required to comply with Hydro One's distribution license requirements to connect DERs in accordance with the Distribution System Code. To ensure the reliable connection of DERs, this program includes:

- Development of connection impact assessment reports that identify system upgrades, if any, required to enable a DER connection and to mitigate any potential negative impacts to distribution customers prior to the connection being made;
- Development of cost estimates for the overall connection; and
- Required program coordination activities that are not directly related to individual connections, such as sustainment of power quality monitoring capability.

DER Connection Program expenditures from Hydro One's previous investment plans were established in light of Ministry of Energy directives regarding DER facilities and the Independent Electricity System Operator's Feed-In-Tariff (FIT) and other renewable energy procurement programs. Since the end of the FIT program in 2017, the DER activity in Ontario has undergone a major shift from retail generators participating in different IESO programs like RESOP, FIT, HCI, HESOP, CHPSOP etc. to behind-the-meter (BTM) Load Displacement Generators (LDG) participating in the IESO's Industrial Conservation Initiative (ICI) program and Net Metering program.

- The Ontario Net Metering program is regulated by Ontario Regulation 541/05, and continues to be eligible to renewable generators only.
- The IESO ICI program allows large distribution connected load customers to reduce their Global Adjustment (GA) costs by reducing their electrical demand during the top five hours of Ontario peak demand in a year. The majority of these load customers are installing non-renewable energy generation projects that range in size from 500 kW to 20 MW depending on size of the load facility. During the last couple of years, the generation

applications received by Hydro One from these load customers include CHP/co-generation, natural gas, diesel generators, and Battery Energy Storage Systems (BESS). The ICI program is expected to continue for the foreseeable future.

Table 4 illustrates the transition of DER connections away from the FIT program. The last FIT contracts issued in 2017 were gradually connected over the following three years until 2020. For 2021 and beyond, the forecast assumes near-zero IESO contracts and higher participation in Net Metering. Load displacement DER began participating in the ICI program in 2017, and are expected to continue for the forecast period. A slight drop is forecasted in 2022-2023 to account for the expected saturation of eligible customers that have already participated. Micro-Embedded DER also show a sharp drop-off after the 2018 year when the majority of the contracts issued in 2017 were connected. A small number of micro-embedded DER is expected to connect under the Net Metering program for the forecast period.

Table 4 - DER Connection Volumes (2018-2020 actuals / 2021-2023 forecast)

Program	2018	2019	2020	2021	2022	2023
	Actual			Forecast		
IESO Programs (FIT, HCI, LRP, HESOP, CHPSOP, etc.)	74	78	41	2	2	2
Net Metering	25	39	17	50	50	50
Load Displacement	11	21	17	20	15	15
Micro-Embedded (≤ 10 kW)	759	178	138	150	150	150

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for DER connections based on historical study costs, and forward looking estimates of anticipated DER volume.

2.3 DISTRIBUTION STANDARDS PROGRAM

Table 5 - Summary of Distribution Standards OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Distribution Standards Program	0.6	0.2	0.5	1.2	1.4	1.5

The forecast 2023 OM&A expenditures for the Distribution Standards Program is $1.5M, which is $0.8M, or about 117%, higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($0.7M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast expenditure is $0.9M higher and about $1.0M higher compared to 2020 and 2018 actuals. This increase is primarily required to update existing standards and guidelines, which are required to ensure consistent design and deployment of equipment to the field, including overhead, underground, and stations equipment. Currently and over the JRAP period, there is a focus on new and/or updated standards associated with smart devices, and integration of new technologies to the existing system; the piloting of new technologies will lead to future standards development and field deployment. As the technology evolves, the frequency of standard updates increase to enable effective deployment. Hydro One is forecasting this work to increase the amount of expenditure over and above historical expenditure, to maintain existing standards. The 2023 forecast expenditure is in-line with the 2022 bridge year and 2021 forecast.

PROGRAM INTRODUCTION

The Distribution Standards Program supports the planning, design, installation, operations, and maintenance of Hydro One's distribution system by maintaining and developing new distribution technical standards for power system assets such as stations, transformers, lines, and other distribution equipment.

Hydro One's distribution technical standards define suitable equipment and provide consistent design approaches. This ensures clear direction is in place for field employees to carry out work procedures in order to safeguard electric utility employees and the public where electrical equipment is installed, operated and maintained. The use of repeatable and consistent designs provide flexibility for resourcing work, standardizes maintenance approach to avoid additional cost due to different design variations, and enables cost savings from bulk purchasing using standardized technical specifications.

Hydro One's distribution standards also incorporate company policies and requirements to ensure compliance with regulations such as the Electrical Distribution Safety Regulation (O. Reg. 22/04) and the Electrical Safety Code (O. Reg. 164/99). Through these OM&A expenditures, Hydro One Distribution monitors and influences emerging industry standards and requirements for new standards mainly through participation in Canadian Standards Association working groups.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for Distribution Standards activities based on historical standards volumes, and forward looking estimates based on anticipated priorities as described above.

2.4 RESEARCH DEVELOPMENT AND DEMONSTRATION (RD&D)

Table 6 - Summary of RD&D OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Research Development & Demonstration	3.2	2.6	2.3	5.0	5.0	5.9

The forecast RD&D OM&A expenditures for 2023 is $5.9M which is $2.4M or 67% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($3.5M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast expenditure is $2.6M higher. The test year expenditure is $3.6M and $2.7M higher compared to 2020 and 2018 actuals, respectively. 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. Compare to the 2022 bridge and 2021 forecast, the 2023 test year is marginally higher by $0.9M.

PROGRAM INTRODUCTION

The RD&D program supports Hydro One's adoption of new technologies to improve operational effectiveness, safety, and system reliability.

The RD&D program addresses: (i) operational needs by resolving technical challenges experienced by Hydro One to improve the management of existing distribution facilities to deliver safe and reliable supply to customers, (ii) strategic needs by engaging in research and demonstration of emerging technologies, and (iii) other electricity industry changes arising from innovation and policy initiatives for example: the OEB's Advisory Committee on Innovation, and the IESO's Innovation Roadmap and Market Renewal.

The following examples are representative of distribution related initiatives supported through the Corporate RD&D program, and provide further context on the additional funding required over the JRAP period:

a) Assessing and investigating the benefits and risks of future-oriented "disruptive" technologies which are new to the industry and present material growth opportunities and/or risks. The main areas of "disruptive" technologies that are a focus of current RD&D efforts are:
    - Microgrids: A microgrid is a group of interconnected loads, generation and storage which can operate as "standalone/isolated" grids or can be utility connected. Microgrids represent both challenges (i.e., in terms of technology and

potential loss of customers from the traditional grid space) and opportunities (i.e., customer reliability improvements and potential business benefits). In particular, they offer a potential solution for customer service in hard-to-reach areas such as islands, avoiding costs of long distribution or submarine cable connections.

- Electric Transportation: A potential key contributor to energy demand growth in Ontario will be the electrification of transportation. Hydro One is actively monitoring developments related to electric vehicles, and participating in a variety of industry forums such as Electric Power Research Institute (EPRI) and the Centre for Energy Advancement through Technological Innovation (CEATI). In addition to electric vehicles (cars), it is expected that other forms of electric transportation will emerge quickly, such as electric buses. If transit authorities in the province decide to deploy a large number of electric buses, significant demands on lines and station assets will result.

b) Investigating better ways of doing current work, with the potential to improve efficiency, health, and safety for ongoing work and maintain the reliability of the distribution system. The main areas of "innovative" technologies that are a focus of current RD&D efforts are:

- Asset Management Practices: Ongoing review with industry partners of Hydro One's asset management practices and tools used by other utilities and maintenance policies and practices in order to determine common practices and areas for improvement or further study.
- Industry engagement and research: Ongoing research into emerging issues related to technical impacts of public policy decisions.
- Reliability and Resiliency Practices: Review, monitoring, and testing of assets to assess resiliency related to the system's capability to respond and recover following disruptive events. Through this research, perspectives on the practices and guidelines used by utilities to achieve service reliability and resiliency goals will be identified which will contribute to maintaining and improving distribution system reliability as well as system resiliency during major weather events.

Much of this research is conducted through partnerships with industry, including EPRI and CEATI on a subscription basis. This participation model is a cost-effective approach that allows Hydro One to leverage joint funding with other utilities, risk sharing, and access to the broader expertise of companies with similar interests or challenges.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for Research Development and Demonstration activities based on historical research studies and engagements, and forward looking estimates based on anticipated priorities as described above.

2.5 CUSTOMER POWER QUALITY PROGRAM

Table 7 - Summary of Customer Power Quality Program OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Customer Power Quality Program	0.1	0.1	0.0	0.1	0.1	0.1

The 2023 Test Year forecast Distribution Development Customer Power Quality Program OM&A for 2023 is $0.1M, which is in-line with historical actual and forecast expenditures and in-line with the bridge year expenditure. The change relative to the 2020 actuals is due to rounding.

PROGRAM INTRODUCTION

In the industry, voltage sags due to faults occurring on power systems are a principal cause for a large number of equipment and process disruptions experienced by industrial customers, such as automotive plants, manufacturing facilities, and material processing plants. Our own experience upon investigating many of our customer complaints is consistent in this respect. There is also an industry wide consensus that many of the process disruptions experienced by industrial facilities are addressed most cost-effectively through changes made to the equipment controls themselves (relatively minor retrofits and design changes). Hydro One has chosen to focus on helping customers understand the power quality disturbances inherent to the nature of electricity supply systems, and also to help them coordinate this with the sensitivity of their equipment to power quality disturbances. The Customer Power Quality program includes:

- expanding monitoring capability on the distribution system to enhance visibility of power quality at customer delivery points, and
- providing third-party audits to assist customers to identify ways to improve their equipment's tolerance of power quality events.

The expansion of power quality monitoring capability is achieved by leveraging customer's existing retail revenue meter functionality to provide power quality data into Hydro One's power quality monitoring network. The benefits of this monitoring at customer's site include: more efficient and faster power quality event investigations; better understanding of plant equipment's sensitivity to inevitable power quality disturbances to identify areas in the plant where efforts can be focused on improving power quality tolerance.

Third-party audit consists of an onsite inspection of customer's facilities and equipment to identify the power quality resiliency weak links, analysis of available power quality data, and specific recommendations for targeted mitigating measures to improve equipment's resiliency to such events. Improving power equipment resiliency reduces the frequency of equipment tripping and any associated production losses for companies.

Historically, power quality monitoring and investigations focused on Hydro One equipment only. In 2017, Hydro One created a formal power quality program to work with load customers on power quality issues cooperatively. Through this program, Hydro One provides customers with information about power quality environment in sufficient detail to allow a coordinated approach to managing power quality performance within the customer facilities based on recognizing the constraints and limitations in the capabilities of the power delivery system.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for the Customer Power Quality program based on historical work program volumes.

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DISTRIBUTION CUSTOMER CARE OM&A

1.0 SUMMARY OF CUSTOMER CARE OM&A

Hydro One's distribution system is among the largest in North America, providing approximately 1.4 million customers in many of Ontario's hardest to reach locales with a safe and reliable connection to the electricity they need. This includes Residential, Small Business, Commercial and Industrial (C&I) Customers, and Large Distribution Accounts (LDA), as well as First Nations communities across Ontario. Hydro One is striving to become a customer-driven company, committed to listening to customers, understanding their needs and preferences, and enhancing the customer experience based on customers' evolving expectations. Hydro One's Customer Care OM&A funds customer-facing activities that help achieve this goal.

The Customer Care program allows Hydro One to:

- respond to customer inquiries through digital channels or when they contact the call center;
- actively engage with customers and provide energy advice;
- obtain meter readings;
- issue timely and accurate bills;
- process customer payments;
- manage a collections program to recover revenue; and
- provide financial assistance to low-income customers through the Ontario Energy Board's Low-Income Energy Assistance Program (LEAP).

Through its interactions with customers, Hydro One aims to satisfy customers' electricity needs, help customers understand and manage their bill, provide energy usage analytics and conservation advice, and offer financial assistance to low-income customers. Successful execution of these activities leads to meaningful improvements in customer satisfaction and customer perception. Hydro One will monitor several key measures, as outlined in DSP Section 3.5, in order to continually shape its vision of an enhanced customer experience.

Hydro One is also implementing a number of capital investment initiatives to improve customer satisfaction and address changing customer needs and expectations. These initiatives are described in more detail in GSP Section 3.11, G-GP-07.

Table 1 provides a summary of Hydro One's Distribution Customer Care OM&A expenditures for the Historical Period (2018-2021), Bridge Year (2022), and Test Year (2023).

The envelope and Test Year forecast variances throughout this exhibit rely on a comparison of the 2018 actual amounts escalated by inflation as detailed in Exhibit E-03-01.

Table 1 - Summary of Customer Care OM&A Allocated to Distribution ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Call Center Operations P(1)	42.5	34.5	34.5	34.6	33.5	38.3
Meter Reading	18.2	16.1	15.8	16.0	16.8	17.7
Third Party Support P(2)	15.5	15.9	17.6	24.7	23.8	25.0
Field Support	2.2	2.3	1.1	2.8	2.7	2.7
Regulatory Compliance (LEAP)	4.4	2.2	0.5	2.5	2.5	2.7
Net Bad Debt	13.6	16.9	31.8	15.4	15.1	18.0
Customer Care Staffing	15.3	9.9	9.8	12.4	13.4	13.9
Total	**111.7**	**97.8**	**111.2**	**108.6**	**107.9**	**118.3**

The forecast Distribution Customer Care OM&A expenditure for 2023 is $118.3M, which is $5.1M, or 4.2% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($123.4M), and includes Customer Care OM&A forecast expenditures for the acquired utilities (Norfolk, Haldimand, and Woodstock). Hydro One has been able to keep total Distribution Customer Care OM&A expenses at a rate of growth less than inflation.

Relative to the average historical and forecast period (2018-2021), the 2023 Test Year forecast expenditure is $11.1M higher, primarily due to increases in Third Party Support Costs. Compared to the 2022 Bridge and 2021 forecast, the 2023 forecast is $10.5M and $9.9M higher primarily due to higher Call Center Operation and Net Bad Debt expenses. These increases are primarily due to an increase in call center costs to accommodate the concurrent upgrade of the Customer Information System (CIS) and replacement of the existing Advanced Metering Infrastructure (AMI) system. The forecasted Net Bad Debt is in line with pre-pandemic levels and prior proceedings. Relative to the 2020 actuals, the Test Year forecast is $7.2M higher, primarily due to higher forecast expenditures for Third Party Support, Customer Care Staffing and Call Center Operations. Compared to 2018 actuals, the 2023 forecast is $6.6M higher primarily due to Third Party Support and Net Bad Debt forecast expenses.

Section 2.0 provides detailed program and sub-program descriptions and variance explanations for each of the Distribution Customer Care OM&A programs.

2.0 CUSTOMER CARE OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

2.1 CALL CENTER OPERATIONS

Table 2 - Call Center Operations OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Call Center Operations P(1)	42.5	34.5	34.5	34.6	33.5	38.3

The forecast Distribution Call Center Operations OM&A expenditure for 2023 is $38.3M, which is $8.7M, or 18.5% lower than 2023 figure that would result from escalation the 2018 last rebasing actual expenditure by inflation ($47M). Hydro One has been able to keep Call Center Operation OM&A expenses at a rate of growth significantly less than inflation.

Relative to the average historical and forecast actuals (2018-2021), the 2023 Test Year forecast is marginally higher by $1.8M. Compared to the 2022 Bridge Year, 2021 Forecast, and 2020 Actuals, the 2023 forecast is $4.8M, $3.7M, and $3.8M higher respectively. The Test Year increase relative to 2022 is primarily due to an increase in labour requirements to support the development of the AMI 2.0 project to replace the aging smart meters and the associated network infrastructure. Starting in 2022, the forecast also includes efficiencies stemming from the new Customer Technology Modernization (CTM) project that was implemented throughout the last quarter of 2020 and the first quarter of 2021. Compared to 2018 Actuals, the 2023 forecast is $4.2M lower due to the in-sourcing of the Call Center.

PROGRAM INTRODUCTION

Call Center Operations reflect Hydro One's costs to deliver customer-facing services, including: call center services, billing, collections, settlements, and distributed generation services to Hydro One customers. Customers contact Hydro One in several ways, including telephone, interactive voice recognition (IVR), letters, email, through the myAccount portal, and through the company's website.

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.

For 2021, expenditures are projected to remain stable at 2019 and 2020 levels.

EXPENDITURE FORECAST LEVEL

The 2023 expenditure forecast level reflects Call Center resources required to deliver customer-facing services and to support development of major customer projects, the forecast also includes efficiencies stemmed from the CTM project.

2.2 METER READING

Table 3 - Meter Reading OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Meter Reading	18.2	16.1	15.8	16.0	16.8	17.7

The forecast Distribution Customer Care Meter Reading expenditure for 2023 is $17.7M, which is $2.4M, or 12% lower than the last 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($20.1M). Hydro One has been able to keep Meter Reading OM&A expenses at a rate of growth significantly less than inflation.

Relative to the average historical and forecast period (2018-2021) and the 2022 Bridge Year, the 2023 Test Year forecast is marginally higher by $1.2M and generally in-line with 2022. Compared 2021 Forecast and 2020 actuals, the 2023 forecast is $1.7M and $1.9M higher. The 2023 forecast is $0.5M lower than the 2018 actuals. 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. Consequently, the 2023 forecast expenditure is $1.9M higher relative to the 2020 actual and in line with the 2022 bridge year.

PROGRAM INTRODUCTION

Hydro One has approximately 1.4 million smart meters deployed across the province. However, approximately 3% of the customers require a manual meter read due to the limited geographical reach of the Smart Meter Network infrastructure. This program supports automated reading of smart meters through the Smart Meter Network infrastructure and manual meter readings for hard-to-reach customers.

EXPENDITURE FORECAST LEVEL

The 2023 expenditure forecast level is driven by the volume of manual meter reads, which is expected to go up as a result of failing meters.

2.3 THIRD PARTY SUPPORT

Table 4 - Third Party Support OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Third Party Support P(2)	15.5	15.9	17.6	24.7	23.8	25.0

The forecast Distribution Customer Care Third Party Support OM&A expenditure for 2023 is $25.0M, which is $8.0M, or 46% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($17.1M). Compared to the average historical and forecast period (2018-2021), the 2023 Test Year forecast is $6.6M higher. Relative to 2022 Bridge Year and 2021 Forecast, the 2023 Test Year is generally in-line. The 2023 Test Year forecast is $7.4M and $9.5M higher relative to 2020 and 2018 actuals respectively.

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.

For the 2022 bridge year, the $0.9M decrease compared to 2021 is driven by a lowered Canada Post forecast as more customers transition to the eBilling solution, in part caused by Canada Post ending its ePost program in December 2021. For the 2023 test year, costs are projected to increase by $1.2M, mainly due to eBilling transaction fees that are starting to incur in 2023 and continue on an annual basis.

PROGRAM INTRODUCTION

This funding is required for third party services that support Customer Service Operations, including: postage services, e-billing services using Canada Post's ePost solution, toll-free phone numbers for the call center, payment processing services, customer communication, the collection of customer feedback and surveys, and collection agency costs for outstanding final-billed accounts. Third party support also covers OM&A expenditure for digital channels, value added customer services providing personalized energy advice, and a new density review program. The majority of these costs are dictated by market prices and/or competitive procurement processes.

EXPENDITURE FORECAST LEVEL

The 2023 expenditure forecast level reflects funding for third party services that support Customer Service Operations, which include the expansion of customer programs and services described above to achieve a renewed focus on customer experience. Third party support also covers OM&A expenditure for digital channels and other value added customer services.

2.4 FIELD SUPPORT

Table 5 - Field Support OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Field Support	2.2	2.3	1.1	2.8	2.7	2.7

The forecast Distribution Customer Care Field Support OM&A expenditure for 2023 is $2.7M, which is $0.3M or 11.1% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($2.4M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast is marginally higher by $0.6M and in line with the 2022 Bridge and 2021 Forecast. Compared to 2020 and 2018 Actuals, the 2023 forecast is $1.6M and $0.5M higher respectively. These variance are primarily due to the outlier year, 2020.

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.

PROGRAM INTRODUCTION

Field Support costs fund Customer Care field activities, including disconnection of electricity due to non-payment, reconnection when payment is received, investigation of high bill inquiries, and other services that require an on-site field visit.

EXPENDITURE FORECAST LEVEL

The 2023 expenditure forecast funds the normal level of Customer Care field activities for Hydro One Distribution and the acquired LDCs.

2.5 REGULATORY COMPLIANCE (LEAP)

Table 6 - Regulatory Compliance (LEAP) OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Regulatory Compliance (LEAP)	4.4	2.2	0.5	2.5	2.5	2.7

The forecast Distribution Customer Care Regulatory Compliance Low-Income Energy Assistance Program (LEAP) expenditure for 2023 is $2.7M, which is $2.2M, or 45% lower, than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($4.9M). Relative to the average historical and forecast period (2018-2021), the 2023 forecast is marginally higher by $0.3M and is in-line with 2022 Bridge and 2021 forecast amounts. Relative to 2020 actuals, when LEAP applications dropped due to COVID and a temporary suspension of the program, the 2023 forecast is $2.2M higher and $1.7M lower than the 2018 actuals.

Relative to 2018, LEAP spending decreased in 2019 mainly due to changes in LEAP eligibility and changes to Hydro One's disconnection policy. Despite an increase in minimum wage, the OEB did not adjust the <$28,000 income requirement to be eligible for the program, resulting in fewer qualified applicants. Starting in 2019, Hydro One stopped disconnecting customers with balances owed under $1,000, thereby driving fewer customers to apply for the LEAP program.

PROGRAM INTRODUCTION

As mandated by the Ontario Energy Board (EB-2008-0150), Hydro One contributes 0.12%, or $1.9M, of its Distribution revenue requirement annually to LEAP, which provides emergency relief to eligible low-income customers. The United Way of Greater Simcoe manages this fund as Hydro One's lead agency. Depending on customer demand and volume of LEAP applications that meet the eligibility criteria, Hydro One provides funding in excess of this amount.

Similar to Field Support, the LEAP program was heavily impacted by the COVID-19 pandemic, and spending declined in 2020. As customers had alternative financial support available to them

(CERB, CEAP), the need for LEAP lessened, and a significant drop off in applications and approvals was seen throughout 2020. Additionally, due to the OEB's extension of the disconnection moratorium, the OEB temporarily suspended the LEAP program from May 1st to July 31st, 2020 since customers faced no threat of disconnection.

EXPENDITURE FORECAST LEVEL

Starting in 2021, LEAP applications are expected to increase and return back to (at least) 2019 levels. Hydro One plans to contribute additional funding in 2021 and beyond. The 2023 LEAP amount is determined by allocating 0.12% per cent of Hydro One's Distribution Revenue forecast as per the OEB mandate (EB-2008-0150), the amount is then supplemented according to historical funds usage and the arrears trends

2.6 NET BAD DEBT

Table 7 - Net Bad Debt OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Net Bad Debt	13.6	16.9	31.8	15.4	15.1	18.0

The forecast Distribution Customer Care Net Bad Debt OM&A expenditure for 2023 is $18M, which is $3.0M or 20% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($15.0M), which is in line with the OEB approved amount of $18M annually for the years 2018-2022. Relative to the average historical and forecast period (2018-2021), the 2023 forecast is $1.4M lower. Compared to 2022 and 2021, the 2023 forecast is $2.9M and $2.6M higher respectively, primarily due to Hydro One setting the Test Year forecast amount at the previously approved OEB amount for 2018-2022 as noted earlier. The 2023 forecast is $14M lower than 2020 Actuals and $4.4M higher than 2018 Actuals. In 2020, Hydro One's Net Bad Debt expenses almost doubled compared to previous years because of the COVID-19 pandemic and the financial strain it put on residential and non-residential customers. To reflect the heightened risk of non-recoverability of outstanding balances, the Company applied a manual provision of $14.3 M in March 2020, which was approved by auditors.

The pandemic and uncertainty relating to customer collections and overdue Accounts Receivable (AR) continue to pose a material risk relative to OEB approved levels. Throughout 2020, overdue ARs increased steadily, and this trend is continuing in the first months of 2021. In March 2021, Net Bad Debt provision rates were revised to reflect the increased risk of uncollectible accounts receivables caused by the continued impacts of the COVID-19 pandemic on customers' ability to pay and more accurately reflect its bad debt exposure. For 2021 and 2022, there is an estimated $10M average annual risk to OEB approved amounts, largely related to sustained economic impacts associated with COVID-19.

PROGRAM INTRODUCTION

Hydro One is focused on helping customers stay current with their bills and providing a variety of payment options in order to keep arrears at a minimum. This cost category reflects bad debt expenses, net of recoveries. Hydro One's bad debt provision rates reflect the company's best estimate of overdue accounts receivable balances and amounts that will be uncollectable or written off in the future. This is based on the aging of accounts receivables, the probability of default, and historical trends.

EXPENDITURE FORECAST LEVEL

Hydro One is committed to reducing Net Bad Debt as a percentage of overdue AR, which is reflected in the 2023 forecast that keeps the level in line with the OEB approved amount from prior proceedings. However, if the impact of the pandemic is sustained, the $10M risk will persist until economic conditions return to pre-pandemic levels. The Company will assess the COVID-19 impact on Net Bad Debt and follow the OEB guidelines on the recoverability of expenses.

2.7 CUSTOMER CARE STAFFING

Table 8 - Customer Care Staffing OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Customer Care Staffing	15.3	9.9	9.8	12.4	13.4	13.9

The forecast Distribution Customer Care Staffing OM&A expenditure for 2023 is $13.9M, which is $3M, or 18% lower, than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($16.9M). Hydro One has been able to keep Customer Care Staffing OM&A expenses at a rate of growth significantly lower than inflation.

Relative to the average historical and forecast period (2018-2021), the 2023 forecast is higher by $2.1M and relatively in-line with the 2022 Bridge Year. Compared to the 2021 forecast, the 2023 expenditures are forecasted to be $1.5M higher. 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.

PROGRAM INTRODUCTION

This expenditure includes labour costs to oversee the Customer Care programs, including the call center, billing, meter reading, collections, settlements, distributed generation services, and customer project delivery and implementation.

EXPENDITURE FORECAST LEVEL

The 2023 expenditure forecast level reflects labour costs required to oversee and deliver various Customer Care programs to provide a high-level of customer service across all segments.

Hydro One is striving to respond to our customers' desire for increased customer service while maintaining or reducing Customer Care OM&A expenditure per customer in the test year and over the term of the plan period. Hydro One's performance against this metric from 2018 to 2023 is set out in Table 9 below.

Table 9 - Customer Care OM&A Allocated to Distribution Cost per Customer

Customer Service	Historical				Bridge Year	Test Year
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Total OM&A ($M)	$111.7	$97.8	$111.2	$108.6	$107.9	$118.3
Number of Customers (Million)	1.37	1.38	1.39	1.42	1.42	1.43
Customer Care OM&A Cost per Customer	$82	$71	$80	$77	$76	$83

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DISTRIBUTION O&M WORK EXECUTION STRATEGY

1.0 INTRODUCTION

This exhibit outlines how Hydro One efficiently delivers a large and complex work distribution program while meeting approved expenditure levels.

The Operations and Maintenance (O&M) portfolio consists of discrete demand-based and planned programs for Lines, Stations and Forestry. Each program is necessary to maintain system performance, and ensure that current assets operate as intended and undesired vegetation is cleared.

To succeed in this variable and complex operating environment, Hydro One employs a nimble and dynamic process to re-prioritize and transition between planned and demand work as required. This re-prioritization also involves balancing priorities between capital and maintenance activities. Section 2 sets out the detailed process that Hydro One employs to effectively plan and execute required maintenance work, including the nimble approach that the company uses to re-prioritize work as necessary. The subsequent sections discuss maintenance program oversight and governance mechanisms, the demand-based and planned maintenance programs themselves, resourcing, safety culture, continuous improvement efforts and productivity.

2.0 PROGRAM DELIVERY PROCESS

Hydro One uses a formal work acceptance and release process for both demand and planned distribution maintenance work programs. The workflow process attempts to minimize any impacts to planned programs resulting from the unpredictable nature in demand work, which is forecast based on historical peaks in demand and work performed upon customer request. The planning process helps ensure that sufficient time is allocated for:

- ordering materials;
- coordinating with other capital or maintenance work;

- coordinating with other internal and external work groups;
- securing outages and optimize bundling and reliability improvements; and
- scheduling work when site conditions are optimal.

For planned maintenance work within Distribution Lines & Stations, a scope of work is issued annually under which specific units are identified for replacement based on risk-assessment and priority. This information is provided to the Distribution Work Management team, which reviews and allocates accomplishments across all operations centres and subsequently release this information to the Field Business Centres (FBC) for review. The role of the FBC is to review the high level plan and determine the most efficient way to plan and schedule the work programs across the respective regions. Technology such as Geographic Information System (GIS) mapping in the upfront planning process enables improved cross-program planning and execution efficiencies. This becomes especially important when coordinating defect correction maintenance activities, since other defects at that same functional location are also addressed and cleared during the same field visit. The FBC coordinates with technical and execution resources to ensure any required obligations are met, required material is ordered and equipment and fleet requirements are secured.

Forestry's planned maintenance work is also issued a scope of work, outlining specific feeders to be inspected and executed within the year. Feeders are selected based on priority and reliability metrics and are circulated to Distribution Work Management, which supports the FBC and Forestry with developing quarterly plans that align with expected budgets, volumes and other work program obligations. Dedicated Forestry planning and scheduling resources were recently introduced into the FBC to improve planning, scheduling, optimization of resources and spend across the province. The planning process needs to account for the time required for Forestry technicians to inspect and notify landowners that will be impacted by the work, seasonality and restrictions such as herbicide spraying permissions and half-load season. Seasonality is key for certain planned vegetation work, such as brush control as this work needs to be conducted once snow is gone, regardless of vegetation treatment to ensure roots are accessible and effectively addressed. As a result, this type of work would typically be completed between spring and fall. Once defects have been identified by Forestry technicians and all permits and obligations are satisfied, this work is bundled and released to Forestry for execution.

Due to the largely demand-driven nature of Distribution's work program, historical peaks in demand are used to execute planned investments, with the goal of minimizing interruptions and delays to planned work. Seasonal factors are also taken into consideration, particularly in the summer months where high density cottage areas experience an influx in requests and island work that requires water access. When demand requests are higher than expected, the FBCs adjust the schedules to accommodate priority work. This could require Distribution to adapt by shifting resources across operations centres. There are mechanisms in place to minimize resource impacts, which include scheduling of dedicated crews for demand work (such as trouble calls) to minimize interruptions to planned work, while maintaining flexibility to address emergent and demand related requests. Dedicated crews is also a strategy that is used for planned program work as well, as some programs such as Polychlorinated Biphenyls (PCB) Test and Inspect have seen higher success in data collection with the use of dedicated crews.

2.1 EXECUTION STRATEGY

Hydro One's nimble distribution maintenance strategy requires coordinated planning and execution strategies. This coordinated approach allows the organization to remain focused on its commitment to "be the safest and most efficient utilities." Hydro One has implemented a range of strategies to improve efficiency and maintenance work outcomes. The company has worked to balance long-term preventive maintenance programs for switches, distribution transformers, and instrument transformers. It has established maintenance frequencies and plan dates to minimize outages.

Detailed job planning and frequent communication between crew members and supervisors is emphasized as key communication elements for incident prevention and operational efficiency. Ensuring that frontline distribution workers and supervisors are well informed of potential risks and are actively engaged in safe work planning helps improve workplace health and safety, optimize resource deployment, and minimize execution delays where possible. This in turn mitigates crew mobilization and demobilization and in turn mitigates overall costs.

Focusing on upfront strategic planning and scheduling helps Hydro One improve visibility into upcoming work. As a result, the organization is capable of bundling various work programs under a common work plan by geographic area with the ability to advance lower priority work provided it can be done more efficiently. Bundling work reduces crew windshield time and the number of required mobilization and demobilization activities for field staff; drives effective resource, fleet and material planning; optimizes outage requirements; and allows the organization to be more cost efficient.

2.1.1 EXECUTION FACTORS

Due to the non-discretionary nature of Hydro One's distribution maintenance expenditures, the organization must re-prioritize planned activities to meet demand obligations and maintain a safe and reliable distribution network. This also includes leveraging flexible resource options, implementing governance oversight to monitor risks and opportunities, and continuously seeking opportunities to become more efficient in planning, scheduling and executing work programs.

Other factors affecting the execution of planned maintenance include:

- data and technology factors;
- equipment and fleet accessibility;
- outage scheduling; and
- site conditions.

These factors are summarized in the following sub-sections.

2.1.1.1 DATA AND TECHNOLOGY FACTORS

It is particularly important that data is properly input into the system of record. The patrol programs funded within the overall portfolio are responsible for collecting this information, which subsequently drives the maintenance that is required in future years. While Hydro One has advanced its use of data by incorporating mobile technology and tools into its Lines and Forestry operations, that enhanced data comes with the need to invest in training and system upgrades as technology needs continue to evolve. Furthermore, quality assurance is required to ensure data is being captured and recorded as required to remain compliant and effectively utilize resources and funding. The Distribution Lines Patrol (DLP) and PCB Test and Inspect programs are both examples where this is imperative to satisfy regulatory, safety and environmental obligations.

2.1.1.2 EQUIPMENT & FLEET ACCESSIBILITY

Identifying necessary equipment and fleet requirements (including associated regular maintenance needs on these assets) to complete various maintenance programs is an important part of Distribution's execution planning. Specifically, during the planning process, Distribution considers the scope of work required, site conditions, access and seasonal factors to secure suitable equipment. As specialized fleet and equipment are often stored in central locations, it is critical that this is factored into the planning process to ensure appropriate coordination occurs and maintenance activities are executed when required. Equipment enhancements have improved work execution efficiency (for example, Distribution uses a feller-buncher, which is a fleet vehicle that significantly increases efficiency by cutting trees and stacking them in clusters. It is used to widen and reclaim heavily backlogged and overgrown corridors). To help ensure that specialized equipment is effectively shared across the organization, Hydro One's execution strategy emphasizes early and strategic release of work to provide sufficient time to plan and schedule the use of specialized and shared equipment such as boats.

2.1.1.3 OUTAGE SCHEDULING

There are circumstances where maintenance activities require parts of the system to be electrically isolated while work is being performed. Obtaining the required planned outages becomes increasingly difficult as the distribution system grows larger and more complex with the addition of distributed energy resources, smart technology, and supplied load increases. Planned outages are also susceptible to cancellation, which is often due to storm activity, customer demands or system constraints. When planned outages are cancelled, crews have to be demobilized and rescheduled for a future date. To mitigate the possibility of increased project costs and limited work accomplishment due to these unforeseen issues, Hydro One has made improvements to internal processes and communication with regard to outage planning and bundling of work. Examples include meetings to review work plans and required outages to improve coordination between controlling authorities and formally establishing lead times for outage approvals. This allows Distribution to better utilize system outages, plan resources more efficiently, and increase the total volume of work that can be executed, minimizing customer interruptions and improving their experience.

2.1.1.4 SITE CONDITIONS

Varying terrain and seasonal factors across the province impact site conditions, affecting resource needs and equipment and material requirements. The upfront planning process takes into consideration the optimal season to complete work, urban and rural environments, on- and off-road access points, required equipment, and optimal crew size. Site conditions such as soil type, water table, seasonal influences, site disturbance, previous tree failures and future uses for the site are also important considerations that can impact execution strategies. This also includes the use of any herbicide applications which require permission to use, public notice and also need to take into account weather conditions such as wind and rainfall for optimal results. Although these circumstances can be difficult to predict and reactive in nature, to the extent possible the organization leverages environmental conditions as appropriate to complete work more efficiently. For instance, there are situations where frozen surface conditions are ideal for access across swamp-like environments or challenging access points that may be easier with use of snowmobiles or off-road equipment.

3.0 PROGRAM OVERSIGHT AND GOVERNANCE

Hydro One maintains robust oversight over its distribution work portfolio, with significant improvements made in recent years to drive necessary program and project management and improved forecasting and reporting capabilities. Maintenance portfolios are monitored and scrutinized at multiple levels to ensure that material changes to scope, cost or schedule are identified. Monthly governance meetings are held to review forecasts and performance results. This also involves review of demand trends to evaluate risks and opportunities. Portfolio progress and risk-assessments are compiled for review by senior leadership to facilitate key business decisions and ensure the health of the overall portfolio is maintained. In addition, detailed monitoring and reporting are provided regionally to highlight local performance and any risks by tracking costs, unit accomplishments and schedule performance.

If funding adjustments are required, Hydro One employs a thorough re-direction process, as described in SPF Section 1.7. The Redirection Committee will provide advice and direction on investment adjustments that are required to the business plan to address emerging business needs or to seize opportunities related to the planning and execution of Hydro One's Investment Plan.

4.0 WORK PROGRAMS

Hydro One Distribution's maintenance work programs consist of both demand-based and planned programs. Demand maintenance work is driven by customers who are connected to Hydro One's distribution network and represents approximately 25% of Distribution's maintenance expenditures. The demand portfolio utilizes historical analytics to forecast program spend and unit volumes for programs however, non-discretionary nature of demand programs can have an impact on volume of work, resource needs and subsequently requires the ability to adjust planned work accordingly. Planned maintenance programs are driven by the need for Hydro One to safely and cost effectively manage reliability, sustain assets over the long term and remain compliant with all regulations.

This section summarizes major Distribution O&M programs, organized around Hydro One's lines and stations work programs (section 4.1) and forestry maintenance programs (section 4.2). Specific details regarding these expenditures are outlined in Exhibit E-03-02.

4.1 LINES & STATIONS

This section describes lines and stations maintenance programs, divided between demand-based and planned programs which are presented in sections 4.1.1 and 4.1.2, respectively.

4.1.1 DEMAND MAINTENANCE

This section describes Hydro One's major demand-based lines and stations maintenance work programs, in sections 4.1.1.1 and 4.1.1.2, respectively.

4.1.1.1 LINES

The major demand maintenance programs for Distribution Lines include Trouble Calls, Cable Locates, and other requested work (e.g., Disconnect and Reconnects, and Meter Reading), all of which have non-discretionary regulatory, safety or environmental obligations.

The Trouble Call program is the largest Distribution Lines O&M expenditure, through which Hydro One responds to customer, safety and system needs that require an immediate or timely response. This work includes responding to service interruptions, resolving public safety hazards and repairing failed equipment. At a minimum, trouble calls (whether emergency or non-emergency) must be responded to with crews arriving on-site within 110 minutes at least 80% of the time following dispatch. Emergency trouble calls must adhere to an OEB Service Quality Indicator (SQI) measure whereby response is required within 120 minutes in rural areas and 60 minutes in urban areas at least 80% of the time. The unpredictable nature of this program and variability of weather events requires the organization to adapt and deploy resources as required to maintain a safe and reliable Distribution network.

Cable Locates involves locating Hydro One-owned and maintained underground or submarine cables to minimize the risk of infrastructure damage, loss of service or injury. Requests are initiated by a customer or contractor through the Ontario One Call system and governed by the *Ontario Underground Infrastructure Notification System Act, 2012*, which stipulates that anyone in Ontario must contact Ontario One Call prior to digging. Locates are generally completed during normal working hours, unless it is deemed an emergency locate which is defined as loss of service that could result in an imminent or significant safety or environmental hazard. Specifically, Cable Locate activities include maintenance of required locate equipment, notifying customers of cable location via surface marking, installing stakes or providing a sketch with adequate accuracy to permit safe digging or excavation. Funding for this program accounts for fees from Ontario One Call for distribution locate dispatch and costs to support contracted Locate Service Providers (LSPs) who complete standard and emergency locates on behalf of Hydro One when possible. Historical information is used to budget expected work volumes and associated costs. In recent years, work requests have exceeded anticipated volumes.

Demand maintenance also includes addressing various requests directly from customers, contractors or the Electrical Safety Authority. Examples include disconnect and reconnects (so work can be safely performed near electrical infrastructure) and requests for unscheduled meter reads (which involve move-in, move-out or priority reads). These requests also have specific OEB SQI measures to ensure customer inquiries are addressed in a timely manner and appointment commitments are upheld, requiring the ability to adjust priorities and execution crews accordingly.

4.1.1.2 STATIONS

Corrective maintenance is demand-based and includes trouble call response and corrective maintenance of transmission equipment at stations or on transmission circuits.[1] Trouble calls are generated by system events, alarms, or equipment operations requiring attention and staff deployment. These situations may require urgent corrective maintenance and repairs to ensure system reliability, the safety of workers and the public, and to maintain the health of power system equipment. Corrective maintenance may also be performed on station and line assets as a result of inspection findings, equipment operations, or asset health analytics. Resources and funding may be require redirection within the execution of the annual work program as a result of these factors. Some examples of the types of demand corrective work within Distribution Stations that are performed by transmission personnel are Switch Maintenance, Transformer Maintenance and Recloser Maintenance.

4.1.2 PLANNED MAINTENANCE

This section describes Hydro One's planned lines and stations maintenance work programs in sections 4.1.2.1 and 4.1.2.2, respectively.

4.1.2.1 LINES

Planned maintenance programs within Distribution Lines include Defect Correction, Distribution Patrols, PCB Test and Inspect.

The Minimum Inspection Requirements in the DSC require Hydro One to conduct patrols on poles, lines and equipment every six-years in rural areas and three-years in urban areas. The company annually selects specific feeders for visual inspection of overhead and underground lines equipment along with submarine cable and connection point inspections. Although defects

[1] Both planned and demand work within Distribution Stations is performed by Transmission personnel and charged to Distribution.

on the distribution system can be discovered in multiple ways, the main source of identified defects is the patrol program.

The DLP program collects transformer nameplate information which provides important details regarding transformer age to determine if PCB testing or inspection needs to occur. PCBs are a toxic compound to humans and the environment and as a result, Environment and Climate Change Canada has implemented a series of end-of-use deadlines which Hydro One is obligated to meet. As PCBs were previously used as a dialectic and coolant in electrical equipment, some distribution lines equipment still contain PCBs in the insulating oil and must be eliminated by 2025. Collecting this information, obtaining oil samples and ensuring PCB results are recorded are especially important in ensuring that Hydro One is compliant per federal PCB regulations.

4.1.2.2 STATIONS

Planned maintenance on station equipment consists of preventive maintenance activities performed annually to maximize equipment performance, increase the lifespan of assets, and maintain reliability. Hydro One analyzes and prioritizes work to help ensure the best use of program funding to meet these goals. Because of the dynamic environment in which this work is performed, planned work completion is monitored and reprioritized on an ongoing basis through planning and scheduling processes.

Examples for the type of work completed for Distribution Stations planned Preventative and Corrective are Recloser Maintenance, Stations Inspections, Transformer Diagnostics, Switch Maintenance, Oil Sampling and Batteries Maintenance & Inspection.

4.2 FORESTRY

This section describes Hydro One's demand-based and planned forestry maintenance programs, which are presented in sections 4.2.1 and 4.2.2, respectively.

4.2.1 DEMAND MAINTENANCE

Trouble Calls are the leading demand maintenance activity for Forestry, as many weather events result in tree-related incidents that require the expertise of Forestry crews to clear downed trees and other unwanted vegetation. Forestry's demand maintenance portfolio also includes the Public Safety and Reliability program, which addresses various internal and external requests that require immediate action before the next regular maintenance cycle. Similar to Distribution Lines demand programs, prompt corrective action of customer inquiries is required and must be addressed within certain timeframes depending on the nature of work required to ensure all hazards are addressed and customer satisfaction is maintained.

4.2.2 PLANNED MAINTENANCE

Forestry's planned work program consists of preventative maintenance activities to manage vegetation and maintain clearances on Distribution corridors. Trees are the primary cause of distribution outages; planned maintenance is crucial to minimize vegetation growth that results in costly unplanned maintenance and frequent, lengthy, and capital-intensive storm restoration efforts. The Optimal Cycle Protocol (OCP) was implemented in 2018 to transition Hydro One's rights-of-way to a stable and sustainably managed system in a way that improves public safety and reliability, through the use of a prescriptive scope of work and a focus on clearing vegetation with the biggest impact. As part of the OCP, Forestry Technicians conduct time-based patrols whereby vegetation defects are identified using a visual assessment method, landowner notification is performed and necessary permits are obtained to comply with all internal processes and external regulations. Work to address defects identified on each feeder is planned and scheduled based on SAIDI contribution, vegetation type and cost. Defects are cleared by Forestry execution crews. The targeted cycle length is two to five years, taking into consideration minimum inspection requirements as outlined in the DSC as well as feeder condition and performance to optimize resource utilization, spend and geographical conditions.

Other components of planned maintenance include brush control which focuses on clearing multiple brush stems that are or at risk of growing into distribution lines. In addition, herbicide is applied at all outdoor Distribution station properties and recloser sites to provide a layer of insulation against step and touch potential for anyone within the station, as weeds and vegetation can be conductive and circumvent insulating benefits provided from insulated footwear. Plants growing within the station also pose tripping hazards. The elimination of unwanted weeds and vegetation through the use of herbicides eliminates these hazards.

5.0 RESOURCING STRATEGY

Distribution's resource strategy is designed to ensure that the organization safely and efficiently delivers its work program within approved expenditure levels, while maintaining commitments to Hydro One customers. Hydro One uses a work-based approach to staffing, under which the company sources staff according to work programs rather than planning the work around the number of internal resources available. To address the fluctuating and seasonal nature of Distribution's work program, Hydro One maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, hiring hall, temporary, and contract staff for both Lines and Forestry. The company's Distribution resource strategy includes using Hydro One's robust apprenticeship and training programs with the guidance of experienced tradespersons and technicians to learn the required skills and support the various work programs. Forestry resources are also shared between Distribution and Transmission portfolios which requires the organization's execution strategies to be integrated to enable workforce flexibility and drive efficient planning and execution of all vegetation.

Hydro One Distribution intends to maintain a relatively flat level of regular status full-time equivalents (FTEs) throughout the rate period. In the Distribution organization, regular FTEs are Power Workers Union (PWU) represented and Society of United Professionals (SUP) represented staff, or are members of management that are not represented. Anticipated hiring into regular status PWU or SUP roles is primarily limited to the level required to contend with attrition. During the 2023-2027 period, there will be limited increases in casual status FTEs (casual employees within the Distribution organization that are members of the PWU Hiring Hall, or members of a Building Trade Union, such as Labourers) to account for the need to maintain an adequate level of labour resources to support supplemental maintenance and trades work related to short-term projects, peak work volumes and intermittent work programs. 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.

To execute planned work efficiently, Hydro One Distribution expects to continue strategically balancing staffing levels with the optimized use of overtime (OT) hours to manage demand. Distribution uses OT primarily to meet work requirements that bear a limited degree of predictability. Most OT within Distribution is classified as “demand overtime” and is associated with customer demand and emergency work such as Trouble Calls. This is distinct from “planned overtime” which is the planned scheduling of additional work to meet project or work-related completion schedules while managing the size of the workforce or perform work outside of regular working hours to minimize outage impact to customers. For Distribution, demand overtime is necessary to address trouble calls, equipment failure, high priority defect corrections, and storm response. The Distribution work execution plan for the 2023-2027 forecasting period assumes OT usage will remain static. These planning assumptions are based on an analysis of types of work that result in overtime hours as well as the average observed over the four year period prior to the filing of this application.

Workforce flexibility is a fundamental aspect of Distribution’s resource model, while maintaining alignment within the parameters of the applicable collective agreements. Hydro One utilizes contractors when it is recognized that a specific skillset required on a non-regular basis is not available internally or there is an influx of work with a short term need for additional resource support. This is necessary to ensure the efficient execution of the work program and address ongoing variation in requirements for specific skills. As a result, Hydro One has continued to focus on its outsourcing options through the use of Purchased Service Agreements (PSA) and Request for Proposals (RFP). By stipulating the business requirements and necessary skillset, Hydro One maintains control of the scope of work while driving price transparency and efficiency among proponents. For example, due to the increased number of kilometers addressed annually under the OCP approach and backlog of defects to clear to shorten future cycle lengths and reduce maintenance costs, the Defect Correction program required a pool of trained foresters beyond the capacity of regular and hiring hall staff. Forestry successfully leveraged the use of a three year PSA from 2018 to 2020 to address the short term accumulation of necessary vegetation work as part of the OCP resourcing strategy.

Hydro One has also focused on developing relationships with First Nations communities by offering vegetation management opportunities within right of way corridors for Hydro One distribution assets on reserve lands. Through Fixed Price Contracts, Forestry has contracted and will continue to contract with First Nations to clean up trees pruned or removed and manage underbrush along right of way corridors within First Nations lands. For safety reasons, all work performed by First Nations communities is outside of the proximity limits of approach to electrical circuits.

6.0 SAFETY CULTURE

Hydro One is striving to transform and improve safety culture through robust safety analytics and grass-roots employee engagement. The company’s Safety Improvement Team has connected with more than 4,200 workers across the company, completed an analysis of Hydro One’s historical performance, and gathered safety best practices from external companies. From this research, the team has outlined a plan to eliminate serious injuries and fatalities by 2024. This will be accomplished by addressing the root causes of our safety issues, transforming culture, and by embedding the right values, mindsets and behaviours. Further details regarding Distribution’s safety initiatives and performance are outlined in DSP Section 3.10.

7.0 CONTINUOUS IMPROVEMENT

Distribution has initiated significant improvements to equip its employees with modern tools to drive improved field productivity, safety, reliability and better integrate the organization. The Forestry organization implemented SAP Work Manager, similar to the Lines organization, to advance its approach to collecting, planning, tracking, executing, and analyzing work programs. Further leveraging the use of GIS, grid modernization as well as exploring the use of advanced technology such as remote sensing to assess vegetation growth, provides opportunities to further advance O&M improvements. Technological advancements and enhanced data collection are also providing the ability to better inform planned maintenance activities. For example, with this continued evolution and growth, information collected on tree-caused outages is now able to better inform planned vegetation programs and isolate geographical or species patterns.

8.0 PRODUCTIVITY

Distribution has demonstrated the ability to identify and execute various productivity initiatives, realizing the financial benefits as a result. Cable Locates and After Hours Emergency Locates Outsourcing, OCP Trouble Call Reduction, Crew Dispatch Optimization and Forestry DLP initiatives provide examples of productivity improvements.

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. Continuing to pursue the contractual agreements that have been successfully implemented will remain the focus of these initiatives, as they have proved to be effective and produced positive productivity results for Hydro One.

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. Additionally, with the implementation of the OCP model and expected improvements to vegetation management outcomes, Forestry is able to complete maintenance on more feeders annually and minimize tree caused outages.

The adoption of the OCP model resulted in Forestry Technicians conducting feeder patrols in advance of work execution. This presented an opportunity for Forestry Technicians to complete overhead asset inspections in conjunction with the annual vegetation management defect patrols, which was previously completed by Lines staff. In doing so, Hydro One was able to eliminate the cost of completing a lines patrol every year, and ensures that overhead assets are inspected every two to five years to align with the frequency of right-of-way Forestry patrols.

Distribution continues to seek opportunities to improve process efficiencies that result in cost savings in the execution of its maintenance programs as outlined in SPF Section 1.4.

The Distribution Lines organization has initiated an efficiency improvement initiative known as Project Lighthouse. The objective of Lighthouse is to investigate, evaluate and implement various efficiency opportunities within the Distribution Lines organization. The anticipated improvement opportunities expected from Project Lighthouse in regards to introducing upstream efficiencies to improve planning and schedule practices, technology use and coordination among work groups will benefit Distribution's work execution over the application period. For further details on this project, please refer to DSP Section 3.10.

9.0 SUMMARY

Distribution has developed a comprehensive strategy to deliver a large and complex maintenance work program within approved expenditure levels, while maintaining the necessary flexibility to adjust in a safe and effective manner. The organization remains focused on continuously improving planning to drive efficiencies, while leveraging its flexible workforce to support inevitable fluctuations in demand-based work. Maintaining robust oversight over the distribution maintenance portfolio and continuing to identify safe, efficient and cost-effective ways to execute work will remain at the forefront for Distribution Lines, Stations and Forestry.

SUMMARY OF COMMON AND OTHER OM&A

1.0 INTRODUCTION

This exhibit provides a summary of the expenditures which are shared between Hydro One Networks and its affiliates, and which, in respect of Hydro One Networks, are subsequently allocated to the Transmission and Distribution business segments.

2.0 SUMMARY OF COMMON AND OTHER OM&A COSTS

Hydro One defines Common OM&A Costs as costs incurred to provide service on a shared basis to Hydro One and its affiliate companies. Hydro One's Common OM&A Costs are the costs which it incurs for the purposes of performing the following services: Common Corporate Functions and Services (CCF&S)[1] as detailed in Exhibit E-04-02; Planning as detailed in Exhibit E-04-03; and Information Solutions as detailed in Exhibit E-04-04.

The provision of these 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.

Hydro One has maintained its commitment to cost reductions that were identified in connection with the most recent Transmission application (EB-2019-0082). The significant commitment to reduce corporate costs across the organization is the primary driver of the decrease in the 2019 actuals from 2018 levels of the CCF&S and Planning categories. The reductions were achieved primarily through a reduction in vacancies and limiting consulting contracts to critical functions,

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[1] CCF&S is comprised of common corporate functions that provide services on a shared basis to all affiliates and business units. These functions include corporate management, finance, human resources, indigenous relations, communications and stakeholder relations, outsourcing services, general counsel, regulatory affairs, security management, internal audit, and facilities and real estate.

with an overall focus on building internal capabilities. Their forecasts have been materially maintained at or below the rate of inflation.

Additionally, Cost of Sales - External Work (as detailed in Exhibit E-04-06 for Transmission and Exhibit E-04-07 for Distribution), and Other OM&A (as detailed in Exhibit E-04-02) are also included in the overall Common and Other OM&A costs category. These costs include the cost of sales for external work, as well as the other costs including those associated with the non-service cost component of Other Post-Employment Benefits (OPEB) and the recovery of capitalized overheads within Other OM&A.

Table 1, below, summarizes Hydro One's total Common and Other OM&A Costs over the Historical, Bridge and Test years.

Table 1 - Summary of Total Common and Other OM&A Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Common Corporate Functions & Services (CCF&S)	203.4	192.6	183.9	206.5	207.8	214.6
Planning	46.8	40.2	39.5	39.0	41.1	42.5
Information Solutions	125.5	136.2	131.2	137.4	134.9	141.8
Cost of Sales - External Work	18.8	9.0	11.8	10.4	9.3	10.1
Other OM&A	-222.5	-256.1	-195.6	-239.4	-247.4	-203.0
Total[2]	**172.1**	**121.9**	**170.7**	**153.9**	**145.8**	**206.1**
Year over Year Change		**-29.2%**	**40.0%**	**-9.8%**	**-5.3%**	**41.4%**

Table 2 and Table 3, below, summarize Hydro One's portion of the Common and Other OM&A Costs allocated to Transmission and Distribution over the Historical, Bridge and Test years.

[2] Total Common and Other OM&A costs include the cost of Common OM&A services provided on a shared basis to Hydro One Transmission, Distribution and other non-regulated segments/affiliates.

Table 2 - Summary of Total Common and Other OM&A Costs Allocated to Transmission ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Common Corporate Functions & Services (CCF&S)	92.5	88.2	88.6	90.7	94.9	96.9
Planning	31.0	26.7	25.3	25.2	26.6	27.4
Information Solutions	50.4	53.7	51.2	51.4	51.2	53.7
Cost of Sales - External Work	8.4	3.7	7.7	6.4	4.9	5.7
Other OM&A	-127.4	-145.6	-102.3	-122.1	-126.8	-118.7
Total	**54.9**	**26.7**	**70.5**	**51.6**	**50.7**	**65.0**
Year over Year Change		**-51.3%**	**163.8%**	**-26.8%**	**-1.7%**	**28.3%**

Table 3 - Summary of Total Common and Other OM&A Costs Allocated to Distribution ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Common Corporate Functions & Services (CCF&S)	80.1	76.9	76.4	83.8	87.2	89.1
Planning	15.7	13.5	14.2	13.6	14.4	14.9
Information Solutions	73.8	81.1	78.4	83.8	81.5	85.9
Cost of Sales - External Work	10.4	5.3	4.1	4.0	4.4	4.4
Other OM&A	-95.1	-110.5	-93.4	-117.3	-120.6	-84.3
Total	**84.9**	**66.3**	**79.7**	**68.0**	**67.0**	**110.0**
Year over Year Change		**-21.9%**	**20.2%**	**-14.7%**	**-1.4%**	**64.2%**

3.0 VARIANCE EXPLANATION FOR COMMON AND OTHER OM&A

The variance explanations for Common OM&A[3] values as presented in Table 1 above are provided at the total levels, rather than based on the specific amounts allocated to each of Hydro One Transmission and Hydro One Distribution. Items within Common OM&A are subject to B&V's allocation methodology as discussed in Exhibit E-04-08.

[3] CCF&S, Planning, Information Solutions

Variance explanations for Cost of Sales - External Work and Other OM&A are provided as applicable to the Transmission and Distribution businesses of Hydro One.

3.1 COMMON CORPORATE FUNCTIONS & SERVICES (CCFS)

Total CCF&S costs have increased by approximately $11M from 2018 to 2023 as shown in Table 1, which represents a compound annual growth rate of 1.1% over this period and is below the rate of inflation. Commitments to corporate cost reductions are considered in the bridge and test years, due to the corporate cost reductions, as previously described. CCF&S costs are further discussed in further detail in Exhibit E-04-02.

3.2 PLANNING

Total Planning costs for 2018-2020 have decreased primarily as a result of the corporate cost initiative and maintaining commitments made in the 2020-2022 Transmission application. The 2022 bridge year shows a $5.7M reduction relative to 2018 actuals. The 2023 test year reflects a cost decrease of $4.3M from 2018 levels before considering the effects of inflation as shown in Table 1. Planning costs are described in more detail in Exhibit E-04-03.

3.3 INFORMATION SOLUTIONS

Total Information Solutions OM&A expenditures have increased from 2018-2023 by a compound annual growth rate of 2.5% which is materially in line with inflation. The costs requested in the test year as shown in Table 1 reflect the anticipated benefits of the new sourcing strategy for information technology services. Additional details on Information Solutions OM&A can be found in Exhibit E-04-04.

3.4 COST OF SALES - EXTERNAL WORK

Cost of Sales - External Work for the Transmission business, decreased by $2.7M from 2018-2023 due to a reduction in work performed for Hydro One's affiliates, and is further detailed in Exhibit E-04-06. Cost of Sales - External Work has decreased by $6.0M from 2018-2023 for the

Distribution business due to a reduction in unregulated revenue, and is further detailed in Exhibit E-04-07.

3.5 OTHER OM&A

Total Other OM&A primarily consists of a credit for capitalized overheads which represents the portion of allocated Common Corporate and/or business unit functions and services that support capital work. These costs are included in Common Corporate services and the budgets of other lines of business. OM&A expenses are thus reduced by the capitalized amounts. Additionally, Other OM&A includes the non-service cost component of OPEB, environmental provision credit, indirect depreciation credit, and any material unexpected or non-recurring expenses.

Year-over-year variances from 2018 to 2023 for the Transmission and Distribution business are primarily due to costs related to the COVID-19 pandemic, the recognition of the non-service component of OPEB, and a reduction to the environmental provision credit. Other OM&A is further described in Exhibit E-04-02.

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Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2018

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$ x 1000
HONI	Other	Supply Chain Services	Cost of services	276	276
HONI	Other	Lease of IT Assets	Shared Asset Allocation	768	768
HONI	Other	Utility Operation Services	Cost of services	1,546	1,546
HONI	Other	Network Operations	Cost of services	1,177	1,177
HONI	Other	Managing Director	Cost of services	120	120
Other	HONI	Meter and Lines and Training Work	Cost of services	404	404
Other	HONI	Business and Power System Operations	Cost of services	19,585	19,585

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$ x 1000
HOI	HONI	Chief Financial Office Services	CCC Allocation Model	25%	1,176
HOI	HONI	General Counsel	CCC Allocation Model	32%	933
HOI	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	23%	4,926
HOL	HONI	Chief Financial Office Services	CCC Allocation Model	0%	-
HOL	HONI	General Counsel	CCC Allocation Model	0%	-
HOL	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	0%	-
HONI	Other	Corporate Services	CCC Allocation Model	1%	1,522
HONI	Other	Financial Services	CCC Allocation Model	7%	2,218
HONI	Other	General Counsel	CCC Allocation Model	7%	2,039
HONI	Other	Other Services	CCC Allocation Model	2%	1,526
HONI	Other	Telecommunication Services	CCC Allocation Model	2%	404

Legend

Legend	"HOI"	Hydro One Inc.
	"HOL"	Hydro One Limited
	"HONI"	Hydro One Networks Inc.
	"Other"	Other unregulated subsidiaries and affiliates, including: Hydro One Inc. Hydro One Limited Hydro One Networks Inc.'s non-regulated segment Hydro One Remote Communities Inc. Hydro One Telecom Inc. B2M Limited Partnership Niagara Reinforcement Limited Partnership Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$ x 1000
HONI	Other	Supply Chain Services	Cost of services	276	276
HONI	Other	Lease of IT Assets	Shared Asset Allocation	768	768
HONI	Other	Utility Operation Services	Cost of services	1,865	1,865
HONI	Other	Network Operations	Cost of services	1,333	1,333
HONI	Other	Managing Director	Cost of services	160	160
Other	HONI	Meter and Lines and Training Work	Cost of services	295	295
Other	HONI	Business and Power System Operations	Cost of services	17,247	17,247

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$ x 1000
HOI	HONI	Chief Financial Office Services	CCC Allocation Model	3%	193
HOI	HONI	General Counsel	CCC Allocation Model	10%	405
HOI	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	33%	3,650
HOL	HONI	Chief Financial Office Services	CCC Allocation Model	0%	-
HOL	HONI	General Counsel	CCC Allocation Model	0%	-
HOL	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	0%	-
HONI	Other	Corporate Services	CCC Allocation Model	4%	7,419
HONI	Other	Financial Services	CCC Allocation Model	7%	1,944
HONI	Other	General Counsel	CCC Allocation Model	6%	1,848
HONI	Other	Other Services	CCC Allocation Model	2%	1,748
HONI	Other	Telecommunication Services	CCC Allocation Model	2%	405

Legend

"HOI" Hydro One Inc.
"HOL" Hydro One Limited
"HONI" Hydro One Networks Inc.
"Other" Other unregulated subsidiaries and affiliates, including:
- Hydro One Inc.
- Hydro One Limited
- Hydro One Networks Inc.'s non-regulated segment
- Hydro One Remote Communities Inc.
- Hydro One Telecom Inc.
- B2M Limited Partnership
- Niagara Reinforcement Limited Partnership
- Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: **2020**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$ x 1000
HONI	Other	Supply Chain Services	Cost of services	276	276
HONI	Other	Lease of IT Assets	Shared Asset Allocation	768	768
HONI	Other	Utility Operation Services	Cost of services	1,574	1,574
HONI	Other	Managing Director	Cost of services	240	240
Other	HONI	Meter and Lines and Training Work	Cost of services	160	160
Other	HONI	Business and Power System Operations	Cost of services	17,977	17,977

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$ x 1000
HOI	HONI	Chief Financial Office Services	CCC Allocation Model	8%	192
HOI	HONI	General Counsel	CCC Allocation Model	21%	423
HOI	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	30%	2,559
HOL	HONI	Chief Financial Office Services	CCC Allocation Model	0%	-
HOL	HONI	General Counsel	CCC Allocation Model	0%	-
HOL	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	0%	-
HONI	Other	Corporate Services	CCC Allocation Model	3%	5,797
HONI	Other	Financial Services	CCC Allocation Model	9%	2,216
HONI	Other	General Counsel	CCC Allocation Model	6%	1,987
HONI	Other	Other Services	CCC Allocation Model	2%	1,803
HONI	Other	Telecommunication Services	CCC Allocation Model	2%	437

Legend

"HOI" Hydro One Inc.
"HOL" Hydro One Limited
"HONI" Hydro One Networks Inc.
"Other" Other unregulated subsidiaries and affiliates, including:
- Hydro One Inc.
- Hydro One Limited
- Hydro One Networks Inc.'s non-regulated segment
- Hydro One Remote Communities Inc.
- Hydro One Telecom Inc.
- B2M Limited Partnership
- Niagara Reinforcement Limited Partnership
- Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2021

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$ x 1000
HONI	Other	Supply Chain Services	Cost of services	276	276
HONI	Other	Lease of IT Assets	Shared Asset Allocation	768	768
HONI	Other	Utility Operation Services	Cost of services	1,156	1,156
HONI	Other	Managing Director	Cost of services	224	224
Other	HONI	Meter and Lines and Training Work	Cost of services	363	363
Other	HONI	Business and Power System Operations	Cost of services	18,964	18,964

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$ x 1000
HOI	HONI	Chief Financial Office Services	CCC Allocation Model	10%	233
HOI	HONI	General Counsel	CCC Allocation Model	58%	317
HOI	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	38%	2,998
HOL	HONI	Chief Financial Office Services	CCC Allocation Model	0%	-
HOL	HONI	General Counsel	CCC Allocation Model	0%	-
HOL	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	0%	-
HONI	Other	Corporate Services	CCC Allocation Model	6%	10,922
HONI	Other	Financial Services	CCC Allocation Model	9%	2,622
HONI	Other	General Counsel	CCC Allocation Model	5%	1,509
HONI	Other	Other Services	CCC Allocation Model	1%	1,105
HONI	Other	Telecommunication Services	CCC Allocation Model	3%	435

Legend

	"HOI"	Hydro One Inc.
	"HOL"	Hydro One Limited
	"HONI"	Hydro One Networks Inc.
	"Other"	Other unregulated subsidiaries and affiliates, including:

- Hydro One Inc.
- Hydro One Limited
- Hydro One Networks Inc.'s non-regulated segment
- Hydro One Remote Communities Inc.
- Hydro One Telecom Inc.
- B2M Limited Partnership
- Niagara Reinforcement Limited Partnership
- Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2022

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$ x 1000
HONI	Other	Supply Chain Services	Cost of services	276	276
HONI	Other	Lease of IT Assets	Shared Asset Allocation	768	768
HONI	Other	Utility Operation Services	Cost of services	1,457	1,457
HONI	Other	Managing Director	Cost of services	229	229
Other	HONI	Meter and Lines and Training Work	Cost of services	363	363
Other	HONI	Business and Power System Operations	Cost of services	20,440	20,440

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$ x 1000
HOI	HONI	Chief Financial Office Services	CCC Allocation Model	10%	238
HOI	HONI	General Counsel	CCC Allocation Model	58%	328
HOI	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	37%	3,047
HOL	HONI	Chief Financial Office Services	CCC Allocation Model	0%	-
HOL	HONI	General Counsel	CCC Allocation Model	0%	-
HOL	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	0%	-
HONI	Other	Corporate Services	CCC Allocation Model	6%	11,723
HONI	Other	Financial Services	CCC Allocation Model	10%	2,825
HONI	Other	General Counsel	CCC Allocation Model	5%	1,643
HONI	Other	Other Services	CCC Allocation Model	1%	1,057
HONI	Other	Telecommunication Services	CCC Allocation Model	3%	434

Legend

"HOI"	Hydro One Inc.
"HOL"	Hydro One Limited
"HONI"	Hydro One Networks Inc.
"Other"	Other unregulated subsidiaries and affiliates, including: Hydro One Inc. Hydro One Limited Hydro One Networks Inc.'s non-regulated segment Hydro One Remote Communities Inc. Hydro One Telecom Inc. B2M Limited Partnership Niagara Reinforcement Limited Partnership Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2023

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$ x 1000
HONI	Other	Supply Chain Services	Cost of services	276	276
HONI	Other	Lease of IT Assets	Shared Asset Allocation	2,077	2,077
HONI	Other	Utility Operation Services	Cost of services	1,474	1,474
HONI	Other	Managing Director	Cost of services	233	233
Other	HONI	Meter and Lines and Training Work	Cost of services	363	363
Other	HONI	Business and Power System Operations	Cost of services	22,033	22,033

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$ x 1000
HOI	HONI	Chief Financial Office Services	CCC Allocation Model	12%	310
HOI	HONI	General Counsel	CCC Allocation Model	58%	334
HOI	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	36%	3,102
HOL	HONI	Chief Financial Office Services	CCC Allocation Model	0%	-
HOL	HONI	General Counsel	CCC Allocation Model	0%	-
HOL	HONI	President/CEO/Chairman/Board/Ombudsman	CCC Allocation Model	0%	-
HONI	Other	Corporate Services	CCC Allocation Model	6%	12,389
HONI	Other	Financial Services	CCC Allocation Model	10%	2,896
HONI	Other	General Counsel	CCC Allocation Model	5%	1,576
HONI	Other	Other Services	CCC Allocation Model	1%	1,025
HONI	Other	Telecommunication Services	CCC Allocation Model	3%	440

Legend

"HOI"	Hydro One Inc.
"HOL"	Hydro One Limited
"HONI"	Hydro One Networks Inc.
"Other"	Other unregulated subsidiaries and affiliates, including:

- Hydro One Inc.
- Hydro One Limited
- Hydro One Networks Inc.'s non-regulated segment
- Hydro One Remote Communities Inc.
- Hydro One Telecom Inc.
- B2M Limited Partnership
- Niagara Reinforcement Limited Partnership
- Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP)

COMMON CORPORATE FUNCTIONS AND SERVICES (CCF&S) AND OTHER OM&A

1.0 INTRODUCTION

Hydro One has certain common corporate functions that provide service on a shared basis to all business units within Hydro One Networks, as well as to affiliates: corporate management, finance, human resources, indigenous relations, communications and stakeholder relations, outsourcing services, general counsel, regulatory affairs, security management, internal audit, and facilities and real estate.

Hydro One determined that these functions could be shared effectively by all business units and affiliates, thereby avoiding costly and unnecessary duplication which benefits customers. These functions are referred to as Common Corporate Functions and Services (CCF&S).

The allocation of CCF&S costs between Hydro One Transmission, Hydro One Distribution, its shareholders and other affiliates is determined by using the common cost allocation methodology described in Exhibit E-04-08. The allocation of these costs between Hydro One Networks and its affiliates is governed by affiliate level service agreements, which are described in Exhibit D-02-03.

This Exhibit describes Hydro One's CCF&S and Other OM&A costs. Other OM&A costs, discussed in Section 3.0 below, is comprised of credits (offsets to OM&A) associated with capitalized overheads, environmental provision, and indirect depreciation, as well as the non-service cost component of other post-employment benefits (OPEBs) and other costs.

In the OEB's decision in EB-2017-0049, the OEB directed Hydro One Distribution to expand its benchmarking to include administrative functions such as billing, call centre and corporate costs. UMS was engaged through a competitive procurement process to undertake a benchmarking study of Hydro One’s common corporate costs. The UMS benchmarking study concluded that Hydro One’s common corporate costs benchmarked well against the comparator group. Hydro One is at or near 1st quartile levels for five functions, and median levels for four functions. The UMS benchmarking study is provided as Attachment 1 to this exhibit.

2.0 CCF&S COSTS AND VARIANCE ANALYSIS

Hydro One has maintained the commitment to the CCF&S cost reductions that were first identified in its previous Transmission application (EB-2019-0082). The significant commitment by Hydro One to reduce corporate costs across the organization is the primary driver of the decrease in the 2019 and 2020 actuals from 2018 levels, which is the primary reason the forecast in the current application is materially maintained at or below the rate of inflation. The historical cost reductions were achieved primarily through a reduction in vacancies and limiting consulting contracts to critical functions, with an overall focus on building internal capabilities.

Table 1 below outlines the total CCF&S costs for Hydro One between 2018 and 2021, the 2022 bridge year, and the 2023 test year.

Table 1 - Summary of Total Common Corporate Functions and Services OM&A ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Corporate Management	32.6	25.9	17.3	29.1	22.4	25.4
Finance	38.3	32.7	31.3	34.0	34.8	33.9
Human Resources	21.5	22.2	23.9	21.7	23.5	26.3
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	12.2	12.2	11.9	14.7	15.1	15.6
General Counsel	9.6	9.0	10.8	9.3	9.7	9.9
Regulatory Affairs	20.6	20.2	21.4	21.5	23.3	21.5
Security Management	5.2	3.9	3.1	4.9	5.7	5.9
Internal Audit	5.6	5.6	4.7	6.0	6.4	6.7
Facilities and Real Estate	57.9	60.9	59.6	65.3	67.0	69.5
Total CCF&S Costs	**203.4**	**192.6**	**183.9**	**206.5**	**207.8**	**214.6**
Change Year over Year		**-5.3%**	**-4.5%**	**12.3%**	**0.6%**	**3.3%**

Total CCF&S costs increased by approximately $11M from 2018 through 2023, which reflects a compound annual growth rate of 1.1% and is below the rate of inflation, primarily due to the following factors:

- Higher Facilities and Real Estate costs due to lease renewals and fixed operating costs for new facilities;
- Higher Human Resources costs owing to investments to develop and execute Hydro One's People Strategy; and
- Higher Indigenous Relations and Communications and Stakeholder Relations costs due to investments to position Hydro One as a trusted partner with Indigenous communities, customers and stakeholders.

The increases are offset in part by cost reductions in Finance and Corporate Management.

From 2022 to 2023, Total CCF&S costs increased by $6.8M largely due to increases in non-recoverable Corporate Management costs, and higher Facilities and Real Estate costs, and

Human Resources costs, for the same reasons identified above in respect of the 2018 to 2023 period.

Table 2 below outlines the amounts that have been allocated to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates during the same time period.

Table 2 - Summary of Allocated Common Corporate Functions and Services OM&A ($M)

Description	Historical 2018 Actual	Historical 2019 Actual	Historical 2020 Actual	Historical 2021 Forecast	Bridge 2022 Forecast	Test 2023 Forecast
Allocated to Transmission						
Corporate Management	3.9	2.4	2.7	1.9	2.0	2.1
Finance	20.8	17.5	15.8	14.5	14.8	14.4
Human Resources	10.4	10.9	12.4	10.2	11.0	12.4
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	4.6	4.5	4.4	7.2	7.3	7.6
General Counsel	5.0	4.3	5.2	4.5	4.7	4.8
Regulatory Affairs	9.2	9.0	9.6	10.6	11.6	10.6
Security Management	2.9	2.1	1.6	2.6	3.0	3.1
Internal Audit	3.0	2.9	2.4	3.0	3.2	3.3
Facilities and Real Estate	32.7	34.7	34.3	36.2	37.3	38.7
Total	**92.5**	**88.2**	**88.6**	**90.7**	**94.9**	**96.9**
Change Year over Year		**-4.7%**	**0.4%**	**2.4%**	**4.6%**	**2.1%**
Allocated to Distribution						
Corporate Management	4.0	2.9	2.5	2.7	2.7	2.8
Finance	15.0	13.0	12.9	15.8	16.2	15.7
Human Resources	9.7	9.0	9.7	10.0	10.8	12.1
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	7.5	7.5	7.2	6.9	7.1	7.3
General Counsel	3.2	3.4	4.2	3.9	4.0	4.1
Regulatory Affairs	10.8	10.7	11.2	10.3	11.0	10.3
Security Management	2.3	1.7	1.4	2.2	2.6	2.6
Internal Audit	2.3	2.6	2.1	3.0	3.2	3.4
Facilities and Real Estate	25.2	26.1	25.2	29.0	29.7	30.8
Total	**80.1**	**76.9**	**76.4**	**83.8**	**87.2**	**89.1**
Change Year over Year		**-3.9%**	**-0.7%**	**9.6%**	**4.1%**	**2.2%**
Allocated to Other	**30.9**	**27.4**	**18.9**	**32.0**	**25.7**	**28.6**
Total	**203.4**	**192.6**	**183.9**	**206.5**	**207.8**	**214.6**

The changes in the Hydro One Transmission and Distribution CCF&S costs are largely due to the same factors noted above for changes in total CCF&S costs. The Transmission and Distribution businesses' CCF&S costs in the 2023 test year are approximately $13M greater than 2018 actuals, which represents a compound annual growth rate of 1.5% over this period and is below the rate of inflation. Holding these costs to a level below expected inflation is largely the result of the corporate cost reductions previously described above, and the voluntary exclusion of compensation for executive officers of Hydro One Inc. and Hydro One Networks Inc. from revenue requirement in this Application (in addition to the requirement to exclude compensation for executive officers of Hydro One Limited pursuant to the *Hydro One Accountability Act, 2018* (Bill 2)) as further described in Exhibit E-06-01. Table 3 below shows the detailed breakdown between labour, non-labour and where appropriate, other costs included in the CCF&S costs for the bridge and test period.

Table 3 - Summary of Allocated Common Corporate Functions and Services OM&A by Cost Type ($M)

Description	Cost Type	Total Costs		Allocated to Transmission		Allocated to Distribution	
		2022 Forecast	2023 Forecast	2022 Forecast	2023 Forecast	2022 Forecast	2023 Forecast
Corporate Management	Labour	12.1	12.6	1.0	1.1	1.5	1.6
	Non-Labour	10.3	12.8	0.9	1.0	1.2	1.2
	Total	**22.4**	**25.4**	**2.0**	**2.1**	**2.7**	**2.8**
Finance	Labour	23.9	24.6	10.2	10.5	11.1	11.4
	Non-Labour	10.9	9.4	4.6	3.9	5.1	4.3
	Total	**34.8**	**33.9**	**14.8**	**14.4**	**16.2**	**15.7**
Human Resources	Labour	19.8	21.5	9.2	10.1	9.0	9.8
	Non-Labour	3.7	4.8	1.8	2.3	1.8	2.3
	Total	**23.5**	**26.3**	**11.0**	**12.4**	**10.8**	**12.1**
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	Labour	9.8	10.2	4.9	5.1	4.5	4.7
	Non-Labour	5.2	5.3	2.4	2.5	2.5	2.6
	Total	**15.1**	**15.6**	**7.3**	**7.6**	**7.1**	**7.3**
General Counsel	Labour	6.3	6.5	3.0	3.1	2.5	2.6
	Non-Labour	3.4	3.4	1.7	1.7	1.5	1.5
	Total	**9.7**	**9.9**	**4.7**	**4.8**	**4.0**	**4.1**
Regulatory Affairs	Labour	9.4	9.9	5.3	5.6	3.7	3.9
	Non-Labour	13.9	11.6	6.3	5.0	7.4	6.5
	Total	**23.3**	**21.5**	**11.6**	**10.6**	**11.0**	**10.3**
Security Management	Labour	5.0	5.2	2.6	2.7	2.3	2.3
	Non-Labour	0.7	0.7	0.4	0.4	0.3	0.3
	Total	**5.7**	**5.9**	**3.0**	**3.1**	**2.6**	**2.6**
Internal Audit	Labour	5.5	5.7	2.7	2.8	2.8	2.9
	Non-Labour	0.9	1.0	0.4	0.5	0.5	0.5
	Total	**6.4**	**6.7**	**3.2**	**3.3**	**3.2**	**3.4**
Facilities and Real Estate	Labour	7.7	8.1	6.6	6.9	1.1	1.1
	Non-Labour	1.9	1.9	1.7	1.7	0.2	0.2
	Facility	57.3	59.5	28.9	30.0	28.4	29.5
	Total	**67.0**	**69.5**	**37.3**	**38.7**	**29.7**	**30.8**
Total		**207.8**	**214.6**	**94.9**	**96.9**	**87.2**	**89.1**

2.1 CORPORATE MANAGEMENT

Corporate Management represents those functions responsible for providing overall strategic direction to Hydro One. Corporate Management costs relate to the Board of Directors, the Chief Executive Officer (CEO) Office, the Treasurer, the Chief Financial Officer (CFO) Office, the Ombudsman Office, the Chief Legal Officer, and the Corporate Secretary as advisors to the Board of Directors and corporate officers on overall strategic matters. Table 4 presents the details of Hydro One's total Corporate Management costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 4 - Summary of Allocated Corporate Management Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission						
Board	0.8	1.1	0.9	0.7	0.7	0.7
Chair	0.1	0.2	0.1	0.0	0.0	0.0
President/CEO Office	1.4	0.3	0.2	0.3	0.3	0.3
CFO Office	0.6	0.1	0.0	0.1	0.1	0.1
Chief Legal Officer	0.4	0.0	0.0	0.0	0.0	0.0
Treasurer's Office	-	-	-	-	-	-
Corporate Secretary	0.1	0.2	0.3	0.1	0.1	0.1
Ombudsman Office	0.1	0.0	0.1	0.2	0.2	0.2
Corporate Common LTD	0.5	0.5	1.0	0.5	0.5	0.6
Total	**3.9**	**2.4**	**2.7**	**1.9**	**2.0**	**2.1**
Change Year over Year		**-38.0%**	**10.7%**	**-28.1%**	**2.0%**	**3.4%**
Allocated to Distribution						
Board	0.9	0.8	0.4	0.8	0.8	0.8
Chair	0.1	0.1	0.0	0.1	0.1	0.1
President/CEO Office	1.4	0.3	0.1	0.3	0.3	0.3
CFO Office	0.6	0.1	0.0	0.1	0.1	0.1
Chief Legal Officer	0.4	0.0	0.0	0.0	0.0	0.0
Treasurer's Office	-	-	-	-	-	-
Corporate Secretary	0.1	0.2	0.1	0.2	0.2	0.2
Ombudsman Office	0.1	0.8	0.7	0.7	0.7	0.7
Corporate Common LTD	0.5	0.6	1.0	0.5	0.5	0.6
Total	**4.0**	**2.9**	**2.5**	**2.7**	**2.7**	**2.8**
Change Year over Year		**-27.7%**	**-12.2%**	**4.5%**	**1.8%**	**3.3%**
Allocated to Other	**24.6**	**20.6**	**12.0**	**24.5**	**17.7**	**20.5**
Total	**32.6**	**25.9**	**17.3**	**29.1**	**22.4**	**25.4**

The UMS Group report provided as Attachment 1 to this exhibit has benchmarked Hydro One’s total Corporate Management costs at slightly above the median compared to its peer group. However, as demonstrated in Table 4 above, the majority of the costs are not recoverable from transmission or distribution customers. Specifically, the costs associated with the Strategy & Growth team, corporate donations, Investor Relations, and those positions subject to the *Hydro*

One Accountability Act, 2018 (Bill 2) are borne by Hydro One's shareholders and fall under Allocated to Other in Table 4.

2.2 FINANCE

Hydro One's Finance division provides strategic advice and services related to planning, processing, recording, reporting and monitoring of all financial transactions occurring within the Hydro One group of companies. The Finance division performs the following functions: corporate controller services, corporate tax services, treasury services, risk management, data governance, and business planning and financial support. Table 5 presents the details of Hydro One's total Finance costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 5 - Summary of Allocated Finance Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission	**20.8**	**17.5**	**15.8**	**14.5**	**14.8**	**14.4**
Change Year over Year		-16.3%	-9.3%	-8.3%	2.2%	-3.1%
Allocated to Distribution	**15.0**	**13.0**	**12.9**	**15.8**	**16.2**	**15.7**
Change Year over Year		-13.3%	-0.7%	22.6%	2.0%	-3.0%
Allocated to Other	**2.4**	**2.2**	**2.5**	**3.6**	**3.8**	**3.9**
Total	**38.3**	**32.7**	**31.3**	**34.0**	**34.8**	**33.9**

The UMS Group report has benchmarked Hydro One's Finance costs at the median compared to its peer group (details are in Attachment 1 to this exhibit). Actual costs are decreasing year over year and are within plan levels from 2018 through 2023. The forecast for the bridge and test years shows significant reductions from 2018 values mainly due to the corporate costing reductions which are described above.

The Finance division performs multiple functions, each of which is described in the subsections below.

2.2.1 CORPORATE CONTROLLER

The Corporate Controller function provides leadership and direction regarding financial reporting, corporate and regulatory accounting, accounting and internal control policies, and procedures to ensure statutory and regulatory compliance and consistency with GAAP. The group is also accountable for the pay and expense management functions; ensuring payroll runs are on time and accurate, and the automated expense reporting tool is working as designed.

This group oversees the development of actual financial information and manages reporting processes for appropriate audiences or stakeholders. This group is also responsible for managing and providing direction to the Company on internal financial control matters, employing measures such as organization authority registers and financial policies and procedures. It also provides leadership in respect of the Company's compliance obligations pursuant to Ontario securities laws, including the Multi-Jurisdictional Disclosure System rules for a foreign-issuer registered with the U.S. Securities Exchange Commission.

Many routine financial services are currently outsourced to Inergi LP, including accounts payable, accounts receivable, fixed asset accounting, general accounting, planning budgeting and reporting and pension support, human resources pay services, and a number of administrative services. The outsourcing agreement with Inergi LP expires December 31, 2021 (more information on the agreement can be found in Exhibit E-05-01). Upon expiry, Hydro One plans to transition all finance and accounting full-time employees and related activities from Inergi LP into the company, effective January 1, 2022. Payroll processing activities will continue to be outsourced in a new service contract with Ceridian Canada Limited commencing January 1, 2022.

The Corporate Controller group manages increasingly complex statutory and regulatory filing requirements (e.g. external reporting, regulatory reporting, reporting related to debt and equity offerings). These requirements are continually evolving and require timely and accurate compliance. Timely compliance helps to maintain the Company's positive standing within the capital markets, which helps to keep financing costs down. The Corporate Controller group is also responsible for adherence to regulatory and accounting principles, which ensures the accuracy of financial reporting.

2.2.2 CORPORATE TAX

Corporate Tax group manages the tax affairs (i.e., compliance, audits, and planning) for each corporate entity, partnership and trust within the Hydro One group of companies. This includes matters related to corporate income taxes, excise tax, debt retirement charge, land transfer tax, non-resident withholding tax, payroll and the employer health tax. Corporate Tax services ensure that internal and external tax compliance requirements are met. Moreover, tax consulting services are provided to other departments with respect to payroll tax, taxable benefits, agreements, financing, and all transactions and information related to tax costs for regulatory purposes.

2.2.3 TREASURY

Treasury costs are associated with the following activities:

- Executing on borrowing plans and issuing commercial paper and long-term debt;
- Ensuring compliance with securities regulations, banks and debt covenants;
- Managing the Company's daily liquidity position, controlling cash and managing the Company's bank accounts;
- Settling all transactions and managing relationships with creditors; and
- Communicating with debt investors, banks and credit rating agencies.

A portion of the Treasury budget is recovered through the cost of long-term debt, as described in Exhibit F-01-02 and outlined in Exhibit F-01-04.

Included in Treasury costs are expenses for the negotiations and purchases of insurance policies, and claims management and settlement. These expenses cover premiums paid for Corporate Functions and Services insurance coverage and the cost to self-insure against liability exposures that are either not covered by insurance policies or fall below the specified deductibles.

Table 6 below shows the premiums for all of Hydro One Inc.'s Corporate Functions and Services insurance policies and the cost of self-insurance for the 2018-2023 period. Corporate Functions and Services Insurance Policies are liability policies that cannot be readily assigned to a specific line of business. Self-insurance costs for the 2022 and 2023 period reflect the Company's risk exposures, its long-term history of claims, the deductible on the liability policies, and liability payments to third parties. The main contributor to self-insurance costs are third-party claims, which can fluctuate from year to year.

Table 6 - Summary of Allocated Insurance Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission						
Premiums paid for Corporate Functions and Services Insurance Policies*	1.1	0.9	1.1	1.3	1.3	1.4
Self-Insurance Cost	1.4	0.3	0.2	0.5	0.5	0.5
Total	**2.5**	**1.2**	**1.3**	**1.7**	**1.8**	**1.8**
Change Year over Year		**-50.6%**	**7.7%**	**30.9%**	**1.6%**	**2.2%**
Allocated to Distribution						
Premiums paid for Corporate Functions and Services Insurance Policies*	0.7	1.1	1.3	1.5	1.6	1.6
Self-Insurance Cost	1.0	0.4	0.3	0.5	0.5	0.5
Total	**1.7**	**1.5**	**1.6**	**2.1**	**2.1**	**2.1**
Change Year over Year		**-15.1%**	**7.7%**	**30.9%**	**1.6%**	**2.2%**
Total	**4.2**	**2.7**	**2.9**	**3.8**	**3.9**	**4.0**
Change Year over Year		**-36.1%**	**7.7%**	**30.9%**	**1.6%**	**2.2%**

**The cost of other insurance coverage that applies to only certain lines of business is captured and reported by the lines of business where coverage is applicable*

2.2.4 CHIEF RISK OFFICER

The Chief Risk Officer's department provides an enterprise wide approach to managing risk and embeds risk management into the strategy of the organization. Corporate Risk provides uniform processes to assist decision makers in the understanding of uncertainty and how it can be measured, mitigated and exploited, leading to informed choices, prioritized actions, and resources allocation in line with Hydro One's risk appetite and tolerances.

2.2.5 DATA GOVERNANCE OFFICE

The Data Governance Office (DGO) provides an enterprise wide framework to manage data. The DGO's objective is to improve confidence in data across Hydro One through the delivery of an enterprise wide Data Governance Framework. This enables the corporate strategy by providing high quality information to optimize business decisions.

2.2.6 BUSINESS PLANNING AND FINANCIAL SUPPORT

The business planning and financial support group is responsible for establishing and leading the annual business planning, budgeting, and analysis processes. Additionally, the group is responsible for the following functions:

- Performing business case reviews, business valuations, and transaction support;
- Developing and maintaining financial models;
- Providing analytical support for a variety of financial planning and reporting processes; and
- Compiling forecast information for the appropriate audiences or stakeholders.

2.3 HUMAN RESOURCES

The Human Resources (HR) function designs, oversees, and delivers all of the policies, systems and programs needed to recruit, retain, manage, and motivate a high-performing workforce to achieve Hydro One's strategic objectives. The HR function includes services such as compensation, performance, technology-focused teams enabling the cultural changes, modernization, leadership and Labour Relations competency required to optimize productivity and effectiveness.

Table 7 presents the details of Hydro One's total Human Resources costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 7 - Summary of Allocated Human Resources Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission	**10.4**	**10.9**	**12.4**	**10.2**	**11.0**	**12.4**
Change Year over Year		5.1%	14.0%	-17.8%	8.0%	12.3%
Allocated to Distribution	**9.7**	**9.0**	**9.7**	**10.0**	**10.8**	**12.1**
Change Year over Year		-7.1%	7.7%	2.5%	8.0%	12.6%
Allocated to Other	**1.4**	**2.3**	**1.8**	**1.6**	**1.7**	**1.8**
Total	**21.5**	**22.2**	**23.9**	**21.7**	**23.5**	**26.3**

The UMS Group report has benchmarked Hydro One's Human Resources costs at slightly above the first quartile compared to its peer group. Further details can be found in Attachment 1 to this exhibit.

The Human Resources function is implementing changes to its core operating model, moving towards a strategic HR functional model in alignment with most medium-to-large size North American employers. This model features HR business partner teams supported by centralized shared services.

Human Resources costs have generally been sustained at levels consistent with inflation between 2018 and 2021, if excluding one-time consulting costs incurred in 2020 to develop Hydro One's People Strategy and initiate Organizational Re-design across the company. These investments are intended to align Hydro One's human capital strategy with business priorities, and include a commitment to build a more inclusive and diverse workforce. Incremental increases in 2022 and 2023 continue to support this re-alignment.

The Human Resources department performs multiple functions, which are described in the subsections below.

2.3.1 HR SHARED SERVICES

The HR Shared Services team is a centralized hub for HR administrative activities and services related to employee life-cycle events, such as hiring, leave of absence, promotion, and retirement, focused on streamlined processes and consistent service delivery for employees, managers, and pensioners. This team encompasses the HR Service Centre (HRSC), Workforce Acquisition (WFA), HR Technology and Effectiveness groups.

The HRSC is typically the first point of contact for all regular status employees and pensioners on HR issues, and performs nearly all administrative activities related to employee life-cycle events, such as hiring, leaves of absence and promotion.

The WFA team works in coordination with the Lines of Business to manage the casual trades staff across Hydro One. This team performs tasks related to the life cycle of the casual workforce. Casual trades employees represent nearly a third of Hydro One's workforce (CUSW, EPSCA groups, PWU HH), and are retained and deployed with minimal lead time to support time-sensitive and project-based work programs.

The HR Effectiveness and Technology teams manage HR processes, policies, and systems with the objective of supporting and enhancing HR capabilities while ensuring corporate and legislative compliance. This team manages and maintains the existing HR technology systems and leading implementation of new technologies.

2.3.2 TALENT MANAGEMENT

The Talent Management team delivers core programs relating to:

- Talent acquisition and recruiting for regular status roles both temporary and permanent;
- Performance management, and leadership & development training;
- Succession planning, and organizational design; and
- Designing and delivering equity, Diversity and Inclusion programming and education.

Given Hydro One's performance-based pay structure for management employees, this team is focused on ensuring the standards for performance are aligned with market and Hydro One's strategic objectives, as well as providing the skills and tools required to set goals and track performance. Performance-based compensation requires enhanced rigour and tracking, accountability, and mature judgement and leadership. Although performance-based compensation results in a best-in-class utility, it creates additional responsibilities and accountabilities for managers, directors, and VPs in order to maintain this program's effectiveness and integrity, hence the active role the Talent Management team (and Compensation team) plays in its oversight and delivery.

The Talent Management team is also focused on addressing retention and leadership succession within the non-unionized workforce. As this segment of the workforce is not eligible for compensation programs that are correlated with retention (such as the Defined Benefit pension plan), this group is at even greater risk of turnover.

Talent Management programs enable Hydro One to: maintain a performance and safety oriented culture, minimize disruption due to turnover within the management segment, empower leaders to drive productivity and efficiency, and diversify its talent pool to create a representative and inclusive workforce.

2.3.3 CHANGE AND CULTURE

The core activities of the Change and Culture team are as follows:

- Delivering organizational change management and business readiness expertise for all strategic initiatives and major projects to ensure both the projects and the organization's ability to be project ready, job ready, leader ready, and to enable adoption and sustainability of these cultural and strategic changes;
- Designing and implementing employee experience and recognition programs to promote employee engagement and retention, increased productivity and the ability to respond nimbly to changing needs/trends; and
- Aligning the interests of employees with the interest and values of the Company thereby creating a positive work culture and value for both.

Following the introduction of Hydro One's Corporate Strategy, a people strategy was developed to enhance how we find, manage, reward, and develop staff. It will serve as a touchstone for key shifts required across the organization to build and maintain productivity, inclusiveness, and a place where employees are proud to bring the best of themselves to work.

2.3.4 COMPENSATION

The Compensation team is responsible for the administration of the broad-based and executive compensation programs for management and represented employees including job evaluation, salary administration, the annual compensation cycle and supporting the collective bargaining process. This team is also responsible for the management and administration of all equity programs at Hydro One for both management and represented employees in addition to managing the administration of the long-term incentive plan (currently cash based). The team also supports the annual disclosure components detailed above, and conducts ongoing review of compensation programs and practices more broadly to ensure Hydro One is aligned with market best practices and emerging trends.

2.3.5 REPORTING AND ANALYTICS

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.

2.3.6 EMPLOYEE/LABOUR RELATIONS AND HR OPERATIONS

Hydro One's Employee and Labour Relations, and Operations group is comprised of Human Resource Business Partners, and a Centre of Expertise for all LR-matters supporting the LR competency of the entire organization. The core function is delivered by Human Resource Business Partners who provide strategic advice to managers and employees on issues related to policies and procedures, collective agreement administration, resourcing, performance and discipline, disability accommodation and other large initiatives that impact staff. This group was at the forefront of responding to the unprecedented array of novel issues and problems posed by the pandemic that commenced in March of 2020 such as shifting to remote work, accommodation measures for workers with children and those at higher risk of serious illness, managing leave entitlements, addressing mental health challenges, and adapting to shifting governmental responses (employment benefits, emergency measures, school/daycare closure etc.)

The Labour Relations component of this team provides strategic advice, and training to managers regarding complex collective agreements and related provincial legislation. Given the highly-unionized nature of Hydro One, as well as the complexity and comprehensiveness of its collective agreements, this group provides essential advice relating to staffing competitions & selections, accommodation, external contracting, discipline, performance, leave entitlements, as well as operational matters such as work schedules, location of work, and assignment of duties.

This group also oversees the grievance and arbitration process, providing essential advice for the resolution of disputes and advancing Hydro One's strategic objectives.

Hydro One is a party to multiple collective agreements and a number of mid-term agreements and letters of understanding. The Labour Relations group is responsible for the re-negotiation of the Power Workers Union (PWU), Society of United Professionals (SUP), Canadian Union of Skilled Workers (CUSW) collective agreements and administers all related mid-term agreements and letters of understanding. In light of the relatively short duration of renewal agreements with its core units, the SUP and PWU, the frequency of bargaining cycles has increased, putting greater pressure on the resources of this group. Additionally, as a member of EPSCA, Hydro One is a participant in negotiations with the 17 casual trades bargaining units affiliated with this organization.

2.3.7 PENSION, BENEFITS & WELLNESS

The Pension, Benefits & Wellness team delivers core services and foundational and strategic programming that support the mental, physical, and financial health of all Hydro One employees, specifically:

- administration of the defined benefit and defined contribution pension plans;
- program design and administration of all traditional benefits plans; group life insurance and post-retirement benefits;
- administration and oversight of employee and family assistance, relocation;
- oversight of disability management: sick leave, long-term disability (LTD), accommodation and return-to-work, WSIB; and
- programming and processes related to health and wellness, and medical records case management, as well as pandemic support.

2.4 INDIGENOUS RELATIONS, COMMUNICATIONS AND STAKEHOLDER RELATIONS, AND OUTSOURCING SERVICES

Table 8 presents the details of Hydro One's total Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 8 - Summary of Allocated Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission						
Indigenous Relations	1.0	0.9	0.7	1.8	1.6	1.7
Communications and Stakeholder Relations	3.1	3.1	3.3	4.8	5.0	5.2
Outsourcing Services	0.4	0.4	0.4	0.7	0.7	0.7
Total	**4.6**	**4.5**	**4.4**	**7.2**	**7.3**	**7.6**
Change Year over Year		**-2.7%**	**-0.3%**	**61.2%**	**2.4%**	**3.3%**
Allocated to Distribution						
Indigenous Relations	1.7	1.5	1.1	1.3	1.2	1.3
Communications and Stakeholder Relations	5.1	5.3	5.1	5.0	5.3	5.5
Outsourcing Services	0.7	0.7	1.0	0.5	0.6	0.6
Total	**7.5**	**7.5**	**7.2**	**6.9**	**7.1**	**7.3**
Change Year over Year		**-0.3%**	**-3.7%**	**-4.8%**	**2.9%**	**3.1%**
Allocated to Other	**0.1**	**0.2**	**0.2**	**0.6**	**0.7**	**0.7**
Total	**12.2**	**12.2**	**11.9**	**14.7**	**15.1**	**15.6**

Overall spending for Outsourcing Services is consistent with past years and the forecast for bridge and test years have been established accordingly. The spend for Indigenous Relations and Communications and Stakeholder Relations increases from 2020 to 2023, and is largely due to investments in staff and external services as part of the corporate strategy to position Hydro

One as a trusted partner through engagement with Indigenous communities, customer advocacy, and providing leadership for government and external stakeholders.

The UMS Group report includes Hydro One's Indigenous Relations, and Communication and Stakeholder Relations costs as part of Corporate Affairs, which have been benchmarked at slightly above the first quartile compared to its peer group. Further details can be found in Attachment 1 to this exhibit.

The Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services departments are further described below.

2.4.1 INDIGENOUS RELATIONS

The Indigenous Relations team helps Hydro One develop and maintain mutually beneficial long-term relationships with Indigenous communities who may be impacted by Hydro One's projects and operations. The team's mandate is to advance community-led engagement and includes: (i) undertaking procedural aspects of consultation, guided by law, best practices, and the priorities of Indigenous communities, as early as possible during projects and throughout development; (ii) engaging with Indigenous communities during operations and maintenance activities to provide information and opportunities for input on work which may impact the Indigenous community; (iii) ensuring Hydro One's employees have the skills, training and resources necessary to perform their duties while advancing relationships with Indigenous communities based on mutual respect and understanding of the unique rights of Indigenous people; (iv) advocating for and supporting efforts to increase procurement opportunities for Indigenous businesses; (v) supporting efforts to increase Indigenous employee representation at all levels in Hydro One's workforce; (vi) supporting efforts to increase Indigenous community investment, sponsorships, and grant programs for positive and lasting socio-economic outcomes; (vii) seeking good faith resolution of transmission and distribution line issues on First Nation reserve lands in a fair manner; and (viii) supporting Indigenous education and training opportunities.

Hydro One's First Nations and Métis Engagement Strategy is further described in Exhibit A-07-02.

2.4.2 COMMUNICATIONS AND STAKEHOLDER RELATIONS

Communications develops customer communication material to ensure customers are aware of the Company’s programs, upgrades, planned power outages, and power quality. The team is also accountable for customer education, media relations, and web communications for Hydro One’s corporate website.

Stakeholder Relations manages the Company’s relationship with external stakeholders, the government, energy agencies, municipal associations, industry associations, and energy sector stakeholders. The team is also responsible for providing the Company with strategic advice and support on public policy, projects, customer programs, and other initiatives. The team also leads public consultation, and community engagement in support of new development projects, maintenance work, and forestry programs.

2.4.3 OUTSOURCING SERVICES

Outsourcing Services is accountable for governing three key outsourcing service agreements with Inergi LP, Capgemini Canada Inc., and BGIS Global Integrated Solutions Canada LP. Outsourcing Services ensures contracted services are delivered and that Hydro One maintains a collaborative working relationship with suppliers. It is also responsible for managing the design, development, and implementation of new service delivery agreements with Hydro One’s outsourcing suppliers (e.g., re-tendering or potential new outsourcing). The services currently outsourced include: information technology applications, infrastructure and projects; payroll; finance and accounting; supply chain; and facilities management. Upon expiry of the agreement with Inergi LP, the services for supply chain will be transitioned to Hydro One to be self-performed effective November 1, 2021, while the back-office finance and accounting work activities will transition effective January 1, 2022. Payroll services will be provided by Ceridian Canada Limited, with whom a new agreement has been signed commencing January 1, 2022.

2.5 GENERAL COUNSEL

Table 9 presents the details of Hydro One's total General Counsel costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 9 - Summary of Allocated General Counsel Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission	**5.0**	**4.3**	**5.2**	**4.5**	**4.7**	**4.8**
Change Year over Year		-13.2%	20.5%	-12.9%	4.1%	1.8%
Allocated to Distribution	**3.2**	**3.4**	**4.2**	**3.9**	**4.0**	**4.1**
Change Year over Year		7.1%	23.0%	-8.3%	4.1%	1.8%
Allocated to Other	**1.5**	**1.3**	**1.4**	**0.9**	**1.0**	**1.0**
Total	**9.6**	**9.0**	**10.8**	**9.3**	**9.7**	**9.9**

Total actuals allocated to the transmission and distribution businesses for General Counsel have remained relatively constant across historical years. After accounting for inflation, total spend in the 2023 test year for General Counsel is less than 2018 actuals, showing the ability to manage spend growth at or below inflation.

The Law Department and Corporate Secretariat departments make up the General Counsel office at Hydro One, while the Chief Legal Officer and Corporate Secretary are specifically included in the Corporate Management costs in Table 4, above. The Law Department provides solutions-focused legal services and strategic advice to Hydro One and its affiliates, while the Corporate Secretariat group provides overall guidance in the areas of corporate structure, governance, business ethics, and the Hydro One Code of Business Conduct.

The UMS Group report has benchmarked Hydro One's legal costs at slightly below the first quartile compared to its peer group. Further details can be found in Attachment 1 to this exhibit.

The Law Department performs the following primary functions:

- Provides legal services relating to all of Hydro One's activities, including the Company's major borrowing and financing initiatives, regulatory matters, mergers and acquisitions, litigation, transmission and distribution operations, employer-related activities and health, safety and environment activities.

The Corporate Secretariat group performs the following primary functions:

- Provides corporate secretariat services, which includes supporting the Chair of the Board of Directors, the Board of Directors and its committees, and advises on a variety of board-related matters, such as best practices and emerging trends and issues in the area of corporate governance; and
- Provides advice and direction with regard to Hydro One's Code of Business Conduct (Code) and deals with the review and amendment of the Code and all issues relating to it, such as inquiries, complaints and investigations made under the Code.

The level of required legal and corporate secretariat services is driven by capital and OM&A activities and business, regulatory and legislative requirements, all of which may increase or become more onerous from time to time. Most of the legal work is performed in-house. External legal services are retained when in-house expertise is not available or when the workload exceeds the capacity of the internal legal group.

2.6 REGULATORY AFFAIRS

The Regulatory Affairs Department is charged with developing effective regulatory filings (rates; mergers acquisitions and divestitures; leaves-to-construct; service area amendments; load transfers, etc.), and any motions to review or appeals on decisions, as well as preparing load forecasts in support of investments and rate applications. The Regulatory Affairs staff prepare witnesses across the Company for rate adjudications and build and maintain relationships with senior members at the regulators and similar bodies including Ontario Energy Board (the OEB), Canada Energy Regulator (CER), and Independent Electricity System Operator (IESO) and other stakeholders.

The Regulatory Affairs Department also manages the Company's compliance with reliability standards set by bodies such as the Independent Electricity System Operator (IESO) and the North American Electric Reliability Corporation (NERC). This Department's mandate also includes developing effective processes and proactively monitoring and reporting regulatory compliance in Ontario, and national and internal regulatory requirements related to reliability standards and critical infrastructure protection.

Table 10 presents the details of Hydro One's total Regulatory Affairs costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 10 - Summary of Allocated Regulatory Affairs Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission						
Regulatory Affairs	5.2	3.7	5.0	6.5	7.3	6.3
OEB / Other Costs	4.0	5.3	4.6	4.1	4.3	4.3
Total	**9.2**	**9.0**	**9.6**	**10.6**	**11.6**	**10.6**
Change Year over Year		**-2.8%**	**7.1%**	**10.2%**	**9.4%**	**-8.6%**
Allocated to Distribution						
Regulatory Affairs	5.1	5.0	5.3	4.2	4.6	3.9
OEB / Other Costs	5.7	5.7	5.8	6.2	6.5	6.4
Total	**10.8**	**10.7**	**11.2**	**10.3**	**11.0**	**10.3**
Change Year over Year		**-1.2%**	**4.5%**	**-7.4%**	**6.7%**	**-6.3%**
Allocated to Other	**0.6**	**0.5**	**0.6**	**0.6**	**0.7**	**0.6**
Total	**20.6**	**20.2**	**21.4**	**21.5**	**23.3**	**21.5**

The UMS Group report has benchmarked Hydro One's Regulatory Affairs costs at the median compared to its peer group (details are in Attachment 1 to this exhibit). Increases in Regulatory

Affairs' costs from 2020 through the 2022 bridge year are owing to work on Hydro One's joint rate application. The 2023 test year brings a reduction to total costs, such that, after accounting for inflation, total spend in the 2023 test year is less than 2018 actuals, showing the ability to manage spend growth at or below inflation.

The Regulatory Affairs division performs a number of distinct functions, which are described in this section.

2.6.1 COMPLIANCE

The Compliance function manages Hydro One's compliance with the regulations and policies of the OEB, the IESO, and the CER as they apply to Hydro One's distribution and transmission businesses and its subsidiaries.

The Reliability Standards and Compliance Assurance group reports on the implementation and demonstration to the IESO of compliance with primarily NERC-based reliability standards and Critical infrastructure Protection. The Regulatory Compliance group monitors and advises on implementation of initiatives relating primarily to OEB Codes. The Regulatory Research and Administration group also manages the filing of applications and information with Regulatory bodies, such as the Reporting and Record-keeping Requirements (RRR) of the OEB.

2.6.2 APPLICATIONS

The Applications function manages regulatory applications and provides support to witnesses and support in regulatory proceedings. These services are provided for a range of regulatory applications, including distribution rates and transmission revenue requirement applications, transmission leave–to-construct applications, and applications related to mergers, acquisitions, amalgamations, divestitures, and area and system supply planning.

2.6.3 PRICING AND LOAD FORECASTING

The pricing function provides pricing and cost allocation analysis and support for rate applications. This work entails developing rates for transmission and distribution tariffs and supporting the preparation and defense of rate proposals. The function also assists with the implementation of approved transmission and distribution rates.

The load forecasting function provides load forecasts to enable system planning and financial planning which underpin Hydro One's financial forecasts. The function provides load forecast data including the capture of conservation and demand management impacts, and embedded generation. This function also provides analytical support and load research analysis for a number of the Company’s business units.

2.6.4 OEB / OTHER COSTS

OEB/Other costs include the external costs associated with applications filed with regulatory bodies. Specifically, these costs stem from the provision of notice, stakeholder and consultation activities, provision of expert studies and witnesses, hearing-related expenses, intervenor cost awards, and miscellaneous items. Over the 2023-2027 period, Hydro One anticipates filing one major revenue requirement application for Distribution and Transmission, several facility applications, filings related to real estate and regional planning efforts and several smaller regulatory applications (B2M, NRLP, HOSSM, Remotes).

The OEB/Other costs also include Hydro One’s share of the OEB’s costs, including expenses related to the OEB’s quarterly assessments, proceedings and intervenor cost awards, and regulatory license assessments. Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered from the IESO and Ontario Power Generation and from licensing fees and penalties. OEB costs that are subject to recovery include expenses related to staff, office space, administration and overheads. Hydro One's share of these OEB costs is derived from the allocations to electricity distribution and transmission.

2.7 SECURITY MANAGEMENT

Table 11 presents the details of Hydro One's total Security Management costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 11 - Summary of Allocated Security Management Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission	**2.9**	**2.1**	**1.6**	**2.6**	**3.0**	**3.1**
Change Year over Year		-27.1%	-22.3%	58.9%	16.2%	3.1%
Allocated to Distribution	**2.3**	**1.7**	**1.4**	**2.2**	**2.6**	**2.6**
Change Year over Year		-26.2%	-19.9%	62.2%	16.2%	3.1%
Allocated to Other	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Total	**5.2**	**3.9**	**3.1**	**4.9**	**5.7**	**5.9**

The increase in the Security Management function's costs for the 2018-2023 time period is materially within inflation. The bridge and test year forecast shows increases from 2020 levels in order to fund additional staffing to meet Hydro One's security requirements which are outlined below.

The Security Management function encompasses Cyber Security, Personnel & Physical Security, and NERC Compliance. The primary mandate of the function includes the protection of personnel, property, Information Technology (IT) Systems and information, as well as the development and maintenance of cyber and physical incident response and recovery plans. Security Management establishes security standards for the enterprise, operating a cyber-operations security function that work across the company to provide advice, coordination and solutions to achieve security standards. This ultimately supports the reliable delivery of electricity, the protection of Hydro One's assets, and the continuity or recovery of business functions in the event of a cyber or physical security incident.

The Security Management program is continuously enhanced with new capabilities that are required to meet the following requirements:

- To remain appropriately positioned against an evolving threat landscape that is increasing in complexity and sophistication. This requires Hydro One to augment and deploy new protective technologies and processes to safeguard assets;
- To meet increasing regulatory and legislative requirements, which in turn, drive the need for additional security capabilities and compliance requirements;
- To meet the increasing expectations of customers and stakeholders that entrust Hydro One to safeguard their sensitive information; and
- To manage the risks associated with third party software integrity, vendor personnel security management and third party connectivity into Hydro One's systems.

2.8 INTERNAL AUDIT

Table 12 presents the details of Hydro One's total Internal Audit costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 12 - Summary of Allocated Internal Audit Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission	**3.0**	**2.9**	**2.4**	**3.0**	**3.2**	**3.3**
Change Year over Year		-4.3%	-16.3%	24.1%	5.9%	5.2%
Allocated to Distribution	**2.3**	**2.6**	**2.1**	**3.0**	**3.2**	**3.4**
Change Year over Year		14.3%	-19.8%	45.7%	5.9%	5.1%
Allocated to Other	**0.3**	**0.2**	**0.2**	**0.0**	**0.0**	**0.0**
Total	**5.6**	**5.6**	**4.7**	**6.0**	**6.4**	**6.7**

The increase in the costs from 2018 through 2021 are materially within inflation. The bridge and test year forecasts show increases to support transformational initiatives, such as the HR Pay Project and the insourcing of processes from Inergi LP.

The UMS Group report includes Hydro One's Internal Audit costs as part of Finance, which has been benchmarked at the median compared to its peer group (details are in Attachment 1 to this exhibit).

Internal Audit Services supports Hydro One in achieving its strategic objectives and mission of energizing life for the people and communities of Ontario by employing a systematic, disciplined, and risk-based approach to evaluate and improve the effectiveness of governance, risk management, and internal control processes. The Internal Audit group reports on a functional basis to the Audit Committee of the Board of Directors and administratively to the CFO. It provides independent and objective assurance and consulting services designed to add value by improving Hydro One's processes and controls, and supporting operations. The group's mandate is to provide independent assurance to management of the Company and to the Board of Directors that internal controls are designed and operating effectively in areas of material business risk, both financial and non-financial, and to follow-up and report on timeliness and effectiveness of management actions to address findings from past audits.

2.9 FACILITIES AND REAL ESTATE

Table 13 presents the details of Hydro One's total Facilities and Real Estate costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 13 - Summary of Allocated Facilities and Real Estate Costs ($M)

	Historical				Bridge	Test
Description	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Allocated to Transmission						
Real Estate	7.4	8.6	9.1	7.9	8.4	8.7
Facilities	25.3	26.0	25.3	28.3	28.9	30.0
Total	**32.7**	**34.7**	**34.3**	**36.2**	**37.3**	**38.7**
Change Year over Year		6.1%	-1.0%	5.4%	2.9%	3.8%
Allocated to Distribution						
Real Estate	1.2	1.4	1.0	1.2	1.3	1.3
Facilities	24.0	24.7	24.2	27.8	28.4	29.5
Total	**25.2**	**26.1**	**25.2**	**29.0**	**29.7**	**30.8**
Change Year over Year		3.6%	-3.4%	15.1%	2.3%	3.8%
Allocated to Other	**0.0**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**
Total	**57.9**	**60.9**	**59.6**	**65.3**	**67.0**	**69.5**

The UMS Group report has benchmarked Hydro One's Real Estate costs below the first quartile compared to its peer group. Further details can be found in Attachment 1 to this exhibit.

Hydro One's Facilities and Real Estate OM&A spend has remained within or below inflationary levels from 2018-2020. There is a noted increase in costs from 2021 to the 2023 test year as a result of incremental expenses required for the facilities work program, which responds to current and future anticipated buildings and work space accommodation needs. The increased costs are related to lease renewals and to fixed operating costs for new facilities, including the Integrated System Operating Centre (ISOC), Woodstock Operation Centre, Woodstock Field Business Centre and Customer Contact Centre, and Dunville Operation Centre.

2.9.1 REAL ESTATE SERVICES

The Real Estate function is responsible for acquiring, managing and disposing of real estate rights to meet Hydro One's operating, administrative and other business requirements in a manner that is fair, transparent, efficient and cost effective.

Real Estate’s key work activities include:

- Acquisition of new real estate rights, which support the Company’s transmission and distribution system development and reinforcement project initiatives across the province ensuring the safe and reliable operation of the transmission and distribution system;
- Management and administration of Hydro One’s land rights portfolio of over 200,000 acres of owned, easement and statutory easement transmission corridors and transmission and distribution station lands and other properties;
- Management of the Provincial Secondary Land Use Program (PSLUP) which allows for third-party occupations within Hydro One-owned lands and provincially owned transmission corridors. The program is comprised of more than 1,400 licences, and Real Estate provides the front-line delivery service for third party proposals of new licenses, easements and sales, working with Infrastructure Ontario on behalf of the Ministry of Government and Consumer Services. This work is done in support of external revenues, which are applied as a reduction when determining Hydro One’s rates revenue requirement. Transmission External Revenues are further described in Exhibit D-02-01;
- Management and payment for recurring real estate rights of more than $7M annually (e.g., licenses, permits, leases);
- Management of transmission rights within 24 First Nation Reserves, including acquisition and annual rental rights payments;
- Management of approximately 400,000 unregistered, low-voltage, real estate rights agreements;
- Provision of specialized real estate service activities including management and payment of annual property tax obligations to municipalities; and,
- Maintenance of property records in the Geographic Information System (GIS).

More specific support is provided on an ad-hoc basis. This includes provision of land ownership information, damage claim settlement, road access, and other rights acquisitions. Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on lands/buildings, and employee relocation services as required.

2.9.2 FACILITIES

The Facilities work program addresses all aspects of Company work space and building requirements. This involves managing Company-owned facilities and a portfolio of leased facilities as well as overseeing the construction of new facilities. The work program focuses on ensuring compliance with laws and applicable codes, for example: (a) employee workspace at sites across the province including head office, administrative and service centres, the Ontario Grid Control Center (OGCC), the Integrated System Operating Centre (ISOC), and other work locations, such as the Customer Contact Centre; and (b) storage and garage facilities that meet business requirements.

The Facilities function is accountable for:

- The Management of approximately 45 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses, and taxes;
- Coordination of activities related to the ongoing management, operation, maintenance, and inspection of approximately 400 buildings across 135 operational facilities (including administrative/service centres, OGCC, ISOC), plus an additional 1,000 network buildings (houses power system-related network equipment) across 352 transmission and 1029 distribution sites;
- Managing support services for head office, such as the provision of office supplies, coordinating office moves, and providing tenant services; and
- Developing accommodation strategies and acquiring new employee/trades workspace in line with operational requirements.

Facilities expenses include, but are not limited to, leasing costs, contract management costs for head office, as well as costs for administrative facilities, service centres, and other work locations. A significant portion of the workload needs are met by engaging the strategic outsourcing partners, such as BGIS, as described in Exhibit E-05-01. Facilities costs are largely driven by space needs which are determined by Hydro One's work programs, business and regulatory requirements, and fixed cost related to contractual obligations.

The majority of the Facilities work program costs are fixed in nature. The Facilities work program is driven by fixed-cost contractual obligations, which arise primarily through lease agreements. For example, rent, operating and tax costs are fixed by lease agreements. Other costs are set by Hydro One's contracts with service providers for facility maintenance and other services. It is expected that fixed facility cost components (such as utilities, property taxes, operational costs) will continue to rise.

3.0 OTHER OM&A

Other OM&A is comprised of credits (offsets to OM&A) associated with capitalized overhead, environmental provision, and indirect depreciation, as well as the non-service cost component of OPEB and other costs. These are listed in Table 14.

Table 14 - Summary of Allocated Other OM&A ($M)

Description	Historical 2018 Actual	2019 Actual	2020 Actual	2021 Actual	Bridge 2022 Forecast	Test 2023 Forecast
Allocated to Transmission						
Capitalized Overhead	-124.5	-114.6	-115.3	-115.6	-120.4	-118.1
Non-Service Costs Component of OPEB	-	-	22.0	16.2	17.3	17.0
Environmental Provision	-6.8	-5.6	-7.7	-15.5	-16.2	-7.6
Indirect Depreciation	-5.1	-5.2	-6.2	-6.4	-6.1	-6.2
Other	9.0	-20.2	4.8	-0.8	-1.4	-3.7
Total	**-127.4**	**-145.6**	**-102.3**	**-122.1**	**-126.8**	**-118.7**
Change Year over Year		14.3%	-29.8%	19.4%	3.9%	-6.4%
Allocated to Distribution						
Capitalized Overhead	-77.0	-81.5	-84.4	-88.8	-90.7	-89.9
Non-Service Costs Component of OPEB	-	-	-	-	-	20.1
Environmental Provision	-14.4	-15.5	-14.3	-13.4	-12.9	-5.5
Indirect Depreciation	-13.9	-14.1	-15.1	-15.7	-14.9	-15.2
Other	10.3	0.7	20.5	0.6	-2.1	6.1
Total	**-95.1**	**-110.5**	**-93.4**	**-117.3**	**-120.6**	**-84.3**
Change Year over Year		16.2%	-15.5%	25.6%	2.8%	-30.1%
Allocated to Other	**-**	**-**	**-**	**-**	**-**	**-**
Total	**-222.5**	**-256.1**	**-195.6**	**-239.4**	**-247.4**	**-203.0**

3.1 CAPITALIZED OVERHEAD CREDIT

Capitalized overheads represent the portion of allocated Common Corporate and/or business unit functions and services that support capital work. These costs are included in Common Corporate services and the budgets of other lines of business. OM&A expenses are thus reduced by the capitalized amounts.

Capitalized overhead costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization study performed by Black & Veatch, as described in Exhibit C-08-02. Generally speaking, all else equal as the capital work program increases, more overheads are capitalized and less are expensed as OM&A. The change in OM&A in the test year in relation to the change in capitalized overhead costs for Transmission and Distribution is shown in Table 14 above, and Appendix 2-D at Attachment 1 of Exhibit C-08-02.

3.2 NON-SERVICE COST COMPONENT OF OPEB

Non-service cost component of OPEB reflects the impact on OM&A of implementing the OEB's decision in the 2020-2022 Transmission application. The increase to Distribution OM&A begins in the 2023 test year as the decision occurred during the current 2018-2022 distribution rate period.

3.3 ENVIRONMENTAL PROVISION

In 2001, Hydro One first recognized a liability on its balance sheet for the present value of the future estimated environmental expenditures needed to manage the risks associated with two legacy environmental issues inherited from Ontario Hydro. These risks pertained to polychlorinated biphenyls (PCB) and two chemically contaminated lands, also known as land assessment remediation (LAR). Since then, Hydro One has continued to update this liability based on environmental statutes or regulations issued by the Canadian government for PCBs, and environmental site assessments performed for LARs. In determining the amounts to be recorded as environmental liabilities, Hydro One estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information.

Future expenditures are required to inspect, test and remediate the contamination. Environmental work is initially recognized in the Sustainment OM&A work program and is detailed in Exhibit E-02-02 for Transmission, and in Exhibit E-03-02 for Distribution. The amount is then removed from OM&A as the costs are charged to the balance sheet provision. The offsetting environmental regulatory asset is amortized based on the pattern of expenditure. Refer to Exhibit D-01-01 for the proposed treatment of future expenditures in revenue requirement for 2023-2027 related to these expenditures.

PCB remediation work is required to be completed by December 31, 2025, as per federal PCB regulations. The reduction of the environmental provision credit from 2022 to 2023 in both Transmission and Distribution reflects the fulfillment of remediation work from prior years, and the re-forecasting of the remaining obligation.

3.4 INDIRECT DEPRECIATION

Transportation and Work Equipment (TWE) charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes, it is necessary to remove this depreciation amount from OM&A work programs and appropriately charge it as a depreciation expense. This credit is relatively flat year over year.

3.5 OTHER COSTS

These costs represent unexpected or non-recurring expenses, such as adjustments to provisions, vacation reserves, Gregorian or fiscal calendar adjustments, and inventory adjustments. Costs are relatively flat throughout the period, with larger OM&A increases seen in 2018 mainly due to project write-offs, and in 2020 due to incremental costs associated with COVID-19.

Final Report

Hydro One Networks Inc.
Common Corporate Costs Benchmarking Study

Prepared for

Torys LLP

Submitted by

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EXECUTIVE SUMMARY

In the Ontario Energy Board's (OEB's) March 7, 2019 decision in the matter of Hydro One's Distribution Rates for 2018 to 2022 (EB-2017-0049), the OEB directed Hydro One to continue its current benchmarking efforts for key programs, including vegetation management, pole replacement, station refurbishment and IT. Additionally, the decision stated that the OEB expects Hydro One to expand its benchmarking to include administrative functions such as billing, call centre and corporate costs.

To that end, Torys LLP ("Torys"), acting on behalf of Hydro One Networks Inc. ("HONI"), engaged UMS Group to benchmark Hydro One's corporate costs that are centralized and shared between its Transmission and Distribution businesses, as well as each of its affiliates.

This report discusses the approach used in executing the benchmarking including the metrics chosen, the selection of the comparator group utilities, and the collection and analysis of data used for the benchmarking. This Study presents and interprets the benchmarking data from Hydro One and the Comparator Group. It also provides insights into the relative level of Hydro One's common corporate costs by function, and where appropriate, discusses potential drivers of cost differences. The overall finding from the benchmark is that Hydro One's common corporate costs are very competitive with the Comparator Group. Of the 9 functions benchmarked, 5 are at or near 1st Quartile levels and 4 are at or near Median levels.

SECTION I - INTRODUCTION

In the OEB's March 7, 2019 decision in the matter of Hydro One's Distribution Rates for 2018 to 2022 (EB-2017-0049), the OEB directed Hydro One to continue its current benchmarking efforts for key programs, including vegetation management, pole replacement, station refurbishment and IT. Additionally, the decision stated that the OEB expects Hydro One to expand its benchmarking to include administrative functions such as billing, call centre and corporate costs.

Objective

The objective of the Study was to measure and assess Hydro One's common corporate costs in relation to an appropriate comparator group of utilities. As such, the Study was undertaken using the following parameters:

- Determine the type of information to be gathered and the type of utilities that should be used for comparison purposes.
- Perform analysis to identify an appropriate group of utilities to compare Hydro One's common corporate costs against.
- Determine the appropriate normalization measures for each metric.
- Ensure a common understanding of the identified costs across the comparators by defining the costs uniformly.
- Measure and assess Hydro One's common corporate costs in relation to the benchmarked utilities.

Approach

UMS Group implemented the following Project Approach to benchmark Hydro One's 2019 Common Corporate Costs, evaluate them against the costs of the comparator utilities, and understand the key drivers of variances. 2019 costs were used as they were the most recent set of full year actual costs available. The benchmark itself was purely quantitative with minimal adjustments made to Hydro One or Comparator cost data. Analysis and explanation of variances was focused on better understanding the likely factors driving quantitative differences. In order to select a comparator group, the UMS team identified companies which were operationally similar to Hydro One in terms of size, structure, and service territory from both Canada and the U.S.

The project made use of and leveraged existing UMS data from its ongoing Global Learning Consortia, multi-client benchmarking and best practice studies, and client-sponsored targeted benchmarking studies. In addition, data was collected from comparator utilities as needed to supplement and update the UMS benchmarking database. The cost components of each common corporate cost function and the comparator group members were reviewed and confirmed with Torys and Hydro One.

Report Outline

The ensuing Report is divided into several sections as described below:

- Section I – Introduction: A high-level description of the objective and approach for the Study.
- Section II – Project Approach: A description of the process and rationale for scope determination, data collection, normalization of data, and comparator group selection.
- Section III – Study Results: A discussion of findings and conclusions around the common corporate cost functions benchmarked.
- Appendix A: A description of UMS Group's Qualifications.

SECTION II – PROJECT APPROACH

UMS Group used elements of its proprietary and time-tested approach in order to independently benchmark Hydro One's common corporate costs. This approach is designed to produce a transparent benchmark, present a relevant comparison between utilities, use normalisation factors that are pertinent to each cost category, and select a comparator group which minimizes the need for adjustments to cost data.

There were a number of steps undertaken to execute the benchmarking Study:

1. Determine the Scope of the Study.
2. Define the desired characteristics of the comparator group.
3. Define appropriate normalisation factors for each function or service.
4. Review the design with stakeholders in order to answer questions.
5. Collect, validate, and normalise data to perform the benchmark.
6. Evaluate results and identify any need for further validation with comparator group members.

The following discussion expounds on these aspects of the approach and describes how they contributed to achieving an objective and relevant benchmark.

Scope Determination

One of the initial activities in the Study was to submit a data request for functional descriptions of Hydro One's major activities, roles, and responsibilities for each function with common corporate costs. In addition, cost component breakdowns for each relevant function were requested in order to understand how costs were grouped.

Following the receipt of this information, a series of phone interviews was held with Hydro One personnel to discuss the cost components of the various functions to be benchmarked and ensure that the composition of those costs was understood.

Comparator Selection

In order to execute the benchmarking, a comparator group of Canadian and U.S. utilities was developed focused on those who had both Transmission and Distribution, were of comparable size as Hydro One, and/or had a more rural territory in terms of distribution customers per square kilometre. To ensure an adequate number of comparators, utilities were also included for which UMS already had recent common corporate cost data and were viewed as reasonably comparable.

Finally, other Ontario utilities were included in the target comparator group even though they only have Distribution and are municipally owned. While they are not necessarily considered good comparators for all common corporate functions, it was viewed as important to include some local utilities which operate under similar legal and regulatory conditions.

An initial list of 22 potential comparators were approached to participate in the Study. From these, 16 agreed to participate, although 4 were unable to provide sufficient data to enable a comparison. The resulting comparator group represents a reasonable and acceptable comparison group for Hydro One.

Table 1: Comparator Group

AES	Oklahoma Gas & Electric
ATCO	PG&E
El Paso Electric	PSE&G
EPCOR	Sask Power
Hydro Ottawa[1]	SDG&E
Manitoba Hydro	Southern California Edison
NV Energy	Toronto Hydro[1]

[1] While these utilities declined to participate, benchmarks were developed based on data from their recent distribution rate filings for comparison purposes.

Normalization Factor Development

As costs are driven by the size and scale of utility operations, any benchmark comparison needs to account for the inevitable difference between the utilities in the comparator group. Therefore, in order to compare costs across utilities, it is necessary to adjust or "normalise" the costs to put them on a common basis. As the different functions benchmarked have different cost drivers, normalisation factors were selected which are correlated with the relevant costs either as direct drivers or as representative of the key drivers. For example, Corporate Management costs tend to be driven by the size and complexity of the utility, so Revenue was selected as a representative measure (or proxy) for these factors. Table 2 below summarizes the normalization factors for each function.

Table 2: Normalisation Factors

Function	Normaliser	Reason for Normaliser Selection
Corporate Management	Revenue	Costs are typically driven by size and complexity for which revenue is a proxy.
Finance	Revenue	Costs are typically driven by the amount of financial activity for which revenue is a proxy.
Real Estate	Employees	Costs are typically driven by quantity of facility and land assets for which number of employees is a proxy.

Human Resources	Employees	Costs are typically driven by the number of employees.
Legal	Revenue	Costs are typically driven by size and complexity for which revenue is a proxy.
Regulatory Affairs	Revenue	Costs are typically driven by size, complexity, and regulatory environment for which revenue is a proxy.
Asset Management Planning	Net Asset Base	Costs are typically driven by size of the asset base.
Corporate Affairs	Customers	Costs are typically driven by the amount of customer outreach for which number of customers is a proxy.
System Operations	Circuit Kilometres	Cost differences are typically driven by the amount of circuits.

Design Review

Once the Scope Determination, Comparator Selection, and Normalisation Factor Development was completed, a review session was held with Torys and Hydro One to answer questions and receive feedback on the design in order to ensure the benchmarking would produce comparable results. This session was focused on ensuring clarity around the decisions made in the design and was not an opportunity for Torys and Hydro One to modify the design to suit their needs.

Data Collection and Validation

A data collection template was created to assist both Hydro One and the Comparator utilities in providing data. This data comprised both demographic and cost data.

Table 3: Demographic Data Collected

Number of Distribution Customers
Number of Employees
Annual Revenue
T&D Asset Base (net)
T&D Circuit Kilometres (or Miles)

Table 4: Cost Information Collected

Corporate Management Costs	Legal Costs
Finance Costs	Regulatory Affairs Costs
Real Estate Costs	Asset Management Planning Costs
Human Resources Costs	Corporate Affairs Costs
System Operations Costs	

For Hydro One, the costs benchmarked reflect the common corporate costs for each respective function. However, the same may not be true for all of the comparator group utilities as the costs for some of these functions may be spread between different lines of business. In these cases, comparable costs were collected regardless of where in the organization they occurred.

For Hydro One and each comparator utility, the cost data was collected along with the demographic data for the normalisers. For U.S. companies, costs were converted to CAD at an exchange rate of USD:CAD = 1.327 (the average exchange rate in effect in 2019 per U.S. Internal Revenue Service) and miles were converted to kilometres. If comments submitted by comparators indicated that non-typical costs were included in a function, UMS requested that these non-typical costs be removed and the utility's benchmark submission be revised appropriately. Where necessary, costs were moved between functions within individual comparator utilities to align with the group as a whole, based on where most utilities collected those costs.

There were several cost "buckets" that needed to be moved for Hydro One (and some comparator utilities if appropriate) in order to align costs across functions. These were as follows:

- Strategy and Innovation costs were moved from Asset Management Planning to Corporate Management.
- CFO's Office costs were moved from Finance to Corporate Management.
- HR Pay Service costs were moved from Finance to Human Resources.
- Regulator assessments for fees and allocated costs were removed from Regulatory Affairs costs for all utilities which included them.
- Indigenous Relations costs were included in Corporate Affairs.
- Real Estate costs were removed from Finance and benchmarked separately.
- Property Insurance for Equipment (e.g., Transformers) common corporate costs were removed from all utilities' costs.

Not all of the comparator utilities provided data for all of the functions. In those circumstances where a utility did not, this was because it did not operate that function as a common corporate service and was unable to adequately collect the relevant costs from the different functions in which they were incurred to provide a set of comparable costs. For example, Asset Management Planning costs were only submitted by 10 of the comparator utilities. The utilities which did not submit costs, typically did not have a central asset management organization and have asset management planning-related functions throughout the utility making cost aggregation difficult.

SECTION III – STUDY RESULTS

Overall, the Hydro One common corporate costs benchmarked compare well to the comparator group. Hydro One is at or near 1st quartile levels for 5 functions and median levels for 4 functions.

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.

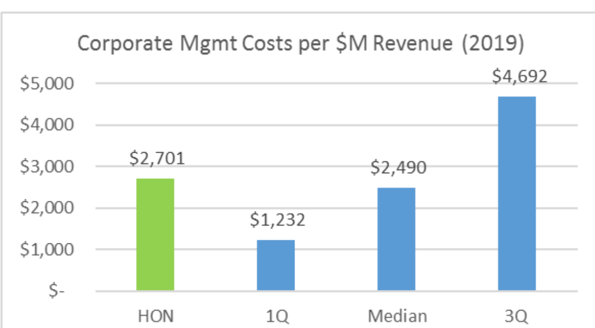
Table 5: Summary of Benchmark Results (2019 Costs)

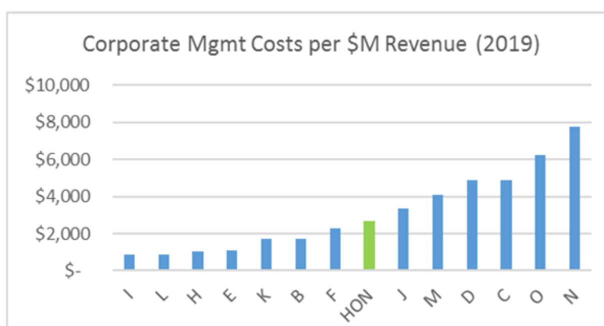
Function	Normaliser	Hydro One	1st Quartile	Median	3rd Quartile
Corporate Management	$M of Revenue	$2,701	$1,232	$2,490	$4,692
Finance	$M of Revenue	$5,777	$4,472	$5,777	$8,371
Real Estate	# of Employees	$1,150	$1,205	$1,983	$3,630
Human Resources	# of Employees	$2,612	$2,601	$3,226	$4,538
Legal	$M of Revenue	$2,048	$2,170	$2,848	$3,649
Regulatory Affairs	$M of Revenue	$1,695	$1,107	$1,695	$2,088
AM Planning	$M of Net Assets	$1,598	$1,529	$2,749	$5,774
Corporate Affairs	# of Customers	$6.2	$6.0	$9.4	$15.2
System Operations	Circuit kM	$323	$304	$321	$429

Corporate Management

Hydro One's 2019 Corporate Management costs per $million of revenue are slightly above the Median level. While these costs are above the median level, they are pre-allocation and most of the costs are not recovered from ratepayers.

Figure 1: Corporate Management Costs



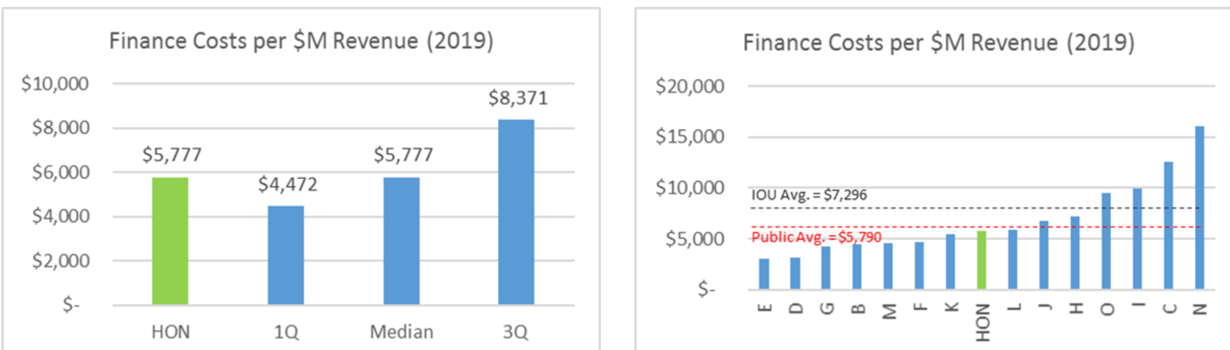


Note: Corporate Management costs include those related to overall company direction, rather than specific company business functions – Board of Directors, Chairman's Office, CEO's Office, President's Office, COO's Office, Strategy and Innovation, Ombudsman's Office, etc.

Finance

Hydro One's Finance costs per $million of revenue are at the Median level. Utilities which are municipally or provincially (i.e., publicly) owned, had lower average normalized cost ($5,790 per $million revenue) than investor-owned utilities ($7,296 per $million revenue). While data was not collected at a detail level to enable determination of the direct cause, a reasonable hypothesis is that this cost difference is due to these utilities avoiding many of the financial regulator (i.e., security commissions) and investor-related costs associated with an investor-owned company. Despite these additional costs, Hydro One's Finance costs are below both the investor-owned and publicly-owned averages.

Figure 2: Finance Costs

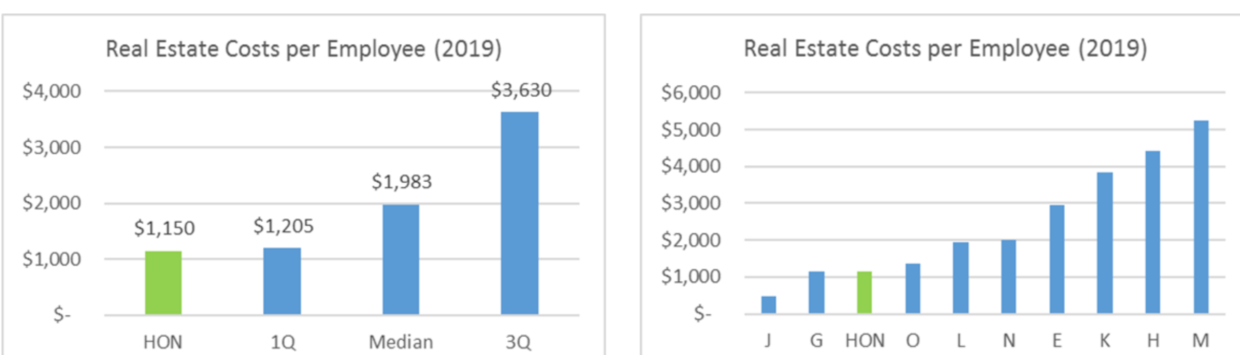


Note: Finance costs are those which provide strategic advice and services related to planning, processing, recording, reporting and monitoring of financial transactions – Controller Services, Treasury, Tax, Audit, Insurance, Business Planning, and Risk Management.

Real Estate

Hydro One's Real Estate costs per Employee are slightly below the 1st Quartile level.

Figure 3: Real Estate Costs

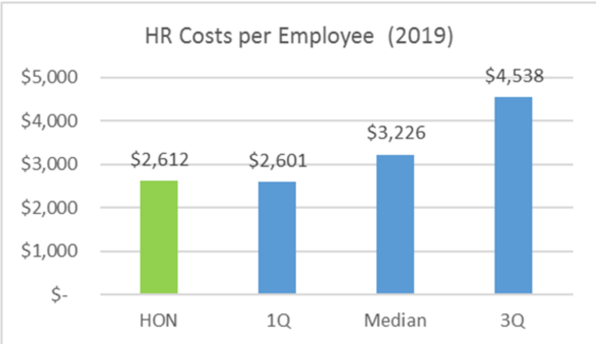


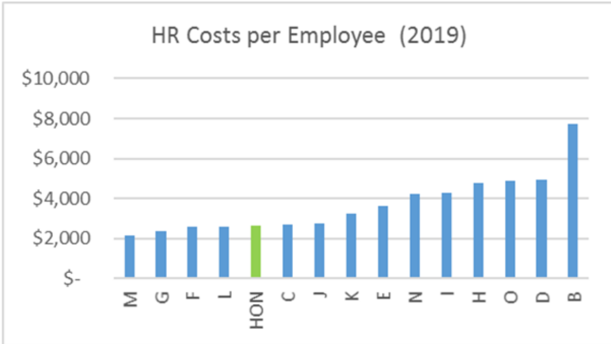
Note: Real Estate costs are those associated with providing functions related to managing land rights and services related to managing property.

Human Resources

Hydro One's Human Resources costs per employee are slightly above the 1st Quartile level.

Figure 4: Human Resources Costs



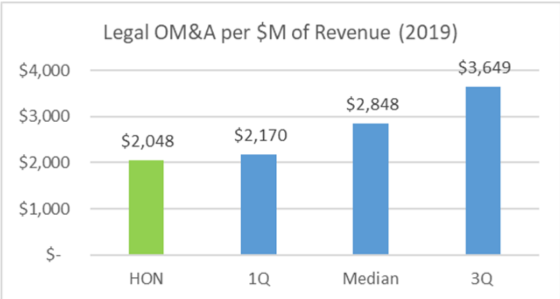


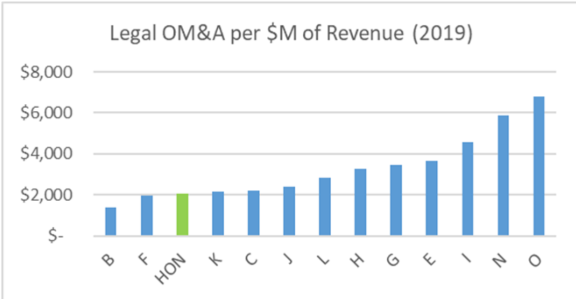
Note: Human Resources costs are those related to the policies, systems, and programs to attract, manage, engage, and retain a workforce to execute business strategy – recruiting and development, HR Services, health and wellness, diversity, employee and labor relations, and payroll management.

Legal

Hydro One's Legal costs per $million of revenue are slightly below the 1st Quartile level.

Figure 5: Legal Costs



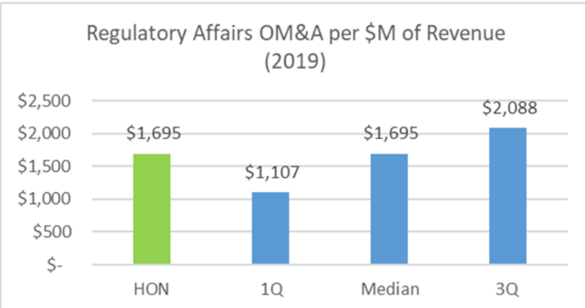


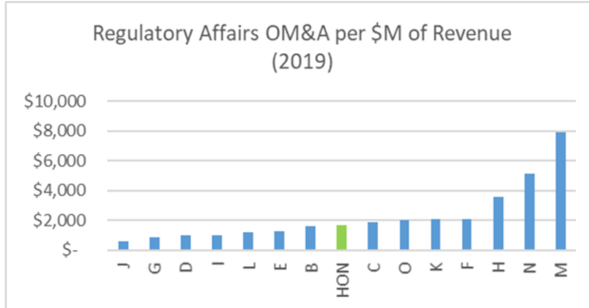
Note: Legal costs are those which ensure compliance with law, provide legal services, and provide corporate secretariat services.

Regulatory Affairs

Hydro One's Regulatory Affairs costs per $million of revenue are at the median level.

Figure 6: Regulatory Affairs Costs



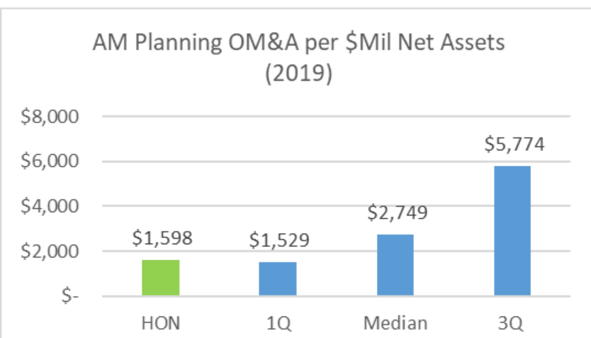


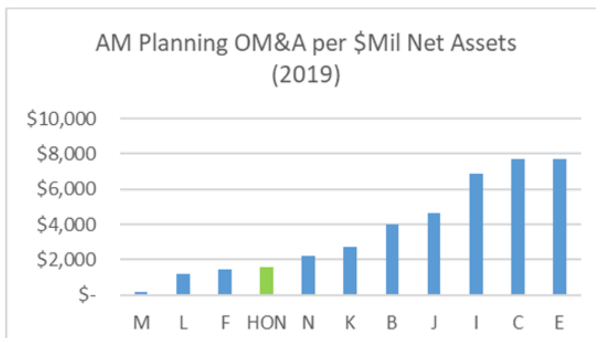
Note: Regulatory Affairs costs are those associated with dealings with regulatory bodies including the utility commission, Federal regulator, etc., as well as development of regulatory strategy and coordination of submissions. User fees or other assessments by Regulators to fund their operations are not included.

Asset Management Planning

Hydro One's Asset Management Planning costs per $million of Net Assets are slightly above the 1st Quartile level.

Figure 7: Asset Management Planning Costs





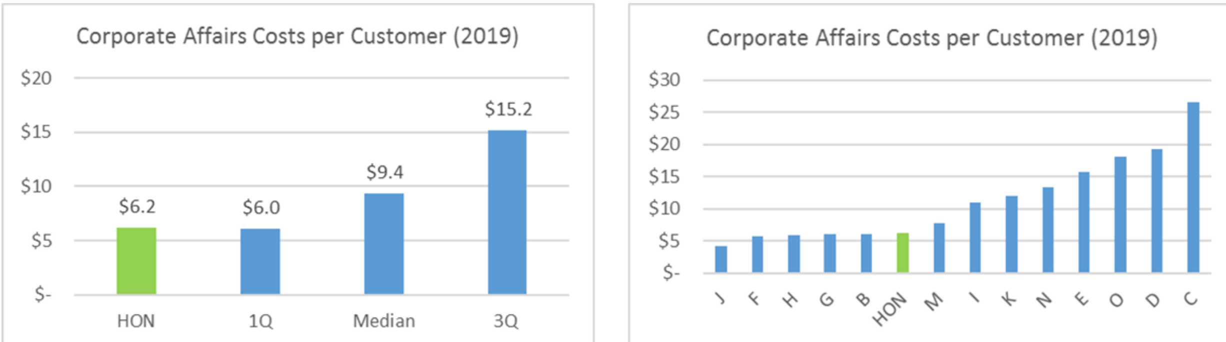
Note: Asset Management Planning costs include those to develop the investment plan, manage investment strategies, scope network expansions and new or modified customer connections, and undertake the asset management of transmission and distribution assets.

Corporate Affairs

Hydro One's Corporate Affairs costs per Customer are slightly above the 1st Quartile level. This performance level is achieved despite the fact that Hydro One has a robust Indigenous Relations function which many of the comparator group members do not. Removing these costs would reduce Hydro One's normalized cost from $6.2 to $4.4 per customer. However, spending on

Indigenous Relations has been identified as a strategic priority by Hydro One to ensure that Indigenous concerns are identified, understood, and addressed.

Figure 8: Corporate Affairs Costs



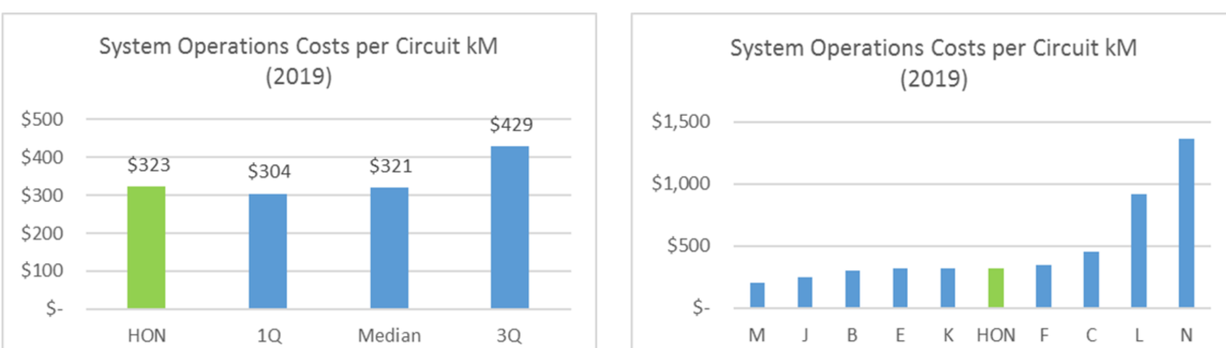
Note: Corporate Affairs costs include those associated with communicating to stakeholders other than Investors – government affairs, public affairs, Indigenous Relations.

System Operations

Hydro One's System Operations costs per $million of revenue are slightly above the Median level. UMS analysis of the cost for Transmission Operations versus the cost for Distribution Operations identified significant differences between these costs. The average Transmission Operations cost per transmission circuit kilometre ($1,422) was approximately 7 times higher than the average Distribution Operations cost per distribution circuit kilometre ($207).

Hydro One has the second highest percentage of Transmission circuit kilometres compared to Total T&D circuit kilometres. At 19%, this is significantly higher than the Comparator Group average of 11%. Therefore, higher than average aggregate System Operations costs would be expected with this higher than average ratio of Transmission circuit kilometres to Total T&D circuit kilometres.

Figure 9: System Operations Costs

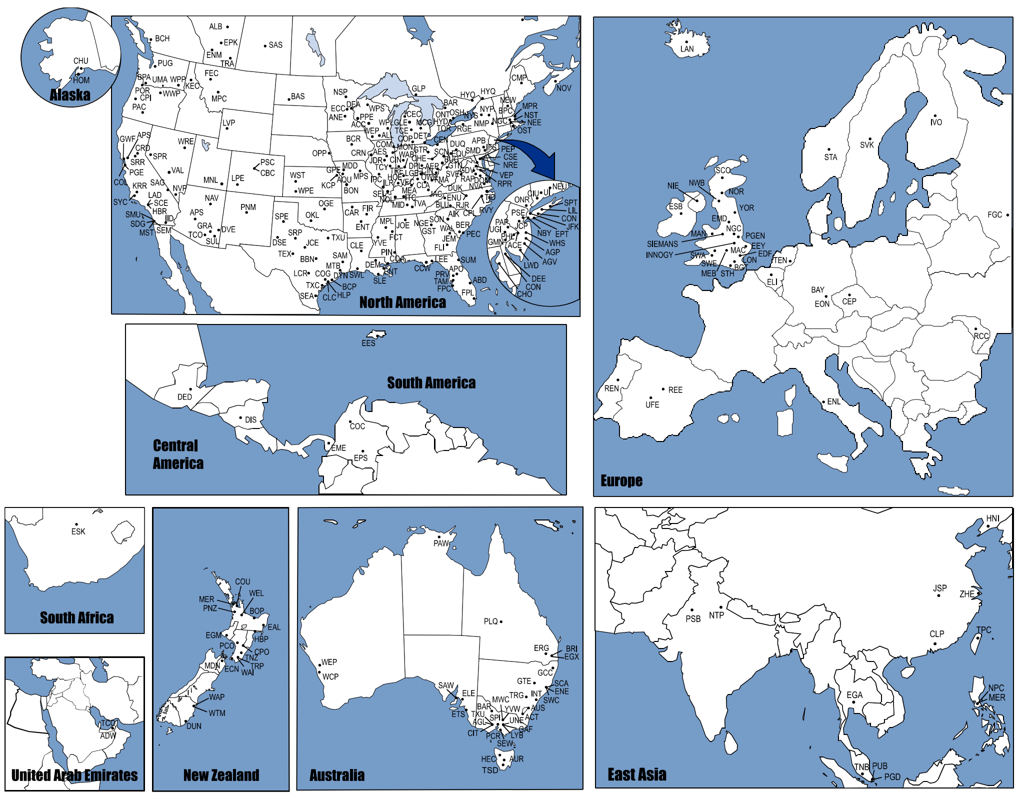


Note: System Operations costs are those associated with supporting the coordination and dispatch of crews as required, planning for and reacting to system contingencies, scheduling and coordinating planned outages, providing customer notifications, and monitoring and reporting on system performance.

APPENDIX A – UMS GROUP QUALIFICATIONS

UMS Group has been a leading provider of utility benchmarking services for 31 years. UMS conducted its first utility benchmark in 1989 and began its first Benchmarking and Best Practice Consortia in 1990 (PACE - Performance And Competitive Excellence).

Since that time, UMS Group has continued to be a global leader in electric industry multi-company assessment and benchmarking studies. The key differentiator in our performance assessment approach is the depth of our understanding of industry best practices to drive operational performance. Our benchmark programs define current best practice productivity and service level performance in all major functional areas. Demonstrating the breadth of our experience, we have performed engagements on *six continents* with more than *300 companies*. A partial map of our clients is presented below:



UMS Group's performance database, developed and maintained over the past 30 years and its UMS Group-facilitated industry consortia of leading Generation, Transmission, and Distribution companies around the world provide significant insights into the drivers of best practices and resulting top quartile service and cost level performance.

Apart from these credentials, UMS has accomplished similar projects with clients in various markets around the world.

Experience Summary of Project Lead - Steven J. Morris

Mr. Morris is a Vice President of UMS Group. He has 32 years of consulting and management experience with the last 25 years spent in the electric and gas utility industries. He has significant expertise in performance improvement, organizational design, strategic planning, asset management, and financial analysis, and has written/edited dozens of analytical reports on utility industry topics.

Mr. Morris is the corporate leader of UMS' Global Learning Consortium solution which provides facilitated research and sharing to assist utilities in understanding industry trends, practices, and benchmarks. He also created and oversees the North American Substation Best Practice Collaborative, a utility-directed community which benchmarks and shares best practices in substation maintenance, construction, and asset management.

Prior to joining UMS, Mr. Morris worked for both Andersen Consulting and Navigant Consulting. He also founded Research Reports International, a business focused on providing data and information on key issues facing the industry to electric and gas utility executives. Mr. Morris holds a B.A. in Economics and an M.B.A., both from Cornell University.

Highlights of Experience

Led the Corporate Services piece of a Productivity Benchmarking and Assessment of a Canadian Distribution System Operator. Led benchmarking of all relevant utility functional areas against a 33 company peer group. Interviewed managers of Corporate Services functions to identify organizational structure and work practices that might offer opportunities for productivity improvement. Developed recommendations for improving efficiency and performance.

Led a project for a Northeastern gas and electric utility to perform an in-depth review of its Training, Fleet, and Warehouse/Logistics functions and make recommendations for improving performance. Benchmarked cost, performance and staffing levels against peers and conducted a study of industry best practices in each area. Researched and surveyed utilities on how they were using technology in each area and where they were achieving the greatest successes.

Led a project for a Northern electric utility to assess to evaluate the effectiveness and efficiency of current staffing practices, work management practices, and asset management/planning processes for Transmission, Distribution, Supply Chain, and Fleet. Performed an on-site review of current operations and specific processes and practices through interviews and field observations. Collected data in a number of performance domains to analyze and compare against industry peers. Facilitated process review workshops in the areas of New Service Orders, Work Management, and Capital Projects. Identified areas where opportunities for improvement in efficiency and/or effectiveness exist. Developed recommendations for capturing the value represented by each opportunity, and identified the relative benefit to be gained through its implementation. Developed a high-level roadmap for implementing the recommendations.

Led several benchmarking projects for Gas Transmission and Gas Distribution for a Canadian Gas Utility. Projects benchmarked financial, safety, environmental, and operational performance against North American peers to understand where the utility currently ranked. Assessed value of existing corporate metrics to drive improvement and suggested new metrics focused on Continuous Improvement.

Led a Cost Efficiency Study for a Canadian Electric Utility. Assessed both Transmission and Distribution business function practices and processes to identify specific opportunities for gaining cost efficiency without negatively impacting performance. Project included documentation review, interviews of Executives and Managers, and field observations with Supervisors and Crews. Also performed benchmarking and analysis of cost and performance to validate findings and identify additional opportunities for savings.

Led a project for an Asian electric utility to identify areas of opportunity in T&D for cost savings and staffing reductions over time, through the adoption of industry best practices. Benchmarked the functional areas against peers to identify where costs and staffing levels were out of alignment with top performers. Conducted interviews and observations to understand performance drivers. Developed specific recommendations around organization structure, staffing levels, and staffing mix to achieve best practice performance levels.

Led several studies of utility accounting of plant investments in order to assist clients in optimizing their allocation of expenditures for major maintenance among capital and O&M accounts. Performed industry surveys of property accounting policies for coal-fired and hydropower generation, as well as for natural gas compression and storage. Identified the factors considered in determining if a cost is capitalized, the specific criteria used (e.g., length, percentage replacement, etc.), and the approach and strategies for managing the decision to capitalize spending. Identified opportunities for clients to revise their property accounting methodology based upon how others are addressing similar work.

COMMON CORPORATE OM&A - PLANNING

1.0 INTRODUCTION

Hydro One plans its Transmission and Distribution businesses using an asset management model. Plans are designed to maintain or replace, as necessary, transmission and distribution assets in a cost-effective manner, so that they function as originally designed, providing safe and reliable service to Hydro One's customers, consistent with the planning process described in SPF Section 1.7.

The total costs associated with the planning function for the historical (2018-2021), bridge (2022) and test (2023) years are shown in Table 1.

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

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Planning	46.8	40.2	39.5	39.0	41.1	42.5
Total	**46.8**	**40.2**	**39.5**	**39.0**	**41.1**	**42.5**
Allocated to Transmission	31.0	26.7	25.3	25.2	26.6	27.4
Allocated to Distribution	15.7	13.5	14.2	13.6	14.4	14.9
Allocated to Other[1]				0.2	0.2	0.2

The 2023 test year costs of $42.5M reflects a $4.3M (9%) reduction relative to 2018 actuals, as a result of cost containment initiatives, and structured staffing strategies, which enabled Planning to manage a generational shift. Relative to historical years in 2019-2021, the 2023 test year is approximately $2.9M higher than the average. In comparison to the bridge year of 2022, the 2023

[1] As discussed in Exhibit E-04-08, the amounts allocated to Other in Table 1 above reflect costs allocated to Hydro One Inc., Hydro One Limited, Hydro One Networks non-regulated segment, Remotes, B2M, NRLP, HOSSM as well as other non-regulated segments.

test year is $1.4M higher. These marginal increases reflect the required upfront support for a growing capital work program, and standard escalation and inflation.

Of these total costs, Table 1 shows the amounts that have been allocated to Hydro One Transmission and Distribution during the same time period, consistent with the common cost allocation model described in Exhibit E-04-08. In accordance with Hydro One's overhead capitalization policy, a portion of these costs are capitalized, as described in Exhibit C-08-02.

Planning's activities are divided into accountabilities and practices which can be specific to the Transmission or Distribution business, or common across both segments. Activities include:

- identifying potential asset and system needs by monitoring equipment condition and reliability performance;
- scoping and developing candidate investments to address asset and customer needs and business requirements, including maintaining asset condition and improving long-term reliability;
- coordinating planning with customers, including responding to customer requests for new or expanded connections and addressing customer concerns regarding reliability or power quality to enable customer growth;
- leading coordinated infrastructure planning through the bulk and regional planning process described in SPF Section 1.2;
- conducting the investment planning process described in SPF Section 1.7;
- developing functional standards to optimize the life-cycle costs of transmission and distribution assets while maintaining system safety and reliability as assets age and deteriorate;
- monitoring asset condition, performance and risk to inform intervention measures, including required maintenance or capital investment;
- development and implementation of transmission and distribution asset maintenance and lifecycle sustainment strategies, including establishment of maintenance cycles,

specification and identification of asset maintenance plans, and formalization of corrective actions to address asset deficiencies;

- identification of approaches required to implement reliability centred and condition based maintenance practices, including identification of annual maintenance plans for scheduling and execution;
- managing the investment development and investment release processes, and engaging with service delivery units to enable the effective execution of specific investments;
- performing analytics, producing reports and conducting special studies in such areas as reliability performance
- obtaining customer feedback regarding potential investments;
- supporting the redirection of funds and re-prioritizing investments in response to unforeseen events and work execution opportunities, and integrating changes into future investment plans;
- interfacing and collaborating with neighbouring utilities, regulatory and planning authorities on matters of planning direction, requirements, policy and guidance;
- leading continuous improvement initiatives to ensure an integrated approach to data, systems, and processes and implementing enhancements to support tools, leading to improved asset management approaches;
- providing expertise on various national and international industry entities, forums and standard-setting bodies including the International Council on Large Electric Systems, the Canadian Electricity Association, Standards Council of Canada, Canadian Standards Association, North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), the Independent Electricity System Operator (IESO), the International Electrotechnical Commission, the Institute of Electrical and Electronics Engineers, the National Institute of Standards and Technology and the North American Transmission Forum;
- overseeing the development, implementation and maintenance of research, development and demonstration initiatives that address operational and strategic challenges in conjunction with industry and research organizations such as the Electric

Power Research Institute and the Centre for Energy Advancement through Technological Innovation; and

- providing technical support to conduct investigations and specialized studies and developing technical solutions for Hydro One stakeholders, such as power system disturbance investigations, short circuit studies, power quality and harmonic assessments, delivery point and system reliability analysis, stray voltage investigations, geomagnetic disturbance research, and reliability performance assessments.

In addition to these activities, Planning staff actively participate in industry and reliability standards development processes in order to monitor and track the status of proposed new and revised standards and guidelines. Planning staff contribute to OEB working groups, including those related to technical and policy issues, such as those address distributed energy resource policy or integrated provincial planning processes. Planning staff also serve as the transmitter representative on the IESO Technical Panel, which reviews and recommends amendments to the Ontario wholesale electricity market rules and advises the IESO board of directors on specific technical issues related to the operation of the Ontario electricity market.

Included in Common Corporate Operations, Maintenance & Administration (OM&A), Hydro One has allocated its share of Planning amounts for property, boiler and machinery insurance. The costs are provided in Table 2.

Table 2 - Property, Boiler and Machinery Insurance ($M)

Description	Historical			Bridge		Test
	2018	2019	2020	2021	2022	2023
Property, Boiler, and Machinery Insurance	6.4	7.1	8.4	8.6	8.9	9.1

2.0 TEST YEAR AND VARIANCE EXPLANATION

The workload within the Planning organization is anticipated to increase due to an increasingly complex power system planning environment that is reflected in the TSP and DSP. The planning environment is also challenged by the introduction of more complex and stringent compliance requirements, evolving customer needs, preferences and priorities, regulatory and performance expectations, and industry standards and codes.

Despite continued cost pressures and inflation, Hydro One’s planning costs are expected to be controlled, as indicated in Table 1. Relative to the 2018 historic year, the 2023 test years reflects a $4.3M (9%) decrease, with marginal year-over-year increases through the test year, driven in part by increased insurance costs.

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COMMON CORPORATE OM&A - INFORMATION SOLUTIONS

1.0 INTRODUCTION

Information Solutions manages the computer systems (hardware, software, and applications), data and voice communication systems, and security operations that support Hydro One's business processes and facilities to allow employees to perform their work. This exhibit presents the OM&A costs associated with Information Solution's work program. Following the below overview of the overall spending, Section 2.0 provides further details on the underlying programs. For Information Solution's capital investments, please refer to GSP Section 4.8.4.

Table 1 below provides a summary of Information Solutions' OM&A expenditures for the period of 2018 to 2023, which are allocated to Hydro One's transmission and distribution segments. The costs are organized into the following five program areas:

1. Information Technology (IT) Sustainment – These sustainment costs support existing Hydro One IT applications and infrastructure to ensure business continuity.
2. Business Telecom – Business telecom costs cover data and voice telecommunications services and associated operation and maintenance of Hydro One's telecom network, which is comprised of a mixture of company-owned and leased facilities and equipment.
3. IT Development – These development costs cover application upgrades, enhancements, and the OM&A portions of capital projects.
4. Security – These costs are required to remediate and improve security capabilities by driving continuous improvement in security awareness, security threat intelligence and analysis, data protection, industry partnerships and collaboration on security risk management, workforce screening, and the ongoing maintenance and support of security software technologies.
5. IT Management and Project Control – These costs fund the development and implementation of IT strategies, policies and processes, IT architectural standards for application interoperability, infrastructure capacity, network security, regulatory compliance, and IT governance.

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**
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

The proposed 2023 test year funding level for Information Solutions is $141.8M, including $53.7M allocated to Transmission and $85.9M allocated to Distribution.[2] In relation to 2020 actual costs of $131.2M, this amount represents a $10.7M (8.1%) increase. At the program level, the largest contributors to the overall increase are IT Development and Security costs, which are increasing by $4.8M and $3.9M respectively relative to 2020 actuals.

IT Development involves OM&A costs related to IT solutions that cannot be capitalized. Such solutions include change management (e.g., facilitating training and adoption), “data cleansing” and migration preparation, and strategy-related work (e.g., vendor selection, early discovery work). In 2023, the increased costs are primarily related to the increase in capital technology solutions, which in turn require a proportional increase in change management efforts, and often data cleansing or manipulation in order to ensure successful migration to new systems.

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[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.

[2] The allocation of costs between Transmission and Distribution is based on the Black and Veatch Common Corporate Cost Allocation Study provided in Exhibit E-04-08, Attachment 1.

Security OM&A is crucial to the ongoing protection of Hydro One's personnel, physical and cyber security. The proposed increase for 2023 is driven by the following:

- An expanded set of security technologies that require increased maintenance support through third party services;
- An expanded Workforce Screening program to enhance personnel security;
- Identity and access management through a new system (SailPoint) that centralizes, streamlines, and reduces the risk associated with the management of access to Hydro One physical and electronic systems; and
- Enablement of security awareness, governance and risk management across the organization.

The proposed Information Solutions OM&A expenditures provide Hydro One lines of business with reliable access to technology to complete their day-to-day work operations. These expenditures ensure key systems and generated data are available to support customer service, work management, and security programs by reducing the risk of unplanned IT system outages, protecting these systems from security threats, and enabling work programs through technology and data.

Overall, the proposed 2023 funding level of $141.8M is aligned with the forecast costs for 2021 of $137.4M, adjusted for inflation. The forecast of $134.9M for 2022 is slightly lower than 2021 and 2023 due to fluctuations in IT Development costs, which align with the drop in Information Solutions' capital spend in 2022 (refer to GSP Section 4.9.3 for further details on the capital spend). The expenditures associated with each of the five program areas are discussed in detail in Section 2.0 below.

The allocation of program level costs to Transmission and Distribution are shown in Table 2 and Table 3, respectively.

Table 2 - Information Solutions Costs Allocated to Transmission

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
IT Sustainment	27.1	33.9	30.5	30.9	30.7	31.7
Business Telecom	9.1	9.3	10.0	9.6	9.6	9.7
IT Development	5.1	2.4	2.3	4.5	3.7	4.2
Security	1.4	1.8	1.7	2.5	2.8	3.2
IT Management and Project Control	7.7	6.4	6.7	3.9	4.5	5.0
Total Information Solutions Costs Allocated to Transmission	**50.4**	**53.7**	**51.2**	**51.4**	**51.2**	**53.7**

Compared to 2020 (the last Transmission rebasing year), overall Transmission-allocated costs will increase by $2.5M (4.8%) in 2023. This amount is $0.7M (1.2%) lower than the 2023 figure that would result from escalating the 2020 last rebasing actual expenditure by inflation ($54.4M). The most significant increases from 2020 to 2023 are due to the same factors impacting the overall amounts in Table 1 – i.e. increases in IT Development and Security. Offsetting these increases is the overall cost reduction in IT Management and Project Control by $1.7M between 2020 and 2023.

Table 3 - Information Solutions Costs Allocated to Distribution

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
IT Sustainment	45.9	57.4	54.4	55.1	54.8	56.5
Business Telecom	8.7	8.8	8.0	7.7	7.7	7.8
IT Development	10.1	6.5	7.2	12.0	9.0	10.2
Security	2.5	3.0	2.9	4.3	4.7	5.3
IT Management and Project Control	6.5	5.3	5.8	4.7	5.4	6.0
Total Information Solutions Costs Allocated to Distribution	**73.8**	**81.1**	**78.4**	**83.8**	**81.5**	**85.9**

Distribution rebasing last occurred in 2018. The proposed Distribution-allocated expenditures for 2023 is $12.1M (16.4%) higher than 2018. This amount is $2.6M (3.1%) higher than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($83.3M). This is mainly driven by an increase in the annual IT Sustainment costs between 2018 and 2019, with 2019 levels held relatively steady for 2020 onwards. In 2019, adjustments and improvements were made following an internal review of how IT third party contract costs were identified, forecasted, and recognized. These adjustments included moving costs of IT contracts that were previously funded by other lines of business to the IT Third Party Contract category. Similar to Transmission, an increase in Security costs allocated to Distribution is required. Relative to 2018, Security costs for 2023 are higher by $2.4M to accommodate increases relating to: third party contracts, expanded workforce screening program, identity and access management, and enablement of security awareness, governance and risk management.

2.0 INFORMATION SOLUTIONS OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

2.1 IT SUSTAINMENT

IT Sustainment costs support Hydro One IT applications and infrastructure. These costs relate to outsourced services and third-party software or hardware license and maintenance fees, and include two sub-programs:

- Base IT Sustainment – refers to internal support for application sustainment and IT services provided by Capgemini, including application, infrastructure, project, and help desk services;
- Third Party Contracts – refers to hardware maintenance, and software license and maintenance fees paid to third-party vendors of IT applications and infrastructure.

IT Sustainment costs for historical, bridge and test years are provided below in Table 4.

Table 4 - IT Sustainment OM&A Costs ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Base IT Sustainment	47.5	49.0	49.0	46.0	44.0	44.0
Third Party Contracts	26.4	43.1	36.7	40.8	42.2	44.9
Total Sustainment	**73.9**	**92.1**	**85.7**	**86.8**	**86.2**	**88.9**
Allocated to Transmission	27.1	33.9	30.5	30.9	30.7	31.7
Allocated to Distribution	45.9	57.4	54.4	55.1	54.8	56.5
Other	0.9	0.8	0.8	0.8	0.7	0.7

The 2023 forecast for IT Sustainment OM&A costs is $3.2M (3.7%) higher than 2020 actual costs. This amount is $3.1M (3.4%) lower than the 2023 figure that would result from escalating the 2020 actual expenditure by inflation ($92.1M). While spending for 2021 and 2022 is forecasted to be relatively flat, 2023 test year costs are $2.8M higher than 2022 due to increase in software spend for new capital projects.

The sub-programs presented in Table 4 are discussed in the following sections.

2.1.1 BASE IT SUSTAINMENT SERVICES

"Base IT Sustainment Services" refers to the IT services required to monitor existing IT applications and infrastructure, and perform required support and maintenance to keep services operational. The delivery of these services includes work performed by Capgemini (refer to Exhibit E-05-01, Section 6.0 for further information) as well as in-house staff. Base IT Sustainment Services include four categories:

1. Application Maintenance – Maintenance and support of approximately 800 business software applications. Capgemini manages support for the large enterprise SAP, Microsoft SharePoint and Microsoft Customer Relationship Management (CRM) solutions, while Hydro One manages most other applications in-house;
2. Data Centre services – Operations, maintenance, and management of IT hardware (servers, mainframe, storage area network, network routers, and switches), operating

systems, and other infrastructure located at the data centre (production and backup) facilities. Capgemini provides support for IT Service Management, Business Continuity Plan & Disaster Recovery Support, Infrastructure Monitoring, End to End Incident Management, and Batch Job Processing;

3. Distributed server sustainment – Support services to maintain and operate the application and file servers used to run business applications and admin systems such as file storage, email exchange, and security monitoring systems; and
4. Help Desk – Daily management and maintenance services delivered to Hydro One personnel across the province by telephone, remotely, or through field technicians, along with the implementation of Artificial Intelligence services to enable transactions such as password resets.

The new support agreement with Capgemini and repatriation of Inergi resources (refer to Exhibit E-05-01, Sections 5.0 and 6.0 for further information) have enabled Hydro One to lower costs for Base IT Sustainment services. Under the former Inergi contract, support was provided as a fixed fee service (2019 and 2020 actuals were $49M per year). Under Hydro One’s new contract with Capgemini, IT Base Sustainment will be provided through a combination of Capgemini support, at a negotiated competitive rate, as well as in-house support by Hydro One. The repatriation of Inergi resources to support Base IT Sustainment has resulted in savings due to lower overhead and work efficiency gains (including the ability to more effectively balance resources and activities among Base IT Sustainment and other project and program needs as required). Overall, these efforts and changes have led to immediate forecasted savings of $3M for 2021 and $5M for 2022 compared with 2020 actuals.

2.1.2 THIRD PARTY CONTRACTS

Third Party Contract costs are comprised of fees related to hardware maintenance and software license and maintenance fees paid to third-party vendors of IT applications and infrastructure. Hydro One’s payment of third party contract fees is typically subject to annual audits by third-party vendors.

In 2019, Hydro One performed an internal review of how its IT third party contract costs were identified, forecasted, and recognized. As part of this review, a number of adjustments relating to the management of third party contracts were identified and made, including the following:

- Future forecasts have been adjusted to better account for the new technologies planned for implementation in the period, and subsequently requiring ongoing third party contract costs.
- Future forecasts have been adjusted to account for inflation, particularly when existing multi-year fixed price contracts are required to be renewed.
- 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.
- Data entry processes for the contracts have been reviewed and adjusted to ensure more accurate billing, particularly for multi-year contracts.

The implementation of the above-noted adjustments in the latter half of 2019 led to the increase in actual IT third party contract costs from 2018 to 2019 (as well as in actual and forecast costs from 2020 onward).

In 2020, Information Solutions engaged Gartner to perform an Enterprise IT benchmarking assessment of Hydro One's 2019 IT spending and staffing to provide insight relative to industry comparators (refer to GSP Section 4.3.3 for details). This assessment noted that while Hydro One's spending in software and hardware has increased significantly from 2015 to 2019, Hydro One's spending in these areas remain lower than the Peer Group and the Industry average.[3] This reflects Hydro One's prudence in managing IT spending to support, maintain, and enable critical business functions and enhanced work practices relative to industry comparators.

[3] Gartner, Enterprise IT Spending and Staffing Benchmark (April 16, 2020) – GSP Section 4.3 Attachment 3, page 20.

Forecast third party contract costs for 2023 reflect a slight increase over the bridge years, accounting for overall inflationary increases to existing third party contracts, as well as increased costs for additional planned technology solutions being deployed to support ongoing business needs.

2.2 BUSINESS TELECOM

Business Telecom costs cover data and voice telecommunications services and associated operation and maintenance of Hydro One's telecom network, which is comprised of a mixture of company-owned and leased facilities and equipment. Changes in costs vary with the addition of data and voice telecom capacity at sites throughout the province and security-related services for the expanding telecom network. These costs primarily relate to third-party services and are summarized in Table 5.

Table 5 - Business Telecom OM&A Costs ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Operations and Carrier Management	8.0	8.0	7.9	8.2	8.2	8.3
Field Services	1.9	1.9	2.0	1.8	1.8	1.8
Voice and Data Networks Services	7.8	7.7	8.0	6.8	6.8	6.8
Mobility Services	0.4	0.9	0.6	1.0	1.0	1.0
Total Business Telecom	**18.2**	**18.5**	**18.5**	**17.8**	**17.8**	**18.0**
Allocated to Transmission	9.1	9.3	10.0	9.6	9.6	9.7
Allocated to Distribution	8.7	8.8	8.0	7.7	7.7	7.8
Other	0.4	0.4	0.4	0.4	0.4	0.4

Historical actuals for Business Telecom are relatively flat despite additional customer-oriented services being introduced within the Mobility Services sub-program starting in 2021. The proposed Business Telecom OM&A expenditure for the 2023 test year is $0.5M lower than 2020 actual expenditure, primarily due to savings from productivity and procurement initiatives.

The sub-programs presented in Table 5 are discussed in the following sections.

2.2.1 OPERATIONS AND CARRIER MANAGEMENT

This sub-program encompasses services provided by Hydro One Telecom Inc. (Hydro One Telecom) to provide telecommunications monitoring and network operations for Hydro One's power system and business operations. These services are critical to ensure Hydro One personnel can communicate effectively throughout the province and with customers. These items include service and support for internet, phone and mobile devices used by all Hydro One employees. The costs remain stable from 2018 to 2023, with minor increases anticipated for 2023 to account for inflation.

2.2.2 FIELD SERVICES

The Field Services sub-program funds the maintenance and repair of voice and data telecom equipment, as well as the handling of connection changes for moves, additions, changes, and deletions (MACDs). Given Hydro One's dispersed workforce throughout the province, it is important to ensure that staff have the proper support for the voice and data devices used in the field and to monitor and implement required changes to the field devices (e.g., adding or changing phones and phone numbers). This sub-program also includes the ongoing maintenance and monitoring of the backend IT service that allows Hydro One to perform these Field Services.

Costs in 2023 are expected to remain the same as 2021 and 2022, which is overall $0.2M lower compared with 2020 spend. The reduction in spend in 2021 compared with prior years is a result of a planned roll out of soft phones, which allow users to take/make calls from their computer, and would result in fewer physical phones in offices that would be required to be maintained.

2.2.3 VOICE AND DATA SERVICES

The Voice and Data Services sub-program is required to provide local and long distance telephone service to Hydro One staff at corporate and field offices and to ensure customers are able to contact Hydro One Call Centers. This sub-program enables Hydro One to maintain the voice and data business telecommunication infrastructure and includes monthly data charges for circuit usage and data network services that connect Hydro One sites. These functions are essential to Hydro One's ability to run its business processes at over 130 locations throughout Ontario.

While actual spend in this sub-program will depend on data usage, costs are forecast to be lower from 2021 and onward by about 15% ($1.2M) due to investments in 2020 made to improve the overall voice data architecture resulting in annual telecom charge reductions by $1.2M.

2.2.4 MOBILITY SERVICES

This sub-program funds mobile phone services as well as customer notifications. Specifically, costs include monthly rate plans for cell phone usage (voice and data) to major carriers such as Bell and Rogers as well as hardware upgrades for users when eligible or for the replacement of lost devices. Starting in 2021, customer notification services have been added to this sub-program to enable new capabilities for mobile interaction with customers, such as outage-related or other notifications via SMS.

Mobility Services costs of $1.0M for 2023 are anticipated to be $0.4M higher compared to 2020, but in line with 2019 actuals. While mobile phone service rates decreased in 2020 and led to lower sub-program costs, the increase in forecast for 2021 onwards reflects the new services related to customer notifications being introduced starting in 2021.

2.3 IT DEVELOPMENT

IT Development covers application upgrades, enhancements, and the OM&A portions of capital projects, which are required to maintain applications to versions that fall within vendor support (i.e. older versions may no longer be supported by vendors, not receiving necessary security patches, bug fixes, or compatibility corrections with other IT software). Costs are reflected in Table 6.

Table 6 - IT Development OM&A Costs ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Enhancements	6.2	3.6	2.6	4.8	4.9	5.1
Upgrades	5.9	1.8	2.5	4.3	3.7	3.7
Capital Projects	3.1	3.4	4.4	7.4	4.1	5.6
Total IT Development	**15.2**	**8.8**	**9.6**	**16.4**	**12.7**	**14.4**
Allocated to Transmission	5.1	2.4	2.3	4.5	3.7	4.2
Allocated to Distribution	10.1	6.5	7.2	12.0	9.0	10.2
Other	0.0	0.0	0.0	0.0	0.0	0.0

Historical actuals for IT Development are trending up due to increased cost of enhancements and increased capital project-related spending attributable to increased IT project spending (as reflected in GSP Section 4.9). The proposed IT Development OM&A expenditure for the 2023 test year is $1.9M (12.5%) higher than the average spend across 2018-2022. This increase is largely attributable to capital project-related spend that is planned for 2023.

IT Development costs are divided into three categories:

1. Enhancements - include changes to SAP and Non-SAP systems to meet legal/regulatory requirements, to deliver business functionality that meets the objectives of the business, and to further Hydro One's application rationalization strategy;
2. Upgrades - necessary software releases, periodic version upgrades, and application replacements that do not meet the total capital threshold of $0.5M; and
3. Capital Projects - business process re-engineering costs, such as training and change management costs, that are required when new or revised IT applications are introduced but are not capitalized as per Hydro One's accounting practices.

The sub-programs presented in Table 6 are discussed in the following sections.

2.3.1 ENHANCEMENTS

Enhancement costs allow for minor modifications to various IT applications to improve business processes or meet regulatory obligations. Examples of spend in this category for 2021 include SAP enhancements to accommodate customer rate changes and ongoing GIS map information updates. Forecasted future spend includes minor enhancements to existing applications, in alignment with Information Solution's architectural principle (as discussed in GSP Section 4.2.4) of leveraging existing applications to meet additional business needs where possible and minimizing the additional costs of deploying/supporting different technologies.

2.3.2 UPGRADES

Upgrades need to be performed on IT systems to keep applications and infrastructure in a vendor-supported state. Most notably, this category includes spend required for annual SAP patching and version updates in order to maintain vendor support. Other examples include small application updates to correct a discovered defect, or to create a new data field or drop down option within a program to align with current years work programs. Costs for upgrades in 2019 and 2020 were lower than historical due to efficiencies gained from hardware refresh investments which temporarily eliminated the need for certain OM&A costs associated with patches and updates for older systems. Expenditures in 2021 returned to a level that is closer to historical norm and include required SAP patches. Forecasts for 2022 and 2023 are slightly lower than 2021 and 2018 actuals due to the timing of required system updates.

2.3.3 CAPITAL PROJECTS

Spend for Capital Projects fluctuates with capital project-related expenditures, capturing business process re-engineering costs, such as training and change management, as well as post in-service defect correction support (typically done for larger transformation projects). 2020 actual spend was higher than historical years due to the increase in capital project delivery, including projects such as the Distribution Design Optimization and Transformation (DOT) and the HR Payroll Transformation (See GSP Section 4.9.2 for details). Spend in 2023 is based on the planned capital project delivery portfolio, and includes necessary business process reengineering costs for projects such as the GIS platform replacement and SAP S/4HANA migration investments (as detailed in GSP Section 4.11, G-GP-05 to G-GP-08).

2.4 SECURITY

Information Solutions is also accountable for planning and executing Hydro One's security programs. These programs protect the Company from personnel, physical, and cyber security risks. Hydro One's security capability is managed and overseen through enterprise-wide Security Governance to enable resilient business operations.

For the JRAP, the Security OM&A costs managed by Information Solutions are presented in three separate exhibits, so as to maintain consistency with the cost mapping presented in the previous Transmission and Distribution applications.

1. General Security – These costs are required to remediate and improve security capabilities by driving continuous improvement in security awareness, security threat intelligence and analysis, data protection, and workforce screening (as discussed in Section 2.4.1 below)
2. Security Management – The Security Management function encompasses Personnel, Physical, NERC and General Cyber Security. These costs are included within common corporate costs, as presented under Exhibit E-04-02, Section 2.7 and also discussed in Section 2.4.2 below.
3. NERC Cyber Security – These costs enable maintenance activities that are required to sustain the compliance of Hydro One systems and facilities with NERC Critical Infrastructure Protection (CIP) standards. The costs are included under Transmission OM&A Sustainment, as presented under Exhibit E-02-02, Section 2.1.6 and also discussed in Section 2.4.3 below.

For clarity, the costs pertaining to Hydro One's Security Management and NERC Cyber Security functions are not captured as part the Information Solutions OM&A shown in this Exhibit E-04-04 (as summarized in Table 1 above). Nevertheless, to provide the full context of Hydro One's unified security strategy, these two functions are discussed in conjunction with General Security in the following subsections.

2.4.1 GENERAL SECURITY

With growing threats of cyber attacks, Hydro One is increasing its focus on the security of its computer and data systems. Table 7 below reflects General Security costs to remediate and improve security capabilities, commensurate with an increased threat risk profile and industry practices. Proposed General Security expenditures will drive: continuous improvement in the security awareness program; security threat intelligence and analysis through improved machine-to-machine threat information exchange (e.g., through the Canadian Cyber Threat Exchange and NERC Electricity Information Sharing and Analysis Center); increased vulnerability testing by vendors to validate the security controls that protect Hydro One's assets and identify potential risks; and application security remediation.

As part of Hydro One's strategy to effectively address evolving and escalating cyber security threats, it has established a partnership with the Communications Security Establishment, an agency of the Department of National Defense, to collaborate on innovative methods that leverage the Government of Canada's federal cyber security capabilities and intelligence. Hydro One is also working with Canada's largest banks and telecommunications providers to exchange information on cyber security related topics.

In addition to securing digital assets, Hydro One continues to make investments in its physical and personnel security program. Hydro One has planned enhancements that will improve the security of its staff including workplace harassment and bullying prevention, active threat training, protection of sensitive employee data, expanded workforce screening, enhanced security awareness, and travel-related security.

Table 7 - General Security OM&A Costs ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total General Security	**3.9**	**4.8**	**4.6**	**6.8**	**7.5**	**8.5**
Allocated to Transmission	1.4	1.8	1.7	2.5	2.8	3.2
Allocated to Distribution	2.5	3	2.9	4.3	4.7	5.3
Other	0.0	0.0	0.0	0.0	0.0	0.0

The proposed General Security OM&A expenditure for the 2023 test year is $3.9M (85%) higher than the 2020 actual expenditure. Starting in 2021 through to 2023, General Security OM&A costs are expected to increase due to the following:

- Increased third party contract costs for the maintenance and support of an expanded set of security technologies;
- Expanded Workforce Screening program to enhance personnel security;
- Identity and access management – new team to manage the new system (SailPoint) that centralizes, streamlines, and reduces the risk associated with the management of access to Hydro One physical and electronic systems; and
- Increases to security awareness, governance and risk management.

2.4.2 SECURITY MANAGEMENT

The Security Management function encompasses Cyber Security, Personnel & Physical Security, and NERC Compliance. The primary mandate of the function includes the protection of assets (including personnel, property, IT systems, and information) as well as the development and maintenance of cyber and physical incident response and recovery plans. Security Management establishes security standards for the enterprise, operating a cyber-operations security function that works across the company to provide advice, coordination and solutions to achieve security standards. This ultimately supports the reliable delivery of electricity, protection of Hydro One's assets, and the continuity or recovery of business functions in the event of a cyber or physical security incident.

The Security Management program is continuously enhanced with new capabilities that are required to meet the following requirements:

- To remain appropriately positioned against an evolving threat landscape that is increasing in complexity and sophistication. This requires Hydro One to augment and deploy new protective technologies and processes to safeguard assets;
- To meet increasing regulatory and legislative requirements, which in turn drive the need for additional security capabilities and compliance requirements;
- To meet the increasing expectations of customers and stakeholders that entrust Hydro One to safeguard their sensitive information; and
- To manage the risks associated with third party software integrity, vendor personnel security management and third party connectivity into Hydro One's systems.

Table 8 presents Hydro One's total Security Management costs (which are included as part of Hydro One's Corporate Common Costs outlined in Exhibit E-04-02, Section 2.7).

Table 8 - Summary of Allocated Security Management Costs ($M)[4]

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Actual	Forecast	Forecast
Total Security Management	**5.2**	**3.9**	**3.1**	**4.9**	**5.7**	**5.9**
Allocated to Transmission	2.9	2.1	1.6	2.6	3.0	3.1
Allocated to Distribution	2.3	1.7	1.4	2.2	2.6	2.6
Other	0.0	0.1	0.1	0.1	0.1	0.1

Over the 2018-2023 period, Security Management costs increase materially within inflation. The bridge and test year forecast shows increases from 2020 levels in order to fund additional staffing to meet Hydro One's security requirements.

[4]These costs are not included in the total Information Solutions OM&A presented in Table 1 above. They are considered Corporate Common OM&A costs and are included in the total presented in Table 1 under Exhibit E-04-02.

2.4.3 NERC CYBER SECURITY

Hydro One must comply with cyber security standards that are intended to ensure the integrity of the Ontario Bulk Energy System (BES) and all of the interconnected BESs across North America. NERC CIP standards require regular testing and update of the relevant security systems and procedures affecting transmission assets and utility personnel. These standards are designed to mitigate cyber security risks to BES facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cyber security incident, would affect the reliable operation of the BES.

The specific maintenance and support activities within the NERC Cyber Security function include:

- Maintaining the various cyber security assets (e.g. firewalls, intrusion detection systems, malware detection systems, physical security systems), including third party contract costs for the maintenance and support of these technologies;
- Conducting annual vulnerability assessments of critical cyber assets and security perimeters;
- Managing, operating and monitoring cyber security systems (e.g. maintaining personnel access lists, patch management, maintaining logs, updating firmware, periodic tests);
- Tracking the life cycle of critical cyber security assets, including proper disposal to ensure the destruction of sensitive information; and
- Conducting ongoing assessments and testing of hardware and software components to ensure compliance.

NERC CIP standards are constantly evolving to mitigate potential threats to the interconnected North American power system. The next generation of NERC CIP standards are in the final stages of development and include inter-control center communication and virtualization. These standards are expected to be approved with compliance due dates in the 2022-2024 timeframe.

Table 9 below outlines Hydro One’s NERC Cyber Security expenditures (which are included as part of the Transmission Sustainment OM&A costs presented in Exhibit E-02-02).

Table 9 - NERC Cyber Security OM&A Costs[5]

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
NERC Cyber Security	**14.6**	**11.8**	**13.7**	**15.5**	**18.4**	**21.5**
Allocated to Transmission	14.6	11.8	13.7	15.5	18.4	21.5
Allocated to Distribution	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0

More specifically, this OM&A program funds the necessary maintenance and support work required to operate, maintain, and monitor the systems related to Hydro One's NERC Cyber Security program, including services provided by external resources. Cyber security systems include telecom, physical security, laboratory, central site tools and remote site systems. Hydro One's technical engineering teams also continuously evaluate and test hardware and software components to address compliance issues due to emerging threats or vendor-initiated changes (e.g., new features or functionality and hardware modifications).

Additionally, this program funds annual assessments and audits required by NERC CIP standards. Vulnerability assessments verify that implemented security controls have not been intentionally or unintentionally modified and that Hydro One's assets continue to meet system security management requirements. Threat risk assessments evaluate potential emerging threats and vulnerabilities of Hydro One's transmission stations. The results of these assessments and audits are used to improve Hydro One's NERC Cyber Security program and ensure the company remains compliant.

This program also includes compliance-related projects and work triggered by new or revised NERC CIP standards. Expenditures have been identified to address NERC-related continuous

[5] These costs are not included in the Total Information Solutions OM&A presented in Table 1. They are considered Transmission Stations Sustainment OM&A costs and are included in the total presented in Table 1 under Exhibit E-02-02.

improvement (identified outside of capital investments) that is required for Hydro One's compliance.

The proposed 2023 test year expenditure is $21.5M. This is higher than the 2020 actual expenditure of $13.7M (which is both the most recent actual expenditure and the last rebasing actual expenditure), the historical average for 2018-2021, and the 2021 forecast, and slightly higher than the 2022 bridge year forecast. The increase is due to compliance with regulatory obligations – including security needs related to evolving security threats and NERC CIP standards – and the establishment of a new, in-house Joint Security Operations Centre (JSOC), a 24/7 cyber and physical security monitoring centre located at the Integrated Systems Operating Centre (ISOC). Hydro One anticipates completing the 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.

To avoid adverse business impact and disruptions, Hydro One must proactively mitigate growing cyber security risks (as identified in the 2020 National Cyber Threat Assessment by the Canadian Center for Cyber Security) and maintain the appropriate level of response to physical security threats. As part its efforts in this regard, Hydro One is moving to insource key operational components of physical, personnel and cybersecurity monitoring that are currently outsourced. This will ensure better alignment with Hydro One's security strategy, emergency response processes, quality expectations and security risk management programs, which are especially important given the transition from analog to digitally connected devices and the emergence of cloud-based services – meaning that Hydro One must monitor and protect a larger security perimeter than ever before.

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. Under current outsourcing arrangements, service providers are not provisioned access to 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. The proposed insourcing arrangement will allow Hydro One to efficiently and effectively leverage the on-site presence and capabilities of in-house staff at the JSOC with direct access to relevant internal systems and information. 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.

2.5 IT MANAGEMENT AND PROJECT CONTROLS

The IT Management and Project Control function develops and implements IT strategies, policies and processes, IT architectural standards for application interoperability, infrastructure capacity, network security, regulatory compliance, and IT governance. IT Management and Project Control responsibilities include hardware procurement, training, detailing vendor responsibilities, architecture development, and research services. Table 10 reflects the historical and projected spending for 2018 to 2023.

Table 10 - IT Management and Project Controls OM&A Costs ($M)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total IT Management and Project Controls	**14.3**	**11.9**	**12.8**	**9.6**	**10.9**	**12.0**
Allocated to Transmission	7.7	6.4	6.7	3.9	4.5	5.0
Allocated to Distribution	6.5	5.3	5.8	4.7	5.4	6.0
Other	0.1	0.2	0.3	1.0	1.0	1.1

The 2023 test year forecast of $12.0M is $0.7M lower than 2020 actuals. This is due to efforts in 2021 to review all staffing responsibilities that fall within this program, which resulted in certain resources being allocated directly to capital projects, as the associated work was directly related to the management and execution of those projects. Costs in 2022 and 2023 are forecasted to be higher than 2021 due to increased headcount. This increased headcount is required to manage and oversee the approximately 160 employees being repatriated from Inergi and to enable new and improved capabilities as part of Information Solutions' transition to the new Target Operating Model (see GSP Section 4.10.4 for further details).

OPERATIONS OM&A

1.0 SUMMARY OF OPERATIONS OM&A

This exhibit presents the OM&A expenditures associated with System Operations' work program. These expenditures are required to sustain and update the tools, systems and infrastructure that are critical to the reliable and safe operations of Hydro One's transmission and distribution system in accordance with applicable requirements (including the Transmission System Code, Distribution System Code, IESO Market Rules and NERC/NPCC reliability standards) and good utility practice. This Section 1.0 provides an overview of the overall expenditures, while Section 2.0 below provides further details on the underlying programs. For information regarding System Operations' capital investments, please refer to GSP Section 4.8.5.

Currently, the 24/7 real time operation of Hydro One's transmission and distribution system is conducted at the Integrated System Operations Centre (ISOC). The Back-Up Ontario Grid Control Centre (BU-OGCC) is located at a separate site and is activated in the event the ISOC or its computer systems are rendered unavailable. A suite of systems and tools are used at the ISOC and BU-OGCC to monitor and control transmission and distribution assets, manage customer outage information, coordinate and dispatch crews as required, plan for and react to system contingencies, schedule and coordinate planned outages, provide customer notifications, and monitor and report on the performance of the transmission and distribution systems. Newly integrated smart devices on the distribution system are also monitored to ensure alignment with existing infrastructure and optimize the impact on distribution operations.

Furthermore, Operations OM&A expenditures support health, safety and environmental (HSE) activities that are required pursuant to Hydro One's regulatory obligations and commitment to be the safest and most efficient utility.

Hydro One manages its Operations OM&A expenditures in the following key categories:

- **Operations** – These costs account for the staff and work activities required to ensure the safe and reliable operation of the transmission and distribution system, including the planning, scheduling and execution of outages, and back office staffing.
- **Operations Support** – These costs ensure that the various operating computer tools and systems are kept current and functional. This includes the maintenance and support of the modernized distribution system.
- **HSE** – These costs support the HSE initiatives required to meet Hydro One's regulatory obligations and commitments to minimize environmental impact and protect the health and safety of employees, customers and the public.

Table 1 below presents the total forecast Operations OM&A expenditures for the 2023 test year, along with actual expenditures for the bridge and historical years. The total includes costs allocated to Hydro One's Transmission and Distribution businesses.[1]

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

Description	Historical			Bridge		Test	Cost Allocation (Transmission, Distribution, or Common)
	2018	2019	2020	2021	2022	2023	
	Actual	Actual	Actual	Forecast	Forecast	Forecast	
Operations	53.2	47.2	45.8	48.9	52.2	52.0	Common
Operations Support	34.3	36.5	33.1	36.9	35.0	35.1	Common
HSE	3.2	3.9	2.0	2.8	2.7	2.7	Common
Total Operations OM&A	**90.7**	**87.6**	**80.9**	**88.5**	**90.0**	**89.8**	
Allocated to Transmission	53.4	51.0	47.9	48.8	48.6	49.0	
Allocated to Distribution	37.3	36.6	33.0	39.7	41.3	40.8	

[1] Cost allocations are based on Black and Veatch's Allocation Study presented in Exhibit E-04-08, Attachment 1.

The proposed $89.8M in total Operations OM&A spending for the 2023 test year is designed to reflect Hydro One's commitment to reliably operate the transmission and distribution system and manage HSE risks, in alignment with regulatory compliance obligations and customer needs and preferences. This amount is below 2018 actuals, and consistent with 2019 actuals and 2021 and 2022 forecast. The only anomaly in the year to year spend profile occurred in 2020, when actual spending was only $80.9M. The lower spending in 2020 was mainly driven by the deferral of work due to the COVID-19 pandemic, which resulted in a corresponding reduction in field switching and operations work.

There is some fluctuation in costs allocated to Transmission versus Distribution. Compared to 2018, the 2023 forecast allocated to Transmission is lower by $4.4M, whereas the 2023 forecast allocated to Distribution is higher by $3.5M. This results in an overall net decrease of $0.9M. The fluctuation stems from the reshuffling of staff between Transmission Operations and Distribution Operations (as discussed in Section 2.1 below).

Tables 2 and 3 show the breakdown of the total costs in Table 1 as allocated to Hydro One's Transmission and Distribution businesses, respectively.

Table 2 - Operations Costs Allocated to Transmission ($M)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Operations	32.5	28.8	27.3	25.0	26.4	25.0
Operations Support	19.5	20.2	19.5	22.3	20.8	22.6
HSE	1.4	2.0	1.1	1.5	1.4	1.4
Total Allocated to Transmission	**53.4**	**51.0**	**47.9**	**48.8**	**48.6**	**49.0**

Transmission-allocated costs from 2020 (the last rebasing year for Transmission) to 2023 remain relatively steady, with a gradual increase of $1.1M (2.3%) between these years. This amount is $1.8M (3.6%) lower than the 2023 figure that would result from escalating the 2020 last rebasing actual expenditure by inflation ($50.9M).

Some fluctuations are seen at the program level for Operations and Operations Support. The Operations line item decreases by $2.3M between 2020 and 2023. As noted above, the fluctuations stem from the moving of staff from Transmission Operations to Distribution Operations, which occurred in 2021 to align with System Operation's long term vision towards the management model of grid dispatch (as discussed in Section 2.1 below). This decrease was offset by a $3.1M increase in Operations Support between 2020 and 2023 due to the atypical lower spend in 2020, as described above.

HSE expenditures remain relatively stable from 2020 to 2023.

Table 3 - Operations Costs Allocated to Distribution ($M)

Description	**Historical**				**Bridge**	**Test**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Operations	20.7	18.4	18.4	23.8	25.9	27.0
Operations Support	14.8	16.4	13.6	14.5	14.2	12.4
HSE	1.8	1.9	1.0	1.3	1.3	1.3
Total Allocated to Distribution	**37.3**	**36.6**	**33.0**	**39.7**	**41.3**	**40.8**

Distribution-allocated costs varied year over year, but the overall annual average increase between 2018 (the last Distribution rebasing year) and 2023 is $3.5M (9.3%). This amount is $0.3M (0.6%) lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($41.0M).

Similar to the trend seen at the overall level, 2020 actual costs were lower than other years due to the deferral of work resulting from the pandemic. The annual spend levels forecasted for 2021, 2022 and 2023 align with 2018 and 2019 levels (considering inflationary increases).

At the program level, Distribution-allocated costs increase in Operations and slightly decrease in Operations Support, as a result of the above-noted reshuffling of staff between Transmission Operations and Distribution Operations.

2.0 OPERATIONS OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

Hydro One's test year Operations OM&A expenditures are discussed below for each of the key categories presented in Table 1: Operations, Operations Support, and HSE.

2.1 OPERATIONS

Hydro One operates its transmission and distribution system from a shared facility known as the ISOC. In the event the ISOC or its computer systems become unavailable, back-up operating facilities located at a separate site called the BU-OGCC are activated.

The Operations program within overall Operations OM&A enables Hydro One to effectively deliver core operational functions that are critical to the level and quality of service delivered to customers in real time. These functions include scheduling and overseeing planned outages, reacting to unplanned outages, coordinating emergency response, and monitoring system performance. Costs from year-to-year can vary due to factors such as storm activity, volume of planned outage requests, and unplanned interruptions. Costs associated with the Operations program are presented below in Table 4.

Table 4 - Operations Program OM&A Costs

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Operations	**53.2**	**47.2**	**45.8**	**48.9**	**52.2**	**52.0**
Allocated to Transmission	32.5	28.8	27.3	25.0	26.4	25.0
Allocated to Distribution	20.7	18.4	18.4	23.8	25.9	27.0

To deliver the above-noted Operations functions (including associated training requirements), Hydro One requires $52.0M for the 2023 test year – an increase of $6.2M from 2020 actual costs. This variance is particularly accentuated due to the overall lower cost levels in 2020, as discussed above. The proposed test year costs are aligned with 2018 actuals and 2022 forecast. Overall, Operations costs have resisted inflationary pressure, largely due to the leveraging of technology to improve operational effectiveness. Operations costs related to transmission and distribution are further discussed below:

- The proposed Transmission Operations OMA budget for 2023 is $25.0M, which is lower than 2020 historical costs due to staff moving from Transmission Operations to Distribution Operations in connection with a strategic change in the grid dispatch model. Transmission Operations has been streamlined by leveraging technology and through a better/separate focus on the Distribution-related function by splitting Transmission Operations and Distribution Operations.
- The proposed Distribution Operations budget for 2023 is $27.0M, which is higher than 2018 historical costs, mainly due to the reshuffling of staff from Transmission Operations to Distribution Operations to support the increased deployment of modernized distribution system technology, including automated devices, switches, and fault indicator devices. This increase is offset by the above-noted decrease in Transmission Operations.

Specific Operations functions for managing planned and unplanned outages, coordinating emergency response, and monitoring system performance are further described below.

2.1.1 MANAGEMENT AND IMPLEMENTATION OF PLANNED OUTAGES

Successful outage planning is core to Hydro One’s business as it seeks to efficiently and safely maintain the transmission and distribution systems while limiting customer interruptions. Planned interruptions are coordinated and managed from the ISOC and typically account for 5% to 15% of the duration of all Hydro One transmission and distribution customer interruptions.

With respect to reliability outcomes explored during customer engagement, customers identified outage frequency and duration reduction relating to extreme weather events and reduction in the overall number of day-to-day outages as their top priorities.[2] Hydro One's approach for coordinating planned outages to capture efficiencies and mitigate impacts on customers involves:

- Assessing all connected electrical equipment and devices that would be included in outage planning to determine appropriate limits and control actions;
- Assessing forecasted system conditions, system limits, and operating constraints;
- Identifying and notifying customers of upcoming outages through auto-dialer, phone, fax, newspapers, flyers, radio, door-to-door visits, etc., and providing network outage updates to customers via Hydro One's mobile applications;
- For planned outages, addressing customer concerns related to outage times and dates by rescheduling and/or grouping planned outages where possible and modifying work scope to restrict the outage in other cases; and
- Complying with all established safety procedures and during outage work activities to ensure the safety of Hydro One staff, customers and the public.

Also, Hydro One's Transmission System Outage Grouping (TSOG) and Distribution System Outage Grouping (DSOG) processes help to enhance outage related services and drive operational efficiencies. Through these processes, Hydro One is able to more effectively communicate and engage with customers, better understand the impacts of the planned outages on customers' operations, and enhance System Operations' ability to provide services that meet customer needs. Improved outage coordination has resulted in a reduction in outage cancellations and annual transmission planned outages since 2011.

Furthermore, in 2020, Hydro One launched an initiative to create an end-to-end outage management process that supports Distribution System Average Interruption Duration Index (D-SAIDI) reductions related to planned outages. The objective was to minimize customer service interruptions and improving customers' experience relating to outages by:

[2] Innovative Research Group, Hydro One Customer Engagement Report (December 2020) – SPF Section 1.6 Attachment 1, page 16

- Enhancing coordination and visibility of planned work to minimize the number of outages and interruptions required;
- Minimizing potential rework across lines of business through clearly defined criteria and requirements for requesting studies or interruptions; and
- Identifying the roadmap for outage management technologies to support an improved/redesigned outage planning process.

This initiative will be further advanced by improving equipment bundling functionality within the Network Outage Management System (NOMS).

2.1.2 RESPONSE TO AND MANAGEMENT OF UNPLANNED OUTAGES

Equipment failures, vegetation contact, road accidents, severe weather and lightning are among the factors that could result in unplanned service interruptions on the transmission and distribution system. Unplanned outages typically account for 85% to 95% of Hydro One's total customer outage durations on the transmission and distribution system.

Distribution modernization has challenged how we have traditionally operated. With the rollout of remotely controllable and fault locating equipment on Hydro One's distribution system, System Operations will play a critical role in driving the expected business outcomes.

System Operator competency is critical to the reliable operation of the transmission and distribution systems. To effectively support distribution modernization, System Operations conducted a review in 2019 of Control Room layout and functionality, organizational structure, interaction with other lines of business, hiring and promotion practices, and training programs. The primary conclusions were the following:

- A greater focus on Distribution Operations was required to drive distribution reliability.
- The skillset to operate the distribution system is different to that of the transmission system and warrants tailored training. This led to the creation of separate Transmission Operator and Distribution Operator roles.

- The review identified the need to better align work protection practices relative to industry peers.

As a result, a new organizational structure was implemented in January 2021 to modernize Control Room operations. This reorganization involved reclassifying the positions of Dispatcher and Controller, and introducing distinct Operator roles (and related supervisory roles) for distribution and transmission. The dispatch function has been incorporated into the Distribution Operator role.

As a result of these changes, the anticipated efficiency gains will result in fewer FTEs required over the longer-term to sustain operations. The size of the workforce for System Operations is projected to decrease by approximately ten regular status FTEs (in PWU and non-represented/management roles) from 2023-2027. The planned decreases to FTE levels will occur through attrition and efficiency gains related to the modernization of the Control Room.

Furthermore, System Operations has pursued various process improvements. For example, a Work Protection Decentralization Project is underway, which involves transitioning work protection responsibilities out of the Control Room and into the field. This project is expected to improve situational awareness and allow Transmission Operators to better focus on system operator-specific tasks (i.e., better aligning their duties with the Transmission Operations function).

Hydro One continues to review technologies, processes and best practices to more effectively deliver critical System Operations functions. Consistent with outcomes that customers value, areas of focus and ongoing improvement include real-time communication with customers, increasing distribution automation (including automatic fault locates and isolation) to minimize restoration times, and optimization of outage duration and operating costs.

2.1.3 EMERGENCY RESPONSE COORDINATION

The Hydro One Emergency Response System is activated in response to widespread interruptions due to weather impacts. The specific responses vary depending on the severity and location of weather events, the number of customers affected, and the expected time to restore service.
During transmission-related emergency events, Transmission Operators activate emergency voltage reduction measures, initiate independent action to mitigate emergent conditions, and/or coordinate and perform routine emergency switching procedures with large generating stations and extra-provincial operating entities.

During distribution-related events, Dx Operators dispatch crews based on the volume and severity of power-off calls until the command system is switched to Field Operations Centre Dispatch mode. At the Field Operations Centres, supervisors dispatch damage assessment crews and restoration crews at a local level and manage emergency response with firsthand knowledge of the actual problems and more efficient allocation of resources. For larger emergency conditions, which may be more widespread, Incident Command Centres and Forward Command Posts are activated to manage Hydro One's response with the local area command arrangements. Distribution Operators assist with media notifications to inform and update customers, municipalities and other agencies of outage progress and other Hydro One response updates.

2.1.4 SYSTEM PERFORMANCE MONITORING AND REPORTING

Hydro One monitors and reviews system reliability data to identify system performance issues and challenges and develop appropriate action plans. System performance reporting is also made to the OEB. Data required to calculate Hydro One's reliability indices, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), is collected at the ISOC.

Outage inquiries from customers and data extracted from the various applications and systems are reviewed to identify emerging performance issues, establish required action plans, and identify opportunities to further improve system performance and minimize customer interruptions. The Customer Operating Support group has placed increased focus on communications with customers, providing system statistics that allow customers to make more informed decisions on investments, outage planning and operations.

2.2 OPERATIONS SUPPORT

Operations Support expenditures are required to sustain and enhance the tools, systems and infrastructure that are critical to the reliable and safe operations of Hydro One's transmission and distribution system in accordance with applicable requirements (including the Transmission System Code, the Distribution System Code, IESO Market Rules and NERC/NPCC reliability standards) as well as good utility practice.

Forecast Operations Support spending for the 2023 test year is $35.1M, as shown in Table 5 below. This level of funding is essential to sustain the ongoing availability and functionality of real-time monitoring and control facilities, systems, and tools that are critical to the overall reliability of the transmission and distribution system.

Table 5 - Operations Support OM&A Costs

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Operations Support	16.2	17.3	17.9	20.4	18.8	20.4
Transmission Operations Support	6.0	5.7	4.5	5.3	5.1	5.5
Distribution Operations Support	12.1	13.6	10.7	11.2	11.1	9.1
Total Operations Support	**34.3**	**36.5**	**33.1**	**36.9**	**35.0**	**35.1**
Allocated to Transmission	19.5	20.2	19.5	22.3	20.8	22.6
Allocated to Distribution	14.8	16.4	13.6	14.5	14.2	12.4

Operational tools and systems at the ISOC and BU-OGCC require ongoing maintenance in order to ensure their functionality and deliver intended benefits. While a number of factors may drive Operations Support expenditures, product lifecycles and vendor support agreements are the major determining factors for asset maintenance. In adherence with IT industry standard practice, Operations assets are managed through a lifecycle program in order to ensure the availability of vendor support and minimize the likelihood and impact of failure. Furthermore, the proposed OM&A costs fund essential services to support the day-to-day operation of the transmission and distribution system, such as monitoring, controlling and switching, as described in Sections 2.2.1 - 2.2.3 below.

The three categories of Operations Support expenditures (Common, Transmission and Distribution) are further discussed below.

2.2.1 COMMON OPERATIONS SUPPORT

Common Operations Support expenditures are required to maintain functional viability and lifecycle management of the Operations Information Technology (IT) systems – in particular, to ensure all IT systems and tools are within vendor support periods. The spending requirement for Common Operations Support in the 2023 test year is $20.4M.

The main program within Common Operations Support is Operating Technology (OT) Support ($18.4M in 2023), which maintains computer tools, systems and hardware in relation to the operation of Hydro One transmission and distribution assets. The OT Support program ensures the continuity and availability of systems through required support, maintaining the viability of systems for operational response, dispatch, communication, and outage planning. Proper lifecycle sustainment practices help reduce costly extended support, break-fix emergency repairs, and impactful outages.

The primary and critical transmission and distribution operating systems maintained as part of OT Support include: the Network Management System (NMS), Distribution Management System (DMS), Outage Response Management System (ORMS), Network Outage Management System (NOMS) and the Electronic Log. Typical OT Support services include asset lifecycle management, systems performance monitoring, configuration and release management, planning and minor modifications and enhancements.

Additionally, this program supports common OT infrastructure at the ISOC and BU-OGCC, including software licenses, database servers, switches, virus servers, firewalls, network and infrastructure, radio system and IT building facilities.

Given the critical nature of OT Support, reductions to this program would leave critical applications unsupported and result in the expiration of software licenses and vendor maintenance contracts. A prolonged disruption to critical systems supported under this program (e.g., NMS, DMS, ORMS and NOMS) would severely impact the operations of the transmission and distribution system.

The remaining $2.0M costs under Common Operations Support consist of the following programs:

- Integrated Voice Communications Technology (IVCT) Support - maintains the IVCT system as the control room's method of communicating with customers.
- ARCOS Resource Management Sustainment - enables timely response to adverse weather and customer restoration by automating the resource transition between daily operations and emergency scenarios.
- System Control Modifications – involves minor modifications of Operations tools.

2.2.2 TRANSMISSION OPERATIONS SUPPORT

Hydro One System Operations relies on a number of systems, tools, and associated competencies to manage and operate the transmission system. The Transmission Operations Support category funds services, operating systems and tools that are essential to the planning and execution of transmission outages. The spending requirement for Transmission Operations Support in the 2023 test year is $5.5M.

The main Transmission Operations Support program is Field Switching – Stations and Lines, which involves the manual field switching of transmission system elements that cannot be remotely controlled. This program ensures switching activities are performed in a safe manner in support of planned outages, and also funds responses to unplanned outages and third party requests.

The other Transmission Operations Support programs are:

- Operating Diagram Maintenance (Transmission) - ensures that ongoing changes to transmission system interconnectivity/elements are reflected on the operating diagrams accurately and in a timely fashion.
- Emergency Preparedness (Transmission) - ensures the Hydro One Emergency Response Implementation Procedures for the transmission system are updated annually and to ensure emergency communications and backup generator testing are completed.
- Field Verification (Transmission) - required for equipment and print verification to facilitate incident reporting and to ensure diagrams are adequately maintained.
- IMS Workflow Automation and Transmission Reliability Standards – ensures effective record retention and reporting in relation to reliability standards compliance.

2.2.3 DISTRIBUTION OPERATIONS SUPPORT

Hydro One System Operations relies on a number of systems, tools, and associated competencies to manage and operate the distribution system. The Distribution Operations Support category provides funding for services, operating systems and tools that are essential to provide additional monitoring and control and planning and execution of outages on the distribution system. Furthermore, Distributed Generation penetration on the distribution system will continue to significantly influence system operation and requirements for ongoing support (e.g. changes to station and operating diagrams, data collection activities and updates to the DMS network model). The forecast spend for Distribution Operations Support in the 2023 test year is $9.1M.

The main Distribution Operations Support program is Distribution Modernization Sustainment ($7.1M for 2023). This program funds the sustainment of the DMS and telecommunication for smart grid devices, which allow system operators to remotely manage a distribution system enabled with distribution automation. The program supports Hydro One's long term vision towards a modernized distribution system and provides the following benefits and opportunities:

- Improves the monitoring and management capabilities of the distribution system.
- Enhances the reliability of the distribution system by increasing field crews' situational awareness of the real-time state of the distribution system and location of faults.
- Increases operational efficiencies related to how the distribution system is studied in the planning time frame and provides more real-time operations tools for the control room and field crews.
- Improves the efficiency of distribution load transfer and configuration studies by leveraging the accurate network topology and the state estimation function.
- Improves efficiency of storm management by providing a real time weather impact prediction model of the distribution system.

Other Distribution Operations Support programs include:

- Data Collection and Information Updates - funds the demand category work required to update distribution system connectivity information and gather accurate field information describing equipment additions and changes on the distribution system
- Distribution Storm Management Customer Satisfaction Surveys - conducted to obtain Hydro One customer feedback on measuring planned, unplanned and storm event outage management performance.
- Emergency Preparedness (Distribution) - funds the annual Provincial Lines work related to emergency generator testing, emergency communications testing, annual reviews of emergency preparedness procedures and the execution of emergency drills.
- Field Verification (Distribution) - verifies the accuracy of distribution station operating diagrams.
- Weather Prediction Tool – enables proactive mobilization in anticipation of major weather events
- RSA Archer – Business Continuity – identifies potential threats and impacts to Operations resulting from emergency events.

2.3 HEALTH, SAFETY AND ENVIRONMENT (HSE)

Programs within this category involve HSE initiatives that are required to meet Hydro One's legal obligations and to align with Hydro One's commitments to the safety of its employees, customers, the public and the environment. The HSE programs are described below, and the costs are presented in Table 6.

Safety Programs – These programs support Hydro One's Health and Safety Policy and Public Safety Policy, and include:

- **"Journey to Zero"** – As part of its commitment to becoming the safest and most efficient utility, Hydro One strives to eliminate all serious injuries and fatalities. The company's Journey to Zero program focuses on the implementation of the Safety Improvement Team's recommendations and a Human Success strategy. In essence, this program identifies situations in which potential errors could result in a workplace injury, customer interruption, or damage to assets and equipment, and recommends tools and behaviors to help minimize the likelihood of such errors.
- **Public Electrical Safety** – This program supports public safety education programs to ensure members of the public remain safe. The program focuses on the impact of power line contact, proximity to overhead power lines, danger of tampering with electrical equipment, etc. Education sessions include: the Building Safe Communities program; Hazard Hamlet electrical safety presentations to elementary school children across Hydro One's service territory; and public safety presentations at various community events.
- **Employee Health and Safety** – This program allows Hydro One to conduct specific employee occupational hygiene monitoring such as: indoor air quality, electromagnetic field frequency, noise surveys and assessment of employee exposures to physical, chemical and biological agents.
- **HSE Contractor Pre-Qualification** – This program entails comprehensive HSE reviews to ensure all hired contractors are qualified to carry out work for the company.

- **HSE Management System (HSEMS)** – Hydro One conducts maintenance audits to ensure its HSEMS is meeting the Occupational Health and Safety Assessment Series (OHSAS) standard and maintain the necessary registration for the HSEMS.

Training Programs – These programs support Hydro One's Health and Safety Policy and include:

- **Employee Health and Safety Learning** – This program ensures employees are educated on safe work practices and are prepared for the potential critical hazards they may face in the field or in the office. E-learning modules are developed and refreshed to enable remote training and allow the timely and cost-effective delivery of required training. Hydro One is also in the process of evaluating new training approaches (i.e. web casting, video streaming, mobile learning, simulation and knowledge transfer technologies) to improve training effectiveness. Hydro One endeavors to protect the safety of apprentices and future skilled labour by facilitating knowledge transfer from senior staff through alternative training technologies.
- **Specialized Training** – This program involves specialized training to certain field employees within Operations (i.e. Ice and Water Rescue, Human Success) to ensure that they are able to perform work in potentially hazardous situations.
- **Training Lab Installation/Maintenance** – This program supports the establishment of training labs and the ongoing need to ensure that up-to-date technology for training is available.

Environmental Programs – These programs support sustainability, biodiversity and heritage resource management in alignment with Hydro One's Environment Policy, and include:

- **Sustainability** – Promotes environmental sustainability, manages risks associated with environmental impacts and climate change, and supports Hydro One's commitments in connection with the Canadian Electricity Association's Sustainable Electricity Company designation.
- **Biodiversity** – Ensures compliance with federal and provincial laws regarding the protection of migratory birds, endangered species, and associated habitat. This program

involves the development of special treatment requirements for areas containing migratory birds and endangered species. It also involves developing and implementing a system to relay these requirements to staff responsible for developing work programs.

- **Heritage Resource Management** – Ensures compliance with heritage legislation by supporting studies, company policies and documentation to manage Hydro One's heritage assets.

Table 6 outlines the historical, bridge year and forecast HSE costs.

Table 6 - HSE Program Costs ($M)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
HSE Program Costs	**3.2**	**3.9**	**2.0**	**2.8**	**2.7**	**2.7**
Allocated to Transmission	1.4	2.0	1.1	1.5	1.4	1.4
Allocated to Distribution	1.8	1.9	1.0	1.3	1.3	1.3

The forecast HSE spend for 2023 is $2.7M, which is consistent with average historical spending and the forecasted costs for 2021 and 2022.

2019 costs are approximately $1M higher than average due to the launch of the Safety Culture and Human Success program and the completion of a Safety Assessment Survey. 2020 costs are approximately $1M lower than average largely due to the impact of the COVID-19 pandemic, which prevented the execution of the majority of Hydro One's Public Electrical Safety programs (including the inability to host education sessions as part of community events and in elementary schools throughout Hydro One's service territory).

COMMON CORPORATE COSTS OM&A - TRANSMISSION COST OF SALES - EXTERNAL WORK

1.0 OVERVIEW

This exhibit details Hydro One Transmission's cost of sales for external work. Hydro One directly tracks the cost of sales that include station maintenance activities, engineering and construction work and other smaller activities that are competitive services requested by customers and are individually priced. Exhibit D-02-01 describes the categories of external work and the associated revenues.

Hydro One does not directly track costs for all its unregulated service revenues, in particular for secondary land use and other external revenues. These costs are embedded in the company's Common Corporate costs, as further described in Exhibit E-04-01. The costing of external work is calculated the same way as for internal work and further described in Exhibit C-09-01 to C-09-04.

Table 1 provides Hydro One Transmission's cost of sales for the 2018-2023 period.

Table 1 - Cost of Sales – Transmission External Work ($M)

	Historic				Bridge	Test
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
	Actual	**Actual**	**Actual**	**F/Cast**	**F/Cast**	**F/Cast**
Station Maintenance	2.9	2.5	2.1	2.9	2.9	2.9
Engineering & Construction	0.1	0.1	0.2	0.4	0.4	0.4
Other	5.4	1.1	5.4	3.1	1.6	2.4
Total	**8.4**	**3.7**	**7.7**	**6.4**	**4.9**	**5.7**

The proposed 2023 Test Year budget of $5.7M is lower than the last rebasing actual expenditures in 2020[1] and lower than the prior five-year average (2018-2022: $6.2M). The proposed 2023 budget is lower than the 2021 forecast and higher than the 2022 forecast. The variance is primarily driven by the Other category of work, as further described below.

2.0 PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide variance analysis for each component comprising the cost of sales associated with external work.

2.1 STATION MAINTENANCE

Costs for station maintenance are directly related to the volume of work performed by Hydro One to support Ontario's key generating suppliers: Ontario Power Generation Inc., Siemens Westinghouse Inc. and Bruce Power LP. The 2023 Test Year expenditures are forecasted to be $2.9M, which is slightly higher than the most recent actuals and equal to the 2021-2022 forecasts. The increase is primarily driven by the adjusted scope of work Hydro One is required to provide.

2.2 ENGINEERING AND CONSTRUCTION

Hydro One's engineering and construction activities focus on various work supporting Hydro One Telecom Inc. (HOT). In particular, Hydro One supports HOT with its customers request for new interconnections with Hydro One's optical fibre infrastructure by providing design/quotes/builds related to HOT work within Hydro One's transmission station property.

Costs for engineering and construction are directly related to the volume of work performed by Hydro One to support Hydro One Telecom operations. The 2023 Test Year expenditures are

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[1] And lower than the 2023 amount that would result when adjusting the 2020 actuals for inflation: 2020 actual expenditures increased by inflation for 3 years: $7.7M x (1+2%)^3 = $8.2M i.e. ($5.7M/$8.2M - 1)% = -30%; Inflation as presented in Exhibit E-03-01.

forecasted to be $0.4M, which is slightly higher than the most recent actuals and equal to the 2021-2022 forecasts. The variance is primarily driven by an increased number of requests from HOT for new interconnections within Hydro One's optical fibre infrastructure.

2.3 OTHER

Other category expenditures represent the cost of work performed for Hydro One's affiliates, such as B2M and NRLP, and other miscellaneous cost of goods sold. The 2023 Test Year expenditures are forecasted to be $2.4M, which is lower than 2020 and 2021 but higher than the 2022 forecast. Similar to the categories above, expenditures in this category are directly related to the volume of work performed by Hydro One to support its affiliates.

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COMMON CORPORATE COSTS OM&A – DISTRIBUTION COST OF SALES – EXTERNAL WORK

1.0 OVERVIEW

This exhibit details Hydro One Distribution's costs for regulated and unregulated external revenues that are not included in other OM&A programs. Regulated Revenues are based on OEB-approved specific service charges, which are detailed in Exhibit L-04-01, whereas Unregulated Revenues are based on charges determined by Hydro One Exhibit D-02-02 which describes the associated external revenues over the 2023 to 2027 period.

In this Exhibit, the cost of Regulated Revenue consists of: new connections primarily of subdivision and rural residential facilities, service upgrades to increase supply capacity, street light maintenance, and forestry work. The cost of Unregulated Revenue includes costs associated with storm restoration, Hydro One Remotes transport work equipment used for emergency services and Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) training and development.

Table 1 sets out Hydro One's planned expenditures for the 2023 Test Year, along with the forecast and actual spending levels for the Bridge Year (2022) and Historical Period (2018-2021) years, for each of the four Sustainment OM&A categories.

The envelope and Test Year forecast variances throughout this exhibit rely on a comparison of the 2018 actual amounts escalated by inflation as detailed in Exhibit E-03-01.

Table 1 - Summary of OM&A Costs of External Revenue ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Cost of Regulated Revenue	1.2	1.2	1.3	2.4	2.4	2.5
Cost of Unregulated Revenue	9.2	4.1	2.8	2.9	2.9	2.9
Total	**10.4**	**5.3**	**4.1**	**5.3**	**5.3**	**5.4**

The forecast Distribution OM&A Costs of External Revenue expenditure for 2023 is $5.4M, which is $6.1M, or 53% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($11.5M). Hydro One has been able to keep total Costs of External Work OM&A expenses at a rate of growth significantly less than inflation.

The 2023 forecast expenditure is lower than the average historical and forecast expenditures (2018-2021) by about $1.0M and in-line with the 2022 Bridge and 2021 Forecast expenditures. Relative to 2020 and 2018 actuals, the 2023 forecast expenditure is $1.3M higher and $5.0M lower respectively. The increase relative to 2020 actuals is primarily due to increases in the forecasted cost of regulated revenues, as described below.

The 2023 Test Year forecast for Cost of Regulated Revenue of $2.5M is $1.2M or 88% higher than the 2023 figure that would result from escalating the 2018 last rebasing actual by inflation ($1.3M). Relative to the average historical and forecast expenditures (2018-2021), the 2023 test year forecast is $1.0M higher primarily due to higher forecasted contestable emergency work, customer connections and joint use services, which consists of construction activities and vegetation management. Compared to 2022 Bridge and 2021 Forecast, the 2023 Test Year expenditure is in-line. Relative to 2020 and 2018 actuals, the 2023 forecast is $1.2M and $1.3M higher respectively, for the same reasons noted above.

The 2023 Test Year forecast for Cost of Unregulated Revenue is $2.9M which is $7.3M or 72% lower than the 2023 figure that would result from escalating the 2018 last rebasing actual expenditure by inflation ($10.2M). The 2023 forecast is lower or in-line relative to historical, forecast, and bridge year expenditures. Expenditures for 2018 and 2019 were higher than expected due to unexpected storm restoration efforts in Manitoba, Nova Scotia, Baltimore, Boston and Vermont. Hydro One has been able to keep the Cost of Unregulated Revenue OM&A expenses at a rate of growth significantly less than inflation.

2.0 PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

2.1 COST OF REGULATED REVENUE

PROGRAM INTRODUCTION

Table 2 - Cost of Regulated Revenue OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Cost of Regulated Revenue	1.2	1.2	1.3	2.4	2.4	2.5
Total	**10.4**	**5.3**	**4.1**	**5.3**	**5.3**	**5.4**

The cost of Regulated Revenue consists of miscellaneous services such as: customer new connects and service upgrades, street light maintenance and forestry work.

EXPENDITURE FORECAST LEVEL

The forecast expenditure is based on the levels of forecasted, customer connections and joint use services, which consists of construction activities and vegetation management. Given the demand nature of this work, forecasts are based on historical volumes.

2.2 COST OF UNREGULATED REVENUE

PROGRAM INTRODUCTION

Table 3 - Cost of Unregulated Revenue OM&A ($M)

	Historical				Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Cost of Unregulated Revenue	9.2	4.1	2.8	2.9	2.9	2.9
Total	**10.4**	**5.3**	**4.1**	**5.3**	**5.3**	**5.4**

The cost of Unregulated Revenue is comprised of costs associated with Hydro One Remotes transport work equipment usage on emergency services, MEARIE training and development and storm support.

EXPENDITURE FORECAST LEVEL

Forecast expenditure is based on the levels forecasted for MEARIE training and Hydro One Remote operations, of which work equipment usage for Remote work contributes to the majority of expenditures. The forecast is informed by Hydro One Remotes to complete annual vegetation and line maintenance activities and corresponding fleet requirements.

COMMON CORPORATE COSTS & ALLOCATION METHODOLOGY

Hydro One defines Common Corporate Costs as costs incurred to provide service on a shared basis to Hydro One Networks and its affiliate companies. Examples of Hydro One's shared functions include, but are not limited to, Finance, Human Resources, General Counsel, Planning, and Regulatory Affairs. The provision of these services is centralized to enable them to be delivered to Hydro One Networks and its affiliates efficiently. In addition to the need to allocate Common Corporate Costs between Hydro One Networks and its affiliate companies, for those Common Corporate Costs that are allocated to Hydro One Networks there is a further need to allocate Common Corporate Costs to the Distribution and Transmission business segments.

Hydro One uses a Common Corporate Cost allocation methodology to allocate these costs among affiliates and business segments. A list of Hydro One's affiliates and business segments can be found in Table 4 of Attachment 1 to this exhibit. To the extent that these costs cannot be directly assigned and charged to a particular affiliate or business segment, Common Corporate Costs are allocated either on the basis of cost drivers (e.g., HR is allocated based on headcount) or on the basis of time surveys and time studies (e.g. interviews and time tracking studies). The purpose of the allocation process is to ensure that affiliates and business segments each share a portion of the cost that is appropriate for the level of service they receive.

Common Corporate Costs can be incurred in support of both OM&A work and Capital work. Consequently, it is necessary to allocate some Common Corporate Costs to Capital work. This is completed through the application of an Overhead Capitalization Rate, which is an additional charge on Capital work to recover a portion of Common Corporate Costs that is commensurate with the level of service provided on a shared basis in support of that Capital work. Exhibit C-08-02 covers the Overhead Capitalization Rate in greater detail.

For greater clarity, in instances when costs can be directly attributed to OM&A or Capital work for an affiliate or business segment for a sustained period of time, those costs are assigned directly to the relevant affiliate or business segment in connection with the specific OM&A or Capital work that is being completed. These direct costs are excluded from Hydro One's Common Corporate Cost Allocation Methodology because they are assigned or transferred to the relevant affiliate or business segment prior to calculating the total Common Corporate costs that are considered in the allocation methodology. Any costs that are not billed directly are subject to the Common Corporate Cost Allocation Methodology.

Common Corporate Costs as defined by Hydro One include the provision of Common Corporate Functions and Services (CCF&S) costs (Exhibit E-04-02) and portions of Customer Care costs (Exhibits E-02-04 and E-03-04), Planning costs (Exhibit E-04-03), System Operating (Operations) costs (Exhibit E-04-05) and Information Solutions costs (Exhibit E-04-04).[1]

1.0 ALLOCATION METHODOLOGY

Since 2004, in connection with each rate application for Transmission and Distribution, Hydro One has engaged an independent expert to prepare a Common Corporate Cost Allocation Study to recommend a best practice methodology for allocating common corporate costs among the affiliates and business entities which receive services from the shared functions, and to provide a report setting out their findings and recommendations.

The initial Common Corporate Cost Allocation Methodology was developed for Hydro One by Black and Veatch Corporation (B&V) in 2004. B&V was routinely engaged by Hydro One in subsequent proceedings to refine the previously approved methodology on a go forward basis. This methodology was utilized and subsequently endorsed by the OEB in each of the following Transmission revenue requirement proceedings: EB-2006-0501/EB-2008-0272/EB-2010-0002/EB-2012-0031/EB-2014-0140/EB-2016-0160/EB-2019-0082 as well as in each of the

[1] System Operating (Operations) Costs as presented in Exhibit E-04-05 and Customer Care Costs as presented in Exhibits E-02-04 and E-03-04 are not part of Summary of Common Corporate Costs presented in Exhibit E-04-01.

following Distribution rate proceedings: RP-2005-0020/EB-2005-0378/EB-2007-0681/EB-2009-0096/EB-2013-0416/EB-2017-0049.

Hydro One agrees with the OEB's most recent Transmission and Distribution decisions to "conduct a detailed review of Hydro One's common corporate costs and shared assets allocation methodologies".[2] As a result, for the current application, Hydro One undertook a competitive RFP process to select an appropriate vendor to undertake a detailed assessment of each of the following: (i) Common Corporate Cost Allocation Methodology, (ii) Overhead Capitalization Methodology, and (iii) Methodology for allocating Shared Assets.[3] Though open to engaging a new expert, after evaluating multiple proposals Hydro One selected B&V once again for this engagement. However, B&V was selected with a new lead expert for the study, and a mandate to take a fresh, detailed and critical look at the methodologies and to refine them where appropriate on the basis of best practises. The 2023 Black and Veatch report (2023 B&V Study) is provided as Attachment 1 to this exhibit, with conclusions and results outlined on page 28 of the report.

The three studies performed by B&V are related, and to an extent dependent on each other, as they utilize common drivers underpinned by the principles of cost causation. Common Corporate Costs are allocated to the affiliates and business units utilizing the cost allocation Methodology, and applicable costs are then allocated to capital work via overhead rates, set by the Overhead Capitalization methodology (see Exhibit C-08-02). The Shared Assets rates are

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[2] In its Decision and Order in EB-2019-0082 at p. 95, the OEB ordered that "a detailed review of Hydro One's common corporate costs and shared assets allocation methodologies (capital and OM&A) be filed as part of Hydro One's combined transmission and distribution application due to be filed for 2023 revenue requirement and rates." Furthermore, in its Decision and Order in EB-2017-0049 at p. 79, the OEB indicated that it expects the common corporate allocation methodologies to be examined in detail when Hydro One files a single application for distribution rates and transmission revenue requirement.
[3] While the allocation of Shared Assets is assessed together with the Common Corporate Cost Allocation Methodology and the Overhead Capitalization Methodology in a single consolidated report from B&V, the allocation of Shared Assets component of that report is not relevant to this exhibit and is instead discussed in Exhibit C-03-01.

determined using the output of the study, and are used to allocate assets between Transmission and Distribution (see Exhibit C-03-01).

As part of the 2023 B&V Study, and consistent with its prior practice in supporting Hydro One rate applications, detailed interviews were conducted by Black and Veatch for all common corporate departments in order to update the services provided and cost drivers used to allocate the common corporate costs in prior proceedings.

In contrast to prior proceedings, Hydro One's Planning (Asset Management), Operating (Network Operating) and Customer Service departments (Customer Care) have historically conducted time studies to support cost allocation as part of the methodology. However, for this engagement, organizational realignment has allowed for more direct allocations to be made via time surveys and driver based allocations.

Hydro One accepts the results of the 2023 B&V Study as a reasonable and fair approach to the allocation of common corporate costs among the affiliates and business segments using the services of the shared functions. This methodology is largely based on the methodology employed in prior studies and accepted by the OEB in numerous Distribution and Transmission rate decisions (see Appendix A of Attachment 1 to this exhibit). Enhancements to the Common Corporate Cost Allocation methodology, include the introduction of time surveys for all services provided on a shared basis rather than using specific four-week time studies for a limited subset, enhancements related to the presentation of executive costs in connection with *Hydro One Accountability Act, 2018* (Bill 2), and the introduction of a three-factor allocation driver to reflect the fact that the effort associated with carrying out particular activities relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity.

2.0 2022 BRIDGE YEAR ALLOCATED AMOUNTS

Table 1 below provides the annual allocation of 2022 bridge year CCF&S costs, to all business units by department.

Table 1 - Allocation of 2022 Bridge Year CCF&S Costs ($M)

	Total	Transmission	Distribution	Other
Corporate Management	**22.4**	2.0	2.7	17.7
Finance	**34.8**	14.8	16.2	3.8
Human Resources	**23.5**	11.0	10.8	1.7
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	**15.1**	7.3	7.1	0.7
General Counsel	**9.7**	4.7	4.0	1.0
Regulatory Affairs	**23.3**	11.6	11.0	0.7
Security Management	**5.7**	3.0	2.6	0.1
Internal Audit	**6.4**	3.2	3.2	0.0
Facilities and Real Estate	**67.0**	37.3	29.7	0.0
Total CCF&S Costs	**207.8**	**94.9**	**87.2**	**25.7**

3.0 2023 TEST YEAR ALLOCATED AMOUNTS

Table 2 below provides the annual allocation of 2023 test year CCF&S costs, to all business units by department.

Table 2 - Allocation of 2023 Test Year CCF&S Costs ($M)

	Total	Transmission	Distribution	Other
Corporate Management	**25.4**	2.1	2.8	20.5
Finance	**33.9**	14.4	15.7	3.9
Human Resources	**26.3**	12.4	12.1	1.8
Indigenous Relations, Communications and Stakeholder Relations, and Outsourcing Services	**15.6**	7.6	7.3	0.7
General Counsel	**9.9**	4.8	4.1	1.0
Regulatory Affairs	**21.5**	10.6	10.3	0.6
Security Management	**5.9**	3.1	2.6	0.1
Internal Audit	**6.7**	3.3	3.4	0.0
Facilities and Real Estate	**69.5**	38.7	30.8	0.0
Total CCF&S Costs	**214.6**	**96.9**	**89.1**	**28.6**

The amounts allocated to Other in Table 1 and Table 2 above reflect costs allocated Hydro One Inc., Hydro One Limited, Hydro One Networks Non-regulated segment, Hydro One Remotes, B2M, NRLP, HOSSM as well as other non-regulated segments. Hydro One has excluded from its request for recovery in this application any costs that have not been allocated to Hydro One Networks' Transmission and Distribution business segments (as well as any costs that must be excluded on the basis of the *Hydro One Accountability Act, 2018* (Bill 2)).

Table 3 below reconciles the results of the B&V methodology with the allocation of 2023 test year CCF&S costs from Table 2.

Table 3 - B&V Methodology and Common Cost Reconciliation for 2023 ($M)

	Total	Transmission	Distribution	Other
Black & Veatch Study	**303.8**	130.6	139.6	33.6
Less Planning	**-42.5**	-27.4	-14.9	-0.2
Less System Operating	**-53.8**	-25.0	-27.0	-1.8
Less Customer Care	**-40.9**	-6.6	-32.4	-1.9
Less IT Services	**-11.4**	-4.7	-5.6	-1.1
Plus Facilities	**59.5**	30.0	29.5	-
CCF&S Total	**214.6**	**96.9**	**89.1**	**28.6**

4.0 VARIANCE ANALYSIS

Variance analysis with explanations is provided in Exhibit E-04-02 for CCF&S, Exhibit E-04-03 for Planning, Exhibit E-04-04 for Information Solutions, Exhibit E-02-04 and Exhibit E-03-04 for Customer Care and Exhibit E-04-05 for System Operating (Operations).

Hydro One Networks Inc.

REPORT ON CORPORATE COST ALLOCATION REVIEW

JUNE 9, 2021

BLACK & VEATCH

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1 Glossary

Affiliate: A corporation is an affiliate of another if one of them is a subsidiary of the other or both are subsidies of the same corporation or each is controlled by the same person, as further defined in the Business Corporations Act (Ontario).

Affiliate Relationships Code: Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters, revised March 15, 2010, sets out rules that govern the conduct of utilities as that conduct relates to their respective Affiliates. This code covers a number of objectives with the following two relating to the content of this report and the 2020 Review: (1) protecting ratepayers from harm that may arise as a result of dealings between a utility and its affiliate; (2) preventing a utility from cross-subsidizing affiliate activities.

Capitalized Common Corporate Costs: A portion of applicable Common Corporate Costs that support capital expenditures and are included as overhead costs on Transmission and Distribution capital expenditures.

Common Corporate Costs: Costs incurred to provide Shared Services to Hydro One and its affiliate companies.

Corporate & Shared Cost Allocation Methodology: The methods and processes employed to allocate common corporate costs among Hydro One, its Affiliates, and the Tx and Dx businesses comprised of three components: (1) the allocation of Common Corporate Costs, (2) a methodology for capitalizing Common Corporate Costs for the Tx and Dx businesses, and (3) a methodology to allocate the use of Shared Assets.

Cost Causation: The guiding principle for cost allocation is that cost responsibility should follow cost causation. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the cost that has been incurred. Costs are recognized as being caused by a service or group of services if (a) the costs are brought into existence as a direct result of providing the service or group of services; or (b) the costs are avoided if the service or group of services is not provided.

Cost Center: The lowest tier of Hydro One's organizational structure where Costs Centers roll-up into individual Line of Businesses.

Overhead Capitalization Rate: Percentages that are applied to the cost of Transmission and Distribution capital expenditures to recover the Capitalized Common Corporate Costs.

Overhead Capitalization Rate Methodology: The methods and processes employed to develop the Overhead Capitalization Rate for the Transmission business and the Overhead Capitalization Rate for the Distribution business.

Shared Assets: Tangible and intangible fixed assets that are held by Hydro One Networks and are utilized by multiple businesses of Hydro One.

Shared Services: Centralized business operations that support multiple businesses, affiliated companies, or multiple parts of the same organization.

2 Summary

2.1 PURPOSE AND ORGANIZATION OF REPORT

Black & Veatch Canada Company ("Black & Veatch") is pleased to submit to Torys LLP, as legal counsel on behalf of Hydro One Networks Inc. ("Hydro One"), this Report which describes our Corporate & Shared Cost Allocation Methodology review. The review conducted by Black & Veatch establishes a methodology to allocate corporate costs among Hydro One, its affiliate companies, and between the Transmission ("Tx") and Distribution ("Dx") businesses with three components: (1) a methodology to allocate Hydro One's common corporate operation, maintenance, and administrative ("OM&A") costs ("Common Corporate Costs"), (2) a methodology for capitalizing a portion of Common Corporate Costs for the Tx and Dx businesses, and (3) a methodology to allocate the use of Shared Assets. In general, the methods employed across these three components are described collectively as Hydro One's Corporate & Shared Cost Allocation Methodology. Our work updating and evaluating Hydro One's Corporate & Shared Cost Allocation Methodology began in April 2020 and continued through May 2021. 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.

Black & Veatch is experienced in conducting affiliate cost allocation reviews across North America and have provided reports to Hydro One on their Corporate & Shared Cost Allocation Methodology since 2005. The general methodology first recommended by Black & Veatch, adopted by Hydro One, and accepted by the OEB during Black & Veatch's first engagement in 2005 has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with subsequent reports issued in numerous Tx and Dx base rate proceedings. A list of these past reviews and reports is provided in Appendix A.

In the OEB's March 7, 2019 decision in the matter of Hydro One's Distribution Rates for 2018 to 2022 (EB-2017-0049), the OEB indicated that, as part of Hydro One's rebasing application for Transmission revenue requirement and Distribution rates for 2023-2027, the OEB intends to examine Hydro One's Corporate & Shared Cost Allocation Methodology in detail. The OEB reiterated this expectation in its decision on Hydro One's Transmission Rate application for 2020-2022 (EB-2019-0082). The goal of this Report is to provide details on Hydro One's methods to aid in the OEB's understanding and review. Further, during past reviews, reports were prepared and submitted independently for the three components (allocation of Common Corporate Costs, capitalization of Common Corporate Costs, and allocation of Shared Assets) and separately for the Tx and Dx businesses. This report will cover the three components jointly and discuss the results for both the Tx and Dx businesses. The major sections of this report are described below.

1. Glossary –Definitions of key terms used within this report.

2. Summary – Provides a description of the report, Black & Veatch's assignment, descriptions of the three components, and executive summary of the conclusions.

3. Corporate Cost Allocation Framework – Discusses the use of and reliance on Shared Services and Shared Assets and provides a description of the Hydro One organization.

4. Guiding Principles of Cost Allocation – Covers the primary principles employed in developing the Corporate & Shared Cost Allocation Methodology.

5. Allocation of Common Corporate Costs – Describes the methodology used to allocate Hydro One's Common Corporate Costs among Hydro One, its affiliate companies, and between the Tx and Dx businesses.

6. Overhead Capitalization Rate Methodology – Describes the methods used to develop the Overhead Capitalization Rates which are applied to the cost of Transmission and Distribution capital expenditures to recover the Capitalized Common Corporate Costs.

7. Allocation of Shared Assets – Describes the method used to allocate the use and cost of Shared Assets among Hydro One, its affiliate companies, and between the Tx and Dx businesses.

2.2 BLACK & VEATCH'S ASSIGNMENT

Black & Veatch focused our effort during this review on evaluating and identifying changes in the methodology that may be appropriate due to changes in the business of Hydro One, changes arising from outside factors (e.g., governmental or regulatory requirements), technological change (e.g., availability of additional or more detailed information), or other relevant considerations. The goal of this detailed and methodical review was to recommend and establish a best practice Corporate & Shared Cost Allocation Methodology for Hydro One for each of the three components described in detail below.

Consistent with Black & Veatch's standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., headcount, budgeted amounts) subject only to their overall reasonableness and factual accuracy, but without our independent confirmation.

2.3 COMPONENTS OF HYDRO ONE'S CORPORATE & SHARED COST ALLOCATION METHODOLOGY

The three components of Hydro One's Corporate & Shared Cost Allocation Methodology are described below.

2.3.1 Allocation of Common Corporate Costs

Common Corporate Costs are incurred to provide Shared Services to Hydro One and its affiliate companies. The provision of these Shared Services is centralized so there is a need to allocate costs across the various Affiliates utilizing either cost drivers (e.g., certain Human Resources costs are allocated on company headcount) or time surveys and studies (e.g., interview and time tracking studies). The purpose of these allocations is to ensure no cross-subsidization between Affiliates nor between the Tx and Dx businesses by allocating Common Corporate Costs in accordance with the level of services being received.

An overview of the methodology is described below:

- Through interviews with Hydro One personnel, identify the Shared Services included in Common Corporate Costs and the particular activities performed to provide these Shared Services.
- Through interviews with Hydro One personnel, time surveys, and analyses of time spent by employees, distribute the costs of each Shared Service among the activities performed by that Line of Business to provide that Shared Service.
- Distribute the cost of each activity among Hydro One, its affiliate companies, and between the Tx and Dx businesses based on direct assignment (see Section 4.3) or on cost drivers (see Section 4.4) when direct assignment is not possible.

Further, in instances when costs associated with Common Corporate Costs can be directly attributed to work for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers. These costs are not included in Hydro One's Corporate & Shared Cost Allocation Methodology given they are recorded and transferred prior to determining the total Common Corporate Costs that are included in the allocation methodology.

2.3.2 Capitalizing Common Corporate Costs for Tx and Dx Businesses

Common Corporate Costs support both OM&A expenditures and capital expenditures; so there is a need to further distinguish Common Corporate Costs between those that (a) only support OM&A expenditures, (b) directly support capital expenditures, and (c) are overhead costs that support both OM&A expenditures and capital expenditures. Those costs that directly support capital expenditures and a portion of the overhead costs that support both OM&A expenditures and capital expenditures, are recovered through an Overhead Capitalization Rate. This rate is an additional charge on capital expenditures to recover Common Corporate Costs in proportion to the amount of Shared Services used to support those projects. Costs that only support OM&A expenditures are excluded from this calculation.

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.

2.3.3 Allocation of Shared Assets

In addition to the allocation of Common Corporate Costs it is necessary for compliance with the Affiliate Relationships Code to also allocate the use of Shared Assets among Hydro One, its affiliate companies, and between the Tx and Dx businesses. The general process employed to conduct this review was to gain an understanding of the particular nature of the Shared Assets, the Shared Services that the Shared Assets provide support for, and the use of the Shared Assets by Hydro One, its Affiliates, and the Tx and Dx businesses. With this understanding, allocation options were reviewed and decided upon to allocate the costs of these Shared Assets among Hydro One, its

Affiliates, and the Tx and Dx businesses. The results of this allocation support the development of the Tx and Dx revenue requirements and transfer pricing relating to the use of Shared Assets.

2.4 EXECUTIVE SUMMARY - RESULTS OF REVIEW

Black & Veatch believes that Hydro One's Corporate & Shared Cost Allocation Methodology is appropriate for Hydro One, because it achieves the purposes for which it was designed: to distribute costs in a manner that is consistent with OEB precedent and established regulatory practice for cost allocation, to ensure legislative compliance (i.e., Hydro One Accountability Act), and to promote transparency and efficiency.

While the general methodology employed by Hydro One remains the same as past Corporate & Shared Cost Allocation Methodologies, there are a few modifications and improvements made during the 2020 review. The 2020 Review conducted by Black & Veatch resulted in the following enhancements:

Time Surveys - In each of the past reviews, some of the allocation factors were developed using time studies, whereby individuals across specific Shared Services (customer relations, asset management, and operations) tracked their daily time for a four-week period. As a result of feedback and considerations made by Black & Veatch during this 2020 Review, the four-week time study was replaced with a time survey in which individuals were asked about time spent by a particular Cost Center's employee or those employees were asked directly. Rather than review a specific four-week period through a time study, interviews were conducted, and details were provided on how the employees in these Cost Centers spend their time across the entire year by using a time survey.

Hydro One Accountability Act, 2018 (Bill 2) - During the 2020 review Black & Veatch recommended updating the methodology to reflect cost-causative principles when allocating all executive costs but to flag Hydro One Accountability Act, 2018 (Bill 2) costs so they can easily be traced through the method and excluded when developing any costs for ratepayer recovery.

Three-Factor Allocation Driver - For Hydro One's Corporate & Shared Cost Allocation Methodology the three-factor allocation driver based on Capital, Labour, and Revenue was utilized to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor. Previously the methodology utilized two multi-factor allocations; (a) an equal weighting of total revenue and total assets and (b) an equal weighting of total revenue and total OM&A.

The methods being employed by Hydro One are directly in alignment with past methods resulting from the previous reviews conducted by Black & Veatch. While each review is unique and enhancements to the general methods have been made incrementally during each review they are in alignment with methods first recommended by Black & Veatch, adopted by Hydro One, and accepted by the OEB during Black & Veatch's first engagement in 2005. These methods have since been applied to Hydro One's Business Plans and reviewed by Black & Veatch with subsequent reports issued in numerous Tx and Dx rate proceedings. In these past rate proceedings, the results of Hydro One's Corporate & Shared Cost Allocation Methodology have directly been utilized in the development of Tx and Dx revenue requirements, subjected to intervenor and regulatory scrutiny and accepted by the OEB as part of the approved revenue requirement calculation methodology.

2.4.1 Summary Tables of Corporate & Shared Cost Allocation Methodology

Hydro One's Corporate & Shared Cost Allocation Methodology has been applied by Hydro One to its Business Plan data for 2023 and the results of this methodology for the three components are provided below.

Table 1 - Distribution of Annual Common Corporate Costs

Business	2023
($ Millions)	$
Transmission	130.59
Distribution	139.61
Other	33.62
Total	303.81
(% of Total)	%
Transmission	43%
Distribution	46%
Other	11%
Total	100%

Table 2 - Overhead Capitalization Rate for Tx and Dx Businesses

OVERHEAD CAPITALIZATION RATE	2023
Transmission Rate	8.00%
Distribution Rate	9.00%

Table 3 - 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%**

3 Corporate Cost Allocation Framework

3.1 THE USE OF AND RELIANCE ON SHARED SERVICES AND ASSETS

Large corporations utilize Shared Services as an effective and efficient strategy for providing support services to affiliate companies and different business segments. The choice to provide Shared Services rather than to deliver services within each affiliate separately is dependent on the balance between the costs and benefits of decentralized and centralized provision of the services. The centralized provision of services benefits from economies of scale, efficient transfer of knowledge, common systems & support, and the ability of management to identify efficiencies and alignment across Affiliates. Decentralized operations can result in higher costs and different standards but also may provide a benefit of flexibility and recognition of specific requirements. For those services whose benefits outweigh the costs, the provision of the services centrally to multiple Affiliates is more desirable. For those services that require unique functions that only relate to one affiliate or in instances where the service benefits from the flexibility and ability to take into account the unique requirements of an affiliate these should remain decentralized. In the end, the balance of centralized vs. decentralized services is largely a question of corporate organizational strategy and will not be exactly the same for all entities. This is a similar question for Shared Assets, where questions of when to share the use of assets across multiple Affiliates and when to purchase assets solely to service one affiliate will depend on the nature of the asset and the particular requirements of the affiliate. Savings can be expected from economies of scale when investing in assets that serve multiple Affiliates; even if those Affiliates may be serving different markets (e.g., software infrastructure, office buildings).

Hydro One has developed an organizational structure to take advantage of the benefits of Shared Services and Shared Assets. There are still many functions and assets that remain decentralized given they are directly serving one affiliate or the Tx or Dx businesses, and benefit from direct fulfillment of specific and unique requirements of that affiliate or the Tx or Dx business.

3.2 HYDRO ONE'S ORGANIZATIONS

The Hydro One group of companies includes the wholly owned subsidiaries and partnerships listed in **Table 4**. The OEB regulates, separately, the businesses identified as such in **Table 4**. Each regulated business is required to account separately for its assets, revenues and costs, for both regulatory and financial accounting purposes.

Table 4 – Hydro One Affiliates and Businesses

SUBSIDIARY	BUSINESS SEGMENT	REGULATED	DESCRIPTION
Hydro One Ltd.	Holding	No	Public company that owns Hydro One Inc. and Hydro One Telecom Inc. and other non-regulated businesses. Hydro One Ltd. is owned by public shareholders as well as the Province of Ontario.
Hydro One Inc.	Holding	No	Subsidiary of Hydro One Ltd. Acts as the holding company of Hydro One's rate regulated businesses, including Hydro One Networks Inc.
Hydro One Networks Inc.	Distribution	Yes	Owns and operates a distribution system which spans approximately 75% of Ontario and serves over 1.3 million customers.
	Transmission	Yes	Owns and operates substantially all of Ontario's electricity transmission system.
	Non-Regulated	No	Costs incurred by Hydro One Networks in support of the Dx and Tx businesses that are not recoverable from ratepayers.
Hydro One Sault Ste. Marie Limited Partnership	HOSSM	Yes	Subsidiary company of Hydro One Inc. that connects Northern Ontario to Southern Ontario and is the second-largest electricity transmitter in the Province
Hydro One Remote Communities Inc.	Remotes	Yes	Subsidiary company of Hydro One Inc. that owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario.
B2M Limited Partnership	B2M Transmission	Yes	B2M is a partnership that carries on the business of owning and operating a continuous transmission line between the Bruce Nuclear Power Development and Hydro One's Milton Switching station.
Niagara Reinforcement Limited Partnership	NRLP Transmission	Yes	NRLP is a partnership that carries on the business of owning and operating a transmission circuit between the Allanburg Transmission Station near Niagara Falls and Hydro One's Middleport Transmission Station.
Hydro One Telecom Inc.	Telecom	No	Subsidiary company of Hydro One Ltd. that sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.

4 Guiding Principles of Cost Allocation

4.1 THE NEED FOR COST ALLOCATION

Cost allocation is required when costs are not tracked for each activity that relates to an individual recipient of services. For instance, a Shared Service employee in accounts payable could track time spent processing each invoice and the entity being charged for that invoice and this time sheet record could be used to allocate costs for that employee to each entity. However, this is not practical or desirable given invoices may relate to multiple entities, time spent may be on improving or ensuring the process of reviewing invoices is effective, and activity-based time tracking requires significant time for the employee simply to track their time spent. If this was always practical, then there would be no need for cost allocation principles or methods; costs would simply follow the time sheets for all employees. This however is not practical given the time and effort for employees to track their time and the fact that there will always be employees who work on processes or projects that simultaneously benefit multiple business entities (i.e., the accounts payable manager who trains employees and works with the information systems division to develop more streamlined processes).

4.2 PRINCIPLES OF COST ALLOCATION

The guiding principle for cost allocation is that cost responsibility should follow cost causation. As such, company policy and allocation methodology should satisfy the following criteria:

- The method should be based on cost causation. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the cost that has been incurred. Costs are recognized as being caused by a service or group of services if (a) the costs are brought into existence as a direct result of providing the service or group of services; or (b) the costs are avoided if the service or group of services is not provided.
- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is benefits received (i.e., allocated to the business that received the benefits).
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.

- When relying on estimates, results should be unbiased, reasonably consistent with comparable data, and provided by employees familiar with the costs.

4.3 METHODS OF COST ALLOCATION

There are two methods to allocate or distribute shared costs among a utility's businesses – **Direct Assignment** and **Allocation**.

Direct Assignment is used when it can be reasonably determined that all or a designated portion of an activity is performed for a particular business. Direct Assignment is completed through the use of time studies or time surveys; where participants either fill out time sheets during a sample period or provide an indication of how their time is spent throughout the year.

Allocation is used when more than one business uses an activity, but the portions of the activity that each use cannot be directly established through a time study or time survey. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those entities that cause the cost to be incurred.

4.4 COST DRIVERS

As stated above, a cost driver is a formula for sharing the cost of an activity among those entities that cause the cost to be incurred. The guiding principle that Black & Veatch uses in assigning cost drivers is cost causation and, in cases when cost causation cannot be easily established, cost drivers are assigned based on a review of the level of benefits received (e.g., diversity and inclusion activities may not be caused by a particular affiliate or group of businesses, but the benefits of the programs can accrue to the Affiliates and businesses who participate in the strategies, plans, programs and policies).

Other factors considered in assigning cost drivers include:

- **Practicality** – The cost driver should be understandable, obtainable at reasonable cost, and objectively verifiable in the initial year as well as in subsequent years.
- **Stability** – Cost driver values should be reasonably stable from year to year. When estimates are used, the cost driver should be able to be estimated with reasonable accuracy, and estimates should be unbiased.
- **Materiality** – When choosing between cost drivers, small differences can often be ignored in favor of the above-listed factors, Practicality and Stability.

4.5 TYPES OF COST DRIVERS

Cost drivers can be classified as **External** or **Internal**. **External** drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts. **Internal** drivers are based on values computed as an integral part of the cost allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities.

Table 5 – Types of Cost Drivers

TYPE	DESCRIPTION	EXAMPLES
External Cost Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Headcount (of employees), Kilometers of Lines
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Program Project Costs, Total capital, Total revenue
Blended or Multi-Factor	Weighted combinations of other drivers, used when one or more drives are applicable, and none is clearly preferable	Equal weighting of Capital, Labour, Revenue
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

4.6 BLENDED OR MULTI-FACTOR ALLOCATION

The use of a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified, is a broadly respected and common practice across the utility industry. The most common multi-factor allocation is a three-factor formula, with each factor equally weighted (generally referred to as the Massachusetts Formula), where the three components of the factor are representative of: (1) Capital, (2) Revenue, and (3) Labour. The implementation of the Massachusetts Formula varies slightly as entities use different measures to represent the three components (e.g., net plant/rate base, revenue/margin, labour/headcount).

Often the multi-factor allocator is chosen to account for the idea that the size and scope of a business impacts the level of services provided to that entity from certain common corporate services. The corporate services that are impacted by the size and scope of the business are typically executive costs, board of directors, corporate affairs, CFO/controller, general counsel, and strategic planning. These are high-level costs that relate to the oversight and strategy of the business. The inability to find a single direct assignment that is most appropriate leads to the use of a multi-factor allocation that reasonably represents the size and scope of the business, which impacts the time and effort spent or the service received from these common corporate services. In short, it is more common to see multi-factor allocations as the requirement for an allocation moves away from direct operations up the organization to high-level support and strategy where multiple factors relate to the time and effort spent and benefits received.

For Hydro One's Corporate & Shared Cost Allocation Methodology the three-factor allocation driver based on Capital, Labour, and Revenue was utilized as appropriate to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor.

5 Allocation of Common Corporate Costs

5.1 PURPOSE OF ALLOCATING COMMON CORPORATE COSTS

Hydro One's organizational structure takes advantage of the benefits of Shared Services and as a result it is necessary to allocate the costs for these Shared Services among Hydro One, its affiliate companies, and between the Tx and Dx businesses. While this allocation is in place to avoid cross-subsidization and comply with the Affiliate Relationships Code it also allows Hydro One leadership to evaluate all costs incurred by each affiliate.

5.2 SHARED SERVICES

Hydro One provides Shared Services through the Lines of Business identified in **Table 6**, to the Affiliates and businesses identified in Table 4. Appendix B further describes the Lines of Business listed below.

Table 6 – Lines of Business Providing Shared Services

Cost Grouping	Line of Business
Corporate	Board of Directors Ombudsman President/CEO Office
Customer & Corp Affairs	Corporate Affairs Corporate Sustainability Customer Service External Relations Indigenous Relations
Finance	Audit Business Analysis Chief Financial Officer Corporate Controller Corporate Development Data Governance Facilities & Real Estate Investor Relations Outsourcing Pension Risk Strategic Finance Strategy & Innovation SVP Finance Tax

Cost Grouping	Line of Business
	Treasury
Human Resources	Change Management Labour Relations Talent Management Total Rewards Workforce Acquisition & Support Center
Information Solutions Division	Information Solutions Division
Legal & Secretariat	Corporate Secretariat General Counsel Regulatory Affairs
Operations	Chief Operating Officer Planning System Control

The Lines of Business in **Table 6** organize themselves into Cost Centers which may represent a single activity or multiple activities. For instance, the Audit Line of Business contains two Cost Centers one of which supports financial control assurance and the other provides four services relating to (1) financial statement support, (2) IT and technical audits, (3) operational audits, and (4) Telecom's audit support.

5.3 COST ALLOCATION METHODOLOGY

The allocation methodology for Hydro One's Common Corporate Costs was designed to address the following considerations:

- Compliance with relevant provisions of the Affiliate Relationships Code
- Cost incurrence- Are the costs needed to perform services required by the business?
- Cost allocation- Are costs appropriately allocated among businesses, based on the application of cost drivers /allocation factors supported by principles of causality?
- Cost/benefit- Do benefits received equal or exceed the cost?

An overview of the methodology is described below:

- Through interviews with Hydro One personnel, identify the Shared Services included in Common Corporate Costs and the particular activities performed to provide these Shared Services.

- Through interviews with Hydro One personnel, time surveys, and analyses of time spent by employees, distribute the costs of each Shared Service among the activities performed by that Line of Business to provide that Shared Service.
- Distribute the cost of each activity among Hydro One, its affiliate companies, and between the Tx and Dx businesses based on direct assignment (see Section 4.3) or on cost drivers (see Section 4.4) when direct assignment is not possible.

Further, in instances when Common Corporate Costs can be directly attributed to expenditures for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers. These costs are not included in Hydro One's Corporate & Shared Cost Allocation Methodology given they are recorded and transferred prior to determining the total Common Corporate Costs that are included in the allocation methodology.

The Corporate & Shared Cost Allocation Methodology was first applied to Hydro One's Business Plan (BP 2006-2010). Black & Veatch has also reviewed the application of the methodology to subsequent business plans, as listed in Appendix A. The purpose of this portion of the 2020 Review is to evaluate if the methodology is still appropriate, evaluate what changes may be appropriate, and to provide support to Hydro One in implementing those changes that are recommended.

Based on our discussions with Hydro One personnel and detailed review of the past methods employed, Black & Veatch determined that the Corporate & Shared Cost Allocation Methodology continues to be appropriate for Hydro One because:

- It meets best generally acceptable regulatory practices for cost allocation since it distributes costs based on cost causation, including the use of direct assignment when possible, and then through the use of cost drivers.
- It has been accepted by the OEB.
- It has the support of Hydro One management and is understood and accepted by Hydro One, its affiliate companies, and the Tx and Dx businesses.
- It allows Hydro One, its affiliate companies, and the Tx and Dx businesses to determine precisely what amounts they are charged by department and by activity within the department, and this transparency provides a basis for understanding the nature of the charges and value of the services received.

- It is well-integrated with Hydro One's annual business planning process and produces reasonably stable results over time.
- It accommodates changes in Hydro One's organization, and it can be adapted easily to reflect those changes.

5.4 UPDATES TO METHODOLOGY IN 2020

While the general methodology employed by Hydro One remains the same as past Corporate & Shared Cost Allocation Methodologies there are a few modifications and improvements made during the 2020 review.

5.4.1 Use of and Reliance on Time Studies

In each of the past reviews, some of the allocation factors were developed using time studies of individual employees' time spent between Tx and Dx businesses as well as between OM&A activities and capital expenditure activities. The time study involved individuals across specific Shared Services relating to customer relations, asset management, and network operations tracking their daily time for a four-week period. The time spent across these four weeks were then extrapolated across the entire year to allocate a full year of costs to the Affiliates and between supporting OM&A and capital. The reasonableness of this approach depends highly on two considerations, namely (1) whether the activities conducted during this four-week period accurately represent the activities across the entire year, and (2) whether the individuals are able to accurately track and determine which Affiliates they are serving during each day of the survey.

One area of focus with our detailed evaluation and review was to ascertain the appropriateness of time studies given the change in business operations due to the COVID-19 pandemic. In addition, Hydro One was interested in exploring whether Cost Centers that previously utilized a time study could be accurately allocated using an allocation factor or a time survey (i.e., the questions were asked, "Is there an allocation factor that can more accurately capture the split of responsibilities than a time study that occurs over a single four-week period? Is it reasonable to utilize a time survey and request management and/or employees to develop an estimate of time spent across the course of all twelve months?").

During the interviews with Hydro One personnel most familiar with the Shared Services, we discussed the current challenges of conducting a time study. One item of feedback received was the difficulty of conducting the time study given individuals were switching back and forth regularly between transmission support and distribution support. In the past, the three areas that were allocated on time studies were customer relations, asset management, and network operations. These areas have undergone changes in their organizational structures such that individuals are more often dedicated to either transmission or distribution, whereas in the past there was more time switching back and forth across the Tx and Dx businesses. As such, the new organizational structure facilitated a more direct allocation where employees were fully dedicated to one line of business or where management and/or employees could split an employee’s time across Tx or Dx throughout a full twelve months.

As a result of this feedback and considerations made by Black & Veatch, the four-week time study was replaced with a time survey in which individuals were asked about time spent by a particular Cost Center’s employee or those employees were asked directly. Rather than review a specific four-week period through a time study, interviews were conducted, and details were provided on how the employees in these Cost Centers spend their time across the entire year by using a time survey. Black & Veatch believes the replacement of the four-week time studies with time surveys more accurately captures the time spent by these Costs Centers on activities across the entire year and improves the allocation methodology.

5.4.2 Allocation of Certain Executive Costs to Shareholders - Hydro One Accountability Act, 2018 (Bill 2)

In the last review, Hydro One’s Corporate & Shared Cost Allocation Methodology was updated to ensure compliance with section 78(5.0.2) of the Ontario Energy Board Act, which was introduced under the Hydro One Accountability Act, 2018 (Bill 2), requiring the OEB to ensure that Hydro One does not recover certain executive compensation costs from ratepayers and instead has those costs borne by Hydro One’s shareholders. The previous methodology did this by directly assigning these costs to Hydro One’s shareholders and as a result the methodology departed from a cost-based approach for those instances where such direct assignments were made. Black & Veatch found that departure and direct assignment to be appropriate given they were solely for legislative compliance purposes. During the 2020 evaluation and review Black & Veatch recommended updating the methodology to reflect cost-causative principles when allocating these executive costs but to flag those costs so they can easily be traced through the method and excluded when developing any costs for ratepayer recovery. This results in the same outcome, compliance with the Hydro One Accountability Act, 2018 (Bill 2), but allows for an accurate allocation of these costs to Hydro One, its affiliate companies, and the Tx and Dx businesses. This recommendation was adopted by Hydro One and is incorporated in the current methodology.

5.4.3 Use of a Three-Factor Allocation Driver

The use of a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified, is a broadly respected and common practice across the utility industry. In past reviews these multi-factor allocations were (a) an equal weighting of total revenue and total assets and (b) an equal weighting of total revenue and total OM&A. The most common multi-factor allocation is a three-factor formula, with each factor equally weighted, and is generally referred to as the Massachusetts Formula, where the three components of the factor are representative of: (1) Capital, (2) Revenue, and (3) Labour. The implementation of the Massachusetts Formula varies slightly as entities use different measures to represent the three components (e.g., net plant/rate base, revenue/margin, labour/headcount).

For Hydro One's Corporate & Shared Cost Allocation Methodology the three-factor allocation driver based on Capital, Labour, and Revenue was utilized to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor. Based on Black & Veatch's expertise and experience in performing cost allocation studies the use of the Capital, Labour, and Revenue multi-factor allocation is in alignment with industry practices, and its use reflects the nature of the activity and availability of information. For more details on the use of a multi-factor allocation please see Section 4.6.

Table 7 summarizes the allocation methods and costs drivers used to distribute the Common Corporate Costs among Hydro One, its Affiliates, and the Tx and Dx businesses.

Table 7 - Percentage Allocation of Common Corporate Costs Based on Direct Assignment and Cost Drivers

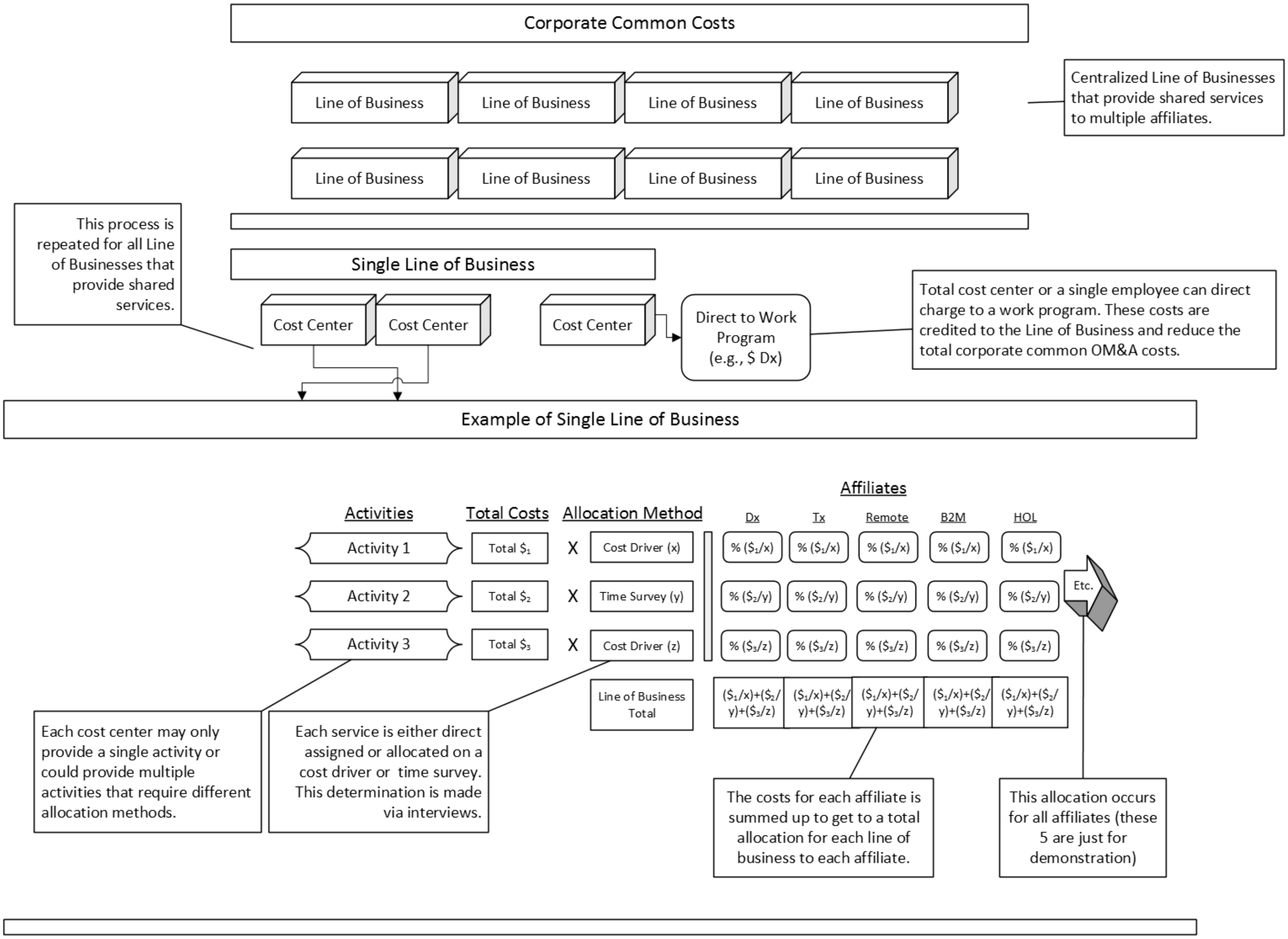
Cost Allocation Method	2023
Direct Assignment - Time Survey	43.98%
Capital, Labour, Revenue	20.00%
Headcount	10.34%
Customer Service (for CSO Sustainment)	7.62%
Internal - Total Cost Center Labour	6.16%
OM&A & Capital Expenditures	4.34%
Total Assets	2.51%
Direct Non-Labour Assignment	2.06%
Capital Expenditures	0.94%
Kilometers of Lines	0.84%
Other Allocators <0.5% for each	1.21%
Total	**100%**

These percentages are in alignment with previous reviews with respect to the percentage of total costs allocated based on direct costs (time survey or time study). In the previous Black & Veatch's Transmission report filed in EB-2019-0082 it was indicated that approximately 59% of costs were allocated using a direct assignment. In the current analyses the direct assigned costs are also approximately 59%, which is the sum of the rows (1) Direct Assignment – Time Survey (2) Customer Service Labour (for CSO Sustainment) (3) Internal – Total Cost Center Labour (for Non-Labour) and (4) Direct Non-Labour Assignment.

5.5 REVIEW PROCESS EMPLOYED BY BLACK & VEATCH

The general process employed to conduct this review was to evaluate the Lines of Business that provide Shared Services to identify specific activities undertaken, review allocation options for those activities, and develop those allocation factors or time surveys to allocate the costs associated with each activity among Hydro One, its Affiliates, and the Tx and Dx businesses. The method is depicted below in Figure 1.

Figure 1 –Common Corporate Cost Allocation Methodology



Task 1. Review Hydro One's current organizational structure and identify Lines of Business that provide Shared Services

The purpose of this Review was to evaluate which Lines of Business provide Shared Services to Hydro One, its Affiliates, and the Tx and Dx businesses. Hydro One captures these Common Corporate Costs within several Lines of Business which are listed in Table 6. Appendix B further describes the Lines of Business and Shared Services based on information provided by Hydro One in discussions and documents. The completion of this task resulted in the total Common Corporate Costs that provide Shared Services by Line of Business and the Cost Centers within each Line of Business.

Task 2. Identify the major activities performed in the provision of Shared Services

The purpose of this task was to identify the activities that are performed in order to provide each of the Shared Services. In short, it is the process of breaking down the Lines of Business into specific activities through reviewing budgeted data for Cost Centers and conducting interviews with each of the Lines of Business. To distribute the resources required to provide the Shared Services based on cost causation, the activities performed were identified and described by Hydro One to Black & Veatch. The activities performed often aligned with the budgeted Cost Centers or a subset of the Cost Center was determined to provide a particular activity. For example, the Line of Business 'Planning' contains four separate Cost Centers which were broken down into seven separate activities, each with a unique allocation factor applied.

Task 3. Review if the major activity provides support directly to OM&A, directly to Capital, or to both OM&A and Capital

The activities identified in Task 2 were also reviewed to ascertain if the activity directly supports OM&A, directly supports capital, or supports both capital and OM&A. This task does not directly support the allocation of Common Corporate Costs but rather supports the development of the Overhead Capitalization Rate calculation by simply flagging all Common Corporate Costs as one of these three categories. The purpose of this task was to flag those costs into three categories: (1) costs that should remain out of the overhead capitalization rate calculation as they are purely OM&A in nature, (2) costs that should be fully recovered from capital expenditures as they directly and wholly support capital expenditures, and (3) costs that support both OM&A and capital and must therefore be split between OM&A and capital within the Overhead Capitalization Rate calculation.

Task 4. Determine the level of costs incurred to perform the activities defined in Task 2

Once the activities were defined for each of the Lines of Business, the costs for each of these activities is derived using budgeted information for each Cost Center. If a Cost Center provides more than one activity, then the total Cost Center's cost was split across those activities based on input from Hydro One personnel familiar with the activities of that Cost Center.

Task 5. Review and choose an allocation methodology for each activity defined in Task 2

The purpose of this task was to choose which allocation method - either a time survey or a cost driver - is most appropriate for each activity. There are advantages and disadvantages to both time surveys and cost drivers. Time surveys can provide specific insights into how an employee or groups of employees spend time throughout a twelve-month period but also require judgement and estimation. Cost drivers are based on data but may not fully reflect the diversity in workload or the multi-faceted nature of what causes a cost to be incurred. Black & Veatch selected an allocation methodology and specific cost drivers based on applying the cost allocation principles discussed in Section 4, its expertise and experience in performing cost allocation studies, industry practices, and consultations with Hydro One as to the nature of each activity and availability of information. Section 4.5 Types of Cost Drivers describes the types of cost drivers.

Task 6. Determine which Affiliates and businesses are causing the activity to be performed or receiving the benefit of the activity

Once the allocation methodology was determined for a particular activity it was necessary to understand which affiliate companies or businesses were causing and/or receiving a benefit from that activity. The primary goal of this task was to ensure that costs were not being allocated to Affiliates who were not being served by the Shared Service activities. For instance, the Line of Business Strategic Finance provides Shared Services activity relating to capital expenditure decision support, for which the cost driver was determined to be Capital Costs, but Strategic Finance does not provide this support to Telecom. Thus, it was necessary to review each defined activity to determine which Affiliates should receive an allocation from the chosen cost driver.

Task 7. Review and determine allocation of non-labour costs

In addition to the detailed review conducted to determine the appropriate allocation methodology for labour costs, a review was completed to ensure non-labour costs were accurately allocated. In some instances, non-labour costs solely represent administrative and general departmental expenses for the Cost Center such as training for which those costs were allocated on the same basis as the labour dollars. In other instances where non-labour costs are unique in nature and should not follow the same allocation as labour a determination was made as to the appropriate cost driver.

Task 8. Populate cost drivers

The purpose of this task was to determine the values of each cost driver that are attributable to Hydro One, its Affiliates, and the Tx and Dx businesses in order to distribute the costs of each activity. The supporting information to develop these cost drivers was provided by Hydro One.

Task 9. Compute total Common Corporate Costs for Hydro One, its Affiliates, and the Tx and Dx businesses

The purpose of this task was to distribute the total cost of each activity based on the results of the time surveys and the chosen cost drivers. For allocations based on cost drivers, the amount allocated was computed by multiplying the activity cost to be allocated by the cost driver value for Hydro One, its Affiliates, and the Tx and Dx businesses. The culmination of Tasks 1-8 is the methodology for allocating the Common Corporate Costs which is applied in Task 9 to the costs within each Business Plan year for development of inputs into Hydro One's operating budgets.

5.6 CONCLUSIONS AND RESULTS

With the inclusion of the enhancements described above, Black & Veatch believes that Hydro One's current Common Corporate Cost allocation methodology is appropriate for Hydro One because it achieves the purposes for which it was designed: to distribute costs in a manner that is consistent with OEB precedent and regulatory practice for cost allocation, ensures legislative compliance (i.e., Hydro One Accountability Act), and promotes transparency and efficiency.

Table 8 presents the results of Hydro One's distribution of the Common Corporate Costs in Business Plan year 2023, among its Transmission, Distribution, and Other businesses.

Table 8 - Distribution of Annual Common Corporate Costs for Ratepayer Recovery

Business	2023
($ Millions)	$
Transmission	130.59
Distribution	139.61
Other	33.62
Total	303.81
(% of Total)	%
Transmission	43%
Distribution	46%
Other	11%
Total	100%

The Common Corporate Costs Allocation Methodology results in a similar outcome as the methods in the past with respect to the percentage of Common Corporate Costs allocated to the Transmission business, Distribution business, and Hydron One and its affiliates (the Other category). There was an approximate 3% movement from the Transmission business to the Distribution business between the results of the affiliate allocation methods applied to 2020 during the 2018 review with the results presented above for 2023 in **Table 8** (i.e., in the past Black & Veatch's Transmission report filed in EB-2019-0082 where the percentages were 46% Transmission and 43% Distribution, with the same 11% as Other). This movement of 3% is not concerning because (1) the results of the 2018 review for 2022 are not directly comparable to the results of the current allocations applied to 2023, and (2) changes in organizational structure and focus are to be expected as Hydro One evolves and adapts to new circumstances. For instance, reviewing past time surveys provided by Network Operations it was noted that this Line of Business is allocating a higher percentage to Distribution that reflects a higher focus on this area on the Distribution business and in particular on system planning activities for the Distribution business. Thus, the Common Corporate Costs Allocation Methodology reflects these changes in the organizational focus in the inputs to the methodology, impacting the allocation of costs to Hydro One, its Affiliates, and the Tx and Dx businesses.

6 Overhead Capitalization Rate Methodology

6.1 PURPOSE OF OVERHEAD CAPITALIZATION RATE

Overhead Capitalization Rates are percentages that are applied to the cost of Transmission and Distribution capital expenditures resulting in a portion of Common Corporate Costs being included as part of capital expenditures for each business. The Overhead Capitalization Rate is used to recover Common Corporate Costs that are not directly recorded to capital expenditures due to the nature of the costs; either employees who support capital expenditures but do not directly charge time to a specific capital project (assigned for less than three months or work on multiple projects simultaneously) or employees who perform work that impacts both capital and OM&A projects. For instance, time spent on risk evaluation and risk mitigation simultaneously impacts both capital and OM&A projects; without an efficient and effective risk evaluation and mitigation Hydro One would be unable to undertake OM&A and capital expenditures as effectively. In summary, the Overhead Capitalization Rate allocates to capital both (1) costs for Shared Service activities that directly support capital expenditures but are not billed directly to capital; and (2) costs for a portion of Shared Service activities that relate to both capital and OM&A simultaneously.

6.2 APPLICATION OF COST ALLOCATION PRINCIPLES TO OVERHEAD CAPITALIZATION RATE METHODOLOGY

In addition to alignment with the general principles of cost allocation discussed in Section 4 - Guiding Principles of Cost Allocation, the methodologies for overhead capitalization should address a set of formal, objective criteria that align with company and policy objectives. Guiding regulatory principles for the Capitalized Common Corporate Costs allocation methodology include:

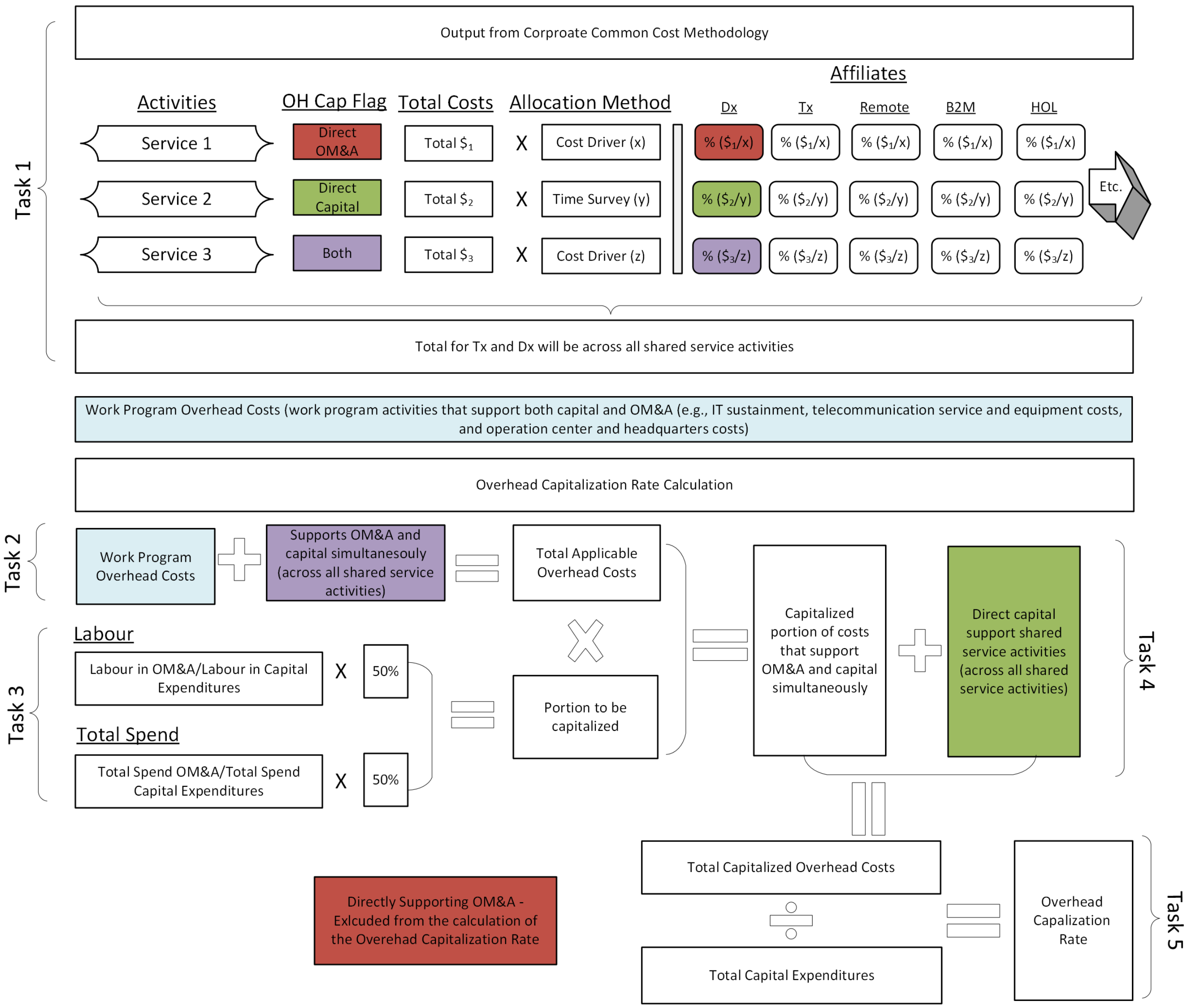
- **Defensible Cost Causation:** To conform to regulatory principles, the methodology should show a causal link between capitalized overhead and capital activity.
- **Distinguishable from Directly Allocated Capital Costs:** The overhead costs must be distinguished from those that are directly charged to capital (i.e., no duplication of costs and distinct sets of costs that are to be included in overhead).
- **Transparency:** The methodology and calculations should be easy to follow and understand by internal users and external reviewers.
- **Freedom from Bias**: The methodology should not contain a bias in the allocation of costs toward either operating or capital activities.

- **Stability:** The methodology should remain stable from year-to-year and not result in disproportionately large variations in the amounts of capitalized overhead from year-to-year.
- **Accuracy of Underlying Data:** Any data used in the methodology should be accurate and able to be relied upon for the purposes intended (i.e., provide an appropriate measure and reasonable approximation of the underlying volume of activity or output).
- **Flexibility/Adaptability:** 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.
- **Cost-effectiveness:** Methodologies should be cost-effective to implement. Additional accuracy may require significant additional cost, and thus an appropriate balance is required between precision and cost, with respect to both implementation costs and on-going costs.

6.3 OVERVIEW OF METHODOLOGY

The purpose of this portion of the 2020 Review is to evaluate if the methodology is still appropriate, evaluate what changes may be appropriate, and to provide support to Hydro One in implementing those changes that are recommended. The final result of the Overhead Capitalization Rate Methodology is to develop two percentages (Overhead Capitalization Rates for Tx and for Dx) that are applied to the cost of Tx and Dx capital expenditures in order to recover a portion of Common Corporate Costs that support capital expenditures for each business. This process is depicted in **Figure 2** below.

Figure 2 - Overhead Capitalization Rate Methodology



The process to do so is described below and each task described is uniquely undertaken for each of the Tx and Dx businesses, since each business has a unique Overhead Capitalization Rate.

Task 1. Review if the major activity provides support directly to OM&A, directly to Capital, or to both OM&A and Capital

As noted in Task 3 of the review process for Common Corporate Cost allocation (section 5.5) each Shared Service activity was reviewed to ascertain if the activity directly supports OM&A, directly supports capital, or supports both capital and OM&A. The purpose of this task was to flag those costs into three categories: (1) costs that should remain out of the Overhead Capitalization Rate calculation as those costs are OM&A Only, (2) costs that should be fully recovered from capital expenditures as they directly and wholly support capital expenditures, and (3) costs that support both OM&A and capital and should therefore be split between OM&A and capital within the Overhead Capitalization Rate calculation. The result of this task and the outcome of the allocation of Common Corporate Costs is that each Shared Service activity allocated to the Tx and Dx businesses is within one of these three categories. (See the OH cap flag column within **Figure 4** above).

Task 2. Calculate Total Applicable Overhead Costs

In addition to the Lines of Business included and reviewed in the Common Corporate Cost allocation process, there are some additional work programs that provide Shared Services. These relate to IT sustainment, telecommunication service and equipment costs, and operation center and headquarters costs. The sum of the activities that support both OM&A and capital resulting from the Common Corporate Cost allocation process and the work programs that support both OM&A and capital is the Total Applicable Overhead Costs. This is a combination of both the centralized Line of Business and the work program costs that support both OM&A and capital.

Task 3. Split Applicable Overhead Costs that support both OM&A and capital

These Total Applicable Overhead Costs (costs associated with activities that support both OM&A and capital and are allocated to the Tx and Dx businesses) need to be split between (a) costs that remain in OM&A, and (b) costs that will be included in the Overhead Capitalization Rate calculation and capitalized. 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.

- **Labour Content-Capital Ratio** - Labour in Tx OM&A versus Labour in Tx capital expenditures OR Labour in Dx OM&A versus Labour in Dx capital expenditures
- **Total Spending-Capital Ratio -** Total Spending on Tx OM&A versus Total Spending on Tx capital expenditures OR Total Spending on Dx OM&A versus Total Spending on Dx capital expenditures

Prior to applying the 50/50 weighting of Labour Content-Capital Ratio and the Total Spending-Capital Ratio to the Shared Service costs that support both OM&A and capital, all Hydro One Accountability Act, 2018 (Bill 2) related costs are removed to ensure no such costs are recovered from capital expenditures for Tx or Dx.

Task 4. Calculate total Capitalized Common Corporate Costs to be recovered from capital expenditures

The total overhead costs to be recovered from capital expenditures is the sum of two components, namely (1) the resulting portion of Total Applicable Overhead Costs after applying the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio in **Task 3** above, and (2) those Shared Service Costs that were flagged as directly and wholly supporting capital expenditures. Any costs that were flagged as OM&A only were excluded from the Overhead Capitalization Rate calculations. The result of this task is the Total Capitalized Common Corporate Costs, i.e., sum of Shared Service and work program costs that will be recovered from capital expenditures.

Task 5. Calculate the Overhead Capitalization Rate

The Overhead Capitalization Rate is derived by dividing the Total Capitalized Common Corporate Costs resulting from **Task 4** by Total Capital Expenditures. The resulting unique Overhead Capitalization Rates for each of the Tx and Dx businesses are then applied to all Tx and Dx capital expenditures, respectively, in order to include these Capitalized Common Corporate Costs as overhead costs on Transmission and Distribution capital expenditures.

Task 6. Application and Monitoring of the Overhead Capitalization Rates

As mentioned above, this entire process is done for Tx and Dx separately to develop unique Tx and Dx Overhead Capitalization Rates. These rates are developed based on Business Plan numbers and other estimates. Hydro One reviews and adjusts the Overhead Capitalization Rates periodically to reflect changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up (in-year) to reflect actual results. Therefore, no adjustments are needed in subsequent years.

6.4 UPDATES TO METHODOLOGY IN 2020

The general methodology for calculating the Overhead Capitalization Rate is the same as past Corporate & Shared Cost Allocation Methodologies, subject to one key enhancement made during the 2020 review.

In past studies the Common Corporate Costs to be split based on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio were derived by only removing costs for specific Shared Services relating to customer relations, asset management, and operations. These are the Shared Services that were subject to the four-week time study which required employees to track time between each affiliate and projects relating to capital and OM&A. Based on the results of the time study the portion of their time that was spent on capital expenditures was directly included as Capitalized Common Corporate Costs and time spent on OM&A was excluded. All remaining Shared Service costs were split based on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

The enhancement made during the 2020 review involves a more extensive review of activities that should be excluded from the costs split based on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio. Rather than only directly assigning the results of a time study for specific Shared Services relating to customer relations, asset management, and operations, the 2020 review is providing for the direct assignment of activities across all Shared Services. As such, the review is providing for any Shared Service activity to flag time spent as OM&A only or capital only and either not included in the total Capitalized Common Corporate Costs or directly included. This enhancement has refined the methodology as the determination of directly supporting OM&A or capital is done for each activity rather than just those Lines of Business that participated in the four-week time survey in the past.

In Black & Veatch's Transmission report filed in EB-2019-0082 approximately 69% of Common Corporate Costs were included in the Total Applicable Overhead Costs and split on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio. This can be compared to the 55% of Common Corporate Costs included in the Total Applicable Overhead Costs in the current analysis. This change represents a larger percentage of costs directly assigned, which improves the precision of the methodology and is a result of extending the review of time spent as OM&A only or capital only and either to all Shared Service activities.

6.5 CONCLUSIONS AND RESULTS

Black & Veatch believes that Hydro One's current Overhead Capital Rate calculation is appropriate for Hydro One because it aligns with the objectives for which it was designed; to fairly attribute to and recover appropriate overhead costs for capital expenditures. Not all costs can be directly attributed to OM&A or to Capital. The current methodology ascertains which activities wholly and directly relate to each of OM&A and capital and which are overhead supporting both OM&A and capital and a causal link between overhead costs and capital activity exists. When interview or time survey results allowed, certain activities were split between activity directly supporting OM&A,

directly supporting capital, or supported both capital and OM&A. In short, where appropriate, activities were further subdivided into groupings of costs across these three overhead capitalization categories. For instance, a portion of the Planning Line of Business Cost Center relating to Distribution Planning is directly assigned to OM&A only and a portion is directly assigned to Capital only based on time surveys. This detailed level of review results in a method that is accurate and transparent. It also directly couples the review and allocation of Common Corporate Costs with the Overhead Capitalization Rate review providing some cost effectiveness in its implementation (e.g., while a review is being done on understanding the nature of the activity with regard to allocating those costs to Affiliates and businesses, discussions on the activities' support of capital or OM&A can occur). Details on the computations utilized to develop the Overhead Capitalization Rate are provided in Appendix C.

Below are the resulting Overhead Capitalization Rates for the Business Plan year 2023 for both the Tx and Dx businesses.

Table 9 – Overhead Capitalization Rate for Tx and Dx Businesses

OVERHEAD CAPITALIZATION RATE	2023
Transmission Rate	8.00%
Distribution Rate	9.00%

In general, the updates to the methodology employed in the 2020 review resulted in a decrease in the total Common Corporate Costs being recovered through the Overhead Capitalization Rate. This was a result of directly assigning more costs to OM&A only rather than only excluding those costs that were within the historical Time Study groups. This however does not necessarily result in a lower Overhead Capitalization Rate given there are different levels of capital expenditures from which to recover these overhead costs. For the Transmission business the Black & Veatch's Transmission report filed in EB-2019-0082 indicated the Overhead Capitalization Rate was calculated at 8.0% in 2023 which is the same as the rate of 8% **Table 9** above. For the Distribution business the Black & Veatch Distribution report filed in EB-2017-0049 indicated the Overhead Capitalization Rate was calculated at 12% in 2018 which is higher than the 9% calculated and shown in Appendix C of this report.

7 Allocation of Shared Assets

7.1 PURPOSE OF ALLOCATING SHARED ASSETS

In addition to the allocation of Common Corporate Costs it is necessary for compliance with the Affiliate Relationships Code to allocate the use and costs of Shared Assets among Hydro One, its affiliate companies, and between the Tx and Dx businesses. Black & Veatch's objective in reviewing the method of allocating Shared Assets was to ensure that the allocation is reasonable, reflects regulatory principles, does not result in cross-subsidization between businesses, and is consistent with the allocation of Common Corporate Costs.

Hydro One provided Black & Veatch with a list of all Shared Assets which is summarized by asset group and subgroup in **Figure 3** below.

Figure 3 – Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	■ Software • Intangibles Software • Computer Equipment • Computer Software ■ Buildings and Telecommunication Equipment • Land • Buildings and Fixtures • Leasehold Improvements • Communication Equipment • System Supervisory Equipment
Minor Assets	■ Aircraft ■ Transportation & Work Equipment ■ Computer Hardware ■ Office Equipment ■ Measurement and Testing ■ Service Equipment- Miscellaneous ■ Service Equipment- Storage ■ Tools

7.2 OVERVIEW OF METHODOLOGY

Most fixed assets are directly purchased by the Transmission or Distribution business and the remaining assets, considered Shared Assets, are held by Hydro One Networks. These assets are allocated to Hydro One, its Affiliates, and the Tx and Dx businesses. The percentage of Shared Assets that are not allocated to Tx or Dx are utilized to develop applicable transfer prices which are costs charged by Hydro One Networks Inc. to its Affiliates for the use of these Shared Assets. The revenues received by Hydro One Networks Inc. from these charges are used to offset the revenue requirements for the Transmission and Distribution businesses associated with the Shared Assets.

The general process employed to conduct this review was to gain an understanding of the particular nature of the Shared Assets and the use of the Shared Assets by Hydro One, its Affiliates, and the Tx and Dx businesses. With this understanding, allocation options were reviewed and decided upon to allocate the costs of these Shared Assets among Hydro One, its Affiliates, and the Tx and Dx businesses. The results of this allocation support the development of the Tx and Dx business revenue requirements and transfer pricing for Hydro One's affiliates.

Task 1. Review the nature and use of the Shared Assets

The asset subgroups listed in **Figure 3** are comprised of dozens of fixed assets. These fixed assets are reviewed to gain an understanding as to the nature of the Shared Asset, the support the Shared Asset provides to the Shared Services, and support provided to particular businesses. This understanding was gained by reviewing documentation and interviews with Hydro One personnel.

Task 2. Review and choose an allocation methodology for the Shared Assets

Black & Veatch selected an allocation methodology and specific cost drivers for each fixed asset based on applying the cost allocation principles discussed in Section 4, its expertise and experience in performing cost allocation studies, industry practices, and consultations with Hydro One as to the nature of each fixed asset and availability of information.

Major Assets

- **Software -** Most of the software included in Shared Assets is enterprise software and Hydro One's SAP system also known as Cornerstone, an enterprise-wide system to support work management, asset management, human resources, financial and other functions. The cost of this software was allocated using cost drivers that reflect the activities supported. For example, capitalized software implementation costs related to Human Resources was allocated based on headcount. Further, some software was directly assigned to one of the businesses (e.g., direct assignment of the customer information system to the Dx business).

- **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%; therefore the costs for buildings used for Fleet were allocated using these percentages.
  - **Cost Drivers** - For example, buildings used to manage both Distribution and Transmission projects are allocated using the cost driver OM&A and capital expenditures, developed as part of the Allocation of Common Corporate Costs methodology.

Minor Assets

Black & Veatch reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft** – Includes helicopter and supporting components. Usage was based on an analysis of time charges (which are recorded to time sheets concurrently with usage) for years 2014 - 1st quarter 2020.
- **Transportation & Work Equipment** – Includes primary vehicles and associated equipment. Allocated using the cost driver “Fleet”, which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2014 - 1st quarter 2020.
- **Computer Hardware** – Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using the cost driver Headcount.
- **Office Equipment** – Includes office furniture and other office equipment. Allocated using the cost driver Headcount.
- **Measurement and Testing Equipment** – Includes testing and measurement equipment and tools used for Distribution. Directly assigned to Distribution.
- **Service Equipment- Storage** – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on total OM&A expenditures and capital expenditures for Tx and Dx businesses.

- **Service Equipment - Miscellaneous** – Includes miscellaneous equipment. Allocated using Total Common Corporate Costs cost driver, developed as part of the Common Corporate Cost allocation methodology.
- **Tools** – Includes Rental tools. Allocated Distribution-20% / Transmission-80% reflecting estimated usage based on information as to which business units are renting the tools.

Task 3. Populated cost drivers

The purpose of this task was to determine the values of each cost driver that are attributable to Hydro One, its Affiliates, and the Tx and Dx businesses in order to distribute the costs of each activity. The majority of the cost drivers were also used in the allocation of Common Corporate Costs so they were already populated during that process (see Task 8 within section 5.5 – Common Corporate Cost Allocation Review Process). Outside of the cost drivers utilized from the Common Corporate Costs Allocation allocations factors were developed for aircraft, fleet, total Common Corporate Costs (outcome of Common Corporate Costs Allocation), central maintenance services, and field offices.

Task 4. Allocated Shared Asset costs to the businesses

The next step in the Shared Asset allocation methodology is to multiply the cost for each fixed asset by the chosen Cost Driver resulting in an allocation of total Shared Asset costs among Hydro One, its Affiliates, and the Tx and Dx business. The Shared Assets allocated to the Tx and Dx businesses are included in the revenue requirement calculation for those businesses.

Task 5. Calculate transfer price charge rates for Affiliates

The full costs of the Shared Assets are allocated to Hydro One, its Affiliates, and the Tx and Dx businesses. The percentage of Shared Asset costs that is not allocated to the Transmission or Distribution businesses is utilized to develop applicable transfer prices which are costs charged to Affiliates for the use of these Shared Assets and applied as an offset to the revenue requirements for the Transmission and Distribution businesses that are associated with these Shared Assets.

Black & Veatch understands that the revenue requirements calculated for the Tx and Dx businesses will initially include 100% of revenue requirement associated with all of the Shared Assets. However, the other revenues received by Hydro One Networks Inc. by means of the transfer pricing are applied as a reduction to the revenue requirements that are ultimately requested for recovery through Transmission and Distribution rates.

The transfer price charge rates represent the usage of the Shared Assets by Hydro One's affiliate businesses. The approach to developing the transfer price charge rates is as follows:

- The portion of each asset that should be allocated to Hydro One and each Affiliate based on the appropriate cost driver was determined (result of Task 4 above).
- A revenue requirement was developed for the Shared Assets subgroup based on the components of the revenue requirement (return on debt, return on equity, taxes, and depreciation expense) for the Tx and Dx businesses for each Shared Asset subgroup.
- This revenue requirement for each Shared Assets subgroup was multiplied by the portion of the Shared Assets subgroup allocated to each affiliate with transfer pricing.
- These resulting dollar amounts were summed for each Shared Asset subgroup for each Affiliate with transfer pricing to develop the total transfer price.

7.3 UPDATES TO METHODOLOGY IN 2020

The general methodology for allocating Shared Assets and developing the transfer pricing is the same as past Corporate & Shared Cost Allocation Methodologies. The 2020 review included a detailed review of the Shared Assets with a particular emphasis on reviewing documentation and gathering details from Hydro One personnel on the 30 capital assets that made up 90% of the total capital costs. Further, the methods employed in allocating Shared Assets is in alignment with the allocation of Common Corporate Costs; where Shared Services and Shared Assets are providing a similar service the allocation factor was the same across the two methodologies.

As noted above in Section 5.4.3 the three-factor allocation driver based on Capital, Labour, and Revenue was utilized to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor. This three-factor allocation driver was applied to computer software and enterprise systems that relate to the overall operations and enterprise applications that utilized by Hydro One, its Affiliates, and the Tx and Dx businesses. Given the nature of these Shared Assets and availability of information the use of the three-factor allocation driver based on Capital, Labour, and Revenue is appropriate for the allocation of these Shared Assets and results in a methodology that is in alignment with regulatory practices.

7.4 CONCLUSIONS AND RESULTS

Black & Veatch believes that Hydro One's current allocation of Shared Assets is appropriate for Hydro One because it aligns with the objectives for which it was designed; to fairly attribute and recover the Shared Assets from Hydro One, its Affiliates, and the Tx and Dx businesses in a manner consistent with regulatory practice and the requirements of the Affiliate Relationships Code. Hydro One's other affiliated businesses which is used to develop any applicable transfer pricing for those Affiliates.

Table 10 below provides the resulting allocation of Shared Asset values as of March 31, 2020 for the Transmission and Distribution businesses. In addition, this table provides a column with "Other" which represents the allocations to Hydro One's other affiliated businesses which is used to develop any applicable transfer pricing for those Affiliates.

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%**

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.

Appendix A – Past Affiliate Cost Allocation Reviews and Reports

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with subsequent reports issued, as follows:

Table 11 - History of Black & Veatch's Common Corporate Cost Reviews and Reports

BLACK & VEATCH REVIEW	BLACK & VEATCH REPORT
2006 Review	*Report on Implementation of Common Corporate Costs Methodology* dated May 31, 2006
2008 Review	*Report on Implementation of Common Corporate Costs Methodology* dated September 10, 2008
2009 Review	*Report on Shared Services Costs Methodology* dated June 29, 2009
2010 Review	*Report on Shared Services Costs Methodology – 2011* dated February 26, 2010
2012 Review	*Review of Shared Services Cost Allocation (Transmission) – 2012* dated February 1, 2012
2013 Review	*Review of Allocation of Common Corporate Costs (Distribution) – 2013* dated September 19, 2013
2014 Review	*Review of Allocation of Common Corporate Costs (Transmission) – 2014* dated March 17, 2014
2015 Review	*Review of Allocation of Common Corporate Costs (Transmission)- 2015 dated May 4, 2016*
2016 Review	*Review of Allocation of Common Corporate Costs (Distribution) – 2016* dated December 21, 2016
2018 Review	*Review of Allocation of Common Corporate Costs (Transmission)- 2019 dated January 31, 2019*

Table 12 - History of Black & Veatch's Shared Asset Allocation Reviews and Reports

BLACK & VEATCH REVIEW/ASSET VALUES	BLACK & VEATCH REPORT
2006 Review	*Report on Common Assets Methodology 2006* dated May 31, 2006
2008 Review	*Report on Common Assets Methodology 2008* dated September 10, 2008
2009 Review	*Report on Common Assets Allocation- 2009* dated June 29, 2009
2009 Review	*Report on Common Assets Allocation (Transmission) - 2010* dated February 26, 2010
2011 Review	*Report on Shared Assets Allocation (Transmission) 2012* dated February 1, 2012
2013 Review	*Report on Shared Assets Allocation (Distribution) 2013* dated September 19, 2013
2014 Review	*Report on Shared Assets Allocation (Transmission) 2013* dated March 17, 2014
2015 Review	*Report on Shared Assets Allocation (Transmission) 2015* dated May 4, 2016
2016 Review	*Report on Shared Assets Allocation (Distribution) 2016* dated December 21, 2016
2018 Review	*Review of Shared Assets Allocation (Transmission)– 2019* dated January 31, 2019

Table 13 - History of Black & Veatch's Overhead Capitalization Reviews and Reports

BLACK & VEATCH REVIEW	BLACK & VEATCH REPORT
2006 Review	*Transmission Overhead Capitalization Rate Method* dated April 30, 2006
2008 Review	*Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010* dated September 10, 2008
2009 Review	*Review of Overhead Capitalization Rates* dated June 29, 2009
2009 Review	*Review of Overhead Capitalization Rates (Transmission) – 2011/2012* dated February 26, 2010
2011 Review	*Review of Overhead Capitalization Rates (Transmission)– 2013-2014* dated February 1, 2012
2013 Review	*Review of Overhead Capitalization Rates (Distribution)– 2015-2019* dated September 19, 2013
2013 Review	*Review of Overhead Capitalization Rates (Transmission)– 2015-2016* dated March 17, 2014
2015 Review	*Review of Overhead Capitalization Rates (Transmission)– 2017-2018* dated May 4, 2016
2016 Review	*Review of Overhead Capitalization Rates (Distribution)– 2018-2022* dated December 21, 2016
2018 Review	*Review of Overhead Capitalization Rates (Transmission)– 2019* dated January 31. 2019

Appendix B – Common Corporate Costs Allocation - Details on the Lines of Business

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
Hydro One Inc. Corporate Office (HOI)		
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.	Costs are allocated using the results of a time survey and the capital, labour, revenue allocator.
Ombudsman	The Ombudsman Office commenced activity following the Initial Public Offering, in order to address complaints escalated from the Customer Service. Prior to that, the Province of Ontario's Ombudsman had authority to investigate issues related to Hydro One customers.	Labour costs are allocated using the results of a time survey. Non-Labour costs are allocated based on labour costs.
President-CEO Office	Leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. Develops and updates strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.	Labour costs are allocated using the results of a time survey, the capital, labour, revenue allocator, and the resulting allocation of the Board of Directors line of business. Non-labour costs are allocated based on labour costs.
Customer & Corp Affairs		
Corp Affairs	The Communications team supports external and internal communications initiatives, including traditional media and social media. The team is also accountable for customer education and safety programs, corporate reputation, media relations, community investment, employee communications, and web communications for Hydro One's corporate website. The External Relations team also manages the company's relationship with key external stakeholders, such as the government, Ministry of Environment, energy regulators, elected officials, municipal associations, industry associations, and energy sector stakeholders, in order to address customer needs. The team is responsible	Labour and non-labour costs are allocated using the results of a time survey, the capital, labour, revenue allocator, and based on headcount.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	for providing various lines of business with public affairs and community relations advice during the environmental, legal and regulatory approvals phases of a project to ensure requirements are met and public consultations are conducted. The team leads public consultation, environmental assessments, and community engagement functions in support of new development projects, maintenance and forestry programs.	
Corp Sustainability	Work on behalf of entire company to help develop and implement sustainability, including Social and Governance initiatives. Work internally on policies and programs to ensure they are supporting sustainability goals, setting goals and reviewing these - data governance and non-financial data to ensure the right data and governance procedures are in place.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Cust Service	Activities and functions include all touch points with customers. These touch points include billing, account management for large customers, support for self-service tools. Activities also include the long-term strategy and planning for Hydro One's interaction with customers.	Labour costs are allocated using the results of a time survey, kilometers of lines (for Tx key account management), capital expenditures, as well as the capital, labour, revenue allocator. Some direct assignment of non-labour costs to Dx and Tx and non-labour costs allocated based on labour costs.
Ext Relations	Three groups (1) Community Relations – almost entirely facilitating capital maintenance and forestry programs – people in between the company and the physical footprint of the operations. Less of communication element but really an integration of supporting project success. Very integrated project and runs through asset manager, planning departments and environment. (2) Government Relations – enterprise roll with a focus on high level policy implications for the successful implementation of projects and relationship between strategic plans and government policy.	Labour costs are allocated using the results of a time survey, work program costs, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	(3) Policy and Partnerships – public policy and stakeholder relations – high amount of interaction and engagement with various organizations across industry and broader advocacy groups across Ontario.	
Indigenous Relations	Develops and maintains mutually beneficial relationships with Indigenous communities serviced by Hydro One. The team promotes effective relationships with Indigenous customers and communities and promotes business and workforce development for Indigenous peoples. The team also conducts consultations with Indigenous peoples and communities in the early stages of, and throughout, projects or other activities that may impact their Aboriginal rights and/or treaty rights.	Labour costs are allocated based on headcount, OM&A expenditures, and capital expenditures. Non-labour costs are allocated based on labour costs.
Finance		
Audit	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.	Labour costs are allocated using the results of a time survey, work program costs, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs, the results of a time survey, work program costs, as well as the Capital, Labour, Revenue allocator.
Business Analysis	Business Analysis provides financial analysis and analytics for senior leadership team (net income graphs and bridges), input that goes into Board Material, and investor relations and executive leadership team. Customers of these services are primarily Hydro One Networks – some of the consolidated work supports HOL and some supports investors and the Board.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
CFO	Provide Hydro One and subsidiaries with strategic review and approval for all financial and investment decisions. Review policies and procedures, treasury operations and tax planning, financial control and reporting.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Corp Controller	Primarily responsible for corporate	Labour costs are allocated using the

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	accounting, internal reporting, and external consolidated reporting to stakeholders, including Hydro One's regulator, the Ontario Energy Board. Supporting these are the back-office accounting and payroll functions, outsourced to Inergi. The Corporate Controller is also accountable for financial master data management, capital accounting, and the expense management policy and process.	results of a time survey, headcount, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs, the results of a time survey, headcount, capital expenditures, and using the capital, labour, revenue allocator.
Corp Development	Develops the strategy by generating innovative new business opportunities. Responsible for the planning and execution of Hydro One's objectives through identifying and acquiring target companies in line with Hydro One's strategic plan and growth strategy. Costs are directly assigned to Shareholder and non-regulated affiliates.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labor costs and using the results of a time survey.
Data Governance	Tasked with improving confidence in data, across Hydro One's Lines of Business through the delivery of an enterprise-wide Data Governance Framework.	Labour costs are allocated using the resulting allocation from the ISD line of business and using the capital, labour, revenue allocator. Non-labour costs are allocated using the labour costs.
Facility & Real Estate	Manage and acquire rights of way and easements; manage property taxes; manage SLU revenue programs; manage Employee Relocation Program.	Labour costs are allocated using the results of a time survey and based on work program costs. Non-labour costs are allocated based on labour costs.
Invest Relations	Investor Relations commenced activity following the Initial Public Offering, in order to communicate with Shareholders and potential investors and address their concerns. Costs are directly assigned to Shareholder only.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs.
Outsourcing	Contract governance for Inergi IT, Finance and Accounting, Payroll, and Supply Chain, as well as supporting BGIS. Work on new contract terms, pricing, and contractor governance.	Labour costs are allocated using BGIS contract amounts, headcount, work program costs, capital expenditures, the results of a time survey, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Pension	Pension fund contributions.	Non-labour costs are allocated using the defined contributions headcount.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
Risk	The Risk office creates an enterprise-wide comprehensive and uniform approach to anticipate, identify, prioritize, measure, treat and report on key business risks impacting the organization. It puts in place the policies, common processes, competencies, accountabilities, reporting and enabling technology to execute that approach successfully.	Labour costs are allocated using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Strategic Finance	3 primary functions: (1) Long Term Financial Planning: extends to both regulated and consolidating non-regulated segments of Hydro One (2) Decision Support Function: Oversees entire business case/project approval process for capital-based projects – facilitating this entire process and providing financial support. (3) Productivity/Governance Function: Support productivity achievement and calibrating and validating new initiatives throughout the Company.	Labour costs are allocated based on capital expenditures, the results of a time survey, and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Strategy & Innovation	The mandate of the Strategy & Growth team is to support the non-regulated affiliates growth with unregulated electrification business growth opportunities.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs.
SVP Finance	Supports regulatory filings, tax group, strategic finance, data governance across the group with a significant focus on regulated businesses. Remaining activities support undertakings by the holding companies and time on the Board of Directors for Hydro One Remotes.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Tax	Meet internal and external tax compliance requirements and reduce overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, HST, and DRC returns for all entities), tax accounting, and	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	government tax audits.	
Treasury	Debt and equity issuance, capital structure management and oversight of Finance and Treasury function.	Labour costs are allocated using the capital, labour, revenue allocator. Non-labour costs are allocated using the results of a time survey and based on labour costs.
Human Resources		
HR-Change Management	The Change Management team supports (1) companywide change management – big broad corporate initiates company values, rolling out new strategies and (2)change management focused on affiliates/lines of business when they are undertaking major projects. The Diversity & Inclusion team, develops and manages Hydro One's diversity and inclusion strategies, plans, programs and policies.	Labour costs are allocated based on headcount and capital expenditures. Non-labour costs are allocated based on labour costs.
HR-Labour Relations	HR Operations and Corporate Groups that provides frontline support to labour groups – Tx, Dx, telecom, remotes, etc. Support includes discipline process, compensation reviews, workforce planning, reviewing labour risk for operations, organizational design, labour contract provisions, etc. This support is provided for employee/employer relations from the first line works to the executive level.	Labour costs are allocated based on the headcount, union employee headcount, and using the resulting allocation of the Board of Directors line of business, the results of a time survey, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
HR-Talent Management	Primarily employee-related services, including administer compensation & benefits programs; decision support for businesses; talent management (hiring, succession, development, coaching; high potential employee assessments); recruitment (diversity programs, grad program, student/co-op, line of business resourcing); data administration; consulting support to LOBs and corporate functions; VP Human Resources.	Labour costs are allocated based on headcount. Non-labour costs are allocated using labour costs.
HR-Total Rewards	Manage the Pensions (administration of plan, assisting to responding to questions notifying enrollments of new members, etc.). Compensation (job evaluation, salary recommendation, compensation	Labour costs are allocated based on headcount. Non-labour costs are allocated based on labour costs and headcount.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	reviews for management, merit increase, base wage increases, short term and long-term incentives, and collective bargaining units). Health and Wellness Benefits (core health and dental programs, Disability Management, and oversee Health and Wellness training and support).	
HR-Work force Acquisition &Support Centre	Service Center is primarily responding for employee inquires (pensions, benefits, etc.) for all employees across Hydro One except for casual workforce Workforce Acquisition (WAS Team) which focuses on casual workforce and are fully recoverable through work programs. HR Technology supports all HR tools and programs including recruiting, talent management, compensation, etc. as well as supporting entire HR functions and modules within the system that relate to recruiting, compensation, etc.	Labour costs are allocated based on headcount. Non-labour costs are allocated using labour costs.
Information Solutions Division		
Information Solutions Division	The Information Services Division is an integration of business process, information, applications, infrastructure, network and security. The Technology team is responsible for information systems architecture, information security, project delivery and management of information services. The Security Operations team provides services for personnel and physical security, business continuity management, IT security, and compliance sustainment.	Labour costs are allocated based on fixed assets & construction in progress as well as using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Legal & Secretariat		
Corporate Secretariat	Provide direction and analysis in areas of: Board and Committee(s); Office of Chair and Board members; Code of Business Conduct; Community Citizenship; Freedom of Information and Privacy, Corporate Archives, Corporate Records, Corporate Secretariat. Oversee and support Law, Regulatory and Corporate	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	Secretariat General Counsel functions.	
General Counsel	The law group provides legal and strategic advice across all the entities, as well as record management and privacy services. Services and support as required are provided to both capital- and maintenance-related work.	Labour costs are allocated based on work program costs, the resulting allocation of the Board of Directors line of business, and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs and using the capital, labour, revenue allocator.
Regulatory Affairs	Coordinate applications with OEB; compliance with OEB orders; design and implement regulatory policy; manage relationship with OEB. Tasks include: cost allocation and rate design for regulated Tx and Dx, especially rate structures and rates for Tx and Dx tariffs; implement approved rates; support transmitters' representative on IESO Technical Panel; manage settlement.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs and using direct non-labour assignment.
Operations		
COO	The COO office is responsible for the day-to-day operations and success of the Tx and Dx - accountable for end-to-end delivery of Hydro One's work and improving the efficiency and effectiveness of the Companies including both time and effort on sustainment activities and capital expenditures.	Labour costs are allocated using work program costs. Non-labour costs are allocated using labour costs.
Planning	Develop and commit prioritized, defensible transmission and distribution development plans, consistent with corporate strategy, to meet government policy, OPA plans, customer needs, regulatory requirements and industry standards. Conduct Regional Infrastructure Planning to meet OEB requirements and to develop regional plans to meet regional supply needs.	Labour costs are allocated using the results of a time survey and based on work program costs. Non-labour costs are allocated based on labour costs and fixed assets & construction in progress.
System Control	The System Ops team monitors and operates the Ontario electricity grid 24/7 using distribution and transmission grid teams. These teams do scheduling, coordinating of planned outages, and real time management of the electricity	Labour costs are allocated using results of a time survey and kilometers of lines. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	network. There is also a systems operation support team, which provides support to the grid team, including training, engineering support, etc.	

Appendix C - Overhead Capitalization Rate Calculation

This appendix provides details on the method used to compute the Overhead Capitalization Rate, providing specific descriptions of each calculation presented in **Figure 4** on page 58.

Capital Expenditures (rows 1-7)

Total Capital Expenditures represents the cost of Capital Expenditures and is the total cost of Capital Expenditures to which the Overhead Capitalization Rate is applied. Total Capital Expenditures equals total spending for Capital Expenditures reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little Shared Service support.
- Capitalized Overhead is removed to avoid redundancy.
- Capital Contributions by Customers are added because the Shared Services support required is related to gross capital cost, not net capital cost.
- Removal Costs are added because removal of capital assets requires Shared Services support.

Total OM&A (rows 8-10)

Total OM&A is used in computing the portion of Total Spending (capital plus OM&A) related to capital (rows 21-24). The amounts are based on the Business Plan, with adjustments to remove those Work Program costs which are included in Applicable Cost for OH Cap Labour/Spend Allocation (Row 12).

Applicable Cost for OH Cap Labour/Spend Allocation (rows 11-16)

Applicable Cost for OH Cap Labour/Spend Allocation (row 16) represents the combination of both the centralized Line of Business and the work program costs that support both OM&A and capital and are split between (a) costs that remain OM&A and (b) those that will be included in the overhead capitalization rate calculation and capitalized. The calculation of Applicable Cost for OH Cap Labour/Spend Allocation (row 16) is the combination of the below items:

- Total Common Corporate Costs resulting from the Common Corporate OM&A Cost allocation methodology.
- In addition to the Lines of Businesses included and reviewed in the Common Corporate OM&A Cost allocation there are some work program costs that provide Shared Services. These relate to IT sustainment, telecommunication service and equipment costs, and operation center and

headquarters costs; and are included. (row 12)

- Directly assigned Capital total Shared Services are removed because the capitalization of those costs was determined in the Common OM&A Cost allocation. (row 13)
- Directly assigned OM&A total from the Common Corporate OM&A Cost allocation are removed because it was determined that these costs relate directly to OM&A. (row 14)
- Any Hydro One Accountability Act, 2018 (Bill 2) costs that are included in the Common Corporate OM&A Cost allocation are removed. (row 15)

The resulting amount (row 16) represents the combination of both the centralized Line of Business and the work program costs that support both OM&A and capital and are split between (a) costs that remain OM&A and (b) those that will be included in the overhead capitalization rate calculation and capitalized.

Labour Content-Capital Ratio (rows 17-20)

Labour Content-Capital Ratio is derived by summing total work program labour costs within OM&A and total labour costs within Capital Expenditures; then dividing the total labour for Capital Expenditures into this sum; resulting in the portion of Total Labour relative to Capital Expenditures Labour (Row 20)

Total Spending-Capital Ratio (rows 21-24)

Total Spending-Capital Ratio is derived by summing total work program OM&A costs and total Capital Expenditures costs; then dividing the total Capital Expenditures costs into this sum; resulting in the portion of Total Costs relative to Capital Expenditures Costs (Row 24).

Percentage to be Capitalized (rows 25-27)

The percentage of Applicable Cost for OH Cap Labour/Spend Allocation to be capitalized is the average of Labor Content-Capital Ratio (from row 20) and Total Spending Capital Ratio (from row 24), using the appropriate weights (rows 25-26). This percentage is multiplied by the Applicable Cost for OH Cap Labour/Spend Allocation (row 28) to compute Capitalized Portion of Applicable Cost for OH Cap Labour/Spend Allocation (row 29).

Capitalized Common Corporate Costs (rows 29-31)

Capitalized Overhead Coast (row 31) represents the amount of Shared Services work program costs that should be capitalized through an overhead charge to Capital Expenditures projects. The Total Capitalized Common Corporate Costs is derived by summing the Capitalized Portion of Applicable Cost for OH Cap Labour/Spend Allocation (row 29) and the directly assigned Capital total Shared

Services excluding Hydro One Accountability Act, 2018 (Bill 2) costs that were determined in the Common Corporate OM&A Cost Allocation methodology (row 30).

Overhead Capitalization Rate (rows 31-33)

The Overhead Capitalization Rate (row 33) is derived by dividing the total Capitalized Common Corporate Costs (row 31) by Total Capital Expenditures (row 32).

Figure 4 – Overhead Capitalization Illustrative Calculation

	($ millions)	Tx 2023	Dx 2023
1	Capital Expenditures	1,434.0	991.2
2	Less: Minor fixed assets	(29.5)	(57.7)
3	Less: Capitalized overhead	(118.1)	(89.9)
4	Less: Capitalized interest	(36.4)	(7.6)
5	Add: Capital contributions	100.4	70.4
6	Add: Removal costs	61.2	77.5
7	Total CapExp	1,411.6	983.9
8	Total OM&A (direct w ork program / SDOC)	332.6	519.6
9	Less: Work programs applicable for overhead cap	(67.5)	(86.1)
10	Total OM&A	265.0	433.5
	Capitalized Common Corporate Costs		
11	Total Common Corporate Costs per CCCM	134.8	144.0
12	Work programs applicable for overhead cap	67.5	86.1
	Less: Non-applicable CCC for OH Cap		
13	Directly Assigned Capital CCC Excl. Bill 2	(31.0)	(13.5)
14	OM&A Only Costs	(57.8)	(100.1)
15	Bill 2 Costs for Capitalizable OH Teams	(4.0)	(4.3)
16	Applicable Cost for OH Cap Labour/Spend Allocation	109.5	112.2
	Development of OH Cap Labour/Spend Allocation		
	Portion capitalized based on labour content:		
17	Labour in OM&A	137.7	238.8
18	Labour in capexp	412.8	478.4
19	Total	550.4	717.1
20	% capexp	75.0%	66.7%
	Portion capitalized based on total spending:		
21	OM&A	265.0	433.5
22	Capexp	1,411.6	983.9
23	Total	1,676.6	1,417.4
24	% capexp	84.2%	69.4%
	Weighting:		
25	Labour content	50.0%	50.0%
26	Total spending	50.0%	50.0%
27	Portion capitalized based on w eighting of tw o methods	79.6%	68.1%
28	Applicable Cost for OH Cap Labour/Spend Allocation	109.5	112.2
29	Capitalized Portion of Applicable CCC	87.2	76.4
30	Directly Assigned Capital CCC Excl. Bill 2	31.0	13.5
31	**Total CCC Capital Overheads**	**118.1**	**89.9**
32	Total CapExp	1,411.6	983.9
33	Calculated overhead capitalization rate	8.37%	9.14%
34	Rounded	8.00%	9.00%

PURCHASE OF NON-AFFILIATE SERVICES

1.0 INTRODUCTION

This exhibit describes how Hydro One purchases goods and services from third parties other than its affiliates. Specifically, this exhibit discusses:

- in Section 4, the legacy arrangement with Inergi LP (Inergi) which is concluding during the bridge years;
- in Section 5, the sourcing strategy that Hydro One is employing to transition services previously provided by Inergi to new outsourcing partners or to be performed internally; and,
- in Sections 6 and 7, the arrangements in place with Capgemini Canada Inc. (Capgemini) and BGIS Global Integrated Solutions Canada LP (BGIS) for information technology and facilities management services, respectively.

2.0 THE PURCHASE OF GOODS AND SERVICES FROM NON-AFFILIATES

In compliance with the Supply Chain Policy set out Exhibit E-05-02 Attachment 1, Hydro One acquires materials and services from non-affiliates through a process that drives value for money, provides transparency within the company, and builds mutually valuable relationships with key suppliers. This process and the resulting agreements with non-affiliates demonstrate that Hydro One values performance management and continuous improvement as instruments of productivity that mitigate the impact of rates on its customers. Details on Hydro One's supply chain activities and their associated costs are provided in Exhibit C-09-04.

Purchases are authorized by the appropriate position identified in Hydro One's Expenditure !u thority Register (E!R), which is a key element of Hydro One's internal control framework. The EAR delegates authorities from its Board of Directors to senior management and management at the subsidiaries and business units.

3.0 COMMON OUTSOURCING TERMS AND CONDITIONS

Hydro One relies on outsourcing arrangements to operate its businesses. Each service contract that is entered into includes certain contractual mechanisms that derive value to Hydro One, and are detailed in this section. These common mechanisms apply to all outsourcing arrangements described in this exhibit, unless otherwise specified.

3.1 GOVERNANCE FRAMEWORK

Each contract sets out a governing structure that ensures contractual obligations are met and value to Hydro One is maximized while maintaining supplier relationships. Governance of these contracts operates to ensure strategic alignment between the parties, oversee the relationship, review business strategies, review operational and project performance, change management, continuous improvement, and identify and resolve any risks and issues. Committee meetings are held at various levels of leadership to achieve the desired governance and business objectives. In addition, the governing structure includes processes tailored to monitor and derive value in areas such as finance, compliance and performance. These processes are designed to integrate with Hydro One's lines of business.

3.2 SERVICE QUALITY ASSURANCES

Each contract sets out a methodology to measure service performance in terms of timeliness, quality, accuracy, financial and client satisfaction of services, among others. Service measurement ensures that Hydro One receives an acceptable level of service to achieve business outcomes. Service quality is measured using defined service levels or Performance Indicators (PIs). Services are measured in regular intervals (daily, monthly, quarterly, and yearly) for achievement of PIs. The PIs vary based on the nature of the service in question and set both minimum and targeted service levels. When a service provider fails to meet certain PIs, Hydro One is entitled to: (a) a service credit(s) calculated in accordance with predetermined formulae; (b) remediation action, at the supplier's cost, based on a remediation plan that Hydro One has approved; or (c) both, depending on the level of criticality and frequency of such failures.[1]

Services are also measured through client satisfaction surveys conducted by the service provider of Hydro One's relevant business managers and internal users. The service provider must address dissatisfaction revealed by the surveys. Together, Hydro One and the service provider are to identify opportunities and strategies for responding to any issues the surveys reveal.

3.3 CONTINUOUS IMPROVEMENT AND INNOVATION

Each contract contains an obligation for the service provider to deliver continual improvements and innovation in respect of the services being provided to Hydro One. This includes a commitment to establishing a dedicated process to manage and oversee continuous improvement, and improvements to service performance through managed improvements to processes and services in order to increase efficiency and effectiveness (including cost effectiveness) for Hydro One's business. The contracts with Inergi and Capgemini also include annual adjustments to service PIs based on specific criteria and previous performance.

4.0 INERGI LP

4.1 BACKGROUND

On March 1, 2015, Hydro One began its current services arrangement with Inergi (Inergi Agreement), a limited partnership wholly-owned by Capgemini. Under the Inergi Agreement, Hydro One outsourced back-office services (including information technology services, supply chain services, settlements, payroll, and finance and accounting services) and call centre services.

This section describes how the separate services within the Inergi Agreement were amended and extended or insourced over the term of the agreement. As components of the Inergi Agreement

[1] Termination of individual statements of work or any part thereof is allowed under defined circumstances without payment of any penalties or termination charges.

expire throughout 2021, Hydro One will be ending its outsourcing partnership with Inergi and transitioning services through a new sourcing strategy. Further details on this strategy are set out in Section 5.0.

The Inergi Agreement's initial term for back-office services was set to expire on December 31, 2019, with an option to renew the agreement for two additional terms of approximately one year each. Before the initial term expired, the parties agreed to amend the underlying business terms for the following statements of work:

- Effective March 1, 2018, the Inergi Agreement relating to information technology services was amended and extended for 14 months, ultimately expiring on February 28, 2021.
- Effective November 1, 2018, the Inergi Agreement relating to supply chain services was amended to reduce the scope of work and improve services to Hydro One. The amendment extended services for 22 months and expires October 31, 2021. Certain supply chain services were transitioned into Hydro One concurrent with this amendment.

The Inergi Agreement continued for settlements services until the initial term expired on December 31, 2019. On January 1, 2020, Hydro One insourced these services. The work program and associated costs are discussed in Exhibit E-02-04, Section 2.0.

The Inergi Agreement continued for payroll and finance and accounting services until the initial term expired on December 31, 2019. Hydro One extended these services for both additional one-year terms, the second of which expires December 31, 2021. This is further discussed in Sections 5.3 and 5.4 below.

The Inergi Agreement relating to call centre services expired on February 28, 2018. On March 1, 2018, Hydro One insourced these services. The work program and associated costs are discussed in Exhibit E-03-04, Section 2.1.

4.2 SCOPE OF WORK

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. The cost of supply chain services is recovered through the material surcharge rate, which is discussed in detail in Exhibit C-09-04.

4.3 FEE STRUCTURE

Inergi provides finance and accounting and payroll services using a volume-based pricing structure. Fees are charged according to prescribed volumes, as defined in the Inergi Agreement, while meeting or exceeding prevailing service levels. Additional charges apply if there are higher transaction volumes than the prescribed volumes. Conversely, Hydro One is entitled to fee credits if transaction volumes are lower than prescribed volumes.

Supply chain services are provided by Inergi under a fixed fee structure. Fees charged to Hydro One for the provision of all services under the supply chain services SOW are not adjusted based upon volume fluctuations for the performance of services.

Fees for finance and accounting and payroll services are subject to an Economic Cost Adjustment (ECA) using a government published index that reflects movements in a broad-based consumer-focused price index. The ECA is adjusted for inflation sensitivity. The ECA does not apply to supply chain services.

The Inergi Agreement provides for optional benchmarking reviews of fees by SOW. The costs of the benchmarking review are borne equally by Hydro One and Inergi. The review is to be conducted by an independent third party analyst selected from a predetermined list included in the Inergi Agreement. If the benchmarking review of finance and accounting and payroll fees determines that Inergi fees are above the benchmark, Inergi must adjust its fees to the benchmark price. For supply chain services, Inergi is not obligated to adjust its fees due to its fixed fee structure.

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. Further discussion on insourcing of services and associated costs can be found in Exhibit C-09-04, and is also referenced in Section 5.2 below.

4.4 SERVICE QUALITY ASSURANCES

In the contract year ending December 2020, Inergi met or exceeded 95% of total PIs across all SOWs. More details are available in Table 1 below.

Table 1 - Inergi 2020 Performance

Statement of Work	Performance Indicators Measured for 2020	Performance MET	Target Performance NOT MET	Minimum Performance NOT MET	% MET
Information Technology Services	271	255	14	2	94%
Finance and Accounting Services	207	203	4	0	98%
Payroll Services	151	128	16	7	85%
Supply Chain Services	248	245	3	0	99%
Total	**877**	**831**	**37**	**9**	**95%**

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.

5.0 SOURCING STRATEGY FOR OUTSOURCED SERVICES

This section details how the remaining services under the Inergi Agreement have been, or will be, transitioned under Hydro One's new sourcing strategy upon expiry. This section also presents the benefits derived by this strategy. 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.

5.1 INFORMATION TECHNOLOGY SERVICES

Effective March 1, 2021, Hydro One entered into a new outsourcing arrangement with Capgemini for a reduced scope of information technology services (Capgemini Agreement). The remaining portion of information technology services previously provided under the Inergi Agreement were transitioned into Hydro One to be self-performed.

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.

The Capgemini Agreement is described in Section 6, while the information technology work program and associated costs of the insourced activities are discussed in Exhibit E-04-04, Section 2.1.

5.2 SUPPLY CHAIN SERVICES

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. Through insourcing, all supply chain services will operate under a single management team with complete alignment of goals and priorities, which will enable Hydro One to focus on successfully executing the supply chain work program. As part of this transformation, Hydro One will focus on building supply chain staff competencies to regain internal expertise. The supply chain work program and associated costs are discussed in Exhibit C-09-04.

5.3 FINANCE AND ACCOUNTING SERVICES

Upon expiry of the Inergi Agreement, Hydro One plans to transition back-office finance and accounting work activities into the company to be self-performed effective January 1, 2022. Similar to supply chain services, all finance and accounting services will operate under a single management team with comparable benefits. The Corporate Controller work program and associated costs are included in Exhibit E-04-02, Section 2.2.1.

5.4 PAYROLL SERVICES

Upon expiry of the Inergi Agreement, a new contract for payroll processing services will commence effective January 1, 2022 with Ceridian Canada Limited[2] (Ceridian), an industry-leading payroll management company, for a lower cost compared to the Inergi Agreement. These costs are captured within the Corporate Controller work program in Exhibit E-04-02, Section 2.2.1.

5.5 SOURCING STRATEGY BENEFITS

Hydro One developed its sourcing solution based on desired business outcomes. The key objectives were to realize the following benefits:

- Reduce costs;
- Transform services;
- Increase efficiency; and
- Regain internal expertise.

[2] Annual fees paid to Ceridian Canada Limited. is approximately $2.5 million for the provision of payroll services.

Cost Reduction

Over the 2021-2025 period, the sourcing strategy will achieve cost savings in comparison to the same services provided under the Inergi Agreement. This is in consideration of total contracted payments to new service providers including transition, costs associated with repatriation of Inergi employees into Hydro One, and costs to self-perform activities including transition and transformation. The estimated savings are embedded within the costing of the updated business plan through the respective lines of business work programs, as well as reflected in the material surcharge to capital and OM&A projects and programs.

Transforming Services

Restructuring Hydro One's outsourced services has allowed the company to create a competitively attractive outsourced work portfolio, while insourcing allows for greater control over work program initiatives and transformation of business processes as described below.

The structure of the Capgemini Agreement provides Hydro One with increased transparency with respect to the resources, skillsets, and overall value being delivered. The new agreement also provides Hydro One with improved performance metrics aligning with business outcomes. Insourced supply chain and finance and accounting services are also being transformed to better align with internal processes executing work program and strategic initiatives.

Increased Efficiency

In 2020, Hydro One's Information Solutions Division began transitioning to a new Target Operating Model as part of Hydro One's efforts to continuously improve capital work execution by delivering information technology solutions more quickly, more efficiently, and with higher standards of technical support. Hydro One's partnership with Capgemini will enable the success of the Target Operating Model by offering the resources and skillsets that can adapt to agile project delivery. For more information on the Information Solutions Division's Target Operating Model, refer to GSP Section 4.10.4.2.

Insourcing of supply chain and finance and accounting services to Hydro One, together with repatriation of Inergi staff performing the work, will streamline processes end-to-end by reducing hand-offs between parties, and gain control over management of activities. The sourcing strategy with Capgemini for information technology services allows Hydro One to leverage their industry expertise for support and maintenance of our critical solutions such as SAP, as well as for project delivery.

Regain Internal Expertise

Insourcing of several information technology, supply chain and finance and accounting functions previously outsourced under the Inergi Agreement will help regain in-house subject-matter expertise, build knowledge and upskill its internal workforce that will drive enhanced business enablement to the rest of the organization.

5.6 OUTSOURCING FEES FOR SERVICES

Appendix A, Table 4 to this exhibit presents total payments for services outsourced to Inergi for the historical period of 2018-2020, as well as forecasted total outsourcing fees paid to Inergi, Capgemini and Ceridian. The forecast for bridge year 2021 shows a decline in fees reflecting a reduced scope and a lower fee commitment for information technology services within the new Capgemini Agreement. Forecast years 2022 and 2023 show a further decline which reflects insourcing of supply chain and finance and accounting services upon expiration of the Inergi Agreement, and lower fees for payroll services transitioned to the new agreement with Ceridian.

6.0 CAPGEMINI CANADA INC.

6.1 BACKGROUND

As described in Section 5.1 above, Hydro One entered into the Capgemini Agreement for information technology services on March 1, 2021. The initial term of the Capgemini Agreement expires on February 29, 2024, with a further option for two one-year extensions exercisable by Hydro One.

6.2 SCOPE OF WORK

Services provided under the Capgemini Agreement include a portion of what was provided under the Inergi Agreement, and is divided into three separate SOWs: (1) application services, (2) infrastructure services, and (3) project services. Table 2 below summarizes the current scope of each SOW:

Table 2 - Capgemini Scope of Work

Statement of Work	Service Description
Application Services	Services to provide technology platforms, operational, quality control and application support services customized to the service requirements and needs of SAP, SharePoint, Microsoft CRM applications and infrastructure applications.
Infrastructure Services	Services to monitor IT infrastructure (servers, mainframe, storage area network and data storage devices) located at data centre (production and backup) facilities. Services to provide IT service Management and end to end incident management including the Service Desk support to facilitate end user problem reporting, and the systems and processes to document and resolve any application, infrastructure, or system related incident. The service desk provides incident management, problem management and technology change management services to end users of information technology services.
Project Services	IT services leveraging Capgemini's industry expertise to assist Hydro One on portions of finite project work, as to produce a project deliverable, solution or result.

6.3 FEE STRUCTURE

The Capgemini Agreement includes financial provisions that achieve greater flexibility and cost savings compared to the previous Inergi Agreement. Services are provided under a variable pricing model, with an overall annual fee commitment to Capgemini. This arrangement allows Hydro One the flexibility of adjusting service volumes between SOWs driven by the demands of Hydro One's business needs. Annual fees paid for application and infrastructure services do not fluctuate as long as transaction volumes fall within prescribed volumes, as defined in the Capgemini Agreement.

Project services utilizes prescribed rates for project resources based on skill level, which are used to determine a project's value. The sum of the total project values delivered by Capgemini must meet the project services fee commitment. The Capgemini Agreement allows Hydro One to capture savings through lowered average rates for project resources compared to the previous Inergi Agreement.

Increases or decreases to transaction volumes that exceed defined limits within the application and infrastructure service SOWs will trigger a rebalancing of fees resulting in an offsetting decrease or increase, respectively, to the committed spend within the project services SOW. This rebalancing provides flexibility in the allocation of fees between the SOWs, with the aggregate fees remaining unchanged.

The Capgemini Agreement provides for optional benchmarking reviews of fees by SOW. The costs of the benchmarking review are borne equally by Hydro One and Capgemini. The review would be conducted by an independent third party analyst selected from a predetermined list included in the Capgemini Agreement. Hydro One can benchmark once during the initial term after 12 months has passed the SOW effective date. If the benchmarking review determines that the aggregate of Capgemini fees for a given SOW are greater than the benchmark price, Capgemini must adjust its pricing to equal the benchmark price. The annual fee commitment is unaffected by any pricing adjustments as a result of benchmarking. However, the adjustments will entitle Hydro One to receive a greater value for services and further optimize the allocation of fees between SOWs.

6.4 SERVICE QUALITY ASSURANCES

The Capgemini Agreement sets out a methodology consistent with the Inergi Agreement to measure Capgemini's service performance. Each SOW includes improved PIs that more closely align with business outcomes and to industry standard, measuring performance in terms of system availability, service quality, customer satisfaction, timeliness, and budget, among others. Services are also measured through client satisfaction surveys.

7.0 BGIS GLOBAL INTEGRATED SOLUTIONS CANADA LP

7.1 BACKGROUND

Following a competitive procurement process, and in accordance with the terms of a purchased services agreement with the Power Workers' Union, on January 1, 2015, Hydro One began a new facilities management services arrangement (BGIS Agreement) with Brookfield Johnson Controls Canada, which has since been renamed to BGIS Global Integrated Solutions Canada LP (BGIS).

The BGIS Agreement has a 10-year term, which can be extended at Hydro One's option for an additional three years.

7.2 SCOPE OF WORK

The scope of work under the BGIS Agreement is comprised of ongoing daily facilities management, accommodation activities and related maintenance and repair work at its operations centres, transmission stations facilities, distribution stations, administration facilities and rights of way locations. The BGIS Agreement also includes capital project management services related to new facilities as defined by Hydro One.

7.3 FEES

Appendix B to this exhibit sets out the outsourcing fees spent in the historical period of 2018-2020.

Fees billed to Hydro One for BGIS services are categorized into two main segments:

- Management and administrative fees that compensate for overhead and profit; and,

- Pass through expenses, at full cost with no mark-up, for works and services that are performed by BGIS, and supplies and services provided by third parties through BGIS.

Fees are subject to an ECA using a government published index that reflects movements in a broad-based consumer-focused price index. The ECA is adjusted for inflation sensitivity.

The BGIS Agreement provides for optional benchmarking reviews of fees by an independent third party. The costs of the benchmarking review are borne equally by Hydro One and BGIS. Hydro One may request third party benchmarking only after the initial three years of the BGIS Agreement has passed, and every two years thereafter. A benchmark fee adjustment will apply if the aggregate fees are above five percent of the target results.

In the third quarter of 2020, Hydro One exercised its right to a benchmarking review of BGIS's fees for facilities management services, including pass through expenses. The report was completed in October 2020 by ISG. The benchmark findings concluded that the fees charged by BGIS are within market range and that the BGIS Agreement continues to provide good value to Hydro One. As such, there were no changes to the fees charged by BGIS as a result of the review.

7.4 SERVICE QUALITY ASSURANCES

In the contract year ending December 2020, BGIS met or exceeded 92% of total PIs. PI results are presented in Table 3 below. Overall, Hydro One is satisfied with BGIS's performance. Where BGIS's performance did not meet targets during the year against Hydro One's high standards for health, safety and environment is primarily attributable to timing of initial incident reporting. BGIS is required to call in with a preliminary report within four hours of an incident occurring. In some instances this requirement was not met, but continued to submit comprehensive incident reports on time.

Customer satisfaction PIs measures internal client satisfaction of BGIS-performed work. Performance for 2020 was a result of a lower than normal response rate. Hydro One and BGIS are together reviewing its client survey methodology to find opportunities for improving response rates and to obtain meaningful client feedback.

Table 3 - BGIS 2020 Performance

Statement of Work	Performance Indicators Measured for 2020	Performance MET	Target Performance NOT MET	Minimum Performance NOT MET	% Met
Finance	13	13	0	0	100%
Health, Safety & Environment	60	53	0	7	88%
Work Program Accomplishment	72	71	1	0	99%
Customer Satisfaction	36	29	0	7	81%
Total	**181**	**166**	**1**	**14**	**92%**

7.5 CONTINUOUS IMPROVEMENT AND GOVERNANCE

BGIS is able to leverage their capabilities supported by its facility management centre of expertise, network of technicians, suppliers and vendors, strategic sourcing specialists to bring innovation and create value for clients.

APPENDIX A: OUTSOURCING FEES FOR BACK-OFFICE SERVICES

Table 4 - Summary of Total Outsourcing Fees for Back-Office Services excluding BGIS ($M)[3]

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Fees for Base Services[4]	81.4	76.1	72.2	48.8	24.8	24.8
Volume, Scope and Other[5]	4.5	0.0	-0.3	5.4	1.1	1.1
ECA[6]	2.1	1.1	1.0	1.1	0.0	0.0
Subtotal Fees for Based Services	**88.0**	**77.2**	**73.0**	**55.3**	**25.9**	**25.9**
Project Spend (all lines of business)[7]	38.5	41.0	46.6	25.7	22.2	22.2
Total Payments	**126.5**	**118.2**	**119.6**	**81.0**	**48.1**	**48.1**

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[3] Includes payments to Inergi, Capgemini and Ceridian for information technology, supply chain, finance and accounting, payroll, call centre (insourced February 2018) and settlements (insourced December 2019) services.

[4] 2021 decrease due to transition to new service agreement with Capgemini for reduced information technology scope and with a lower fee commitment. 2022 decrease due to expiration and insourcing of supply chain and finance and accounting services, and transition to new service agreement with Ceridian for payroll services.

[5] 2019 decrease due to transition to amended Inergi service agreements for information technology and supply chain, effective March and November 2018, respectively, which provided services under a fixed fee structure. 2021 Forecast includes third party leases and costs paid to Capgemini for one year.

[6] 2022 and 2023: ECA is not applicable for the initial terms of the Capgemini and Ceridian agreements.

[7] 2021 decrease due to a lower spend commitment for projects to Capgemini, as well as lower rates for project resources compared to Inergi Agreement.

APPENDIX B: BGIS FEES

Table 5 – Summary of Total Outsourcing Fees for BGIS ($M)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Management Fee and Admin	4.4	4.9	4.8	5.0	5.1	5.2
Reimbursable Charges	29.2	30.6	30.7	31.9	32.5	33.2
Pandemic Supplies and Cleaning	0.0	0.0	5.7	8.9	0.0	0.0
Subtotal Fees for Sustainment	**33.6**	**35.5**	**41.2**	**45.8**	**37.6**	**38.4**
Facilities Maintenance Capital	7.3	5.0	4.5	2.5	2.6	2.6
Project Delivery[8,9]	23.0	22.7	39.0	18.5	24.1	33.7
Total Payments	**63.9**	**63.2**	**84.7**	**66.8**	**64.3**	**74.7**

[8] 2020 increase in projects is primarily due to the new Woodstock Operating Centre built to consolidate the Woodstock and Beachville operating areas.
[9] 2023 Test Year includes planned project proposals to build two new operating centres and a distribution centre.

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PROCUREMENT PROCESS AND WARRANTY CLAIMS

1.0 OVERVIEW

This schedule sets out the procurement process that Hydro One employs to source materials and services required to execute the company's investment plan, operations, maintenance and other business activities. It summarizes the principles that underlie the company's procurement process (Section 2.0), Hydro One's approach to sourcing planning (Section 3.0), the execution of the sourcing plan (Section 4.0) and the various sourcing methods that the company employs (Section 5.0). It also summarizes Hydro One's approach to managing warranty claims (Section 6.0).

2.0 SOURCING PRINCIPLES

Hydro One procures materials and services through a framework of policies and procedures that are intended to deliver productivity, buying power, improved services and innovation while building valued supplier relationships that allow the company to achieve greater value in its sourcing.

Hydro One's sourcing activities are based on a set of principles: Financial Stewardship; Supplier Relationships; Health, Safety, Environmental and Sustainability; and Indigenous Procurement. These principles are captured in Hydro One's Supply Chain Policy (included as an attachment to this exhibit) and are described below.

FINANCIAL STEWARDSHIP

- Utilizing a value-for-money approach to source materials and services that helps deliver overall value and lowest total cost of ownership.
- Following negotiation strategies to obtain the lowest possible price from qualified suppliers while not jeopardizing quality and maximizing value.
- Ensuring savings, rebates and volume discounts are captured.
- Ensure the right materials and services are delivered to the right place at the right time in a cost effective manner.

- Achieve operational excellence through continuous improvement in collaboration with Supply Chain’s Customers and Suppliers.

SUPPLIER RELATIONSHIPS

- Ensuring that materials and services are acquired from qualified suppliers and establishing consistent expectations for working with suppliers that enhance relationships and the value-for-money proposition.

HEALTH, SAFETY, ENVIRONMENTAL AND SUSTAINABILITY

- Considering responsible ways for sourcing from businesses that conduct operations in a socially responsible manner in accordance with good environmental, health, safety and sustainability practices.

INDIGENOUS PROCUREMENT

- Developing and maintaining relationships with Indigenous Peoples based on mutual respect.
- Encouraging the development and viability of qualified Indigenous businesses, identifying contracting opportunities, conducting workshops, and promoting business networking within Indigenous communities.
- Executing a set-aside process by granting Indigenous businesses more time to complete proposals, directly awarding to qualified Indigenous business, or establishing mandatory Indigenous participation requirements in sourcing events.
- For more information, please refer to Exhibit A-07-02, Section 7.1.

3.0 SOURCING PLANNING

Each year Hydro One develops a sourcing plan that outlines the sourcing priorities for materials and services over the next five years, including a detailed schedule and resourcing plan for the first two years of the plan. The sourcing plan is based on the needs of the business and prioritized based on the expected highest return for productivity savings, operational improvements and service enhancements, organized into categories for different commodities.

For each category, Hydro One develops and executes a sourcing strategy that considers the following factors:

- Identification and engagement of relevant internal stakeholders;
- Defining business requirements;
- Developing an expenditure baseline;
- Analysis of current supply market conditions and trends;
- !n alysis of current suppliers’ prices, offerings and performance-
- Considerations of category specific circumstances, active contracts, user requirements and specifications, stakeholder analysis, commercial considerations, collaborative planning input, supplier relationship level, key leverage points, bid list, disputes with suppliers, business risks, benefits estimates, qualification requirements, consideration of total value, and market research;
- Selection of an appropriate sourcing method, including open competition, competition directed to a subset of suppliers, or direct negotiation; and
- Encourage opportunities for Indigenous inclusion in the category strategy.

4.0 SOURCING EXECUTION

In 2018, Hydro One developed a Category Management Operations Framework to execute the strategy referred to in Section 3.0. This framework categorizes sourcing efforts into four “Category Teams” that consolidate commodity purchases. This framework is now embedded in the company’s supply chain process and polices, including the attached Supply Chain Policy.

As illustrated in Figure 1 below, Hydro One's Category Management Operations Framework is based on four objectives:

1. **Align Categories with Business Objectives** - takes a holistic, strategic view of business objectives and becomes primary service line and positions Supply Chain as a sought-after resource to business stakeholders.
2. **Identify Cross-Organizational Opportunities** - broader view enables Supply Chain to incorporate business needs into activities and identify new pockets of value.
3. **Develop Dynamic Sourcing Strategies** - adjusts rhythm to match cadence and lifecycle of stakeholder processes and business needs.
4. **Create Productivity Savings & Operational Efficiency** - integrate multiple value levers to maximize impact such as strategic sourcing, demand planning, and supplier relationship management.

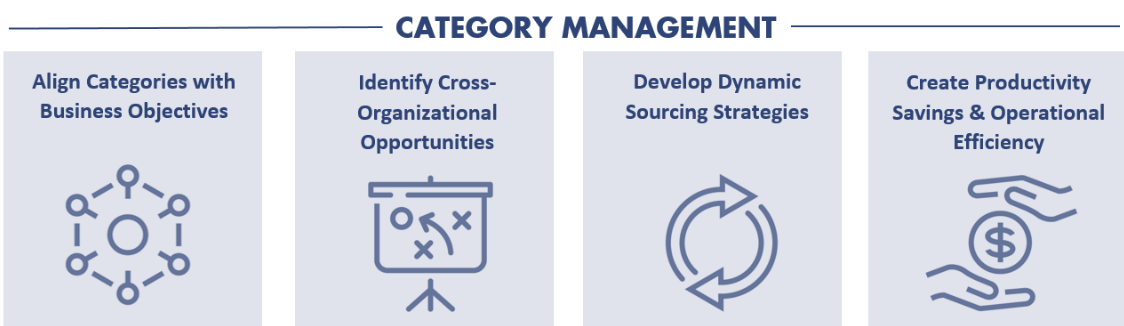

Figure 1: Objectives of Hydro One's Category Management Operations Framework

The category management operations framework organizes spending to accurately represent the distinct categories of sourcing expenditures across the company. The process used to develop spend categorization has three main steps:

- Develop a category structure that segments spend into distinct categories for both internal operations and external supply markets.
- Develop a category structure that aligns to industry best practices and enables the use of category management tools.

- Align category structure with existing functional material classifications to drive consistency in terminology and classifications across all business units.

The classification into categories is fundamental to the category management operations framework. The category tiers are used to:

- Define the relative importance of each category to Hydro One's system operations.
- Govern category management approval authorities.
- Define category management deliverables.

Once the Sourcing Plan has been approved, sourcing teams begin executing the categories as per the plan's timeline. The lifecycle of a category is as follows:

Figure 2: Annual cycle to execute categories

1. **Internal Analysis** – Category Leads in Supply Chain develop a spend profile, engage with key internal stakeholders in impacted Lines of Business and review the current operational model related to the use of the material or service.
2. **Market Analysis** – Category Leads complete an analysis on the cost drivers, trends and complete a marketplace competitive overview. Category Leads conduct research to identify new suppliers or new products/services that could meet the needs of the Line of Business.
3. **Strategy Development** – Leveraging the information learned in the Internal Analysis and Market Analysis phases, the Category Leads will then develop sourcing strategies that will maximize the value to Hydro One based as discussed above in Section 3.0. Strategies are formalized by Category Leads and approved by Supply Chain Management.

4. **Strategy Execution** – Category Leads will execute the strategy using one of the sourcing methods described in Section 5.0 of this exhibit. This phase completes upon the category award and a signed contract with a supplier.
5. **Strategy Implementation** – After a contract has been signed, Category Leads execute a communication plan to all impacted Line of Business stakeholders and ensure a smooth roll out of the new contract.

4.1 ASSURANCE OF SUPPLY

As a result of COVID-19 there were risks of delayed shipments and material availability, especially pandemic related supplies. To address this risk, Supply Chain implemented an Assurance of Supply strategy:

- **Category Management Approach** – As described in Section 4.0 above, Supply Chain has a deep and thorough understanding of the material or service category, its suppliers' industries and end user's needs. Supply Chain relies on market intelligence, transportation expertise, and supplier performance/relationship management to both predict and minimize impact to Hydro One's cost or operation
- **Diversification of Supply Base** – Sourcing strategy development is centered on ensuring redundancy in the supply channels wherever possible. Sole source supply channels are understood and closely managed.
- **Specification Refinement and Consolidation** - Sourcing strategies are executed with Engineering and Technical Service teams to refine specifications to industry standard (as opposed to Hydro One-specific) and to consolidate to as few variations as is possible. This increases market channels, increases manufacturing efficiency, and allows collaboration with peer utilities.
- **Inventory / Strategic Spares** – Hydro One maintains inventory at a central warehouse in Barrie Ontario, and at ~80 Operations Centres across the province. These locations hold inventory on hand to ensure that materials and supplies are available when needed.
- **Collaboration with Peer Utilities** – Hydro One Supply Chain collaborates with several peer utilities, both formally and informally, to identify emerging trends in the marketplace and

collaborate on mitigation strategies, and to pursue collaborative sourcing initiatives where possible.

- **Early Ordering and Committing to Production Slots** – Hydro One Supply Chain and Planning work together to identify opportunities for making early commitments to certain key suppliers in order to guarantee the on time delivery of critical materials.

5.0 SOURCING METHODS

The following are detailed sourcing methods which may be employed:

(1) RFI – Requests for Information

RFI is a process that uses a market research tool sent to a broad base of potential suppliers for a number of purposes, including gathering information, building a supplier database to determine availability of products and services, scoping business requirements, and/or estimating project costs. Responses to RFI questions normally contribute to the content of the eventual RFP, RFPQ, or RFQ document being created but do no result in an award.

(2) RFP - Requests for Proposal

An RFP is a process that uses a document prepared to solicit proposals for the supply of materials or services for which bidders must develop and propose a business application or solution. This competitive bid process is used when one or more of the following criteria are met:

- There is a requirement for custom made/specialized materials or services for which bidders must develop and propose a business application or solution;
- There is a need for engineered equipment and/or construction services, and more than one option exists to address the requirement;
- There are off-the-shelf materials where value added services are required in addition to the materials; and/or
- An alternative solution is sought.

An RFP may result in a Vendor of Record list with pre-established rate cards. These arrangements require a second-stage competitive process, or an award strategy identifying the methodology for determining the award of work.

(3) RFPQ – Request for Pre-Qualification

An RFPQ is a competitive bid process used to solicit supplier capabilities and qualifications, with the intention of establishing a list of pre-qualified suppliers, usually based on financial and/or other technical criteria.

It is used when the following criteria are met:

- There are opportunities to reduce costs for certain categories of materials and services by establishing strategic relationships with a small group of suppliers; and
- There are generally understood technical criteria to pre-qualify the suppliers but specific scopes of work are defined as required.

These arrangements require a second-stage competitive process directed to the pre-qualified suppliers, or an award strategy identifying the methodology for determining the award of work.

(4) RFQ - Requests for Quotation

This competitive bid process is used where a description of exactly what needs to be procured is provided and the evaluation of bidders is made predominantly on price and delivery requirements.

(5) Direct Negotiation

Direct negotiation is used when a competitive process is not feasible or when running a competitive sourcing is not in the best interest of Hydro One. Examples of circumstances when negotiation with a single supplier may be most appropriate include:

- Building key strategic supplier relationships where it is believed that a competitive process may not lead to the best solution or drive the most value for Hydro One;
- A purchase that is of a confidential or privileged nature;
- Where urgency exists and there is only one supplier who can perform the work without causing Hydro One to suffer an unacceptable delay or incur unreasonable costs due to another supplier's learning curve;
- There is only one supplier capable of meeting the requirements;
- To ensure compatibility with existing products, to recognize exclusive rights, such as exclusive licences, copyright and patent rights, or to maintain specialized products that must be maintained by the manufacturer or its representatives;
- Where there is an absence of competition for technical reasons and the materials or services can only be supplied by a particular supplier and no alternative or substitute exists (e.g., original equipment manufacturer, or where the warranty is tied to a particular material and it would be negated by the use of a different supplier’s part);
- The supplier has a statutory monopoly; or
- For the procurement of a prototype, or a first good or service, to be developed in the course of, and for, a particular contract for research, experiment, study, or original development, but not for any subsequent purchases.

6.0 WARRANTY CLAIMS

Hydro One employs a Warranty & Claim Management process that provides a systematic methodology for identifying, assessing and resolving warranty issues and claims, and for seeking compensation, when applicable, from suppliers. The process is tailored to manage warranty issues and claims for major engineered equipment but can be applied to materials and equipment. When materials/equipment fail or are found to be defective, the following process is followed:

- Warranty & Claim Assessment – determine if the materials/equipment are still under warranty, if warranty covers the defect/failure, and Hydro One's cost impact.
- Warranty Claim Form – completed for claims exceeding $25K or where the Line of Business requires assistance from Hydro One’s Supply Chain group to manage the warranty issue with the supplier.
- Warranty Claim Support – Hydro One will:
    - Participate in resolution meetings with the team as required.
    - Provide commercial guidance and direction by ensuring the necessary Supply Chain stakeholders are engaged to help resolve the issue.
    - Coordinate internal commercial discussions with Supply Chain, Inergi, and Law, as required.
    - Help coordinate communications with suppliers to ensure the team received the appropriate level of support to quickly resolve the defect/failure.
    - Work with the supplier to negotiate the appropriate compensation.
- Defect or Failure Resolution - develop an action plan, identifying who will complete the work (e.g., Hydro One or supplier).

Where a warranty does not apply, Hydro One may still have reasons to issue a claim such as latent defect, design not to specifications, or breach of contract.

When the repair is complete, applicable costs will be reimbursed by the supplier.

7.0 ATTACHMENTS

Attachment	Description
1	Supply Chain Policy

SP 1231 R3

Supply Chain Policy

Purpose and Scope

The primary purpose of the Supply Chain Policy is to communicate and reinforce desired values and expectations of the supply chain activities of Hydro One Limited, its subsidiaries and the affiliates it controls (referred to in this document as 'Hydro One' or the 'Corporation').

This policy applies to Hydro One and its outsourcing partner.

Revision Statement

This policy has been revised to include additional key Supply Chain functions: Productivity Savings, Supplier Performance Management & Governance. In addition, links in section 3.0 References have been updated.

Principles

Supply Chain will:

- Acquire materials and services through a process that drives value for money, transparency to its internal customers, and builds mutually valuable relationships with key suppliers.
- Ensure the right materials and services are delivered to the right place at the right time in a cost effective manner.
- Source materials and services with consideration to health, safety and the environment and corporate social responsibility.
- Promote business and workforce development for Indigenous Businesses.
- Achieve operational excellence through continuous improvement in collaboration with Supply Chain's Customers and Suppliers.
- Manage its outsourcing partner to align with these principles.

1.0 Requirements

The key requirements of each Supply Chain function are as follows:

Strategy and Oversight:

- Provide a strategic, cost effective, data driven and analytical planning approach to Supply Chain processes.
- Direct continuous improvement initiatives to achieve operational excellence and cost effectiveness.
- Ensure an effective governance process is in place to manage change.

Sourcing:

- Develop and execute a strategic procurement plan to identify materials and services needed to meet business requirements at the best value for money.
- Employ a mix of procurement processes, including sole source, direct negotiation, and bidding processes that provide the best business outcome.
- Identify and attract qualified suppliers that provide quality products and services.
- Provide opportunity for increased Indigenous Business participation in the provision of products and services.

Purchasing:

- Process Purchase Requisitions on a timely basis to ensure that customer's needs are met.
- Promote improved requisitioning through effectively documented processes and education.

Inventory Management:

- Align to the Inventory Policy (SP0732).
- Manage inventory at optimal levels and locations to satisfy operations.
- Monitor and control the accuracy of inventory data.
- Re-deploy, return or dispose of material to maximize cost savings considering environmental impact.

Logistics:

- Determine the most efficient and economical method to store and distribute materials from Suppliers to Customers.
- Facilitate the movement of returnable containers to Suppliers.

Accounts Payable:

- Remit authorized and timely payments to Suppliers in accordance with the terms and conditions of the respective contracts.
- Capture payments accurately and completely in Hydro One systems, and ensure accurate account distributions.

Customer Service:

- Providing Source-to-Pay support for all internal customers
- Delivering value to all its internal customer and dedicated to providing excellent customer service

Productivity Savings:

- Leverage purchasing power across internal organizations and strategic sourcing events to obtain competitive prices and negotiate significant cost savings

Supplier Performance Management & Governance:

- Negotiating terms and contractual language that mitigate risks and ensures Hydro One's interests are protected.
- Ensuring Suppliers meet financial, health & safety, and insurance requirements.
- Providing supplier performance management to ensure Suppliers are fulfilling their contractual commitments to Hydro One.

Data Management

- Utilize business applications, information management methods, and data management tools to implement procedures and an infrastructure to support the integration and shared use of accurate, timely, consistent and complete Supply Chain Master Data.

2.0 Definitions

None

3.0 References

Expenditure Authority Register

Supplier Code of Conduct

SP0829 - Code of Business Conduct

SP0849 - Corporate Disclosure Policy

SP0732 - Inventory Policy

SP0733 - Inventory Procedure

SP1374 - Indigenous Procurement Procedure

SP0327 - Health, Safety and Environmental Policies

SP0312 - HSE Requirements for Purchase of Contractor Services

SP0826 - Sourcing Procedure

Requisitioner's Guideline

4.0 Document Management

Owner/Functional Responsibility	Director, Supply Chain
Approver	Vice President, Shared Services
Approval Date	April 2020
Effective Date	April 28, 2020
Last Reviewed Date	April 28, 2020
Next Review Date	April 28, 2022

5.0 Appendices

None

CORPORATE STAFFING AND COMPENSATION

1.0 INTRODUCTION AND OVERVIEW

This exhibit describes the aspects of the workforce that build, operate, and support Hydro One's Transmission and Distribution systems; and details the compensation paid to this workforce, as well as the steps taken by Hydro One to prudently and efficiently manage its size and overall cost. To optimize workforce size and composition (i.e. workforce mix), Hydro One will leverage the workforce flexibility achieved in previous rounds of collective bargaining to manage the increase in planned work without significantly increasing the size of its regular workforce. In terms of relative compensation levels, Hydro One has made significant progress in addressing its position relative to market (compared to prior years). Furthermore, Hydro One will continue to pursue market competitiveness through its labour relations strategy, and anticipates moving even closer to market by the end of the rate period.

Part One of this exhibit describes the composition and size of the workforce that Hydro One requires over the 2023-27 rate period to execute its Investment Plan and to operate the Transmission and Distribution systems. As described in this part, Hydro One has undertaken a rigorous workforce planning process to determine the appropriate level and types of resources to deliver its planned work.

Part Two of this exhibit describes the compensation paid to Hydro One's workforce, both unionized (represented) and non-represented, and details the forms of compensation the workforce receives. Given the preponderance of unionized employees, Part Two of this exhibit also discusses the labour relations context that influences the workforce. Additionally, Part Two also addresses the relative competitiveness of Hydro One's levels of compensation, as reflected in the updated 2020 results of the benchmarking study conducted by Mercer Canada (the Mercer Report). As directed by the OEB in EB-2019-0082, this part includes Hydro One's plan to further align its compensation levels with market.

2.0 PART ONE – DESCRIPTION OF HYDRO ONE'S WORKFORCE & RESOURCE PLANNING PROCESS

This section describes the size and composition of Hydro One's workforce and how that workforce is used to deliver Hydro One's planned work. Overall compensation costs are impacted by the size of the workforce, the types of resources engaged (the level and type of FTE[1], known as the workforce mix), as well as the level and form of compensation paid to the workforce. Hydro One's rigorous workforce planning is therefore an essential component of ensuring cost-effective and efficient work delivery.

To execute the planned work, each line of business within Hydro One determines the amount of employees (the level of FTEs[2]) required. Resourcing plans vary across functions (Distribution, Transmission, and Corporate) and between the Transmission and Distribution Lines of Business (LOBs). These plans encompass the increases or decreases required to the workforce, as well as determining whether external resources (contracting out) will be needed and can be used to support increasing levels of work.

Hydro One's workforce is comprised of three types of employees according to their status: (i) regular, (ii) casual, and (iii) temporary. Regular employees make up 67% of the total workforce. Casual employees are approximately 31% of the total workforce, and temporary employees are about 2% of the total workforce as shown in Figure 1.

As shown in Figure 2, approximately 92% of Hydro One's total workforce (regular, casual and temporary) is represented by a union and subject to the terms of a collective agreement.

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[1] Full Time Equivalent (FTE)

[2]At Hydro One, FTEs represent average monthly headcount over a 12 month period. A regular status employee who is budgeted for one year of work, represents one FTE. For casual employees, one FTE equates to 12 person months of work. As causal employees may not work a full twelve months, the resources required are evaluated by FTE levels, not by actual casual headcount.

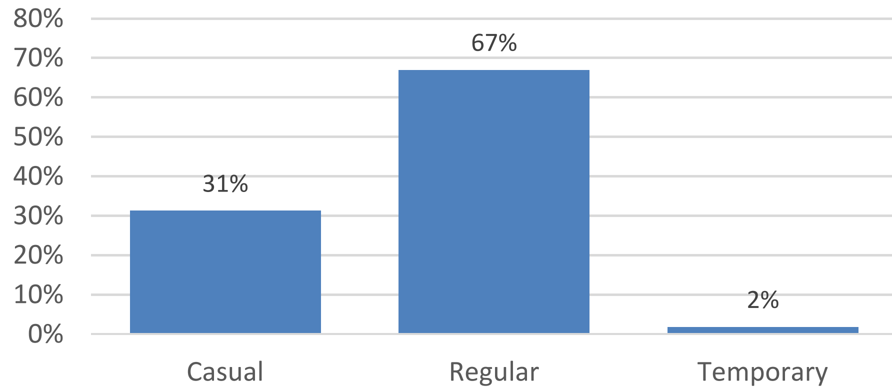

Figure 1: Total Workforce Segments 2020

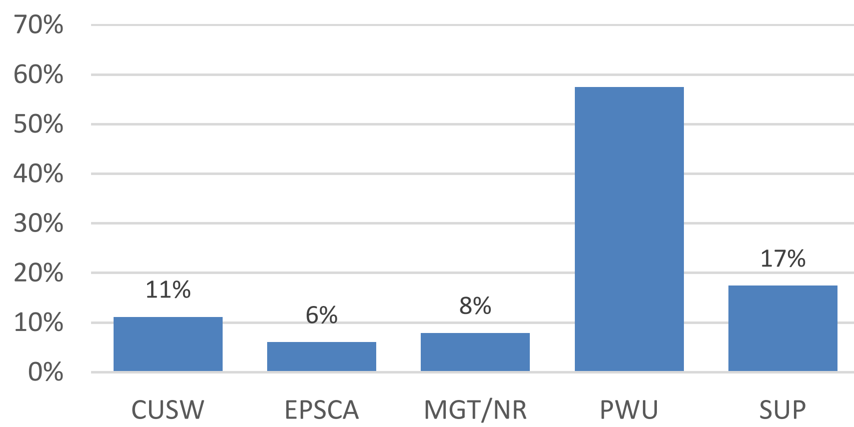

Figure 2: Total Workforce Representation[3] Groups 2020

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[3] CUSW is the Canadian Union of Skilled Workers; EPSCA refers to those employees represented by a casual trades union that negotiates with the Electrical Power Systems Construction Association; MGT/NR refers to management/non-represented, which captures employees in managerial roles, and those who are not represented by a union; PWU refers to the Power Workers' Union; SUP is the Society of United Professionals.

2.1 REGULAR EMPLOYEES

2.1.1 REPRESENTED GROUPS

Approximately 88% of regular employees (and 92% of all employees) are represented by unions. About 63% of regular employees (and 58% of all employees) are represented by the Power Workers' Union (PWU). Approximately 25% of regular employees (and 17% of all employees) are represented by the Society of United Professionals (SUP). In respect of both PWU and SUP represented employees, Hydro One competes to attract, retain, develop and motivate these highly skilled workers in order to execute Hydro One's growing work program. These employees are sought after by other employers, including the Ontario Hydro successor organizations and other utilities.

Employees represented by the PWU perform technical, trades, or clerical work under the main PWU agreement, or customer service and call centre work under the CSO agreement. These employees perform lines, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operations and clerical/administrative work. A significant portion of this workforce is trained internally through the apprenticeship program described below and other trainee programs.

Approximately 40% of regular, full time PWU-represented employees (15% of the entire Hydro One workforce) work as Regional Maintainers (RMs), a role unique to Hydro One. RMs are qualified members of a skilled trade in the areas of Lines, Electrical, Forestry, Civil, or Mechanical work. In addition to obtaining a trades certification, RMs are also expected to be capable of lead hand type duties, contract monitoring, and protection and control duties, in addition to their trade-related responsibilities. On average, it takes four to five years to become minimally qualified in a skilled trade specific to the utility sector through a combination of an apprenticeship/trainee programs and on-the job training. Becoming a fully qualified RM takes another one to three years.

Employees represented by the SUP occupy roles related to technical, engineering, supervisory and/or financial and analytical work. An example of a supervisory role includes the First Line Managers (FLMs) who oversee the work of PWU staff in areas such as Lines, Forestry, and other technical services. SUP-represented staff also play key role in the oversight, analysis, and business planning of network operations, as well as protection and control work and project management.

The collective agreements between Hydro One and the PWU and SUP originate with Ontario Hydro, the predecessor company that was split into five entities in 1999 (referred to hereafter as the OH demerger). The terms of the PWU and SUP agreements are comprehensive and complex. Changes to the terms of these agreements are negotiated through the collective bargaining process. Among the terms of these agreements are:

- conditions of employment: wages, leave (vacation and sick leave etc.), pension and benefits;
- selection language: provisions relating to candidate qualifications for vacancies/job competitions;
- employment security language and severance entitlements: processes for layoffs, seniority, displacement of workers in event of layoffs;
- provisions pertaining to scheduling, hours of work, overtime rates; and
- a description of work jurisdiction and contracting-out provisions.

2.1.2 MANAGEMENT AND NON-REPRESENTED (MGT/N-R) EMPLOYEES

The remaining 12% of the regular workforce (8% of the total workforce) are not represented by a union. These are primarily employees in managerial roles, as well as those positions that are excluded from union representation for reasons such as confidentiality related to labour relations or legal matters.

The managerial workforce leads the company by setting strategy and providing work direction. Hydro seeks to hire a mix of internal and external talent for these roles. In order to attract and maintain an appropriate managerial workforce, Hydro One must provide a market competitive compensation package. Attracting talent from represented roles into management can be challenging for reasons related to compensation and job security. Accordingly, the compensation and benefits package for management employees includes: (i) a market-based and segmented base pay structure; (ii) incentive-based pay or pay at risk; (iii) a defined contribution pension plan;[4] (iv) an optional employee share ownership plan with employer enhancements; and (v) health and dental plan, with paid vacation, short-term sick leave, and long-term disability benefits coverage.

2.2 CASUAL EMPLOYEES

Casual employees are typically retained for 40 hours a week for a fixed period of time to execute and support construction work, supplemental maintenance work, supplemental customer service and clerical support work, or are completing an apprenticeship program.

As presented in Figure 3, casual workers are either:

- Represented by the PWU and employed through a hiring hall as discussed further under Section 2.2.1 below;
- Represented by the Canadian Union of Skilled Workers (CUSW) who perform skills trades work in transmission system construction; or
- Members of a building trades unions, such as the Carpenters, Labourers (LIUNA), Operating Engineers, or Ironworkers, which negotiate agreements with a group of employers known as the Electrical Power System Construction Association (EPSCA).

[4] All management/non-represented employees hired since 2015 participate in the currently offered defined contribution pension plan; those hired prior to 2015 are members of the previously offered defined benefit pension plan.

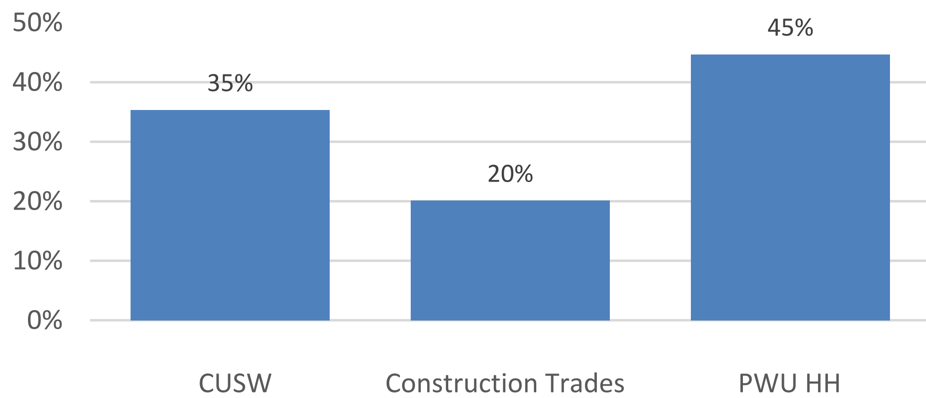

Figure 3: Representation of Casual Workforce

Unlike Regular employees, casual employees are contingent workers hired to perform specific work for a set period of time and then are laid off. For casual trades employees represented by CUSW or one of the construction trade unions that negotiates with EPSCA, conditions closely align with the construction industry, which is subject to specific conditions and exceptions within the larger labour relations and employment law regimes of Ontario. The PWU hiring hall which is discussed under Section 2.2.1 (for both the main agreement, and the Customer Service Organization), CUSW, and other casual construction trades employees, receive a total wage package (including amounts for benefits and pension payments) for each hour worked, and are not entitled to notice and severance when work ceases, (i.e. when they are stand down or are laid off), and do not have access to paid sick leave under the terms of their collective agreements.

The flexible terms of casual labour ensure that workers with the required skill set are hired in the right location for only the duration of the work assignment, and that Hydro One has no ongoing obligations with respect to benefits or pension.

2.2.1 PWU HIRING HALL

The PWU administers a hiring hall (HH) of contingent workers to meet fluctuating work demands (e.g., incremental work, the Apprenticeship Program, and special projects), performing primarily supplemental construction, maintenance, customer service and administrative/technical work. As noted above, similar to casual construction employees, PWU hiring hall workers do not join pension or benefit programs, are not entitled to paid vacation/statutory holidays/sick days off (rather, are paid a % in lieu of statutory holidays and vacation), and can be deployed in a more flexible manner. When workers are required, Hydro One will requisition this labour through a union-run hiring hall directly, and it is up to the union to ensure the labour demands can be met, and the staff within their hall are qualified and ready for work.

2.2.2 PWU APPRENTICESHIP PROGRAM

In addition to using PWU HH labour for temporary and supplemental maintenance work, Hydro One's entire apprenticeship program is subject to the terms and conditions of the PWU HH. Apprentices are employed as casual workers throughout their program, receiving a base salary, and set hourly cash amounts for pension and benefits. The PWU administers the pension and benefits program for these workers as they do for other workers from the HH. There is no guarantee of ongoing work for an apprentice while they are acquiring the necessary training and experience within the lines or electrical trades. Apprentices must apply to a regular position once the program has been completed (after approximately 4 to 5 years). Thus, unlike other utilities, apprentices do not join the pension plan until they have been selected for a regular position. Furthermore, lines trade apprentices are deployed to support both Transmission and Distribution work, making them a flexible and adaptable resource to meet work demands, and support a variety of work programs.

2.2.3 CANADIAN UNION OF SKILLED WORKERS (CUSW)

Hydro One relies on CUSW-represented employees to perform construction industry work on the electrical power systems. Specifically, these employees are lines and electrical tradespersons who perform work primarily on the construction of lines over 50 kV, transmission stations, switchyards, substations, system control centres, and associated telecommunications systems. This group makes up one-third of all casual employees at Hydro One.

2.2.4 CONSTRUCTION TRADES EMPLOYEES

These are casual status employees that are represented by construction (or building trades) unions (such as the Labourers, Operating Engineers, or Carpenters) that supply a contingent workforce through their hiring halls, and negotiate their collective agreements with EPSCA. EPSCA is made up of employers performing construction industry work for the Bulk Electric System on property owned by Ontario Power Generation Inc., Bruce Power LP and Hydro One. This association negotiates and administers collective agreements with the construction trades unions for employers performing work in the Electrical Power System Sector under the *Ontario Labour Relations Act*. There are 17 construction trade unions that negotiate with EPSCA.

2.3 TEMPORARY EMPLOYEES

Temporary employees exist in each of the three groups discussed above (PWU, SUP and non-represented). These employees are typically retained for 12 to 15 months, or up to 2 years for some non-represented positions. Temporary employees are hired to fill positions where the duration/extent of the work does not warrant retention of a permanent employee.

2.4 USE OF EXTERNAL RESOURCES

In addition to the internal workforce described above, Hydro One also uses external resources (such as third-party contractors) to support work execution. The extent to which work can be performed by external resources depends on the type of work to be performed. Also, the existing work jurisdiction of the PWU, and the SUP, may impact the scale and/or type of work that can be performed externally.

2.4.1 CONTRACTING OUT

Hydro One will continue its use of strategic contracting, scaling up as required to meet growing work demand in 2023 and beyond. Contracting out allows Hydro One to efficiently manage higher demand, thereby reducing the need to add additional regular FTEs with their associated long-term costs for pension and benefits. Hydro One maintains its regular staffing levels to correspond generally to its fixed level of work, rather than maintaining a larger complement of internal resources to respond to temporary increases in work demand, incremental/seasonal work, and short-term work. Such resourcing options are primarily contingent on the type of work to be performed.

The PWU Collective agreement contains provisions that address contracting out (referred to as Purchased Services Agreements or PSAs). Some types of work that Hydro One seeks to contract out may require negotiation with the union partners or an award from a labour arbitrator. Factors such as labour availability within existing casual hiring halls may be relevant to the determination of the types and volumes of work that can be contracted out.

Some categories of work have been subject to long-standing PSA arrangements, which have been integrated into the PWU collective agreement. For example, the agreement known as Mid-Term 50, permits the contracting out of entire categories of work, such as: snow removal, janitorial, heavy and/or specialised equipment operation (hydrovac, backhoe), and minor fleet maintenance, thereby allowing Hydro One to contract out work to organizations that specialize in these areas. These arrangements provide flexibility, as they enable on-demand resources to be deployed as required through various contracting partners, and allow Hydro One to avoid the costs of equipment, maintenance, labour, and training for services that are needed on an intermittent basis, or are highly specialized.

For the Transmission organization, there is a long standing practice of contracting out, which is also recognized in the CUSW collective agreement, such as in the provisions which stipulate those employees represented by the International Brotherhood of Electrical Workers (IBEW) can perform electrical construction work through affiliated contractors. In Ontario, there are two electrical unions which represent electrical construction workers in this sector - the IBEW and the CUSW. The language in the CUSW collective agreement allows for work to be contracted out to either (a) CUSW-affiliated contractors, (b) IBEW-affiliated contractors, or c) other contractors agreeing to apply the terms and conditions of the CUSW agreement.

2.4.2 INDIVIDUAL CONTRACTORS

A small portion of work at Hydro One is performed by individuals that are engaged as contractors. These individual contractors differ from the contracted firms retained to scale up operations, or support incremental/specialized work (typically vendors or general contractors that supply specialized services for seasonal/incremental work, or support capital work programs, specific engineering work, or provide other specialized construction services). Hydro One retains individual contractors to perform professional services, primarily in IT operations, as well as for project management functions.

These contractors are retained for their particular skill sets on projects, and/or to perform other work that is not of an ongoing nature. They are engaged for varying amounts of time and paid fees commensurate with their skill sets and the market rate for their skills. The costs associated with retaining contract staff are tracked by work program and not by headcount. Where applicable, the use of contract staff is governed by the terms of the collective agreements between Hydro One and its unions.

2.5 PLANNING PROCESS & ANTICIPATED FTE LEVELS FOR THE RATE PERIOD

As noted, Hydro One's overall workforce compensation costs are determined by the size and composition (mix) of the workforce, as well as the level of compensation paid to the workforce.

In order to ensure costs are managed prudently and efficiently, Hydro One carefully plans its resourcing requirements to determine what types of internal resources (FTEs) and external resources (contractors) are required to execute its work-plan in a cost-effective manner. As shown in Figure 4, the planning framework considers Hydro One and LOBs operational needs, the Investment Plan requirements as well as OEB direction, to develop a consolidated business plan which includes FTE planning assumptions.

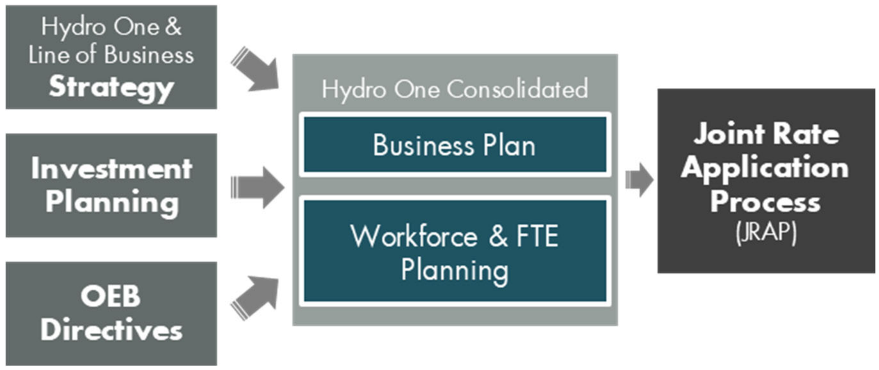

Figure 4: Planning Framework

Based on asset condition, growth, and customer feedback, Hydro One has adopted an Investment Plan which will entail increased levels of capital work. To determine the size of workforce and external resources required to execute the Investment Plan, Hydro One engaged in a multi-stage resource planning process to evaluate its existing staffing levels, assess resourcing options available, and develop the preferred resourcing and execution options appropriate for each LOB.

As discussed below in Part 2, Hydro One has continued to make progress in reducing the level of compensation paid (relative to market median) by negotiating modifications to its collective agreements. However, Hydro One's overall compensation costs are also managed through careful resource planning, and the optimization of existing internal resources. This requires proactive planning for the level and types of FTEs required to deliver the growing volumes of work during the 2023 to 2027 rate period. It also requires leveraging existing workforce flexibility: the efficient assignment of work to existing staff; the increased use of casual labour; and contracting out work where appropriate and consistent with existing collective agreements.

2.5.1 HYDRO ONE'S COMPREHENSIVE APPROACH TO WORKFORCE PLANNING

Hydro One's resource planning process is based on two core tenets:

a) decisions are to be driven by customer-focused outcomes, safety, efficiency and cost-effectiveness; and,

b) the size of Hydro One's regular workforce should correspond to on-going work requirements and incremental work should be staffed efficiently using a mix of regular, casual, temporary and external resources as required.

As noted above, resourcing decisions are impacted by the type of work to be performed. The appropriate resourcing options for each LOB depend on a variety of factors which must be considered, including:

- **Cost** - Identify the mix of resources that will allow Hydro One to deliver its work plan safely, efficiently and in compliance with collective agreements, while minimizing lifecycle cost.
- **Workforce Balance** - As some types of work will be performed by the same workforce regardless of Hydro One's resourcing decisions (i.e. construction work will be performed by the same unions regardless of the employer), the cost of labour is not the sole factor considered in determining the appropriate resourcing option. Incremental increases in specific types of work must be staffed in a manner that does not redirect resources from other work priorities, and time-sensitive work.
- **Duration and scope of work** - The length of the work, and preferred timeline for completion, will impact resourcing decisions. If the work is temporary in nature, external delivery is often appropriate.
- **Complexity/specialization** - Highly specialized, or complex work that is not foundational to electrical grid operations, or is required only intermittently, may be more appropriately contracted out to minimize the cost of training and recruitment. In certain areas (e.g., building design), using external resources also allows Hydro One to access highly specialized expertise and industry leading firms. However, the need to maintain internal expertise may require performing some types of specialized or intermittent work in-house with the resources that perform this work being redeployed to other tasks when not needed for their specialization.
- **Specialized equipment** - Certain work requires investment in specialized vehicles and equipment with associated capital, training, maintenance, and other costs. These costs

may warrant using external firms with greater specialization and higher utilization factors.

- **Technical, security, and risk-related considerations** - Corporate functions that necessitate internal oversight (such as cybersecurity for critical infrastructure), may warrant adding regular FTEs to an existing LOB in the interests of risk mitigation and incident prevention. Oversight and control of processes to maintain service standards also may require retaining certain work internally.

2.5.2 2023-27 WORKFORCE PLANNING PROCESS

To formulate the FTE levels required for 2023-27, each LOB identified the key drivers of its resourcing strategy as well as current staffing levels, and determined the FTEs (regular, casual and temporary) required to support all planned work. The LOBs reviewed their resourcing plans with the support of Human Resources Department (HR) to assess feasibility and labour relations impact. Workforce planning has been fully integrated into the investment and business planning processes to ensure a thorough assessment of the necessary resource levels, and to incorporate resourcing strategies that optimize efficiency.

Hydro One’s planning must also ensure that it is still able to attract, retain, and motivate the workforce resources necessary to complete work, including in light of retirement eligibility levels and the time required to complete the training necessary for skilled positions. As noted in Figure 5 below, approximately 12% to 17% of Hydro One’s workforce is, or will become, retirement eligible over the rate period. These highly-skilled and experienced workers will need to be replaced in a timely fashion. Projected turnover has been accounted for in the FTE forecasts detailed in Table 1 as further discussed below under Section 2.6.

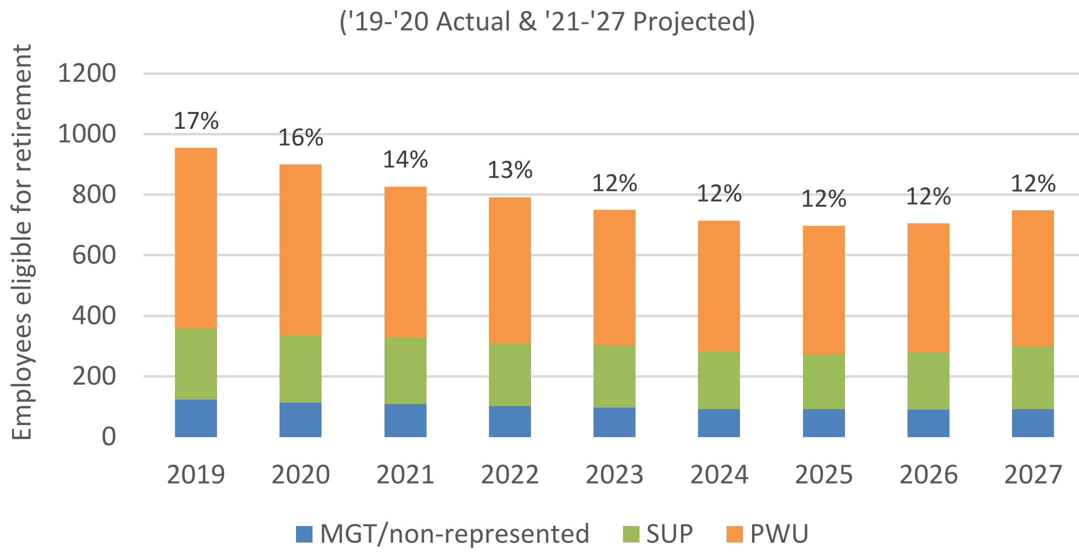

Figure 5: Retirement Eligibility[5]

2.5.3 OPTIMIZING WORK DELIVERY CAPACITY

Hydro One has the ability to accommodate Investment Plan growth without a proportional increase in FTEs because it has the flexibility to assign incremental increases in work (which is typically project-based, temporary, seasonal and/or intermittent) in an efficient and productive manner. In addition to its integrated workforce which allows resources to be deployed across both the Distribution and Transmission businesses, Hydro One also has the ability to increase the use of casuals/temporary labour as required, and to contract out work when appropriate.

Hydro One's integrated workforce creates economies of scale and efficiencies that would not be available through separate Transmission and Distribution operations, such as an integrated Lines Apprenticeship Program, asset management strategy, centralized grid control, and centralized fleet operations and common corporate functions and services. This integrated approach

[5] Based on pension plan membership data as of time of filing. Eligibility is defined as ability to retire with an undiscounted pension.

enables deployment of resources across various projects and programs (e.g., Vegetation Management, New Connections, Pole Replacement, etc.)

For the Transmission and Distribution organizations, enhanced reliance on casual workers and external resources (contracting out) will support the incremental increases in work related to the Investment Plan (subject to availability of qualified contractors). The resources used to deliver the capital and Operations and Maintenance (O&M) work programs for both Transmission and Distribution are described in the Transmission and Distribution work execution exhibits (TSP Section 2.10 and Exhibit E-02-05, and DSP Section 3.10 and Exhibit E-03-05) and for the General Plant lines of business, resourcing plans are discussed further in GSP Section 4.10, Exhibit E-04-05 and Exhibit C-09-04.

Hydro One will also rely on strategic use of overtime (OT) to efficiently control resourcing levels and manage cost. OT work (work performed in addition to or outside of standard work hours within collective agreements) is an important component of Hydro One's resourcing plans - it is necessary to meet work execution requirements, customer needs and preferences, and to plan work efficiently.

The operational realities of Hydro One require two forms of OT: planned OT and demand OT. Planned OT is required to meet execution timelines, enhance the efficiency of work execution such as by minimizing travel time and to accommodate the needs of customers by managing outages during evenings and weekends to limit business disruption. This type of OT is used predominantly in the Transmission business. Demand OT occurs due to the need to execute work that has limited predictability, such as trouble calls, storm damage, and new connections. Demand OT is used primarily in the Distribution business.

All OT must be approved in advance, and is managed and monitored on a regular basis. Planning assumptions are determined by each organization, and based on internal review of previous trends (for demand OT), and work requirements, outages, and customer and/or project requirements for planned OT.

Anticipated OT usage is captured in workforce plans as a percentage of all hours forecast to be worked. Usage rates are based on historical trends specific to the type of work to be performed, and vary across job types and LOBs. The cost per hour of overtime will vary depending on the type of employee performing the work, as well as when the overtime is performed. Cost projections of overtime are calculated based on historical actuals, as explained below. The Mercer Report (Attachment 1 to this exhibit, Section 5 of the report) also addresses Hydro One's OT policies and rates, and confirms that they align with market.

Overall and in summary, Hydro One has a robust planning process that focuses on work plan requirements in order to determine necessary resourcing. Through this process, a prudent mix of internal resources has been determined on the basis of the criteria outlined above. This process ensures Hydro One has a cost efficient and right-sized workforce (with a balance of regular and casual resources), that is supplemented, as required and appropriate, by external resources (contractors) in order to complete the 2023-27 work program.

2.6 ACTUAL AND PLANNED FTEs

The results of Hydro One's planning process are captured in Table 1, which shows Hydro One's actual and planned FTEs for both Transmission and Distribution, reflecting staffing levels appropriate for the type and volume of work to be performed and contracting out portions of incremental work. A significant portion of the growth shown in Table 1 during the 2023-2027 rate period is attributable to increases in the PWU HH to manage work that is not of an on-going nature. Where necessary, Hydro One plans to add a small number of regular and casual FTEs to the existing workforce. Between 2023 and 2027, the total number of FTEs is projected to increase by only 1.4% notwithstanding the significant increase in planned work. During this period, Hydro One has prioritized maximizing output from its existing workforce, and enabling the execution of greater amounts of work with existing staff across all lines of business.

Table 1 - Actual and Planned FTEs for 2019 to 2027

Type	Representation	2019 Actual	2020 Actual	2021 Plan	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan	2027 Plan
Regular	MGT/Non-Represented	613	647	724	760	765	760	760	763	763
	Society	1425	1449	1674	1771	1781	1783	1791	1817	1841
	PWU	3534	3603	3704	3748	3737	3720	3718	3703	3674
	Total Regular	**5572**	**5699**	**6103**	**6280**	**6283**	**6264**	**6269**	**6283**	**6278**
Casual	PWU Hiring Hall	1373	1197	1329	1300	1388	1397	1480	1602	1524
	CUSW	936	948	938	911	912	912	912	912	912
	EPSCA	217	223	198	192	192	192	192	192	192
	LIUNA	272	291	247	237	237	237	237	237	237
	Total Casual	**2798**	**2659**	**2712**	**2639**	**2729**	**2738**	**2820**	**2943**	**2864**
	Temporary	194	152	175	158	159	158	157	157	157
Total		**8564**	**8509**	**8990**	**9077**	**9171**	**9160**	**9247**	**9383**	**9299**

As noted in previous applications, Hydro One's workforce plans rely on a variety of labour resources, including temporary, regular, as well as PWU and construction trade casual labour, to address the fluctuating nature of its work. As such, should work plans change, hiring plans are revised to reflect business needs. Given this reality, the 2019 & 2020 FTE levels reflect variances from previously filed workforce plans as a result of cuts following the Distribution Decision (EB-2017-0049) and the Transmission Decision (EB-2019-0082). These cuts resulted in a fewer casual FTEs retained than previously projected given the reduced levels capital and OM&A envelopes. 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 LOBs due to repatriation of Inergi employees. Further details of this workforce change are discussed in Exhibits E-05-01, E-04-04, and E-04-02.

In addition, the COVID-19 pandemic resulted in delayed hiring for certain roles which accounts for the reduced number of FTEs reported in 2020.

2.7 COST PROJECTIONS OF PLANNING ASSUMPTIONS

The anticipated costs associated with the FTE levels set out in Table 1 above are detailed in the Compensation Cost Table and explanatory notes appended to this exhibit (Attachments 2A and 2B). The Compensation Cost Table, also provided in previous rate applications, includes actual compensation costs for 2018 to 2020, and forecast costs for 2021 to 2027.[6]

Over the past several applications, Hydro One has improved the compensation cost information that is provided. The most recent Transmission and Distribution applications (EB-2019-0082 and EB-2017-0049, respectively) have included year-end FTEs, total headcount, and average month end FTEs, and the compensation costs have been broken down across Transmission and Distribution, and allocated between OM&A and capital as per the Black & Veatch methodology. In those applications, however, only FTE counts were broken down for Transmission and Distribution; FTEs were not allocated between OM&A and capital. In this current application, FTEs (average month end) are used consistently throughout, and both compensation costs and FTEs are allocated across OM&A and capital. Moreover, the allocation relies primarily on the direct assignment of costs rather than using an allocation methodology as in past applications.

3.0 PART TWO – COMPENSATION ELEMENTS & CURRENT MARKET POSITION

Part Two discusses the level of compensation and benefits paid to Hydro One employees. More specifically, this section describes the recent compensation benchmarking results, which are contained in the Mercer Report. Additionally, this section details the compensation and benefits for PWU, SUP, non-represented and executive employees. Furthermore, this part of the exhibit reviews the actions Hydro One has taken, and continues to take going forward, to control

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[6] Actuals for 2018 are the same as reported in the EB-2019-0082 application, but do not include the same breakdown of temporary overtime and burden dollars as are shown for years 2019 to 2027. These categories were not included as separate lines in the compensation table filed in EB-2019-0082, therefore they are not shown in the current table. Furthermore, these amounts were subject to the previous allocation methodology used in the EB- 2019-0082 application.

compensation costs for represented employees and the context in which these efforts are undertaken.

3.1 HYDRO ONE'S LEVEL OF COMPENSATION RELATIVE TO MARKET

Mercer has undertaken an updated compensation benchmarking study, in accordance with the OEB's direction. The purpose of this study is to determine the relative competitiveness of Hydro One's levels of pay. The Mercer Report, appended to this exhibit (Attachment 1), details this study and the results of it.

As set out in the Mercer Report, the updated study shows that Hydro One's overall market position relative to the P50 market median, as of 2020, has improved. It is now 9% above this median.[7] The Mercer Report also confirms that market position for total compensation is typically within 5% of the P50 market median. Thus, an overall level of compensation that is +/- 5% of the P50 is considered to be at market. On this basis, as of 2020, Hydro One's compensation levels are now only 4% above market. These results are shown in Figure 6 below.

			Total Remuneration (Current)					
			Variance to P50					
	Hydro One Group	*# of Hydro One Inc. (2020)*	2008	2011	2013	2016	2017	**2020**
Weighted Average	Non Represented	*155*	-1%	-17%	-1%	2%	1%	**-4%**
Weighted Average	Energy Professionals	*400*	5%	5%	9%	11%	12%	**11%**
Weighted Average	Trades and Technical	*2,801*	21%	18%	12%	16%	12%	**10%**
Weighted Average	***Overall***	***3,356***	***17%***	***13%***	***10%***	***14%***	***12%***	***9%***

Hydro One P50 Relative to Market P50

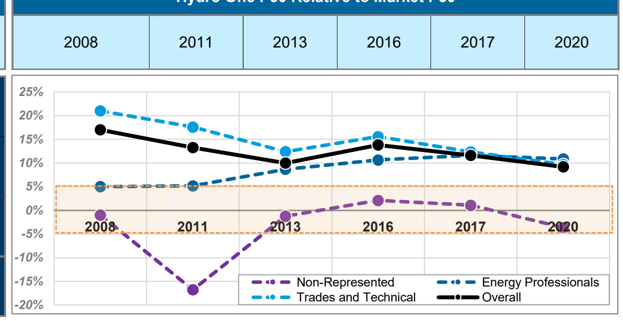

Figure 6: 2020 Benchmarking Results

[7] The overall result of 9% above the P50 market median is comprised of the following breakdown in respect of individual employees groups: Hydro One is 4% below P50 market-median for management and non-represented group; 10% above it for trades and technical group; and 11% above it for the 'energy professionals' group.

By comparison, the previous Mercer benchmarking study conducted in 2017 (and filed in Hydro One's most recent Transmission application, EB 2019-0082 -- the 2017 Study) indicated that Hydro One's overall level of compensation was 12% above the P50 market-median. The 2020 results therefore show a significant improvement study over study in this regard -- from 12% down to 9% in relation to P50; and from 7% down to 4% in relation to the market competitive range. Further, Hydro One has made even greater progress over the past 12 years, from the first study in 2008 in which Hydro One's level of compensation was 17% above the P50 market-median to the current position of 9% above market-median. This significant improvement is the result of a focused effort to achieve market aligned compensation for represented employees, having regard to (and working within) constraints of the collective agreements and the collective bargaining context in which Hydro One operates.

The above improvement in market positioning, confirmed in the Mercer Report, indicates Hydro One's represented compensation is better aligned with market due in part to negotiated changes to the pension plan. Furthermore, introduction of lump sum and equity compensation has reduced longer-term costs associated with pensions.

3.2 TYPE AND LEVELS OF COMPENSATION PAID TO REPRESENTED GROUPS

As is typical in unionized environments, compensation and terms of employment are determined by collective agreements. At Hydro One, regular unionized employees receive a salary that is based on an hourly or weekly rate (35 or 40 hour work week), and are provided vacation, sick leave, long-term disability benefits, health and dental benefits, and other forms of paid leave. The base salary of a represented employee is typically determined by their classification and seniority. Any changes to the wage structure within these agreements is determined through the collective bargaining process.

3.2.1 PWU AGREEMENTS

The current PWU agreements are in effect until 2022 & 2023.[8] These two agreements were renewed in 2020 (ratified in late 2020) and contain annual base wages increases ranging from 1.9% to 2.2% from 2020 to 2022 (main agreement) and from 0.6%[9] to 2.2% from 2020 to 2022 (CSO agreement).

3.2.2 SUP AGREEMENT

The latest SUP agreement (for a two-year term) expired on March 31, 2021. Negotiations commenced in early 2021, and a tentative agreement was reached in June, but has not yet been ratified. The previous agreement included 2% wage increases effective on April 1, 2019 and April 1, 2020.

3.2.3 SHARE GRANTS & EMPLOYEE SHARE OWNERSHIP PROGRAM (ESOP)

PWU and SUP-represented regular, full-time employees who were members of the pension plan as of April 1st (PWU) and September 1st (SUP) 2015, are eligible to receive share grants of Hydro One Limited stock. These grants were negotiated in the 2015/2016 bargaining rounds. Eligibility for share grants continues until 2028 for PWU, and 2029 for SUP employees who maintain active employment and continue contributing to the pension plan (share grants are not issued to retired employees collecting pension benefits). As of April 2021, approximately 2,300 PWU-represented employees and 1,100 SUP-represented employees were receiving share grants. As employees retire, the number of share grants provided is anticipated to decline, as shown in Table 2 and Table 3, below.

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[8] PWU main agreement term is April 1, 2020 to March 31, 2023, the CSO agreement is in effect from October 1, 2019 to September 30, 2022

[9] There was a 0.6% increase applied in January of 2020 from the previous renewal agreement, and then a 1.9% increase that subsequently applied in that year.

Table 2 - Share Grants Issued to PWU

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number of Shares	371,610	353,134	341,308	327,320	311,921	302,600	294,777	289,008	278,720	267,007	262,453	259,246
Change from 2017	--	-5%	-8%	-12%	-16%	-19%	-21%	-22%	-25%	-28%	-29%	-30%

Table 3 - Share Grants Issued to SUP

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Number of Shares	128,327	121,633	114,242	108,506	105,612	102,791	100,743	98,388	95,348	93,699	92,754	91,232
Change from 2017		-5%	-11%	-15%	-18%	-20%	-21%	-23%	-26%	-27%	-28%	-29%

SUP represented employees who are not eligible for Share Grants can opt to participate in an ESOP. Employees can contribute up to 4% of their base salary, made in whole percentages (i.e., multiples of 1%), through payroll deductions on a bi-weekly basis. Hydro One matches 25% of the employee's contribution. Approximately 200 employees participate in this program.

3.2.4 PENSION PLANS - REPRESENTED GROUPS

Regular, full-time employees represented by the SUP and the PWU, are members of the Hydro One Pension Plan (the HOPP). The HOPP is a defined benefit pension plan, and is based on the Ontario Hydro Pension Plan (OHPP) which was established on November 1, 1923. The rights to bargain the terms of the OHPP for represented staff were entrenched during collective bargaining with CUPE Local 1000 (PWU) in 1966 and with the SUP since its inception as a Union in the early 1990's. In 2000, the HOPP was registered and provided a restatement of the existing OHPP terms under the new employer. Although both PWU and SUP workers are members of this plan, there are slight variations in program rules for each group.

PWU HOPP members are currently subject to a retirement formula (age + years of service) of 82 points (referred to as Rule of 82) to be eligible for an undiscounted pension (members with 35 years of service are eligible for an undiscounted pension irrespective of points). The pension benefit upon retirement is based on the average of an employee's highest three years' earnings. On April 1, 2025, the retirement points formula will move to 85 points. For existing employees, the change will apply only to service accrued after this date, and the pension benefit amount will be based on an average of the members' five highest years' earnings. These changes were negotiated during collective bargaining in 2015 and will begin to result in cost savings during the rate period.

SUP represented employees are members of the HOPP, and are divided into two subgroups: plan members prior to November 2005 (known as the legacy plan), and those who joined after November 2005, (known as the new plan). Thus, the rules that apply to the SUP-represented staff depend on whether an employee is in the legacy plan or the new plan.

For those SUP-represented employees in the legacy plan, their pension formula for an undiscounted pension is based on the rule of 82, and their pension benefit amount is based on average of best three years' earnings, similar to the PWU plan. For service earned from April 1 2025 onwards, the pension benefit will be based on average of highest five years' earnings, but the rule of 82 will continue to apply.

Employees under the new plan are currently subject to rule of 85 and their benefit is currently based on the average of the employee's five highest years' earnings. These changes, have been in place since November 17, 2005, and were introduced following a protracted labour dispute between Hydro One and the SUP. All new employees hired into a SUP-represented role on or after that date are subject to these new plan rules. These changes have reduced Hydro One's pension costs.

3.2.5 CUSW

Hydro One negotiates directly with CUSW,[10] and has negotiated a total wage package with CUSW that is below typical market rates for employees that perform similar work, or possess similar skills and certifications, such as employees represented by the IBEW that work in the Electrical Power System Sector.[11] As shown in Table 4 - Comparison of CUSW and IBEW Wages, which compares the CUSW wage rates to those of EPSCA negotiated rates with the IBEW, the total CUSW rate negotiated by Hydro One is $5.73 less (per hour) or nearly 10% lower than the average IBEW rate pursuant to EPSCA-negotiated agreements.

Table 4 - Comparison of CUSW and IBEW Wages

Electrician or Lineman (Journeyperson) – 2020 Rates (Transmission)		
Bargaining Unit	**Base Wage ($)**	**Total Wage Package ($)**
CUSW (Hydro One)	43.90	58.54
IBEW Median (Transmission)	45.41	64.18
IBEW Average (Transmission)	44.87	64.27

3.3 TYPE AND LEVELS OF COMPENSATION PAID TO THE MANAGEMENT & NON-REPRESENTED GROUP

The compensation for this group is based on the principle of creating a pay for performance culture that is aligned with market-based compensation in terms of level and types of pay. Performance-based compensation enhances Hydro One's ability to attract, motivate and retain qualified employees in a competitive labour market. By comparison, a shift away from performance pay in favour of increased base salaries would increase Hydro One's fixed costs and reduce the company's ability to align employee performance with business objectives. As

[10] This is distinct from other construction trades unions that represent Hydro One casual employees (such as the Labourers, or Operating Engineers) who engage in collective bargaining with EPSCA, which acts as an agent for its employer members, such as Hydro One, OPG, and Bruce Power.
[11] IBEW currently represents 14 locals across the province that support work for EPSCA-affiliated employers.

noted above, based on the updated 2020 benchmarking results described in the Mercer Report, the level of compensation of this segement is below market.

3.3.1 MGT/NON-REPRESENTED COMPENSATION – PROGRAM COMPONENTS

The base pay for non-represented and managerial roles is based on a salary structure that is segmented into core and operations. Creating distinct salary ranges for operations roles provides Hydro One with a competitive advantage, as it can tailor compensation to attract talent for jobs that require specific education, skills and knowledge, which are directly related to electric transmission and distribution systems. This segmentation also ensures that Hydro One does not overpay for skills found more readily in the market, and is in line with market compensation practices. Core services positions require education, skills and/or knowledge not necessarily specific to the utility business, and Hydro One can recruit broadly for such roles given the wider availability of the skill-sets and expertise sought.

Each pay band has a minimum, mid-point, and maximum which are aligned to market. The program is targeted to pay approximately at the market median. This target balances the competing demands of attracting, retaining and incenting management non-represented employees against the need to maintain compensation costs at appropriate levels. Base salaries are adjusted through a merit program (there is no annual across-the-board increase) that recognizes individual performance, behaviours, employee potential, operations or core services segment, internal relativities, and external benchmarking.

3.3.2 PERFORMANCE-BASED COMPENSATION

Management and non-represented employees are eligible for annual incentive-based pay as a component of their total cash compensation. The Short Term Incentive Program (STIP) is designed to reward participants for the achievement of annual team (corporate) and individual performance goals. STIP rewards are based on Hydro One’s performance measured against the balanced Team scorecard, and individual performance measured against goals that are aligned with Hydro One's objectives.[12]

Directors and vice-presidents are eligible to participate in a Long-Term Incentive Plan (LTIP). It is an important component of executive and senior management compensation, enabling Hydro One to retain experienced senior managers who have the skills and experience necessary to execute on Hydro One's goals. Participation in the LTIP is determined annually by Hydro One's Board of Directors and is restricted to key talent. The intent is to provide a balance between short-term performance and long-term success. The LTIP also serves as a retention tool, as awards are paid out 3 years following the grant and is a performance-based award program.

3.3.3 EMPLOYEE SHARE OWNERSHIP PLAN (ESOP)

Management and non-represented employees are eligible to participate in an ESOP. Eligible employees can contribute up to 6% of their base salary and Hydro One will provide a 50% match on contributions to a maximum of 3% of base salary. The introduction of the ESOP is an important element of the total compensation program as it: (i) promotes an ownership mentality amongst employees; (ii) facilitates the attraction and retention of talent; and (iii) enhances employee engagement and productivity through company ownership.

3.3.4 PENSION, BENEFITS FOR THE NON-REPRESENTED GROUP

Non-represented and management employees participate in a Defined Contribution pension plan (DCPP) or the HOPP, if their employment began prior to 2015. As noted above, the DB plan has been closed to new entrants since 2015. Future service changes to the HOPP and the introduction of the DCPP have achieved reduced pension expenses for the company, while still providing employees sponsored plans to save for retirement.

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[12] The balanced Team scorecard is based on financial and non-financial objectives such as customer satisfaction, operational results, productivity achievements, and safety. The 2021 Scorecard is provided at Attachment 3.

Non-represented and management employees are eligible to participate in core health and dental and flex benefit programs. Hydro One is currently reviewing its benefits programs in an effort to modernize plans that have remained unchanged for more than 15 years. The program is being redesigned based on the principles of market alignment, internal equity, a wellness focus and encouraging internal talent movement from represented to management role, which is a significant challenge for the organization. This benefits program is being redesigned in a manner that maintains cost neutrality to the existing program.

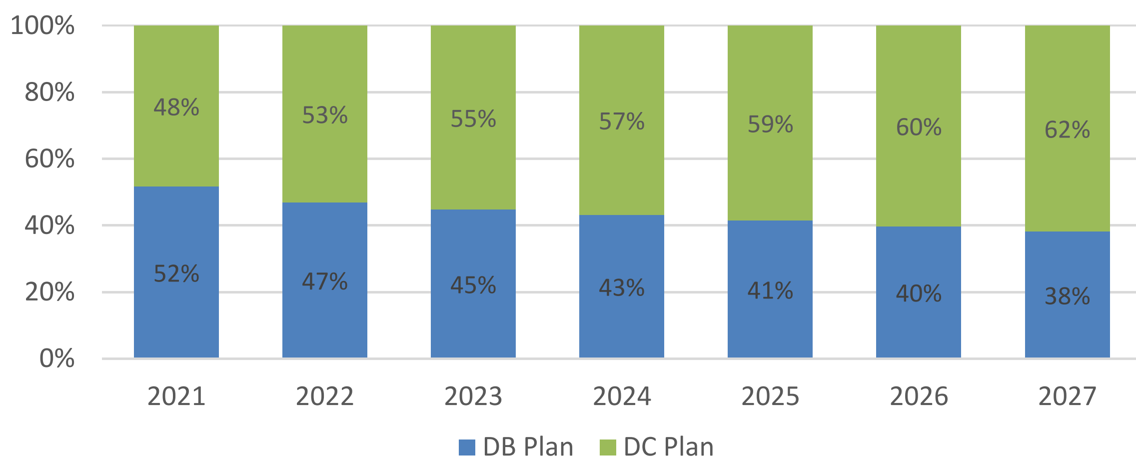

Figure 7: Pension Plan Membership Projections (MGT/N-R)

As illustrated in Figure 7,[13] based on plan member data from 2020, as well as historical retirement turnover trends for the management and non-represented segment, it is anticipated the majority of employees in this segment will be on the DCPP at the beginning of the 2023 rate period.

[13] Includes full-time regular employees in the MGT/N-R group who are employed by Hydro One Networks Inc.

3.4 TYPE AND LEVELS OF COMPENSATION PAID TO EXECUTIVES

3.4.1 EXECUTIVE COMPENSATION

Pursuant to the *Hydro One Accountability Act* (HOAA), Hydro One Networks Inc. (HONI) is not able to recover the compensation costs related to executive positions of Hydro One Limited[14] through rates. This legislation requires the OEB to exclude from rates the compensation costs related to the executives of Hydro One Limited.

As this legislation was passed during the 2018-2022 Distribution rate application process (EB-2017-0049), the OEB directed Hydro One to determine how these changes would impact its revenue requirement. In that application, and in subsequent Transmission applications (EB-2018-0130 and EB-2019-0082), Hydro One elected to voluntarily exclude the compensation for the other four executive officer positions that comprised the Executive Leadership Team (ELT) in place at that time: Chief Legal Officer, Chief Operations Officer, Chief Human Resources Officer, and Corporate Affairs and Customer Care Officer.

In this application, the HOL executive leadership positions, CEO, CFO, and CCDO are excluded from the revenue requirement. The compensation paid for the following executive leadership team positions is also excluded from Hydro One's requested revenue requirement:[15]

- Chief Operations Officer;
- Chief Legal Officer;
- Chief Human Resources Officer;
- Corporate Affairs and Customer Care Officer;
- Chief Safety Officer, and
- Chief Information Officer.

[14] HOL executive officers are the Chief Executive Officer CEO, Chief Financial Officer CFO and Chief Corporate Development Officer CCDO.

[15] Chief Legal Officer is an executive of Hydro One Inc., and the Chief Operations Officer, Chief Human Resources Officer and Corporate Affairs and Customer Care Officer, Chief Information Officer, and Chief Safety Officer are executive officers of Hydro One Networks Inc.

Pursuant to the HOAA, a directive was issued by the provincial cabinet in 2018 to establish executive compensation caps, and limit annual increases to market (inflation) rates. The directive set a limit on the level of compensation for Hydro One's CEO. The total compensation for all other executives is limited to 75% of the CEO's maximum direct compensation. Annual increases to executive salaries are also capped at the lesser of the rate of Ontario Consumer Price Index and the annual rate at which total maximum direct compensation may be adjusted for non-executive managerial employees. The directive also limited the compensation of Board members to $80, 000 annually and the Chair of the Board to $120, 000 annually.

In 2019, Hydro One adopted an executive compensation framework that is consistent with the Directive, and which is reflected in the proposed revenue requirement, as follows:

- No other executive's total compensation will exceed 75% of the CEO's compensation;
- Compensation may be adjusted annually by the lesser of the rate of Ontario Consumer Price Index (CPI) and the annual rate of adjustment for non-executive managerial employees; and
- Compensation for the Board of Directors has been decreased to the levels indicated in the Directive.

4.0 PART TWO – RECENT PROGRESS IN MANAGING THE COMPENSATION OF THE REPRESENTED WORKFORCE

As noted further above, overall compensation costs are determined by the size of the workforce relative to its output, the workforce mix, as well as the type and level of compensation paid to the workforce. As 92% of Hydro One's workforce is unionized, the market positioning in respect of the level of compensation predominantly derives from collective bargaining outcomes. Hydro One has and will continue during the rate period (and beyond) to pursue cost-saving opportunities at each round of collective bargaining, consistent with and responsive to feedback from the OEB.

4.1 ADDRESSING THE HYDRO ONE PENSION PLAN (HOPP)

In the benchmarking studies performed by Mercer, the HOPP is identified as a prevailing factor contributing to Hydro One's compensation being above the market median. The HOPP predates Hydro One; it is a long-standing feature of the legacy Ontario Hydro collective agreements. The HOPP has been addressed by Hydro One through both extraordinary actions (negotiation leading to a work stoppage) and a more typical approach (incremental changes negotiated during bargaining). Hydro One's focus on obtaining changes to the pension plans along with at or below industry wage increases, through the collective bargaining process has contributed to the downward trend in its overall market position. Outlined below are the historical and recent changes which have contributed to this improved market position, while allowing Hydro One to maintain a flexible, efficient, and appropriately-size workforce.

Pension plan formula changes were introduced for SUP represented staff hired on or after November 17, 2005. The average earnings period increased from 36 to 60 months and the requirement for an undiscounted pension increased from 82 to 85 points. The indexing formula of both the post-2005 SUP plan and the management plan was adjusted - the indexation rate was reduced from 100% to 75% of CPI. Hydro One obtained these SUP-related amendments through arbitration following a work stoppage that lasted over three months.[16]

The changes to the SUP pension plan that affected employees hired on or after November 17, 2005 constitute an increasingly significant source of savings as a greater percentage of SUP represented employees come under the new plan. As shown in Figure 8 below, the membership in the legacy plan will continue to diminish over the course of the rate period.

[16] In the round of bargaining that preceded this work stoppage, Hydro One had sought a two-tier wage schedule, improved contracting provisions, and a revision of base hours from 35 to 40, in addition to pension changes. Following this protracted work stoppage and subsequent government imposed arbitration, only the pension plan rule changes noted above were achieved.

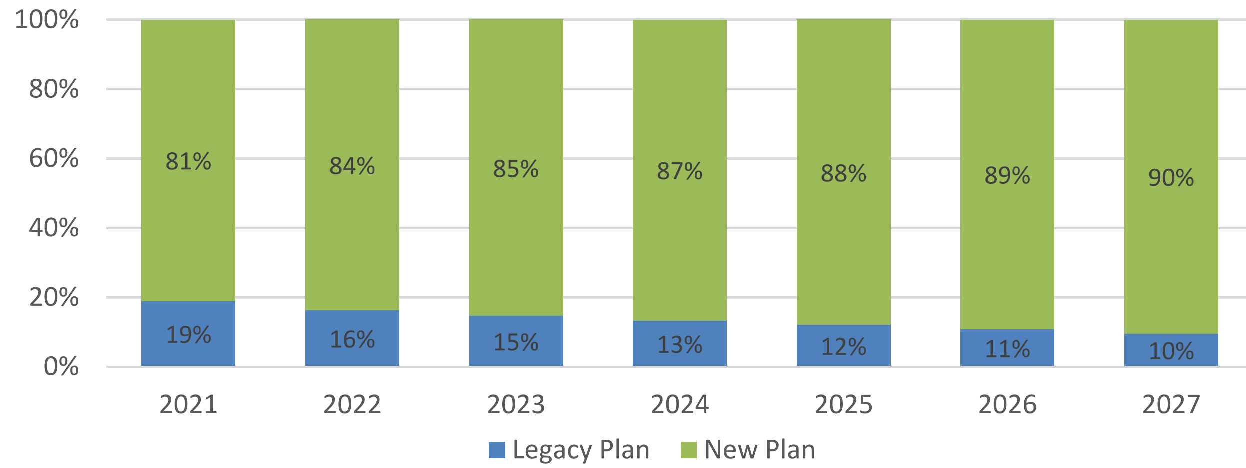

Figure 8: Decreasing Share of SUP Members on Legacy Pension Plan

The estimated cost savings from the changes in the SUP pension plan discussed above totalled $29M from 2010 to 2020, and are projected to be approximately $46.3M from 2021 to the end of 2027. The annual amounts that comprise this total are shown in Table 5 below.

Table 5 - Estimated Annual SUP Pension Plan Savings Due to 2005 Plan Changes

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Savings	$1.5M	$1.8M	$2.1M	$2.3M	$2.5M	$2.7M	$2.8M	$2.7M	$3.0M	$3.7M	$3.9M	$29.0M

Year	2021	2022	2023	2024	2025	2026	2027	Total
Savings	$4.6M	$5.6M	$6.1M	$6.7M	$7.2M	$7.8M	$8.3M	$46.3M

Over a period of many years, Hydro One has also negotiated increases to member contribution rates (the employee's contributions to the plan), though often it is government intervention that has enabled meaningful change. When the Provincial government decided to proceed with an Initial Public Offering (IPO) of Hydro One Limited in 2015, this resulted in joint negotiations with OPG for the PWU agreement at a central table where the mandate and focus was to settle monetary items. During this round of bargaining, the provision of Canadian Controlled Private Corporation (CCPC) shares provided a strategic advantage to Hydro One's bargaining position because of the tax advantages of this form of equity,[17] which conferred substantial benefits to the PWU and SUP represented employees who were eligible to receive this compensation, as well this resulted in ongoing cost-savings for Hydro One.

This form of compensation has inherent cost savings (in comparison to base wage increases), as it is only provided to a defined class of employees who meet the eligibility requirements,[18] and is time-bound (share grants will cease to be paid in 2028 and 2029). Thus, the group of PWU and SUP represented employees who receive share grants will diminish over time, and the long-term impact to pensions is mitigated due to lower increases in base wages. Lump sum payments were also provided for both groups during the 2015/2016 rounds. This meant that Hydro One had the leverage to renew its agreements with the PWU and SUP for wage increases that were less than other utility peers for the years 2015-2018 (the PWU renewal agreement) and 2016-2019 (SUP renewal agreement).

Moreover, Hydro One was able to offer equity compensation in exchange for the PWU accepting further changes to Pension Plan contribution rates, as well as significant changes to the rules of the plan. These changes are scheduled to take effect in 2025, and apply to future service accrual and will have a cost-savings impact on the HOPP, as estimated below. Progress has also been achieved in past negotiations with the SUP, during which similar changes to the pension plan[19] were obtained (as well below-market wage increases of 0.5% per year) by leveraging ESOP and Share Grants.

[17] CCPC shares are a unique form of share that can only be issued before an organization undergoes an IPO. The value of the shares is not required to be included on the individual recipient's tax return in the year the share is issued, but rather only in the year the share is sold. Once shares are sold, Hydro One must report the taxable benefit on the recipient's T4. However, if the share has been held by the recipient for at least two years, the recipient can claim a tax deduction of 50% of the value of the shares sold.
[18] In the 2015/2016 round, only PWU and SUP represented staff who were contributing members to the Pension Plan in 2015 (April and September, respectively) were eligible to receive share grants.
[19] Best five years' earnings instead of three, and increased employee contribution rates.

In 2025, the PWU pension plan will be amended to align with provisions of the new Society pension plan, and the legacy Management defined benefit plan. These changes will entail significant savings for Hydro One, as noted in Table 6 below.

For the period from the end of March 2025 to the end of December 2027, the estimated costs avoided as a result of plan changes discussed above for PWU members total $21.5M.

Table 6 - PWU Pension Plan Savings

Year	2025 (Mar. 31 to Dec. 31)	2026	2027	Total
Savings	$5.6M	$7.8M	$8.1M	$21.5M

Furthermore, incremental changes to contribution rates negotiated during various rounds of bargaining have and will continue to yield cost savings, and will help to improve the relative competitiveness of Hydro One's level of compensation. In recent years, Hydro One has negotiated significant increases to employee contribution rates.

While this progress made by Hydro One has been over multiple rounds of bargaining and has been incremental, the overall cost impact is significant. Since 2012, the proportion of pension costs apportioned to Hydro One has been reduced by nearly 25%, which aligns with the gradual increase in employee contributions rates as evident from Table 7 below.

Table 7 - Pension Contribution Rate Changes PWU & SUP

	Pre-2011	Pre-2013	April 1 2013	April 1 2014	April 1 2015	April 1 2016	April 1 2017	April 1 2018 to present
PWU	**4% Up to YMPE + 6% Beyond YMPE**	4.5% + 6.5% (Apr 1 2011 to Mar 31 2013)	5.5% + 7.5%	6.25% + 8.25%	7.25% + 9.25%	8.25% + 10.25%	8.75% + 11.25%	**8.75% + 11.25%**
SUP - Legacy Plan	**4% + 6%** (Up to Nov 30 2010)	4.5% + 6.5% (Dec 1 2010 to Mar 31 2013)	5.25% + 7.25%	6.25% + 8.25%	7.0% + 9%	7.5% + 9.5%	8.25% + 10.25%	**8.75% + 11.25%**
SUP - New Plan	**4% + 6%** (Up to Mar 31 2013)	4% + 6% (Up to Mar 31 2013)	4.75% + 6.75%	5.75% + 7.75%	6.5% + 8.5%	7.0% + 9%	7.75% + 9.75%	**8.25% + 10.75%**

**YMPE: Yearly Maximum Pensionable Earnings.*

For years 2017 to 2027, the estimated funding (cash) savings as a result of increasing SUP and PWU member contribution rates is $46.4M. The annual figures that comprise this total are provided in Table 8 below.

Table 8 - Estimated Savings from PWU & SUP Pension Contribution Rate Changes[20]

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Savings	$2.2M	$4.9M	$5.7M	$5.8M	$5.8M	$6.1M	$6.5M	$6.7M	$6.9M	$7.1M	$7.3M	$65.0M

4.2 COMPENSATION COST REDUCTIONS DUE TO SHIFT TO DEFINED CONTRIBUTION PLAN

In 2015, Hydro One closed the Management/non-represented defined benefits pension plan, thereby reducing related compensation costs. This decision aligns with the market trend of introducing defined contribution pension plans as the primary form of retirement program. As expected, this program change will continue to yield savings as the demographics of the non-

[20] Estimated savings compare employee contributions both actual (2016-2020) and estimated (2021 - 2027) to employee contributions rates in effect as of April/May 2016. The table outlines the dollar value associated with the percentage increases in employee contribution rates introduced after 2016.

represented group continues to shift through retirements and voluntary turnover. As noted above, anticipated turnover in the non-represented workforce is expected to result in a shift in the number of management/non-represented employees in the legacy defined benefit program.

4.3 IMPACT OF COLLECTIVE BARGAINING ON BASE WAGES

Hydro One has been able to obtain reductions in compensation that provide future cost-savings. In the 2015 round of bargaining for both PWU and SUP, Hydro One achieved cost savings through negotiating wage increases that were below-market and less than inflation in the 2016-2018 period.

4.3.1 PWU NEGOTIATED WAGE INCREASES

- <u>2015-2018 Renewal Agreement</u>: 1% annual wage increases over three years: April 1, 2015; April 1, 2016; and April 1 2017.
- <u>2018-2020 Renewal Agreement</u>: 1.8% on April 1, 2018; 2.0% on April 1, 2019; and 0.6% on January 1, 2020.
- <u>2020-2023 Renewal Agreement</u>: 1.9% on April 1, 2020; 2.0% on April 1, 2021; and 2.2% on April 1, 2022.

4.3.2 SUP NEGOTIATED WAGE INCREASES

- <u>2016-2019 renewal agreement</u>: 0.5% annual wage increases in each of the three years covered by the agreement on April 1, 2016; April 1, 2017; and April 1, 2018.
- <u>2019-2021 Renewal Agreement</u>: 2.0% on April 1, 2019 and 2.0% on April 1, 2020.

4.3.3 COMPARISON WITH MARKET WAGE INCREASES

The above rounds of negotiations with the PWU and SUP successfully resulted in obtaining annual wage increases that compare well to those negotiated by market peers and OH successors. With exception of 2020 for PWU, negotiated increases have been at or below the market median of other utility and OH successor employers who negotiate with the PWU and the SUP, as illustrated below in Figure 9 and Figure 10. Such moderate wage increases entail both immediate cost savings, as well as a reduction in long term costs associated with the pension plans, the ongoing costs of which are impacted by increases to base salary.

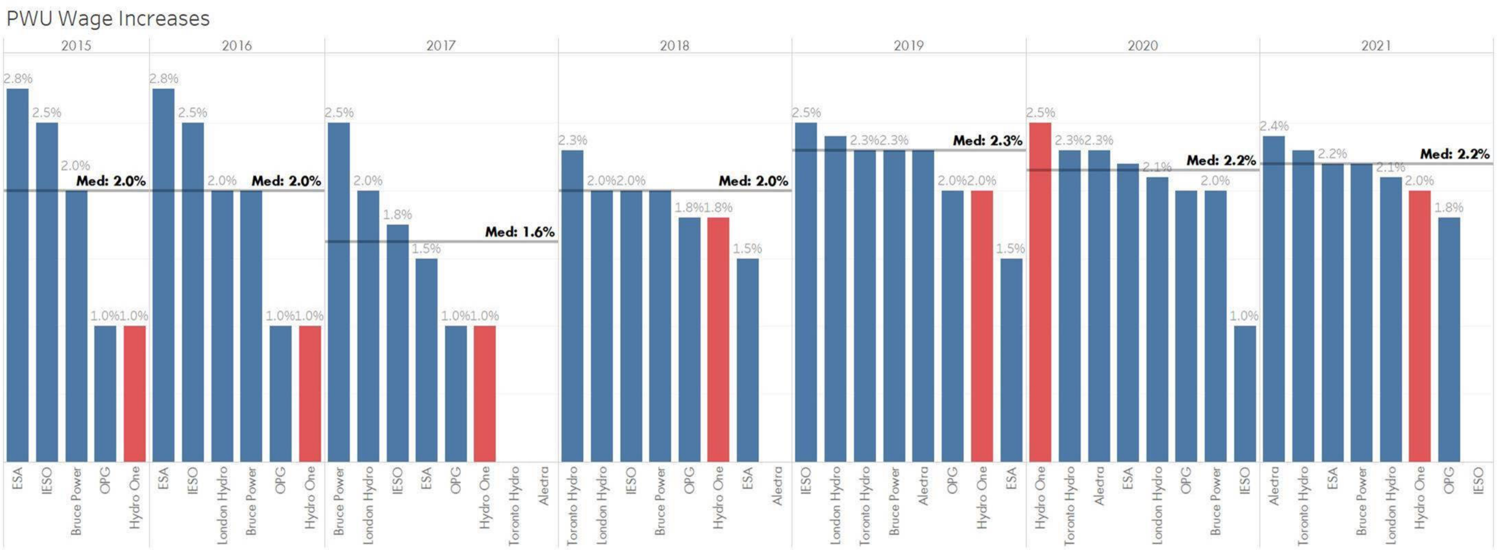

Figure 9: PWU Negotiated Rates for Market Comparators

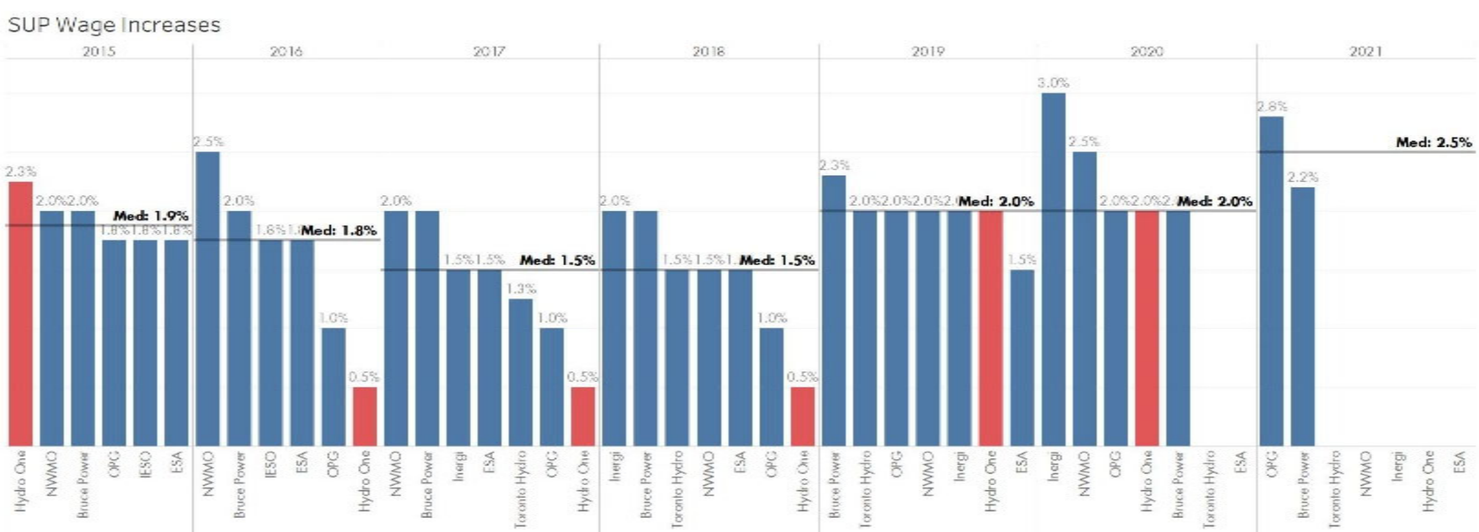

Figure 10: SUP Negotiated Rates for Market Comparators

4.4 BARGAINING CONTEXT – NEGOTIATED CHANGES TO SUPPORT FLEXIBLE RESOURCING

In order to effectively manage and limit total compensation costs, Hydro One's resourcing plans ensure regular staffing levels are reasonable and appropriate to deliver ongoing work and are not sized to meet incremental work demands. This resourcing approach is contingent on the ability to meet incremental work demands through contracting out, utilizing casual labour, and limiting the growth of regular headcount by efficiently deploying the existing workforce. The opportunities to contract out work, rely on temporary influxes in casual labour and maximize efficiency from existing resources are primarily due to previously negotiated changes to the collective agreements

Successive rounds of negotiations since the OH demerger have focused on enabling efficiency or modernizing legacy compensation programs that deviate from compensation trends in the labour market. Through negotiation, Hydro One has achieved workforce flexibility that enables the organization to supplement the regular workforce with the casual workforce and use external resources. The following sections summarize how this flexibility was achieved and the benefits it provides.

4.4.1 PWU-RELATED CHANGES TO LEGACY AGREEMENT

4.4.1.1 INTRODUCTION OF THE PWU HIRING HALL (HH)

To execute the Investment Plan, Hydro One will require additional resources from the PWU HH. Hydro One introduced Appendix A (HH) through the collective bargaining process shortly after the demerger as a way of having a contingent construction-type workforce (casual labour) for incremental work, such as maintenance-related, specialized, and/or project-based tasks. These workers do not join the Hydro One pension or benefit plans. Once the work is complete, these workers can be laid off with no severance or other entitlements owing. Using the HH model allows Hydro One to recruit and build a talent pipeline without making a long-term employment commitment.

PWU HH employees are provided a percentage of their base hourly rate in lieu of paid leave (statutory and vacation days), and a flat hourly amount in lieu of pension and benefits. These amounts are remitted directly to the PWU and the union administers the group Retirement Plan and Health Plan for these employees. Given the amount of paid leave and other benefits that regular PWU employees are eligible to receive, a comparison of costs on a per hourly basis indicates that PWU HH employees are less costly to Hydro One than regular PWU-represented employees.

As previously stated, apprentices at Hydro One are members of the PWU HH during the term of their program. These workers typically have to complete their apprenticeship hours, and apply and be selected to a full-time regular position, as there is no guarantee of ongoing employment.

Completion of an apprenticeship program typically takes four to five years. Hydro One is not required to guarantee ongoing work at the outset of an apprentice's training. Instead, apprentices apply for regular positions once they complete their program. Given that work program demands will fluctuate, this model provides flexibility to hire qualified trades persons as required, not four to five years in advance of potential work. This apprenticeship process also allows Hydro One to manage certain employment-related costs, given the unique employment terms that apply to PWU HH represented staff.

4.4.1.2 PWU MIDTERM 50

Since the OH demerger, Hydro One has sought and achieved flexibility pertaining to contracting out work that historically was subject to the jurisdiction of the PWU. The legacy agreements from Ontario Hydro contained extremely restrictive contracting-out clauses that protected the jurisdiction of the union. Prior to 2001, any on-going work that was within this jurisdiction could only be performed by outside firms if the union consented to a Purchased Services Agreement (PSA), or one was awarded by an arbitrator. PSAs cover the contracting out of certain work for a discrete period of time and for a designated project. Negotiating PSAs became a costly and timely process. Due to a lack of sufficient labour, delays in obtaining PSAs frequently slowed essential work with resulting impacts on customers, costs and timelines.

As indicated above, Hydro One then negotiated Mid-Term 50, so that certain types of work could be contracted to third parties. This novel arrangement is atypical in collective agreements because it permits the contracting out of a wide variety of work. Typical contracting out arrangements require individually-negotiated agreements. This arrangement permits the contracting out of entire categories of work: snow removal, janitorial, heavy and/or specialised equipment operation (such as hydrovac, float trucks, backhoe), minor fleet maintenance, and ensures Hydro One can contract out work to organizations that specialize in these areas. This bargaining achievement eliminated the need to constantly re-negotiate specific types of work (or arbitrate the validity of contracting it out) that recurred intermittently, and are costly to execute due to the seasonal nature of such work or the specialized equipment it requires.

4.4.1.3 PWU CABLE LOCATES - PSA

Another example of the flexibility Hydro One has achieved through collective bargaining is the Cable Locates PSA; negotiated in 2015 (the savings from this change are discussed in SPF Section 1.4). In most circumstances, when cables need to be located, more than one type of underground equipment is involved (e.g. gas lines, water and sewer pipes and electricity and telecommunications cables). This led to the creation of Ontario One Call, where a single organization consolidates locate requests. This separate entity owns the infrastructure, and completes all the required locates at once, thereby lowering costs for all the participating utilities.

In the past, cable locates were performed by PWU-represented employees. This meant that Hydro One was responsible for managing the infrastructure to receive locate requests, dispatch employees to perform the work and ensure all associated administrative work was done. This also prevented Hydro One from participating in the Ontario One Call initiative. Given the PWU collective agreement and the associated work jurisdiction, Hydro One was unable to take advantage of the cost savings and efficiency gains associated with Ontario One Call. Once the Cable Locates PSA was negotiated and entered into, Hydro One could allow Ontario One Call to do this work on its behalf at a significantly reduced price. Further, the staff that would have performed locates could be redeployed to other work and Hydro One no longer had to maintain the infrastructure required to dispatch, perform and track locates.

4.4.1.4 SUP-RELATED CHANGES

A significant shift in Hydro One's labour relations history with the SUP began with the alteration of the dispute mechanism for resolving bargaining impasses which enabled the possibility of a work-stoppage. Prior to the 2005 round of bargaining, the Voluntary Recognition Agreement (VRA) with the Society did not allow for a strike/lock-out regime. In the previous round of negotiations, Hydro One successfully advocated for an agreement term length sufficient to ensure that notice could be given and the next round of negotiations would be done under a strike-lock-out regime. Hydro One was the first successor to move to a strike-lock-out regime with the SUP and, as such, has been able to address issues related to the cost of pensions. The removal of the previous mediation-arbitration regime changed the bargaining relationship, as demonstrated through the incremental changes discussed below.

4.4.1.5 CONTRACTING-OUT – REVISIONS TO THE SUP AGREEMENT

The ability to contract out work covered by the SUP collective agreement has been a focus of bargaining, and Hydro One has made progress on securing contracting flexibility, relative to other successor companies. At the time of the demerger, the SUP collective agreement contained restrictive language that limited Hydro One's ability to contract out work -- Article 67 of the collective agreement included a bilateral process for determining the assignment of work (referred to at the time as a purchased service), and what factors should be used to evaluate the use of external resources.

Starting in 2013, the previous multi-page article was eventually replaced with a single clause: "No employee will be laid off as a direct result of contracting out." This gives Hydro One flexibility to contract out work without any additional requirements beyond this clause. This allows Hydro One to retain services in engineering and construction for projects that are not directly related to the type of engineering and design intrinsic to electrical power systems, and that require a high level of expertise and certification but are intermittent in nature. This required expertise and certification (such as the engineering work related to construction of buildings) is typically specialized, and these types of work are not core to Hydro One. Staffing internally would require a 10-15 year trajectory of hiring, training, and experience to deliver the same level of engineering that can be obtained through contracting out. As such, the flexibility to contract out is essential to cost-effectively execute these types of work. This use of external resources does not displace existing staff but rather allows Hydro One to assign specialized/shorter-term work to firms that have industry-leading expertise.

The terms and conditions of employment for a regular Society employee are somewhat inflexible in light of the restrictive and costly downsizing provisions. Thus, external resourcing flexibility is also consistent with and helps to further Hydro One's long term interests in managing compensation costs through limiting FTE growth to the levels necessary to support ongoing work.

4.4.2 CUSW – CONTRACTING FLEXIBILITY

Hydro One has also achieved contracting flexibility with CUSW and specifically, the ability to utilize non-CUSW affiliated contractors. Although Hydro One has already secured competitive total wage packages, this additional flexibility is required for Hydro One to enter Engineer, Procure and Construct (EPC) contracts. EPC contract arrangements provide efficiency and cost benefits when compared to Hydro One performing all the work internally. To make use of these arrangements, appropriate contracting out flexibility is required within all union jurisdictions.

In most cases with construction contracting, the contractors need to be affiliated with the same unions who would perform the work if it had been completed by Hydro One. However, this is not the case with CUSW as Additional contracting flexibility has been achieved with CUSW. The flexibility is important, as Hydro One's ability to use IBEW-affiliated and other contractors leads to a larger contractor pool and more competitive contractor bids. While contracting out in the construction sector is a normal business practice and is supported by the unions, Hydro One's unique arrangement with CUSW ensures the entire marketplace of electrical contractors can be leveraged.

4.4.3 WORKFORCE FLEXIBILITY: MANAGING RESOURCES DURING A PANDEMIC

At the outset of the Covid-19 pandemic, and prior to the provincial government's assessment of what work would be deemed essential, Hydro One was required to adjust staffing levels quickly and in a cost-effective manner.

Approximately 1,100 casual employees were stood down in early April 2020 as a result of provincial government measures taken at the outset of the pandemic. A series of agreements to prolong the stand-down period (as opposed to imposing the pre-existing layoff period which creates an administrative burden, and delays the process of re-employing the casual trades workforce after a period of work slowdown) were obtained with CUSW and the building trades unions subject to EPSCA negotiated agreements. These agreements guaranteed that these employees could be quickly returned to work once the policy decisions on essential workers had been confirmed, and additional safety protocols implemented. Such an unforeseen work slowdown was executed with minimal cost and disruption to Hydro One.

A similar advantage was obtained by negotiating with the PWU for scheduling flexibility to contend with the pandemic. Letter of Understanding (LOU) # 107 provided greater flexibility in: (i) the use of composites 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.

4.4.4 EXAMPLE OF EFFICIENCY AND COST CONTAINMENT THROUGH ARBITRATION: FORESTRY TECHS & DATA LINE PATROL WORK (ARBITRATION)

Another example of workforce flexibility relates to the assignment of forestry work. Hydro One took steps to reduce the number of staff required to perform data lines patrol work by assigning it to Forestry Techs who were already required to observe and record vegetation interference with poles. Given that their work requires pole observation, it made sense to also task these workers with data lines patrol work, rather than utilize additional staff, which was seen as a redundancy. The PWU resisted the assignment of certain tasks to these technicians, requiring Hydro One to defend its work assignment at arbitration. Although this approach is not directly correlated with a specific productivity savings initiative, the elimination of the redundancy enables efficient outcomes and avoids cost by ensuring staffing levels do not rise unnecessarily.

5.0 PART TWO – LABOUR RELATIONS APPROACH & PLAN TO GET TO MARKET GOING FORWARD

Hydro One’s labour relations approach must recognize the operational realities of the company, such as:

a) The nature of the work requires a high degree of skill, and bears inherent risks to health and safety which must be managed and mitigated;
b) Hydro One’s aging workforce presents ongoing turnover risk, and the need to ensure skilled workers are ready to replace retirements from the existing workforce;
c) Hydro One has an ongoing need to compete for talent with other successor companies and other utility peers;
d) Geographic considerations, including the fact that assets and customers are spread across the province. As such, large segments of Hydro One’s workforce are expected to be able to work in various conditions, and be deployed across the province as required to service customers, address trouble calls and restore larger-scale outages;
e) The nature of Hydro One’s operations requires an integrated workforce which can be assigned to work on both Transmission and Distribution;

f) The need to upgrade and modernize Hydro One's large and highly complex system of assets; and

g) The nature of Hydro One's business is such that the work must be performed locally and is an essential service.

The following additional factors exist in respect of the unions that represent Hydro One employees, which it must also take into account:

i. Much of the work required to operate Hydro One's distribution and transmission business cannot be relocated or centralized;

ii. The SUP and PWU represent workers at all the Ontario Hydro successor companies, as well as some local distribution companies, and have ongoing interests in maintaining parity amongst these bargaining units, despite the divergence in interests and size of the employers represented;

iii. Membership in these unions is spread throughout the province, yet, with exception of the casual trades unions (those agreements negotiated through EPSCA), have standardized base wages; and

iv. These unions are well-funded and stable, given the relative security of the workforces which they represent (as opposed to sectors such as automotive manufacturing, or communications, where membership has decreased in the province).

Each of these considerations - the legacy agreements inherited, the context of labour relations in Ontario, related legislation, and the realities of Hydro One - impact the approach to collective bargaining and mean, as a practical matter, that changes are required to be pursued incrementally through successive collective agreement renewals.

Despite the constraints and challenges imposed by these realities, Hydro One has in recent years bargained successfully to achieve incremental changes to the collective agreements described above – which has enabled the workforce flexibility necessary to achieve efficiency and productivity gains detailed in this application, and has contributed to the improvement in Hydro

One's level of compensation benchmarking results. As described, a key component of Hydro One's resourcing strategy is to contract out incremental work, and use non-regular labour when appropriate to cost effectively execute its work program. This approach to managing long-term resource cost depends on a high degree of adaptability in resourcing options.

Negotiated outcomes with union partners must continue to maintain and, as necessary, expand Hydro One's ability to efficiently assign work internally and appropriately rely on external resources, while also continuing to address the costs of the salaries and benefits paid to existing regular full-time employees.

5.1 COLLECTIVE BARGAINING CONTEXT FOR HYDRO ONE'S LABOUR RELATIONS APPROACH & PLAN GOING FORWARD

Collective bargaining is an iterative process and outcomes occur within the overall context of the electricity sector in Ontario. The PWU and SUP negotiate with electricity sector employers year in and year out, and outcomes from these negotiations affect Hydro One. Ontario's electricity sector employers constitute a mix of public and private sector companies with divergent goals; their bargaining positions reflect their own particular operational needs and priorities that go beyond wages and benefits. However, irrespective of the employer with whom they are negotiating, the unions seek similar outcomes for their membership – improved wages and benefits, and job security – and this has an impact on negotiations with Hydro One.

When negotiations fail to yield an agreement, interest arbitration is typically used to resolve the impasse. Through arbitration, the likelihood of obtaining significant changes is diminished, as arbitration is intended to result in an agreement that aligns with what the parties would have likely achieved through negotiations, and takes into account other contemporaneous union wage agreements. Agreements obtained through arbitration then set expectations for the unions as to what they should aim to achieve in bargaining with other employers.[21]

As experienced during in the 2005 SUP bargaining round which ended with a strike, the use of firm tactics may ultimately place the outcome of collective bargaining in the hands of an arbitrator. This form of dispute resolution inherently limits Hydro One's ability to push for and achieve significant reforms to traditional forms of compensation, including immediate changes that reduce compensation costs.

The market position of Hydro One's compensation is also impacted by unrelated events that affect its market peers in the utility sector. For example, the recently passed *Protecting a Sustainable Public Sector for Future Generations Act* (known as Bill 124) imposes a 1% cap on the compensation of employees in the provincial public sector. This legislation currently applies to Ontario Hydro successor companies that bargain with the PWU and SUP such as Ontario Power Generation (OPG), and the Independent Electricity System Operator (IESO). These restrictions are set to remain in place through 2024, and will possibly continue throughout the rate period.

Although Hydro One is not subject to this legislation, it is an external event that is both outside of Hydro One's control and unrelated to its efforts to control compensation costs, yet may impact its market position.

In conclusion, absent coordinated intervention such as in 2015, it is very challenging to slow the rate of base salary increases and make fundamental changes Hydro One's pension plans for the PWU and SUP. In a stable work environment, such as the Ontario energy sector, where the work cannot be relocated and employers are not facing existential financial distress, collective agreements rarely undergo major changes. Progress can be and has been achieved through

[21] Chaykowski, Richard P. "Time to Tweak or Re-boot? Assessing the Interest Arbitration Process in Canadian Industrial Relations." Commentary No.539. April 2019: Human Capital Policy. CD Howe Institute. Page 14. (Provided as Attachment 4 to this Exhibit)

incremental changes. This is the context in which future rounds of collective bargaining will continue to take place.

5.2 ACHIEVING MARKET LEVEL COMPENSATION

Even before the OEB's most recent decision directing Hydro One to include a plan to bring its levels of compensation in line with market median (EB-2019-0082), Hydro One was focused on the objective of managing compensation costs consistent with prior OEB feedback on this issue. The company remains committed to achieving market-based levels of compensation paid to employees, and to efficiently managing its overall compensation costs, consistent with its strategic objectives. Hydro One recognizes its responsibility to deliver service in the most cost-effective manner reasonably possible.

As noted above, Mercer defines at-market as within +/- 5% of the P50 market median. In light of progress that has been made in recent years, Hydro One is currently 4% above the at-market range. Hydro One intends to take steps to further close this remaining gap through its labour relations strategy going forward.

The Management and Non-represented segment is already 4% below the P50 market median, and therefore is at-market. The Energy Professionals segment is 11% above P50 market median or 6% above the at-market range. The Trades and Technical segment is 10% above P50 market median or 5% above the at-market range. Based on these results and the objectives stated above, the focus of Hydro One's plan to get to market levels of compensation is on the represented segment of its workforce.

In recent negotiations, Hydro One has pursued changes to core components of represented compensation and increased flexibility to assign work in collective bargaining. Previously negotiated changes such as lower-than-market wage increases that reduce pension obligations, lump-sum payments, equity grants or the changes to both SUP and PWU plans, will have an impact going forward and are expected to improve market positioning over multiple studies as employee demographics change. Pension contribution changes that were negotiated between 2005 and 2015 have significantly contributed to the movement towards market median shown in the Mercer Report; as have the below market wage increases Hydro One has been able to negotiate.

Hydro One is committed to achieving market levels of compensation, and anticipates being able to make further progress in this regard during the rate period. Successive rounds of collective bargaining will likely be required to align Hydro One's level of compensation to the market (+/-5%) on an overall basis, having regard to the context in which Hydro One operates. As an integral part of its plan to achieve market compensation, Hydro One has determined its strategy going forward in respect of upcoming rounds of bargaining to advance both near and long-term objectives. Given the highly confidential nature of Hydro One's future labour relations strategy, this strategy for upcoming rounds of bargaining is described in the confidential appendix to this exhibit (Attachment 5).

Hydro One also notes that compensation benchmarking focused solely on levels of compensation paid to employees does not account for efficiency gains achieved through greater workforce flexibility or through the cost-avoidance achieved via longer-term arrangements like MT-50 and the SUP's contracting-out language discussed above. The important role that workforce flexibility plays in the execution of Hydro One's work programs - and associated cost efficiencies - must also inform Hydro One's approach to collective bargaining and labour relations.

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Mercer

welcome to brighter

COMPENSATION BENCHMARKING STUDY
HYDRO ONE NETWORKS INC.
8 JULY 2021

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CONTENTS

1

Introduction and Executive Summary

Hydro One Networks Inc. (“Hydro One”), through its counsel, has retained Mercer (Canada) Limited (“Mercer”) in connection with its joint rate application for Distribution and Transmission (2023-2027) to:

1. Complete an updated Compensation Benchmarking Study (“Study”) in response to the Ontario Energy Board’s (“OEB”) comments or directives in its decision in EB-2019-0082; and
2. Provide our opinion in response to the following question: Besides the level of compensation outlined in the Study results, are there other factors that would need to be considered by the OEB in order to assess the reasonableness of Hydro One’s overall compensation costs? If so, please describe those factors.

The Study is an independent, testable and repeatable market-based assessment of the degree of competitiveness of Hydro One’s total compensation levels including salary, short-term incentives (including lump sum payments, when applicable), long-term incentives (including negotiated share grants, when applicable), pension and employer paid health and group benefits relative to a select peer group. Mercer undertakes a customized survey of total compensation in the market, in order to provide reliable information. This Study was conducted in 2008, 2011, 2013, 2016, 2017 and repeated, following a similar methodology, in 2020.

Prior to each Study, every effort is made to ensure that the approach and methodology used continues to meet industry best standards and will provide an appropriate comparison for Hydro One.

Since 2008, the Study has included regulated Generation, Transmission and Distribution Utilities as well as comparable regulated businesses across Canada. Similarly, the job list has reflected a mix of Transmission, Distribution and Functional benchmark jobs. However, in order to maintain the effectiveness of the Study, the comparator group and job list are reviewed prior to each study to ensure a reflection of the changing talent landscape and nature of the workforce. This review has resulted in revisions to the comparator organizations (see page 9) and survey jobs (page 12) included in the Study. While these changes may have an impact on the study-over-study comparison, Mercer believes they better reflect the current workforce and balance of jobs at Hydro One, as well as the landscape in which Hydro One competes for talent.

Below, we set out the final results of our analysis. Study-over-study trend analysis is provided as well as responses to the OEB’s comments and directive in its decision in EB-2019-0082, including results in respect of overtime policy benchmarking and short and long-term incentive pay benchmarking. Responses to the OEB’s comments or directives can be found throughout this report.

In connection with the Study, Mercer will also be conducting a compensation benchmarking forecast covering the period up to 2027 ("Forecast"). This will be done following completion and ratification of the current round of Society of United Professionals' collective bargaining. Mercer intends to provide an addendum to this report in the coming months, outlining the findings of the Forecast once it has been completed (and subject to any confidentiality issues being addressed).

In response to the question in item #2 above: Though market competitiveness in respect of levels of pay is a reliable factor that should be considered when assessing the reasonableness of Hydro One's overall compensation costs, Mercer's view is that it should not be the single determining factor. In addition, consideration should also be given to the impact that Hydro One's workforce size and mix has on overall compensation costs. Efficiency in respect of size and/or mix of workforce can result in overall compensation costs being reasonable even though pay levels (on a per employee basis) may be above market. Further, there are likely cost saving benefits that result from managing a highly skilled and tenured workforce, including savings through greater employee effectiveness. These factors are addressed further under section 2 below (see page 5).

Summary of Compensation Benchmarking Results

The Study compared the competitiveness of Hydro One's total compensation pay levels to a peer group of Transmission, Distribution and Generation organizations, supplemented with participants from a similar Regulatory Environment. The study reflected 3,354 Hydro One employees in 31 benchmark jobs which represent 59% of Hydro One's total regular full-time equivalents population. In total, our analysis reflected approximately 15,850 incumbents employed in the Canadian energy and/or adjacent sectors.

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**.

The shift in Hydro One's competitive position towards the median, over the Study period (2008 – 2020), is notable given that the peer group, comprised of organizations with operations similar to Hydro One, have been under pressure from key stakeholders over the entire period the compensation cost benchmarking studies have been conducted (2008-2020) to reduce labour costs.

Hydro One's trend towards the market median has been supported by a combination of factors specific to Hydro One. Some of these factors have had an immediate impact, while others, though implemented in the past, have a trailing impact as tenured employees at the higher end of salary ranges / wage grids and/or on grandfathered plans are replaced with new employees. Amongst others, Hydro One's increased use of a cost effective mix of workers has had an immediate contributory impact to the trend towards the market median. However, legacy pension plans that were in place prior to the formation of Hydro One, continue to limit a quicker shift towards the market median. See page 16 for details on these factors.

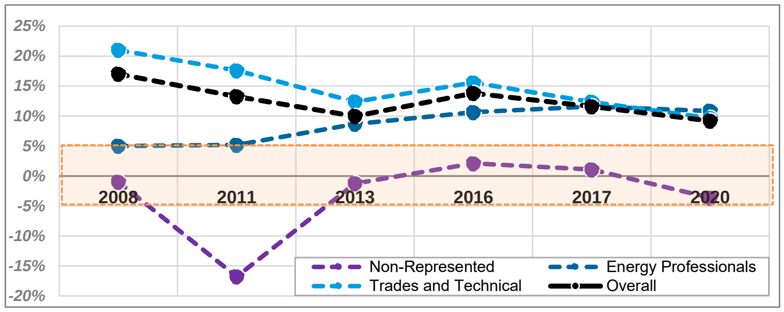
Table 1 below summarizes the results of the 2020 Study compared to the results of the 2008, 2011, 2013, 2016 and 2017 Study. The competitive range (+/- 5% of the market 50th percentile) is highlighted in orange in the chart.

Table 1

			Total Remuneration (Current)					
			Variance to P50					
	Hydro One Group	# of Hydro One Inc. (2020)	2008	2011	2013	2016	2017	2020
Weighted Average	Non-Represented	155	-1%	-17%	-1%	2%	1%	-4%
	Energy Professionals	400	5%	5%	9%	11%	12%	11%
	Trades and Technical	2,801	21%	18%	12%	16%	12%	10%
	Overall	3,356	17%	13%	10%	14%	12%	9%

Hydro One P50 Relative to Market P50

2008 2011 2013 2016 2017 2020



Summary of Overtime Policy Benchmarking Results

Actual overtime costs are highly variable and difficult to normalize across Hydro One's comparator group. In order to ensure appropriate comparisons are made, Mercer compared Hydro One's overtime policy to the overtime policies found in the comparator group. By doing this, Mercer was able to make a direct comparison of how aligned Hydro One's overtime policy is relative to policies in peer organizations. Below are Mercer's findings from the review:

i) **Overtime Rate:** Across all overtime types (e.g. weekday, weekends, call outs etc.) Hydro One's overtime rates are at or below the market median.

ii) **Tiered Rate:** Where tiered rates are used, the amount of hours Hydro One requires to move to the next overtime rate tier (e.g. 1.5x for first 4 hours and 2x afterwards), is aligned with the market median.

iii) **Minimum Hours:** Hydro One is generally aligned to the market in terms of the number of minimum overtime hours offered.

iv) **Overtime Tracking and Approval Process:** Hydro One's overtime tracking and approval process are aligned with predominant market best practice.

Table 2 below presents the prevalence of overtime pay rates across different overtime types for Hydro One and the comparator group ("Market"). The most prevalent overtime rate for each category is highlighted in blue. Please refer to page 21 for additional information and the definition of the types of overtime referenced.

Table 2

	Pay Rate	Standard	Call Out	Weekend	Statutory Holiday	Vacation
Market	1.5x	6%	6%	6%	6%	6%
	1.5x - 2x	29%	24%	18%	18%	29%
	2x	**65%**	**71%**	**76%**	**76%**	**65%**
Hydro One	1.5x	20%	20%	0%	0%	20%
	1.5x - 2x	**60%**	**40%**	20%	0%	**60%**
	2x	20%	**40%**	**80%**	**100%**	20%

Given Hydro One's overtime rates are at or below market and its overtime polices (how overtime is applied) are aligned with market practice, **we conclude that Hydro One's overtime pay practices are, as a whole, generally aligned with or are less generous than overtime pay practices in the market.**

Summary of Short-Term Incentive ("STI") Plan and Long-Term Incentive ("LTI") Plan Benchmarking Results

Across all comparator organizations that provided data for a Non-Represented benchmark job, 80% provide STI to their employees while 25% provide LTI. The lower prevalence of LTI is mainly driven by the low number of senior management jobs included in the benchmark job list – LTI is generally more prevalent at senior level jobs and in publicly traded companies**. Hydro One is generally aligned with the market prevalence** in that all Non-Represented jobs are eligible for STI while only the Director level jobs in the benchmark job list (2 jobs) are eligible for LTI.

In order to assess the competitiveness of Hydro One's STI program and ensure an appropriate comparison relative to peer companies, Mercer compared Hydro One's target total cash compensation (base salary/wages + target STI) for the Non-Represented group to target cash compensation levels seen in peer organizations. By taking this approach, the analysis was able to focus on the design of the incentive programs without any impact of company performance on bonus payout. The result of this exercise was a further **improvement in market positioning (i.e. movement towards the market median) for the Non-Represented group**.

Based on this finding, we conclude 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.

2

Additional Factors to Consider When Assessing The Reasonableness of Hydro One's Overall Compensation Costs

We have been asked to provide our opinion in response to the following question: Besides the level of compensation outlined in the Study results, are there other factors that would need to be considered by the OEB in order to assess the reasonableness of Hydro One's overall compensation costs? If so, please describe those factors.

There are additional factors that the OEB should consider when assessing the reasonableness of Hydro One's, or any other organization's, overall compensation costs. Although higher compensation levels drive higher unit (i.e. per employee) costs, they can also provide cost savings through greater employee effectiveness associated with an experienced, highly skilled and engaged workforce, for example. When evaluating the reasonableness of the total compensation costs for an organization, besides the organization's pay levels and employee effectiveness, the following additional factors should be considered, amongst others:

1. The size and mix of the workforce
   - The size and mix of an organization's workforce are factors that directly impact an organization's actual total compensation costs.
   - Actual total compensation costs are a function of the average total compensation paid to employees multiplied by the number of employees employed. For example, if an organization's workforce is paid, on average, somewhat above the market median but is efficient in respect of its workforce planning and; as such, employs somewhat fewer employees, or an efficient mix/deployment of employees, to complete the work while achieving the same business outcomes than might otherwise be the case, the actual total compensation costs may be similar. Thus, consideration should be given to whether an organization is being reasonably efficient in how it deploys work teams as well as the size of its workforce when assessing the reasonableness of overall compensation costs. Factors that could lead to being able to achieve the same work output with fewer employees include: worker skill level, worker experience, work management practices, work process design, application of tools and technology, and mix of employees.
   - The mix of employees within a workforce, including the proportion of unionized employees, affect an organization's total compensation costs. Unionized populations are subject to, amongst others, collective bargaining agreements, legacy pension plans, and staffing and compensation practices that are different from non-unionized populations. The two largest employee populations at Hydro One, the Trades and Technical and Energy Professionals groups, are unionized. The mix of unionized and non-unionized employee populations and the different compensation practices used in each group should be taken into account when assessing the reasonableness of an organization's total compensation costs.

– "Mix" of employees, in Mercer's view, has three aspects that, if prudently managed, will likely have a material impact on reducing actual total compensation costs. However, these three aspects are not directly captured in this Study of Hydro One's total compensation levels relative to the market median. Two of the three aspects referenced are the number of employees in specific jobs and the number of employees in specific employment arrangements and how they are deployed. An organization that deploys a cost effective and efficient work team to any project will generally save costs. This does not always mean using employees in the job with the lowest total compensation cost as it may be the employees in higher levels or more highly skilled jobs who can complete the work more quickly and potentially with a lower total headcount. Assuming equal productivity, using employees with lower total costs will reduce overall cost for the organization. An example of this is the routine use of "casual" workers for certain work tasks. Again, considering how the mix of employees is managed is part of assessing the reasonableness of actual total compensation costs.

2. Bargaining power of unions and essentiality of service
   – The third aspect of the mix of employees that has a material impact on actual total compensation costs is the level of unionization. Unionized workforces typically have higher total compensation costs, relative to non-unionized populations, due to their negotiating power during the collective bargaining process and their ability to threaten a work stoppage. Moreover, due to the essential nature of the services provided by the utilities industry, some organizations are likely unable to accommodate a work stoppage. This dynamic can inhibit an organization's attempt to control total compensation costs. At Hydro One, all elements of the compensation program are subject to union negotiations for the Trades and Technical and Energy Professionals groups. The comparator group established for the Study included both unionized and non-unionized organizations.

3. Cost saving benefits from increased employee morale and loyalty
   – Competitive or market aligned compensation packages are one of the elements that can result in increased employee morale and loyalty, which in turn contribute to lower turnover rates. These lower rates can drive down talent acquisition (e.g. hiring, sourcing) and onboarding (e.g. training) costs, amongst others. In addition, lower turnover fosters knowledge retention within highly trained employees.

4. Strong track record of safety due to a highly skilled and trained workforce
   – Knowledge retention driven by low turnover rates, and consequently higher compensation levels, can produce indirect benefits, namely increased workplace safety.

When assessing the reasonableness of Hydro One's compensation costs, Mercer believes that consideration should also be given to the cost saving benefits that result from managing a highly skilled and tenured workforce.

3

Guiding Principles

The principles used for the Study were based on Mercer's standard approach in conducting multi-year compensation benchmarking. Mercer ensures that these principles are effectively applied within the context of the Hydro One Study, making adjustments where necessary. These principles include:

1. Principle objective – to revisit the 2008, 2011, 2013, 2016 and 2017 Mercer Study to reasonably compare Hydro One's compensation levels to those of regulated Transmission and Distribution Utilities, Generators as well as comparable regulated businesses across Canada.
   - The 2008, 2011, 2013, 2016 and 2017 Mercer studies were conducted following the same general overall methodology to provide appropriate study-over-study comparisons.
2. Keep it simple to entice survey participants.
   - The data collection process was reviewed and streamlined, where possible, to encourage survey participants to share data. Additional follow-up was provided by Mercer to support comparator participation in the study.
3. Be independent, testable, repeatable and market-based.
   - The study was conducted in a manner that meets each of the criteria listed.
4. Provide participants with the assurance that their information could not be attributable to them.
   - All participants were assured that data would be held confidentially by Mercer and only be shared in aggregate form.
5. Be based on the peer group and benchmark jobs surveyed in the 2017 Mercer study and adjusted as deemed appropriate by the consultant.
   - The 2020 Study targeted similar benchmark jobs and organizations as the 2017 study; however, the following changes were made:
     - The list of benchmark jobs for the 2020 Study was revised to reflect the changing working environment at Hydro One. This resulted in the removal of three (3) out of the thirty four (34) jobs in the 2017 study.
     - The list of peer organizations targeted to participate in the 2020 Study was revised to ensure a continued balance of Generation, Transmission and Distribution organizations, as well as comparable regulated businesses, across Canada. This resulted in a similar peer group used in the 2017 study with the addition of five (5) utility organizations whose services span Generation, Transmission and Distribution. One (1) organization that participated in the 2017 study declined to participate in 2020. One (1) organization was part of a merger and participated under a new name.

6. Mirror the scoping in the 2008, 2011, 2013, 2016 and 2017 Mercer studies for peer selection, job classes, etc. and make only required changes deemed appropriate by the consultant.
   - Though the peer group and job list were revised, the same methodology used in 2008, 2011, 2013, 2016 and 2017 was followed in the 2020 Study for both peer company selection and job classes for inclusion. The selected benchmark job classes for the 2020 Study represented 59% of Hydro One's regular full-time equivalents population.
7. Enable reasonable comparison to the last Mercer study and provide trending analysis for Hydro One.
   - By including approximately 91% of benchmark jobs and successfully collecting data from 79% of peers from the 2017 Study, reasonable comparisons have been made and trending has been assessed.
8. Compare to market median rather than market average ("mean")
   - The 2020 Study is based on a comparison of Hydro One median compensation against market median compensation. Comparison of medians is standard compensation practice; medians are representative of the middle data point in a sample and are less sensitive to outliers than the mean.
     - The 2008, 2011, 2013, 2016 and 2017 studies also compared Hydro One to the median.
   - However, Appendix A provides a comparison of Hydro One's total compensation median against market average – this is something previously requested by stakeholders. On an overall weighted average basis, there is a noticeable difference between Hydro One's median positioning relative to market median and its positioning relative to the market arithmetic mean.
9. No adjustments to reflect regional costs of living amongst the study participants.
10. Hydro One has relied on Mercer's expertise in conducting the study, including to recommend any appropriate changes in methodology and assumptions.

4

Compensation Benchmarking

Peer Groups

Mercer selects peer organizations, for compensation benchmarking purposes, based on a stable metric that reflects the size and operating complexity of the organization (typically, this is revenue and/or total assets). Where there is a relatively small sample of relevant comparator organizations, Mercer generally establishes limits of 33% to 300% of the scope criteria for the organization we are analyzing. Some organizations were included in the analysis despite falling below the 33% of revenue threshold value in order to ensure a robust sample size. These organizations were a mix of regulated Transmission and Distribution Utilities and an Electricity System Operator that are seen as important comparators by stakeholders.

To develop a single peer group for Hydro One, Mercer initially considered all organizations, with 2018 or 2019 annual revenues between 33% and 300% of Hydro One's 2019 annual revenue, from the following areas:

1. Electric utilities, multi-utilities, generation, transmission, and gas utilities industries in Canada as classified by their Global Industry Classification Standard ("GICS")
2. 65 Local Distribution Companies ("LDCs") in Ontario
3. Other comparable regulated businesses (i.e., gas pipelines, regulators, etc.)

Overall, 26 organizations were invited to participate in the 2020 study:

- 20 organizations accepted the invitation and participated in the 2020 study.
  - 16 of the 19 organizations included in the 2017 study were invited to participate.
    - After reviewing the survey submissions provided by Black & McDonald and K-Line Maintenance & Ltd in 2017, it was deemed that the business and staffing model of these contractors was not reflective of Hydro One or other organizations in the peer group. In addition, Hydro One does not generally compete for talent with contractors.
    - Kinder Morgan Canada Ltd. sold their pipeline operations to Pembina Pipelines Corporation; as such, they no longer have the benchmark jobs covered in the Study
  - 15 of these 16 organizations that participated in 2017 also participated in the 2020 Study.
  - 1 organization that participated in the 2017 study declined to participate in 2020.
  - 5 new organizations participated in the 2020 Study.
- Amongst the new participants, Algonquin Power was the only organization that had not been invited to participate in previous studies.

Organizations that did not participate in the compensation benchmarking study indicated that they were unable to participate due to either resource constraints, an insufficient number of relevant benchmark jobs or the divestiture of a relevant business unit.

Following standard industry practice, comparisons were made between Hydro One's incumbents, at the 50th percentile, to the market peer group 50th percentile on base salary, total cash compensation and total compensation.

To ensure that no one organization biased the results, we have weighted our analysis by organization for each job class and not by number of incumbents matched to determine Hydro One's position relative to the market (i.e., the analysis is "Org Weighted"). To preserve the confidentiality of compensation data at both Hydro One and participating organizations, we have aggregated our results.

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. Through the process of assessing what a non-utilities peer group may look like, Mercer encountered the following concerns:

i) Highly populated core trades and technical jobs are unique to the utilities industry; as such, a Study including a non-utilities peer group does not provide a representative market comparison for Hydro One
ii) There will be a greater challenge in getting target non-utilities organizations to participate. This is mainly due to the types of jobs being surveyed that are predominantly reflective of the utilities industry in which Hydro One competes for talent
iii) Leveraging a non-utilities peer group may not reflect the market premium associated with the skillsets specifically required in the utilities industry
iv) One of Mercer's core methodology principles is to compare the compensation practices of an organization to practices in the industry in which it competes for talent. Based on this, Mercer would not advise a non-utilities peer group be used for the Trades and Technical jobs. In addition, though potential talent for the Non-Represented and a subgroup of Society jobs (e.g. Business Analysts) may be sourced from non-utility organizations, these employee groups represent a small population within the Study. As such, any results generated from a comparison to a non-utilities peer group would not provide an appropriate assessment of the degree of competitiveness of Hydro One's overall total compensation pay levels

Based on these concerns, 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.

Market Sample

Summarized in Table 3 below are the participating organizations in the compensation benchmarking.

Table 3

#	Company Name	Revenue[1]	# of Employees[1,2]
1	Enbridge Inc.	$19,954.0	7,699
2	Hydro-Québec	$13,000.0	20,000
3	BC Hydro Power & Authority	$6,269.0	7,141
4	Ontario Power Generation Inc.	$6,022.0	8,390
5	ATCO Ltd.*	$4,706.0	6,500
6	Toronto Hydro Corporation	$3,836.9	1,161
7	Alectra Utilities	$3,779.0	1,482
8	Bruce Power L.P.	$3,611.0	4,057
9	SaskPower	$2,771.0	3,883
10	Manitoba Hydro	$2,629.0	4,736
11	ENMAX Corporation	$2,524.9	1,707
12	TransAlta Corporation	$2,347.0	1405
13	Nalcor Energy	$1,931.0	1,532
14	New Brunkswick Power	$1,924.0	2,569
15	EPCOR Utilities, Inc.	$1,864.0	3,042
16	Emera Inc.*	$1,795.1	2,342
17	Algonquin Power and Utilities Corp*	$1,624.9	2,569
18	Hydro Ottawa Limited*	$1,127.3	599
19	Elexicon Energy*	$489.9	254
20	Indepdendent Electricity System Operator	$191.0	886
75th Percentile		**$4,488.7**	**6,059**
50th Percentile		**$2,577.0**	**2,569**
25th Percentile		**$1,812.3**	**1,424**
Average		**$4,119.8**	**4,098**
Hydro One Network Inc.		**$6,500.0**	**5,699**

[1] *Data as reported by survey participants in CAD ($MM)*

[2] *Representative of full-time equivalents only*

* *New participants in 2020*

Mercer notes that, when measured on revenue, Hydro One is the third largest organization, for which we are able to report revenue, in the sample. Although size has a limited impact on middle management and unionized roles, size may have an impact on compensation for executive roles, as these roles tend to be larger and more complex in larger organizations.

Benchmark Jobs

The compensation survey was designed to benchmark compensation levels from a cross-section of Hydro One's population. To determine the roles to be included in our benchmark analysis, Mercer reviewed jobs that represented all of Hydro One's major business units and covered, at least, 50% of Hydro One's employee population.

To assist with study-over-study comparisons, it was determined that the Study should collect incumbent data using 31 of the 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

In total, 31 benchmark roles were included in the 2020 Study and data is reported for all 31 jobs.

As a result, ***the 2020 Study directly reflected 3,354 Hydro One employees in 31 benchmark jobs which represent 59% of Hydro One's regular full-time equivalents population.***

In the market, Mercer collected approximately 15,850 individual incumbent observations across the benchmark jobs (this figure excludes the 3,354 Hydro One incumbents) ***employed in the Canadian energy and/or adjacent sectors.***

Summarized in Table 4 below are the benchmark jobs organized by major employee group. The results in this report are summarized by the following employee groups. Specifically:

Table 4

Hydro One Group	Job #	Benchmark Survey Title
Non-Represented	1	Financial Director
	2	Regulatory Director
	3	Manager of Construction
	4	Senior Legal Counsel
	5	Engineer F
	6	Operations Manager
	7	Human Resource Manager / Consultant
	8	Administrative Assistant
Energy Professionals	9	Engineer E
	10	Business Analyst C
	11	Engineer D
	12	Senior Protection and Control Supervisor
	13	Estimator/Scheduler
	14	Engineer C
	15	Engineer B
	16	Business Analyst A
	17	Engineer A
Trades and Technical	18	Regional Maintainer - Lines (Supervisory)
	19	Protection and Control Technician
	20	Lineman - Journeyman
	21	Engineering Technician
	22	Regional Maintainer - Lines
	23	Regional Maintainer - Electrical
	24	Fleet Mechanic
	25	Draftsperson
	26	Stock Keeper
	27	Heavy Equipment Operator
	28	Labourer
	29	Data Entry Clerk
	30	Electrical Apprentice
	31	Lines Apprentice

“Energy Professionals” refers to Hydro One jobs represented by the Society of United Professionals (“Society”) and “Trades and Technical” predominantly refers to Hydro One jobs represented by the Power Workers’ Union (“PWU” or “Power Workers”).

See Appendix B for a summary of job descriptions.

Methodology

As outlined in Appendix B, summarized below is the methodology used to determine compensation levels. Specifically:

Base Salary/Wage – Annual base salary at October 1, 2020 - If an hourly rate was reported, Mercer annualized the value by multiplying the standard number of work hours per week by 52 weeks per year. If a weekly rate was reported, Mercer annualized the value by multiplying by 52 weeks per year.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive, bonus or lump sum paid, where applicable.

- Hydro One does not provide short-term incentives or bonus programs to Energy Professionals or Trades and Technical jobs.
- The last lump sum cash payment was made in 2017; as such, this compensation element is not reflected in this 2020 Study.

Benefits and Pensions – To value benefit and pension programs, Mercer applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans.

Total Compensation – Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., share grants, long-term cash, expected value of stock options or share awards) and pensions and benefits.

- Hydro One only provides cash based long-term incentives to two (2) senior level jobs within the Study.
- In 2020, Hydro One provided share grants, to the Energy Professionals and PWU jobs through a previously negotiated collective bargaining agreement.

Findings

Summarized below are the results of our compensation benchmarking analysis.

Overall, **on a weighted average basis, Hydro One's level of total compensation paid to employees is 9% above market 50th percentile / median / "P50"**. When assessing compensation competitiveness, **Mercer considers compensation to be competitive, on an overall/employee group basis, when it is within +/- 5% from the target market positioning which is the market 50th percentile for Hydro One**. Based on this, **Hydro One is positioned 4% above the defined competitive range on an overall basis.**

Hydro One is positioned above the market 50th percentile for the Energy Professionals and Trades and Technical groups – by 11% and 10% respectively. The Non-Represented group is positioned below the market 50th percentile by 4%.

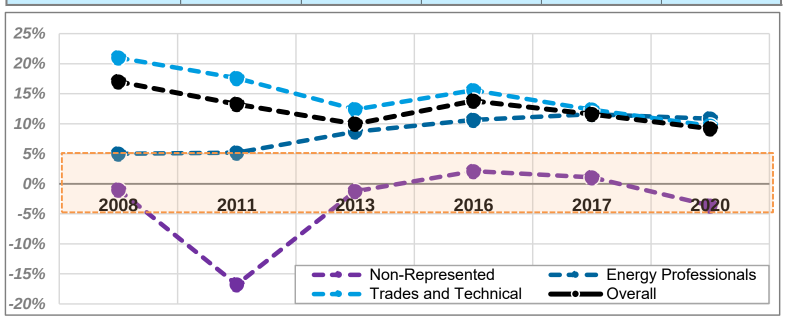
In the 2017 study, Hydro One's overall weighted average as of 2017 was 12% above the market total compensation P50 and 7% above the defined competitive range. Based on this, the result of the 2020 Study represents a 3% shift towards the market median. The defined competitive range has been highlighted in orange in the chart below.

Table 5

			Total Remuneration (Current)					
			Variance to P50					
	Hydro One Group	*# of Hydro One Inc. (2020)*	2008	2011	2013	2016	2017	**2020**
Weighted Average	**Non-Represented**	*155*	-1%	-17%	-1%	2%	1%	**-4%**
	Energy Professionals	*400*	5%	5%	9%	11%	12%	**11%**
	Trades and Technical	*2,801*	21%	18%	12%	16%	12%	**10%**
	Overall	***3,356***	***17%***	***13%***	***10%***	***14%***	***12%***	***9%***

Hydro One P50 Relative to Market P50

2008	2011	2013	2016	2017	2020



Hydro One's trend towards the market median has been supported by a combination of factors specific to Hydro One. Some of these factors, outlined below, have had an immediate impact, while others, though implemented in the past, have a trailing impact as tenured employees at the higher end of salary ranges / wage grids and/or on grandfathered plans are replaced with new employees

Immediate Impact

- An enhanced review of merit increases and broader salary management practices for the Non-Represented group
- Lower short-term incentive payouts to the Non-Represented group
- The use of a cost effective mix of workers that have lower cost pension and benefit packages

Trailing Impacts

- The introduction of lump sum and share grants to represented employees, in exchange for reduced base salary / wage increases
- The cost saving impact of reduced base salary / wage increases on pension and benefit costs
- Some of the effects of proactive changes made to pension plans outlined below. The full impact of these changes will be realized over time as new employees under the revised plans replace older employees under grandfathered benefits
  - Introduction of the Defined Contribution plan for Non-Represented employees;
  - Increased early retirement eligibility rule of 85 (up from 82) for the PWU commencing in 2025;
  - Adjustment to number of years for final average earnings from 3 to 5 years commencing for the PWU and Society (legacy plan) in 2025; and,
  - Employee pension contribution increases
- The natural attrition of the workforce and replacement with less costly employees (e.g. Non-Represented employees on the DC plan)

The following factors have a trailing impact and continue to hinder a quicker shift towards the market median:

- Highly competitive base wages, especially for the most highly skilled Society and PWU jobs
- The relatively high value of legacy collective agreement wages, pension and benefits programs. We note that the legacy Non-Represented pension & benefit and Society pension plans are now closed to new members

Mercer understands that these legacy plans (i.e. Defined Benefit plans) relate to collective agreements negotiated prior to the formation of Hydro One. All PWU employees continue to be covered by the legacy plans. Even if all Non-Represented and Energy Professional employees were covered by the new plans, though beneficial, the difference in overall competitiveness on a weighted average basis would not be as substantial as if the highly populated PWU jobs were not on the legacy Defined Benefit plan; however, the use of casual workers (“hiring hall”) for some of the Trades and Technical benchmarks does reduce compensation costs relative to other PWU jobs and our market data.

For new employees hired into Non-Represented and Energy Professional job classifications, the value of pensions and/or benefits, where applicable, have decreased due to amendments to these plans (see “New” & “Go Forward” columns on the following pages). In addition to this, Hydro One will also benefit from employer cost saving changes made to the legacy Energy Professionals and PWU pension plans that will come into effect in 2025.

As requested by stakeholders in 2011, in addition to comparing Hydro One's P50 to market P50, a comparison was also made of Hydro One median to market average ("mean"). On a weighted average basis, Hydro One's total compensation cost is 7% above market average. Hydro One's position relative to market varies by employee group from 8% below market average for the Non-Represented group to a high of 10% above the market average for the Trades and Technical group. There is a noticeable difference between the market median and market average. This is driven, to a certain extent, by outliers in the data set and the sample size used. See Appendix A for detailed results.

Non-Represented

Summarized in Table 6 below are the results for the Non-Represented roles that Mercer benchmarked at Hydro One relative to the market peer group. See footnote for definitions of current, new and go forward results

In comparison to 2017, the 2020 Total Compensation (current) result has decreased from 1% above market median to 4% below market median.

Table 6

			Hydro One P50 Relative to Market P50[1]				
					Total Compensation[3]		
	Hydro One Group	*# of Hydro One Incumbents*	Base Salary	Total Cash[2]	Current[4]	New[5]	Go Forward[6]
Non-Represented	**Financial Director**	*3*	-5%	-6%	21%	21%	13%
Non-Represented	**Regulatory Director**	*3*	5%	14%	32%	30%	20%
Non-Represented	**Manager of Construction**	*9*	7%	18%	19%	19%	9%
Non-Represented	**Senior Legal Counsel**	*8*	-6%	-9%	-9%	-9%	-11%
Non-Represented	**Engineer F**	*35*	-11%	-9%	-11%	-12%	-18%
Non-Represented	**Operations Manager**	*72*	-3%	-1%	2%	1%	-6%
Non-Represented	**Human Resource Manager / Consultant**	*18*	-23%	-22%	-29%	-29%	-29%
Non-Represented	**Administrative Assistant**	*7*	-5%	-9%	-10%	-10%	-10%
	2020 Weighted Average Non-Represented	*155*	-7%	-5%	-4%	-4%	-10%
	2017 Weighted Average Non-Represented	*172*	-6%	-3%	1%	0%	-12%
	2016 Weighted Average Non-Represented	*167*	-1%	-3%	2%	-1%	-12%
	2013 Weighted Average Non-Represented	*206*	-2%	-4%	-1%	-6%	-
	2011 Weighted Average Non-Represented	*137*	-17%	-20%	-17%	-18%	-
	2008 Weighted Average Non-Represented	*151*	-2%	-4%	-1%	-5%	-

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.)
[2] Base salary plus short-term incentives granted (i.e., bonus/lump sum), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents in the new DB pension and benefits programs.
[6] Based on Hydro One's employee population, assuming all incumbents in the new DC pension and benefits programs.

Energy Professionals ("Society")

Summarized in Table 7 below are the results for the Energy Professional roles that Mercer benchmarked at Hydro One relative to the market peer group.

In comparison to 2017, the 2020 Total Compensation (Current) result has decreased from 12% above market median to 11% above market median.

Table 7

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market P50[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	New[5]
Energy Professionals	**Engineer E**	*79*	0%	-3%	3%	3%
Energy Professionals	**Business Analyst C**	*4*	12%	8%	19%	19%
Energy Professionals	**Engineer D**	*187*	4%	-3%	3%	3%
Energy Professionals	**Senior Protection and Control Supervisor**	*27*	11%	5%	12%	12%
Energy Professionals	**Estimator/Scheduler**	*24*	33%	25%	39%	39%
Energy Professionals	**Engineer C**	*16*	14%	9%	19%	19%
Energy Professionals	**Engineer B**	*34*	27%	24%	35%	35%
Energy Professionals	**Business Analyst A**	*8*	3%	3%	11%	11%
Energy Professionals	**Engineer A**	*21*	19%	15%	24%	24%
	2020 Weighted Average Professionals	*400*	9%	3%	11%	11%
	2017 Weighted Average Energy Professionals	*560*	5%	3%	12%	11%
	2016 Weighted Average Energy Professionals	*612*	5%	1%	11%	10%
	2013 Weighted Average Energy Professionals	*746*	7%	3%	9%	7%
	2011 Weighted Average Energy Professionals	*779*	6%	-3%	5%	4%
	2008 Weighted Average Energy Professionals	*578*	8%	-2%	5%	3%

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.)
[2] Base salary plus short-term incentives granted (i.e., bonus/lump sum), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.

Trades and Technical

Summarized in Table 8 below are the results for the Trades and Technical roles that Mercer benchmarked at Hydro One relative to the market peer group.

In comparison to 2017, the 2020 Total Compensation result has decreased from 12% above market median to 10% above market median.

Table 8

			Hydro One P50 Relative to Market P50[1]		
			Base Salary	Total Cash[2]	Total Compensation[3]
	Hydro One Group	*# of Hydro One Incumbents*			Current[4]
Trades and Technical	**Regional Maintainer - Lines (Supervisory)**	*151*	-3%	-3%	9%
	Protection and Control Technician	*131*	10%	10%	25%
	Lineman - Journeyman	*193*	0%	0%	-1%
	Engineering Technician	*160*	6%	3%	17%
	Regional Maintainer - Lines	*824*	1%	1%	15%
	Regional Maintainer - Electrical	*222*	10%	8%	21%
	Fleet Mechanic	*89*	6%	6%	19%
	Draftsperson	*9*	16%	11%	28%
	Stock Keeper	*69*	19%	19%	36%
	Heavy Equipment Operator	*50*	20%	20%	27%
	Labourer	*242*	0%	0%	1%
	Data Entry Clerk	*61*	23%	13%	33%
	Electrical Apprentice	*154*	-14%	-14%	-7%
	Lines Apprentice	*446*	-1%	-3%	-9%
	2020 Weighted Average Trades and Technical	*2,801*	2%	1%	10%
	2017 Weighted Average Trades and Technical	*2,478*	3%	1%	12%
	2016 Weighted Average Trades and Technical	*2,212*	5%	4%	16%
	2013 Weighted Average Trades and Technical	*2,100*	8%	6%	12%
	2011 Weighted Average Trades and Technical	*2,411*	10%	9%	18%
	2008 Weighted Average Trades and Technical	*1,966*	20%	16%	21%

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.)
[2] Base salary plus short-term incentives granted (i.e., bonus/lump sum), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.

5

Overtime Policy Benchmarking

One of the OEB's comments or directives in its decision in EB-2019-0082 was that Hydro One should, to the extent possible, address the impact of items like Overtime and Utilization of Contract Staff on the 2020 Benchmarking Study Results.

- Mercer has compared Hydro One's overtime policy to the overtime policies found in the comparator group. By doing this, Mercer is able to make a direct comparison of how aligned Hydro One's overtime policy is relative to policies in peer organizations. Below are Mercer's findings from the review:
  - i) Overtime Rate: Across all overtime types (e.g. weekday, weekends, call outs etc.) Hydro One's overtime rates are at or below the market median
  - ii) Tiered Rate: Where tiered rates are used, the amount of hours Hydro One requires, to move to the next overtime rate tier (e.g. 1.5x for first 4 hours and 2x afterwards), is aligned with the market median
  - iii) Minimum: Hydro One is generally aligned to the market in terms of the number of minimum overtime hours offered
  - iv) Overtime Tracking and Approval Process: Hydro One's overtime tracking and approval process are aligned with predominant market best practice

The table below presents the prevalence of overtime pay rates across different overtime types for Hydro One and the comparator group ("Market"). The most prevalent overtime rate for each category is highlighted in **blue**. The 1.5x – 2x range reflects instances where a tiered approach for overtime is utilized (e.g. 1.5x for the first 4 hours and 2x onwards). We note that Hydro One's overtime rates vary across the different union groups within the organization. However, the minimum overtime rate present within the organization is 1.5x up to a maximum 2x. **Standard** represents overtime from working beyond the established standard hours for a job. **Call out** represents a situation where an employee is unexpectedly required to go back to work after they have already left for the day. Weekend, statutory holiday and vacation overtime represent overtime incurred on specific types of days.

Table 9

	Pay Rate	Standard	Call Out	Weekend	Statutory Holiday	Vacation
Market	1.5x	6%	6%	6%	6%	6%
	1.5x - 2x	29%	24%	18%	18%	29%
	2x	**65%**	**71%**	**76%**	**76%**	**65%**
Hydro One	1.5x	20%	20%	0%	0%	20%
	1.5x - 2x	**60%**	**40%**	20%	0%	**60%**
	2x	20%	**40%**	**80%**	**100%**	20%

Given Hydro One's overtime rates are at or below market and its overtime polices (how overtime is applied) are aligned with market practice, **we conclude that Hydro One's overtime pay practices are, as a whole, generally aligned with or are less generous than overtime pay practices in the market.**

Mercer does not include overtime costs when conducting benchmarking exercises due to the variability of the inputs that are required to determine these values. Specifically, overtime values use inputs, namely the number of overtime hours worked, that are volatile and specific to organizations. Overtime may also be impacted by the geographical area an organization services (remote vs dense areas), “acts of god” on operations (e.g. winter storms) and general service requirements (e.g. customer demand). These inputs are challenging to normalize across Hydro One’s comparator peer group; as such, market positioning results are unlikely to be representative of the true cost of overtime at Hydro One. In addition, reliable actual paid overtime data for individual employees is very difficult to collect and validate in a total remuneration study.

Similarly, Mercer does not include contractors in benchmarking studies due to the unique compensation arrangements that govern them. Including contractors may impact the Study’s ability to accurately assess the degree of competitiveness of Hydro One’s total compensation levels.

6

Short-Term Incentive Plan and Long-Term Incentive Plan Benchmarking

One of the OEB's comments or directives in its decision in EB-2019-0082 was a request to compare management group incentive programs (STIP and LTIP) to similar programs in comparator companies.

Across all comparator organizations that provided data for a Non-Represented benchmark job, 80% provide STI to their employees while 25% provide LTI. The lower prevalence of LTI is mainly driven by the low number of senior management jobs included in the benchmark job list – LTIP is generally more prevalent at senior level jobs and in publicly traded companies. Hydro One is generally aligned with the market in that all Non-Represented jobs are eligible for STI while only Director level jobs (2) in the benchmark job list are eligible for LTI.

The ongoing methodology of the Study is to compare Hydro One's actual STI payouts and LTI grants to actual STI payouts and LTI grants seen in its peer group.

- In order to assess the competitiveness of Hydro One's STI program and ensure an appropriate comparison relative to peer companies, Mercer compared Hydro One's target total cash compensation (base salary/wages + target STI) for the Non-Represented group to target cash compensation levels seen in peer organizations. By taking this approach, the analysis was able to focus on the design of the incentive programs without any impact of company performance on bonus payout
- The result of this exercise was a further reduction in market positioning (i.e. movement towards the market median) for the Non-Represented group. Based on this finding, we conclude 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
- As mentioned, LTI grants are not as prevalent amongst Hydro One's Non-Represented employee group, specifically only two (2) jobs in the benchmarking study received LTI grants through the formal LTI program in the 2017 and 2020 study.

APPENDIX A

Hydro One vs. Market Average

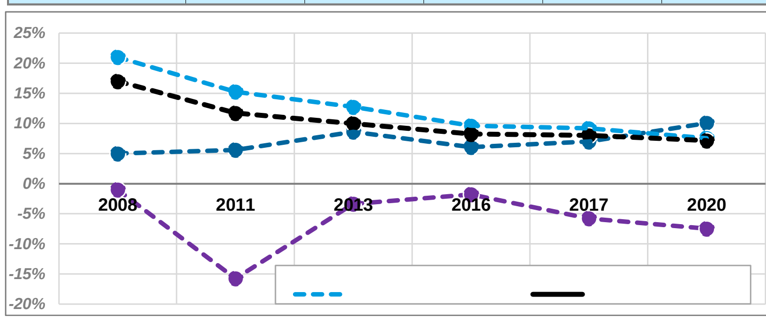
As was previously requested by stakeholders in 2011, and has been provided in study updates since then, summarized in Table 10 below are the results of our compensation benchmarking analysis comparing Hydro One median to market average.

Overall, **on a weighted average basis, Hydro One's total compensation cost is 7% above the market average (mean)**. Hydro One's position relative to market varies by employee group from a low of 8% below the market average for the Non-Represented group to a high of 10% above the market average for the Energy Professionals group.

Table 10

			Total Remuneration (Current)					
			Variance to Market Average					
	Hydro One Group	*# of Hydro One Inc. (2020)*	2008	2011	2013	2016	2017	**2020**
Weighted Average	**Non-Represented**	*155*	-1%	-16%	-3%	-2%	-6%	**-7%**
	Energy Professionals	*400*	5%	6%	9%	6%	7%	**10%**
	Trades and Technical	*2,801*	21%	15%	13%	10%	9%	**8%**
	Overall	***3,356***	***17%***	***12%***	***10%***	***8%***	***8%***	***7%***

Hydro One P50 Relative to Market Average					
2008	2011	2013	2016	2017	**2020**



Non-Represented

Summarized in Table 11 below are the results for the Non-Represented roles that Mercer benchmarked at Hydro One relative to the market peer group.

Table 11

			Hydro One P50 Relative to Market Average[1]				
			Base Salary	Total Cash[2]	Total Compensation[3]		
	Hydro One Group	*# of Hydro One Incumbents*			Current[4]	New	Go Forward[6]
Non-Represented	**Financial Director**	*3*	-6%	-4%	21%	21%	13%
	Regulatory Director	*3*	2%	9%	27%	25%	16%
	Manager of Construction	*9*	7%	9%	10%	10%	1%
	Senior Legal Counsel	*8*	-8%	-8%	-13%	-13%	-15%
	Engineer F	*35*	-14%	-17%	-17%	-17%	-23%
	Operations Manager	*72*	-2%	-4%	-1%	-2%	-10%
	Human Resource Manager / Consultant	*18*	-22%	-26%	-29%	-29%	-29%
	Administrative Assistant	*7*	-6%	-9%	-12%	-12%	-12%
	2020 Weighted Average Non-Represented	*155*	-7%	-9%	-7%	-8%	-14%
	2017 Weighted Average Non-Represented	*172*	-8%	-9%	-6%	-7%	-18%
	2016 Weighted Average Non-Represented	*167*	-2%	-5%	-2%	-5%	-16%
	2013 Weighted Average Non-Represented	*206*	-4%	-6%	-3%	-8%	-
	2011 Weighted Average Non-Represented	*137*	-15%	-17%	-16%	-17%	-

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.)
[2] Base salary plus short-term incentives granted (i.e., bonus/lump sum), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents in the new DB pension and benefits programs.
[6] Based on Hydro One's employee population, assuming all incumbents in the new DC pension and benefits programs.

Energy Professionals ("Society")

Summarized in Table 12 below are the results for the Energy Professional roles that Mercer benchmarked at Hydro One relative to the market peer group.

Table 12

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market P50[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	New[5]
Energy Professionals	Engineer E	79	0%	-3%	3%	3%
	Business Analyst C	4	12%	8%	19%	19%
	Engineer D	187	4%	-3%	3%	3%
	Senior Protection and Control Supervisor	27	11%	5%	12%	12%
	Estimator/Scheduler	24	33%	25%	39%	39%
	Engineer C	16	14%	9%	19%	19%
	Engineer B	34	27%	24%	35%	35%
	Business Analyst A	8	3%	3%	11%	11%
	Engineer A	21	19%	15%	24%	24%
	2020 Weighted Average Trades and Technical	2,801	2%	1%	10%	10%
	2017 Weighted Average Trades and Technical	2,478	3%	1%	12%	12%
	2016 Weighted Average Trades and Technical	2,212	5%	4%	16%	16%
	2013 Weighted Average Trades and Technical	2,100	8%	6%	12%	-
	2011 Weighted Average Trades and Technical	2,411	10%	9%	18%	-
	2008 Weighted Average Trades and Technical	1,966	20%	16%	21%	-

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.)
[2] Base salary plus short-term incentives granted (i.e., bonus/lump sum), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.

Trades and Technical

Summarized in Table 13 below are the results for the Trades and Technical roles that Mercer benchmarked at Hydro One relative to the market peer group.

Table 13

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.
[2] Base salary plus short-term incentives granted (i.e., bonus/lump sum), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.

APPENDIX B

Job Descriptions

Benchmark Job	Survey Code	Generic Description
Administrative Assistant	220.108.430	Requires a general knowledge of departmental procedures, practices and office routine. Possesses good office and computer skills including word processing, spreadsheets, graphics software, and filing. May provide assistance to a more senior Administrative Assistant in a large department.
Business Analyst A	320.392.360	Assists with analyzing internal metrics. Performs responsible and varied business analytical or administrative functions. Assists with preparation documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree and up to 2 years experience.
Business Analyst C	320.392.340	Analyzes internal metrics. Performs responsible and varied business analytical or administrative functions. Prepares documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree with a minimum of 4 years' related experience.
Data Entry Clerk	999.999.002	Perform data processing services including inputting, updating, to various computerized databases and applications of external service providers. Perform clerical/administrative duties in support of system processes. Work with various internal and external contacts and customers in the set up, maintenance, reporting and follow up of non-electricity accounts, customer service orders, materials, corporate charge cards, time reporting, management reporting, damage claims, accounts receivable, etc. Perform administrative services for provincial client group and special projects.
Draftsperson	510.656.420	Incumbent works on standard drafting assignments. Methods are detailed and standard but judgment is required in planning tasks and choice of methods. Accountable for accuracy and adequacy of work performed. May provide technical guidance to less experienced Drafters. Usual qualifications include a technical school diploma or equivalent, with a minimum of 5 years' related experience.
Electrical Apprentice	999.999.112	A five year apprenticeship leading to a Construction and Maintenance Electrician.
Engineer A	510.780.360	Incumbent receives "on-the-job" training in various phases of office, plant or field engineering through assignments or, in some cases, classroom instruction. Tasks assigned are simple and routine in nature. Assists more senior engineers in the preparation of plans, calculations, reports, etc. Few technical decisions are made and these are routine, with clearly defined procedures and guidelines. Works under close supervision and work is reviewed for accuracy, adequacy and conformance with prescribed procedures. Usual qualifications include a university degree in engineering with minimal experience. Incumbents in this job are not required to hold an engineering license in Ontario.
Engineer B	510.780.350	Uses a variety of standard problem solving techniques. May assist more senior engineers in carrying out technical tasks requiring computation methods. Duties are assigned with detailed oral, and occasionally written instructions. Work is reviewed in detail with guidance given. May give limited technical guidance to junior professionals or technicians working on a common project. Usual qualifications include a university degree in engineering with a minimum of 2 years' related experience. The candidate will usually obtain their license through the course of this work and from then on, they will seal their work as a professional engineer. This candidate may also work independently on less complex projects.

Benchmark Job	Survey Code	Generic Description
Engineer C	510.780.340	Incumbent is responsible for varied engineering assignments requiring a broad knowledge of an engineering specialty and the effect the work has upon other fields. Solves problems using a combination of standard or modified procedures. Participates in planning objectives. Performs independent studies, and analyzes, interprets and draws own conclusions; more complex work projects are referred to more senior authorities. Not supervised in detail except on more difficult assignments. May give periodic technical guidance to less experienced professionals or technicians assigned to work on a common project. Typical qualifications include a university degree in engineering with a minimum of 4 years' related experience.
Engineer D	510.780.330	This is the first level of full engineering specialization and is considered the senior level position. Alternatively may be the level at which an individual acts as group leader or work task force leader of a small group of technical personnel. Requires application of well developed technical knowledge in planning, conducting and coordinating difficult assignments. The position requires the modification of established guidelines and initiation of new approaches. Makes independent decisions in planning, organizing and completing technical assignments. Work is reviewed for soundness of judgement but accepted technically as accurate and feasible. Work is assigned in terms of objectives and priorities but informed guidance is available. Advises on technical problems and supervision, and may plan, schedule and review work of professional engineers and technicians. Incumbent must have an engineering license. The candidate will seal all their work and may also seal the work of junior staff who work under their supervision where the junior staff do not yet have their license. This candidate may be asked to be a Subject Matter Expert when reviewing outsourced work.
Engineer E	510.780.320	May have responsibility for coordinating engineering work assignments and making recommendations on technical applications developed by other professional personnel or consultants. May involve the direct supervision of a group of professionals. Provides guidance and training to less experienced staff. Checks work for accuracy and completeness. As a specialist, conducts special, complex and advanced level studies. Work is generally reviewed for results only. Makes independent decisions within broad guidelines and policies. Incumbent must have an engineering license. The candidate will seal all their work and may also seal the work of junior staff who work under their supervision where the junior staff do not yet have their license. This candidate may be asked to be a Subject Matter Expert when reviewing outsourced work.
Engineer F	510.780.310	Incumbent is considered an authority in an engineering field of specialization and acts as a technical consultant to the organization. This level is a dual-stream first level managerial position. Incumbents may be responsible for directing a staff of professional and support employees or act as a technical specialist. Responsible for planning and directing large engineering programs/projects; sets priorities and allocates resources; makes necessary decisions on all day-to-day operating matters within constraints of company policy. Receives work in terms of broad objectives. Usual qualifications include over 15 years experience.
Engineering Technician	999.999.001	Perform technical support work for the Distribution: such as monitoring the performance of the distribution. Negotiate property settlements on distribution/transmission lines and perform joint use activities. Provide administrative support related to preparation of estimates and work orders (WO) work schedules, line layouts, joint use, provision of underground cable and fault location service. Perform staking activities and prepare design packages for new connections, service upgrades, extensions, betterments and relocations.
Estimator/Scheduler	510.330.320	Supervise and direct the work operations of a group engaged in the preparation of capital construction projects, release and study estimates and schedules, construction cost estimates and cost reporting systems.

Benchmark Job	Survey Code	Generic Description
Financial Director	210.100.130	Responsible for providing overall direction for tax, insurance, budget, credit and treasury functions for the organization. Provide short to medium term direction for all corporate financial functions so that financial transactions, policies, and procedures meet the organization's short and medium-term business objectives and are conducted in accordance with regulations, and standards. Activities may include: credit control; cash flow; investment management; tax; insurance; treasury; internal audit; budgeting and forecasting; and foreign exchange. Lead, direct, evaluate, and develop a team of senior managers to ensure that the organization's financial strategy is implemented effectively, consistently and according to established guidelines.
Fleet Mechanic	999.999.011	Regional Field Mechanic is responsible for the scheduled inspection, repair and maintenance, as well as emergency repair of Transport and Work Equipment (e.g. on and off-road tracked bucket machines, digger derricks, cranes, Manlifts, forklifts, backhoes, muskeg tractors, excavators, highway tractors, floats, trailers, pullers/tensioners, vans/pick-up trucks), and the hydraulic equipment on the vehicles (e.g. booms, buckets). Job duties also include maintaining inspection schedules and coordinating/scheduling repairs to be completed or contracted out. Work is performed in a garage &/or on site.
Heavy Equipment Operator	708.729.400	Equipment Operators are operators of heavy earth moving construction equipment such as bulldozers, front-end loaders, forklifts, excavator's backhoes, tension pulling machines, equipment for pole hold drilling and Hydro Vac excavation trucks etc. Generally assist both lines and stations crews. Under lines construction often operate and drive various types of cranes and boom trucks and must hold and maintain the required license(s) such as AZ, 339C, 339A based on the equipment being operated/driven. Operating Engineers/Heavy Duty Mechanics are trained to repair and maintain many types of heavy equipment.
Human Resource Manager / Consultant	120.100.220	This position supports the planning, design, development, implementation and administers policies and programs through functional supervision in all or some of the following areas: employee relations, executive compensation, wage and salary administration, job evaluation, performance management, recruitment and selection and employment equity/human rights.
Labourer	700.792.431	Performs general labour work & assists other construction trades as required. The work involves material handling; hand excavation/backfill; operating equipment; demolition of structures including jack hammering to break up concrete; operating small tools; intermittent tractor/forklift/Bobcat operation; janitorial tasks, flagging, traffic control, equipment monitoring; assisting with formwork, scaffold erection/dismantling; and other miscellaneous labour related tasks as required.
Lineman - Journeyman	920.788.410	Responsible for the installation, maintenance, removal, and inspection of transmission/distribution power lines. Requires 4 years of experience and certification as a Power Line Technician (or equivalent), with 4 years experience/8000 hours, and is red seal certified. Entails on-call work and working at 300 feet, interacting with customers and the public.
Lines Apprentice	999.999.113	A four year apprenticeship leading to a Power Line Technician position.
Manager of Construction	708.100.220	Responsible for providing construction management and supervision within the construction group. Administers construction contracts. Is accountable for construction costs, schedules, safety, product quality and environment performance. Provides input into Project Execution Plans and the associated schedules and estimates. Usual qualifications include 10 to 12 years of experience including supervisory experience. Requires experience in construction management and supervision of various trades.
Operations Manager	700.793.240	Manage and supervise trade, technical and clerical staff. Develop work programs, organize schedules, provide instructions, guidance and checks, monitor work to ensure work quality and accuracy and in conformity to governing regulations. Ensure the administration of procedures, applicable legislation and collective agreements are met. Administer and control contract work. Review work methods, ensure appropriate training. Develops, maintains and enhance customer relationships through direct contact both internally and externally. This position is non-represented. Areas of accountability could be managing staff responsible for operating transmission or distribution systems, the execution of protection, control and station maintenance work programs or managing staff responsible for electrical services such as new connections/upgrades, trouble call/storm restoration or forestry work programs.
Protection and Control Technician	999.999.004	Perform initial inspections, conduct trouble-shooting and preventative maintenance, carry out modifications and repairs as required, on all types of protection, telecommunications, metering and control equipment which comes under Protection and Control (P&C) jurisdiction. Discuss and review results with supervisor, if the equipment is highly critical from the standpoint of system operation, before putting the equipment into service.

Benchmark Job	Survey Code	Generic Description
Regional Maintainer - Electrical	999.999.007	Responsible for the general maintenance and repair work on electrical systems and equipment at various geographical locations. Requires overhauling, maintaining and inspecting equipment such as conductors & insulators i.e. batteries, station bus, cable, compressed air systems, fire protection equipment switchgear i.e. circuit breakers, load interrupters metalclad switchgear, oil circuit breakers, SF6 breakers, air blast breakers, transformers, rotating machines, distribution stations & equipment. Has the necessary knowledge of the trade theory, operating principles, charts, tables, testing equipment and other reference works, to test, dismantle, repair, clean and assemble station electrical equipment within the required specifications. Requires certification as a construction and maintenance electrician (309A, 2200 hours). Also performs mechanical and protection and control work.
Regional Maintainer - Lines	999.999.006	Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Understands and is able to operate the tools of his/her trade, and is familiar with the various instruments, i.e. voltmeters, ammeters and ohmmeters. Must be familiar with hydraulically-operated articulated or telescopic aerial devices. Must provide at own expense any tools listed for the classification if required in his/her work in accordance with the attached tool list. This classification also includes the requirement to hold a Power Line Technician certification (or equivalent), with 4 years experience/8000 hours, and is red seal certified. Entails on-call work and working at 300 feet, interacting with customers and the public. The job will assume Lead Hand duties, as required.
Regional Maintainer - Lines (Supervisory)	999.999.008	This position is responsible for the safety, quality and quantity of the work performed by his/her crew (three or more Regional Maintainers-Lines/Linespersons). They plan work including staffing requirements, assigning work, co-ordinate work with other work groups, ensure proper work practices are followed, report on work performed and engage in good public relations. He/she performs the following physical work activities. Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Also responsible for contract monitoring and lead hand responsibilities.
Regulatory Director	110.200.130	Executive with primary responsibility for preparing, managing, and leading company's testimony in utilities rate cases before local, regional or federal agencies. Responsibilities include development of all research associated with regulatory activities including activity across other regulatory entities and maintaining relationship with all regulators. Develops cost factors in association with utilities rate cases, may or may not, be involved in delivery of testimony. Typically reports to a Top Legal Executive, Chief Operations Officer or a Top Utilities Executive.
Senior Legal Counsel	115.100.340	Responsible for providing management and employees with advice on a broad range of moderately complex conflicting legal principles. The applicable laws and regulations are numerous and varied, and present difficult problems of interpretation. Applies independent judgement in recommending a course of action for a client department, providing input as to the ramifications of a course of action, a legal decision, or a new piece of legislation. Usual qualifications include a law degree, membership in a law society/bar association and/or other relevant jurisdiction with a minimum of 8 year's related experience.
Senior Protection and Control Supervisor	999.999.005	Provide advice and guidance to field and support groups on matters related to the work programs such as protection, instrumentation, control and telecommunications pertaining to the protection, operations, control and maintenance of the electrical power system. Also may participate in the development of standards and procedures. Minimum of 8 years experience. Supervise staff engaged in the inspection and testing of electrical equipment to verify the equipment meets specified requirements and regulations.
Stock Keeper	999.999.009	Receives, receipts, stores, inventories, issues and ships materiel used in operations. Manages materiel, in accordance with established practices and regulations. Is responsible for materiel under his/her control. Performs maintenance, not requiring formal trades qualifications, and assists in tasks where unskilled or semi-skilled ability is required. Operates transport and work equipment.

APPENDIX C

Detailed Compensation Benchmarking Methodology

Summarized in this appendix are supporting descriptions of how Mercer determined values for each of the major components of compensation. Specifically:

Base Salary/Wage – Annual base salary at October 1, 2020. If an hourly rate was reported, Mercer annualized the value by multiplying the standard number of hours per week by 52 weeks per year. If a weekly rate was reported, Mercer annualized the value by multiplying by 52 weeks per year.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive or bonus paid.

Benefits and Pensions – To value benefit and pension programs, Mercer applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans. See detailed methodology below.

Total Compensation - Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., share grants, long-term cash, expected value of stock options or share awards) and pensions and benefits.

Detailed Benefits and Pension Methodology – Total remuneration includes the following values for benefits and pensions:

- Mercer's relative value process applies a broad set of standard cost factors, plus actuarial and demographic assumptions to measure all of the financially significant features of benefit programs on a benefit line basis.
- Effectively, this process isolates the plan design and removes variable factors such as historical experience, demographics, and utilization trends specific to each participant in the study. For example, if two survey participants have an identical benefit offering, the values will be equal regardless of the actual plan costs to each of the employers.

Aligning Values with Hydro One's Actual Costs

Participation & Anti-Selection:

Active Flex Benefits:

- Participation: Mercer uses a standardized set of participation assumptions for all participants that vary only by the number of options that are offered under the plan. Therefore, two identical flex programs will produce similar relative Total Values.
- Anti-Selection: A unique feature of flex plans is that employees who choose richer options are likely to be higher claimers than those choosing poorer options. This is reflected within our methodology by increasing the value of the richer options and reducing the value of the poorer options. The final relative values of the flex plan are a weighted average of the values of each of the options.
- Optional plans that are fully employee-paid (such as optional life) are excluded from the review.
- Low value core plans / catastrophic core plans and spousal top-up plans are excluded from the valuation.

Projection Methodology for Pension Plans

Defined Benefit Plans

- For defined benefit plans, the expected present value of future pension accruals is calculated using the retirement and termination scales for each company's plan design at various earnings levels using a common sample employee demographic (age and years of service). The future value of pension accruals were converted into company provided values by deducting any required employee contributions under each plan. The resulting company provided values were expressed as a percentage of earnings to be applied to the earnings associated with each benchmark job.

Defined Contribution Plans

- For defined contribution benefit plans, the company provided value was set equal to the company contributions.
- Where employees are entitled to choose the level of their contributions, employees were assumed to contribute at the level that would maximize company contributions.

Projection Methodology for Post-Retirement Non-Pension ("PRNP")

Employee-specific factors including earnings and service are projected to each of the assumed retirement ages at which point the benefit payable is determined, actuarially valued and discounted with interest to the current age of the employee. The resulting values are split pro-rata on service into the benefit in respect of past service and the benefit in respect of future service, and the future service benefit value is converted to a level percentage of future pensionable earnings.

- The results are weighted by the assumed retirement rates and combined to produce a single value of future benefit accruals, as a percentage of future earnings, per member.
- Benefits are projected both before and after retirement based on benefit-specific (e.g. medical, dental) inflation assumptions.
- Benefits are coordinated with provincial medical and drug plans.
- Lifetime maximums are reflected where applicable.

Flex Premium Cost Sharing & Credit Allocation:

- Cost sharing is determined using each participant's actual price tag and credit formula.
- Assumptions are made as to where credits would commonly be used, unless they are allocated to specific benefits. These assumptions coordinate with the standardized participation assumptions outlined earlier.

Standard Demographic Assumptions:

- A common population reflecting the general demographics of a Canadian workforce group and adjusted to more closely mirror Hydro One's workforce is used in the analysis.
  - This population reflects a group of employees with an average age of 41 and average service of 12 years.
- For Pension and Post Retirement Non-Pension benefits, the retirement scale for the population is as follows:
  - 25% retirement at age 55
  - 55% retirement at age 60
  - 100% retirement at age 65
  - 70% of the active members are assumed to be married over their career while 90% of members are assumed to be married at the time of their retirement

Other Actuarial Assumptions:

- The following assumptions were used in the review:
  - Discount rate: 5.00% per annum
  - Inflation: 2.00% per annum
  - YMPE Increase: 3.00% per annum
  - Salary Increase: 4.00% per annum
  - Post Retirement mortality: 95% of CPM 2014 Private Sector Mortality projected with CPM-B Scale
  - Termination rates of 1% each year prior to age 55 (for pension values)
  - Medical and Dental inflation/utilization increases

welcome to brighter

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Iain Morris
Senior Client Advisor

About

- Iain Morris is a Senior Client Advisor within Mercer's Career business in Toronto which includes Mercer's Rewards, Organizations Change and Communications practices, amongst others. Iain consults to many of Canada's leading organizations with a focus on total rewards strategy and the design and implementation of performance-linked compensation systems.

Experience

- Iain's primary areas of expertise include incentive plan design, total rewards cost benchmarking, global job levelling and EVP consulting. He also has substantial experience in rewards compliance. Iain has worked with organizations in a wide variety of industries including: utilities, financial services, manufacturing, professional services and consumer products.

Education

- He joined Mercer in 1995 after a number of years with another major global rewards consulting firm. Iain is a graduate of Queen's University. He has been frequently quoted in industry and business publications on total rewards and other human resources issues.

Mercer

Appendix 2-K
Employee Costs

Total FTE Levels

Staff	Transmission 2018 Actual FTEs	2019 Actual FTEs	2020 Actual FTEs	2021 Budget FTEs	2022 Plan FTEs	2023 Plan FTEs	2024 Plan FTEs	2025 Plan FTEs	2026 Plan FTEs	2027 Plan FTEs	Distribution 2018 Actual FTEs	2019 Actual FTEs	2020 Actual FTEs	2021 Budget FTEs	2022 Plan FTEs	2023 Plan FTEs	2024 Plan FTEs	2025 Plan FTEs	2026 Plan FTEs	2027 Plan FTEs
Headcount (Year-end)																				
Regular - MGT/non-represented	na	303	322	358	376	379	376	376	377	377	na	302	324	363	382	384	382	382	383	383
Regular - Society	na	826	834	967	1,025	1,031	1,033	1,033	1,051	1,071	na	583	621	713	751	754	755	763	771	775
Regular - PWU	na	1,054	1,079	1,079	1,100	1,087	1,080	1,073	1,055	1,037	na	2,429	2,471	2,570	2,592	2,595	2,585	2,589	2,593	2,582
Temporary - MGT/non-represented	na	8	13	10	8	7	6	6	6	6	na	10	18	6	4	3	3	3	3	3
Temporary - Society	na	19	14	17	9	10	10	9	9	9	na	17	17	15	15	16	16	15	15	15
Temporary - PWU	na	51	49	60	57	57	57	57	57	57	na	35	35	55	55	55	55	55	55	55
Casual Trades	na	1,477	1,575	1,560	1,549	1,616	1,622	1,627	1,632	1,633	na	595	381	408	384	391	392	422	468	437
Total	**na**	**3,739**	**3,885**	**4,052**	**4,123**	**4,186**	**4,183**	**4,181**	**4,187**	**4,190**	**na**	**3,972**	**3,867**	**4,128**	**4,182**	**4,199**	**4,188**	**4,229**	**4,288**	**4,251**
FTE (Average month-end)																				
Regular - MGT/non-represented	290	295	313	347	365	368	365	365	366	366	348	295	311	348	367	369	367	367	369	369
Regular - Society	607	823	830	963	1,020	1,025	1,028	1,028	1,046	1,066	730	582	605	694	732	735	736	743	751	755
Regular - PWU	1,602	1,065	1,091	1,090	1,112	1,099	1,092	1,085	1,067	1,048	1,925	2,463	2,507	2,608	2,630	2,633	2,623	2,627	2,630	2,620
Temporary - MGT/non-represented	na	9	10	8	6	6	5	5	5	5	na	10	14	4	3	3	3	3	3	3
Temporary - Society	na	19	16	20	10	11	11	11	11	11	na	17	17	14	14	16	16	15	15	15
Temporary - PWU	na	68	53	65	61	61	61	61	61	61	na	70	39	61	61	61	61	61	61	61
Casual Trades	1,748	1,749	1,672	1,656	1,643	1,715	1,722	1,726	1,731	1,732	1,179	1,049	987	1,056	996	1,014	1,016	1,094	1,211	1,132
Total	**4,247**	**4,028**	**3,983**	**4,149**	**4,218**	**4,285**	**4,283**	**4,281**	**4,287**	**4,290**	**4,182**	**4,486**	**4,481**	**4,787**	**4,803**	**4,830**	**4,821**	**4,909**	**5,040**	**4,954**

Staff	Shareholder Allocated 2018 Actual FTEs	2019 Actual FTEs	2020 Actual FTEs	2021 Budget FTEs	2022 Plan FTEs	2023 Plan FTEs	2024 Plan FTEs	2025 Plan FTEs	2026 Plan FTEs	2027 Plan FTEs	Total Transmission + Distribution + Shareholder Allocated 2018 Actual FTEs	2019 Actual FTEs	2020 Actual FTEs	2021 Budget FTEs	2022 Plan FTEs	2023 Plan FTEs	2024 Plan FTEs	2025 Plan FTEs	2026 Plan FTEs	2027 Plan FTEs
FTE (Average month-end)	na	51	45	54	57	57	56	56	56	56	na	8,564	8,509	8,990	9,077	9,171	9,160	9,247	9,383	9,299

Breakdown of Compensation by Type of Pay

Salary & Incentive Pay	Transmission 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M	Distribution 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M
Base Pay																				
Regular - MGT/non-represented	38,863	37,364	40,158	44,609	47,248	48,515	49,066	50,047	51,267	52,292	46,685	36,949	38,805	44,280	47,088	48,276	48,961	49,940	51,155	52,178
Regular - Society	70,250	91,654	96,096	110,132	118,803	121,866	124,589	127,111	131,951	137,216	84,389	64,328	66,986	78,917	84,817	86,882	88,693	91,393	94,197	96,613
Regular - PWU	154,997	105,831	108,875	105,151	109,301	110,048	111,487	112,984	113,059	113,020	186,192	227,338	235,143	236,857	243,966	248,899	252,927	258,574	264,524	268,672
Temporary - MGT/non-represented	839	756	779	735	606	578	466	475	485	494	1,008	773	951	335	243	207	207	212	216	220
Temporary - Society	1,118	1,644	1,458	1,790	994	1,104	1,126	1,103	1,125	1,147	1,343	1,384	1,426	1,240	1,264	1,392	1,420	1,404	1,432	1,460
Temporary - PWU	4,887	4,758	3,361	4,236	4,082	4,164	4,247	4,332	4,419	4,507	5,871	4,600	2,554	3,956	4,041	4,122	4,204	4,288	4,374	4,461
Casual Trades	126,692	121,261	117,776	133,067	134,487	143,336	146,743	150,078	153,499	156,655	78,325	66,067	62,592	73,173	70,245	72,194	73,466	78,352	88,111	86,454
Total	**397,646**	**363,268**	**368,503**	**399,719**	**415,522**	**429,611**	**437,724**	**446,131**	**455,805**	**465,332**	**403,812**	**401,440**	**408,457**	**438,757**	**451,664**	**461,971**	**469,878**	**484,163**	**504,009**	**510,059**
Overtime																				
Regular - Society		4,939	4,682	5,644	6,088	6,245	6,384	6,514	6,762	7,031		4,183	4,946	5,487	5,897	6,041	6,166	6,354	6,549	6,717
Regular - PWU	46,991	16,998	17,964	17,123	17,798	17,920	18,154	18,398	18,410	18,404	31,327	50,650	58,019	55,655	57,325	58,484	59,431	60,758	62,156	63,130
Temporary - Society	na	17	37	31	17	19	19	19	19	20	na	13	18	14	14	15	16	16	16	16
Temporary - PWU	na	87	61	77	74	76	77	79	80	82	na	98	54	84	86	87	89	91	93	95
Casual Trades	18,689	16,447	18,331	19,360	19,567	20,854	21,350	21,835	22,333	22,792	12,459	9,622	11,026	11,743	11,274	11,586	11,791	12,575	14,141	13,875
Total	**71,621**	**38,487**	**41,074**	**42,234**	**43,544**	**45,114**	**45,985**	**46,844**	**47,604**	**48,329**	**47,748**	**64,567**	**74,064**	**72,982**	**74,595**	**76,214**	**77,493**	**79,793**	**82,954**	**83,833**
Performance Dollars																				
Regular - MGT/non-represented		7,766	5,944	9,048	9,683	10,175	10,357	10,564	10,808	11,024		7,588	5,749	8,831	9,491	9,938	10,129	10,331	10,570	10,782
Total	**10,028**	**7,766**	**5,944**	**9,048**	**9,683**	**10,175**	**10,357**	**10,564**	**10,808**	**11,024**	**12,330**	**7,588**	**5,749**	**8,831**	**9,491**	**9,938**	**10,129**	**10,331**	**10,570**	**10,782**
Share Grants																				
Regular - Society	1,243	1,763	1,780	1,382	1,423	1,386	1,361	1,328	1,304	1,304	1,437	984	903	997	1,022	993	974	960	936	924
Regular - PWU	3,382	2,282	2,340	1,771	1,745	1,675	1,628	1,559	1,465	1,412	3,908	4,163	3,742	4,234	4,127	4,014	3,913	3,773	3,611	3,528
Total	**4,625**	**4,044**	**4,120**	**3,152**	**3,168**	**3,061**	**2,989**	**2,887**	**2,768**	**2,716**	**5,345**	**5,147**	**4,646**	**5,231**	**5,148**	**5,008**	**4,887**	**4,733**	**4,547**	**4,452**
ESOP																				
Regular - MGT/non-represented	541	790	848	797	844	867	877	894	916	934	677	668	685	791	841	863	875	892	914	932
Regular - Society	NotInc	36	138	129	137	141	142	145	149	152	NotInc	31	122	141	150	154	156	159	163	166
Total	**541**	**826**	**986**	**926**	**981**	**1,008**	**1,019**	**1,039**	**1,065**	**1,086**	**677**	**699**	**807**	**932**	**991**	**1,016**	**1,031**	**1,051**	**1,077**	**1,098**
Pension *(included in Burdens)*		***35,476***	***33,500***	***31,652***	***48,386***	***46,137***	***47,881***	***47,891***	***48,590***	***51,621***		***36,549***	***34,540***	***39,405***	***56,405***	***61,125***	***62,612***	***63,149***	***65,010***	***66,789***
OPEB *(included in Burdens)*	***55,800***	***58,661***	***62,925***	***52,138***	***57,713***	***56,019***	***58,516***	***60,384***	***62,060***	***65,441***	***58,200***	***60,568***	***67,840***	***68,490***	***70,859***	***77,798***	***80,099***	***83,204***	***86,614***	***88,249***
Burdens																				
Regular - MGT/non-represented	15,691	17,590	18,906	21,001	25,504	26,919	27,793	28,561	29,532	30,608	20,045	17,382	18,255	20,831	25,401	26,771	27,717	28,483	29,450	30,522
Regular - Society	30,163	39,524	41,439	47,492	58,888	62,067	64,749	66,541	69,727	73,690	36,233	27,740	28,886	34,031	42,042	44,249	46,093	47,843	49,777	51,885
Regular - PWU	66,549	45,637	46,950	45,344	54,178	56,048	57,940	59,146	59,744	60,696	79,943	98,034	101,400	102,139	120,928	126,765	131,446	135,361	139,783	144,287
Temporary - MGT/non-represented	na	51	52	49	42	42	35	37	38	39	na	52	64	23	17	15	16	16	17	17
Temporary - Society	na	111	98	120	68	80	85	85	88	90	na	93	96	83	87	100	108	109	112	114
Temporary - PWU	na	320	226	285	280	300	322	336	345	353	na	309	172	266	277	297	319	332	341	349
Casual Trades	52,726	45,569	48,259	54,524	55,287	59,424	61,388	63,027	64,543	65,909	30,356	42,583	39,029	45,627	43,896	45,365	46,441	49,656	55,887	54,857
Total		**148,801**	**155,929**	**168,815**	**194,246**	**204,879**	**212,312**	**217,733**	**224,016**	**231,384**		**186,193**	**187,902**	**202,999**	**232,648**	**243,562**	**252,139**	**261,801**	**275,366**	**282,032**

Total Compensation

	Transmission 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M	Distribution 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M
Regular - MGT/non-represented	65,123	63,510	65,856	75,455	83,279	86,476	88,092	90,066	92,523	94,858	79,737	62,588	63,495	74,733	82,822	85,847	87,682	89,647	92,089	94,414
Regular - Society	107,598	137,915	144,135	164,779	185,339	191,704	197,225	201,640	209,893	219,393	126,020	97,267	101,843	119,573	133,927	138,319	142,083	146,710	151,622	156,306
Regular - PWU	271,919	170,747	176,129	169,388	183,022	185,691	189,210	192,086	192,677	193,531	301,370	380,185	398,304	398,884	426,346	438,163	447,717	458,466	470,074	479,617
Temporary - MGT/non-represented	839	806	831	784	647	620	501	512	522	533	1,008	825	1,015	358	259	221	223	228	233	237
Temporary - Society	1,118	1,771	1,593	1,941	1,080	1,202	1,230	1,207	1,232	1,257	1,343	1,490	1,540	1,337	1,365	1,508	1,543	1,528	1,559	1,591
Temporary - PWU	4,887	5,164	3,647	4,598	4,437	4,540	4,647	4,746	4,844	4,942	5,871	5,007	2,780	4,305	4,404	4,506	4,612	4,711	4,808	4,905
Casual Trades	198,106	183,278	184,366	206,951	209,341	223,614	229,481	234,940	240,375	245,356	121,141	118,272	112,647	130,543	125,415	129,145	131,698	140,583	158,139	155,186
Total	**649,590**	**563,193**	**576,557**	**623,895**	**667,144**	**693,847**	**710,387**	**725,198**	**742,066**	**759,870**	**636,489**	**665,635**	**681,624**	**729,733**	**774,537**	**797,709**	**815,557**	**841,873**	**878,523**	**892,256**

Compensation & FTE by Capital and OM&A Program

	Transmission 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M	Distribution 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M
Total Capital Compensation	453,379	405,302	416,749	448,949	478,189	498,173	510,804	522,225	535,663	549,665	312,560	338,008	346,552	372,338	395,241	406,071	415,398	425,764	445,707	455,384
Total OM&A Compensation	196,210	157,890	159,809	174,946	188,955	195,674	199,582	202,974	206,403	210,205	323,929	327,626	335,072	357,394	379,296	391,638	400,159	416,108	432,816	436,871
Total Capital FTE	na	2,981	2,963	3,096	3,131	3,184	3,188	3,191	3,203	3,211	na	2,180	2,179	2,338	2,342	2,341	2,335	2,338	2,410	2,412
Total OM&A FTE	na	1,047	1,020	1,052	1,087	1,101	1,095	1,090	1,084	1,079	na	2,306	2,302	2,449	2,461	2,488	2,485	2,572	2,630	2,542

Total Compensation: Transmission + Distribution + Shareholder Allocated

Salary & Incentive Pay	Shareholder Allocated 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M	Total Transmission + Distribution + Shareholder Allocated 2018 Actual $M	2019 Actual $M	2020 Actual $M	2021 Budget $M	2022 Plan $M	2023 Plan $M	2024 Plan $M	2025 Plan $M	2026 Plan $M	2027 Plan $M
Base Pay	na	6,512	5,652	6,858	7,236	7,357	7,493	7,617	7,780	7,936	na	771,220	782,612	845,333	874,421	898,939	915,096	937,910	967,594	983,326
Overtime	na	69	102	43	44	41	40	40	41	41	na	103,123	115,240	115,260	118,184	121,368	123,518	126,677	130,599	132,203
Performance Dollars	na	1,621	679	2,131	2,248	2,360	2,418	2,466	2,518	2,568	na	16,975	12,373	20,010	21,422	22,473	22,903	23,361	23,896	24,374
Share Grants	na	47	34	35	38	36	35	34	33	32	na	9,238	8,799	8,418	8,354	8,105	7,912	7,654	7,348	7,200
ESOP	na	70	70	75	75	77	78	80	82	83	na	1,595	1,863	1,934	2,048	2,101	2,128	2,171	2,223	2,268
Burdens	na	3,020	2,621	3,180	3,842	4,022	4,182	4,285	4,418	4,579	na	338,015	346,453	374,995	430,735	452,463	468,634	483,819	503,800	517,994
Total Compensation	**13,113**	**11,339**	**9,158**	**12,322**	**13,483**	**13,893**	**14,248**	**14,522**	**14,871**	**15,240**	**1,299,192**	**1,240,166**	**1,267,340**	**1,365,949**	**1,455,164**	**1,505,449**	**1,540,192**	**1,581,593**	**1,635,460**	**1,667,365**

Compensation Table – Explanatory Notes

For this application, the following changes have been made to the table to improve the presentation of data and projected costs:

1. As directed by the OEB in the most recent Transmission application (EB-2019-0082), FTEs have been broken down by OM&A and Capital, and by Transmission and Distribution. Allocation is based primarily on direct assignment of FTEs. Using direct assignment to allocate FTEs and costs results in variances from previously filed cost and the FTE forecasts and actuals for the years 2019-2022.

2. The number and cost of FTEs allocated to shareholders (Shareholder Allocated) are also shown in the Compensation Table. They are indicated separately from Distribution and Transmission. Shareholder Allocated FTEs represent the portion of FTEs (and related costs) that are allocated to Hydro One's unregulated segments.

3. The historical overtime spend percentage for each organization was used to project future overtime costs based on the assumption of stable overtime usage. Hydro One used 2019 and 2020 actual overtime costs as a percentage of 2019 and 2020 actual base pay to calculate the percentage, which was then applied to the planned base pay costs for each year of the rate period. The increase in the planned cost of overtime for the years 2021-2027 shown in the Compensation Table is attributable to the gradual increase in base wages over this period.

4. The pension costs for the rate period are based on projected employer costs outlined in Exhibit E-07-01 (as well as the attachment to that exhibit, Exhibit E-07-01-02). The increases in years 2022 onwards reflect actuarial cost projections calculated in 2020, and are subject to change since they are based on: market conditions; funding position

of the pension fund; the level of base pension earnings; and the resulting required contribution rates used to compute monthly contributions.

5. The Compensation Table includes the following categories of compensation:
   - Burdens: Legislated (also known as Payroll) burdens, Pension, Other Post-Employment Benefits (OPEB) and Benefits
   - ESOP: Employment Share Ownership Program
   - Base Pay: base wages
   - Pensions: total actual and planned costs of Defined Benefit and Defined Contribution Plans for all employees (represented and non-represented) who are Distribution and Transmission allocated FTEs.
   - Performance dollars: Short Term & Long Incentive Program

FTEs & Compensation Costs - yearly % changes:

In Table 1 below, Hydro One provides a year-over-year analysis of the FTEs and compensation costs broken down by Capital and OMA, pursuant to the OEB’s direction in EB-2019-0082, as well as year-over-year analysis for total FTEs and total compensation of the Transmission and Distribution organizations. The forecast amounts are based on a compounded annual growth rate, given that base pay and associated burdens are anticipated to increase year-over-year. Years with minimal change to FTEs (+/- 0.5% change) will typically result in 1 to 3% increase in costs (to account for any negotiated adjustments to base wages, a standard inflation rate is used for planned year forecasts), assuming no revisions to burden policies or programs.

The variances over forecasted years are also a result of the changes to workforce levels and are impacted by the type (regular, casual) and the representation group of the FTEs that are increasing, decreasing or remaining flat in a given year.

Table 1 - Yearly Changes in FTEs and Compensation Costs

	2019 Actual	2020 Actual	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan	2027 Plan
Total Tx Capital FTE	**2,981**	**2,963**	**3,096**	**3,131**	**3,184**	**3,188**	**3,191**	**3,203**	**3,211**
YOY Change (Capital)		-0.6%	4.3%	1.1%	1.7%	0.1%	0.1%	0.4%	0.3%
Total Capital Compensation ($)	405,302	416,749	448,949	478,189	498,173	510,804	522,225	535,663	549,665
YOY Change (Capital)		2.7%	7.2%	6.1%	4.0%	2.5%	2.2%	2.5%	2.5%
Total Tx OM&A FTE	**1,047**	**1,020**	**1,052**	**1,087**	**1,101**	**1,095**	**1,090**	**1,084**	**1,079**
YOY Change (OM&A)		-2.6%	3.1%	3.2%	1.3%	-0.5%	-0.5%	-0.5%	-0.5%
Total OM&A Compensation ($)	157,890	159,809	174,946	188,955	195,674	199,582	202,974	206,403	210,205
YOY Change (OM&A)		1.2%	8.7%	7.4%	3.4%	2.0%	1.7%	1.7%	1.8%
Total Dx Capital FTE	**2,180**	**2,179**	**2,338**	**2,342**	**2,341**	**2,335**	**2,338**	**2,410**	**2,412**
YOY Change (Capital)		0.0%	6.8%	0.1%	0.0%	-0.3%	0.1%	3.0%	0.1%
Total Capital Compensation ($)	338,008	346,552	372,338	395,241	406,071	415,398	425,764	445,707	455,384
YOY Change (Capital)		2.5%	6.9%	5.8%	2.7%	2.2%	2.4%	4.5%	2.1%
Total Dx OM&A FTE	**2,306**	**2,302**	**2,449**	**2,461**	**2,488**	**2,485**	**2,572**	**2,630**	**2,542**
YOY Change (OM&A)		-0.2%	6.0%	0.5%	1.1%	-0.1%	3.4%	2.2%	-3.5%
Total OM&A Compensation ($)	327,626	335,072	357,394	379,296	391,638	400,159	416,108	432,816	436,871
YOY Change (OM&A)		2.2%	6.2%	5.8%	3.2%	2.1%	3.8%	3.9%	0.9%
	2019 Actual	**2020 Actual**	**2021 Budget**	**2022 Plan**	**2023 Plan**	**2024 Plan**	**2025 Plan**	**2026 Plan**	**2027 Plan**
Tx Total FTE	**4,028**	**3,983**	**4,149**	**4,218**	**4,285**	**4,283**	**4,281**	**4,287**	**4,290**
Tx Total Comp ($)	563,193	576,557	623,895	667,144	693,847	710,387	725,198	742,066	759,870
YOY Change FTE (%)		-1.1%	4.0%	1.6%	1.6%	-0.1%	0.0%	0.1%	0.1%
YOY Change Comp (%)		2.32%	7.59%	6.48%	3.85%	2.33%	2.04%	2.27%	2.34%
Dx Total FTE	**4,486**	**4,481**	**4,787**	**4,803**	**4,830**	**4,821**	**4,909**	**5,040**	**4,954**
Dx Total Comp ($)	665,635	681,624	729,733	774,537	797,709	815,557	841,873	878,523	892,256
YOY Change FTE (%)		-0.1%	6.4%	0.3%	0.6%	-0.2%	1.8%	2.6%	-1.7%
YOY Change Comp (%)		2.3%	6.6%	5.8%	2.9%	2.2%	3.1%	4.2%	1.5%

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2021 Team Scorecard

2021 Team Scorecard						
Corporate Goal	Component Weight	Measure & Definition	Sub Component Weight	Performance Levels		
				Threshold	Target	Exceeds
Health and Safety	20%	Serious Injuries and Fatalities*: *Incidents per 200,000 hours*	50%	0.168	0.107	0.091
		Recordable Incidents: *Incidents per 200,000 hours*	50%	1.040	0.923	0.849
Work Program	20%	Transmissions (Tx) Reliability – average length of unplanned interruptions to multi-circuit supplied delivery points (SAIDI): *Minutes per Delivery Point*	25%	8.0	7.7	5.3
		Distribution (Dx) Reliability – average length of outages in hours that a customer experiences (SAIDI): *Hours per Customer*	25%	6.8	6.1	5.0
		Tx In Service Additions - Delivery Accuracy: *Variance (%) to approved budget of $1,006M*	25%	+/- 5.0%	+/-2.0%	+/-1.0%
		Dx In Service Additions - Delivery Accuracy: *Variance (%) to approved budget of $700M (Dx Application)*	25%	+/- 3.0%	+/-2.0%	+/-1.0%
Productivity	10%	Productivity Savings: *in $M*	100%	$259.5	$305.3	$335.8
Financial	30%	Net Income to Common Shareholders: *in $M*	100%	Redacted		
Customer	20%	Residential and Small Business Customer Satisfaction: *Overall Favourable Impression*	100%	76%	85%	88%

** If the company has a fatality, the attained Serious Injuries & Fatality measure will be reduced to 0% based on the findings of the System Investigation.*

INSTITUT C.D. HOWE INSTITUTE

COMMENTARY
NO. 539

Time to Tweak or Re-boot? Assessing the Interest Arbitration Process in Canadian Industrial Relations

Under the current system, there appear to be few, if any, incentives for employers and unions to internalize the public interest in their negotiations process. There is, however, a direct public interest in such issues as ability to pay, the financial sustainability of the provision of public services and government debt loads.

Richard P. Chaykowski

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The Study In Brief

Interest arbitration, or third-party arbitration, is an essential element of the Canadian industrial relations system, with considerable impact on the public interest, particularly in relation to public-sector industries. As an instrument of labour relations policy, interest arbitration has become the primary alternative to costly work stoppages. By and large, most stakeholders appear to hold the view that the arbitration system functions fairly well, judged at least by the overall satisfaction of unions and employers.

As arbitration's significance in terms of usage and potential economic effect increases, however, several aspects are of concern. In particular, there are questions about (i) whether the design of the interest arbitration model – and, indeed, the broader system of interest arbitration – yields efficient and equitable labour relations and economic outcomes, (ii) whether the use of interest arbitration leads to higher wage outcomes than governments would otherwise pay, and (iii) whether, in crafting decisions, interest arbitrators apply criteria that serve the public interest.

This *Commentary* assesses the current state of the interest arbitration system, and shows that, regarding the overall question of what model and what features might best serve interest arbitration in Canada, there are four areas in which governments should undertake reviews and take steps to strengthen the system and its outcomes:

- introduce certain criteria that arbitrators should consider as serving the best interests of the public;
- identify the skills that mediators and interest arbitrators need, set competency standards and develop training to enhance skills;
- establish an independent roster of mediators and arbitrators; and
- assess the need to further strengthen the role of mediation and/or, more formally, follow a two-stage mediation-arbitration process.

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Interest arbitration, more commonly known as third-party arbitration, is an integral part of the contemporary Canadian labour relations system.

It has had a prominent role in resolving major disputes since the post-war system of collective bargaining was first established in the private sector – for example, for high-stakes disputes in the transportation sector. Interest arbitration became a much more prevalent alternative dispute mechanism once collective bargaining rights were established for employees in the broader public sector because of the potential effect of work stoppages on the delivery of services deemed essential to the public welfare.

Arbitration is now commonly used at the municipal, provincial and federal levels and across industries in the broader public sector. In the private sector, although it is less commonly relied upon, arbitration remains a significant feature of dispute resolution. In turn, arbitration settlements are influential because they may serve as guideposts in other contract negotiations that are settled.

Arbitration, as a form of dispute resolution, is widely used in a variety of workplace contexts, both unionized and nonunionized. In labour relations, arbitration is used to resolve disputes between employers and their employees (and their union) over the terms and conditions of employment as they relate to an existing collective agreement – referred to as rights arbitration. Arbitration is also used to resolve impasses in disputes over the substantive terms and conditions of employment that are normally determined through collective bargaining as the collective agreement expires – referred to as interest arbitration, the focus of this *Commentary*. (Hereafter, "arbitration" refers to interest arbitration.)

The significance of arbitration in industrial relations and, indeed, in terms of determining labour market outcomes – including wages – is amply exemplified by its use to resolve high-profile disputes in key sectors. For example, arbitration was used in 2017 to settle a dispute between Ontario colleges and the Ontario Public Service Employees Union, ending a strike that affected 12,000 employees across 24 colleges and disrupted the studies of approximately half a million students (see Kaplan 2017; Pelley 2017). In Ontario healthcare, negotiations between the province and the Ontario Medical Association (OMA) over compensation began in 2017 and, for the first time, the process included both mediation and binding arbitration in the event of an impasse.

The high stakes and public interest in resolving impasses in public-sector industries have also created incentives for governments to limit unions' right to strike and, in some instances, create a no-strike regime; in these cases, arbitration is a primary option. In other cases, governments have chosen to create a regime in which some portion of the bargaining unit is deemed "essential" and not permitted to strike, while allowing the remainder to strike, but often with little prospect of exerting economic leverage.

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Arbitration, as a mechanism to resolve disputes where strikes are seen as either too costly or not an option, has increasing appeal beyond the standard labour relations framework. The recent agreement between the Ontario government and the OMA to use arbitration as the final dispute resolution mechanism in their compensation negotiations brings arbitration to one of the most complex and, arguably, most high-stakes set of economic negotiations in the province. The approach to pay negotiations with physicians is notable because it has evolved over time without particular attention to the efficacy of the negotiating framework, including whether or not the recent move to experiment with arbitration is suitable. Yet, any outcome of the arbitration process likely will affect the public interest through the impact on healthcare costs across the entire Ontario health sector.

This set of negotiations is noteworthy, as well, because the OMA does not formally function as a trade union. Observing that an interest arbitration model continues to be applied to contexts where workers are not formally unionized – or might not even be employees – is not entirely surprising. In such cases, the immediate negative effect of a disruption of services on public health and safety can be perceived by the public to be especially high, creating the impetus to adopt a decisive resolution process such as arbitration (Adell, Grant, and Ponak 2001, 194) – even though it may not be in the public interest to do so.

Whether or not arbitration is the best approach to resolving disputes that are as complex – by virtue of the scope and complexity of the economic, social and political considerations – as health sector physician compensation is unclear, precisely because of the multidimensionality and breadth of the economic, social and political factors at play in these types of negotiations. This points to the need to assess carefully the limits to relying upon arbitration.

Several aspects of interest arbitration are of concern. There are questions about whether the design of the arbitration model and, indeed, the broader system of interest arbitration, yields efficient and equitable labour relations and economic outcomes, whether the use of arbitration leads to higher wage outcomes than governments would otherwise pay and whether, in crafting decisions, arbitrators apply criteria that serve the public interest.

There are many different potential models of how to conduct arbitration and many parameters that can shape the process as well as the outcomes, such as the scope of arbitrator decision-making, the criteria arbitrators take into consideration and how the process is conducted – for example, whether mediation processes are combined with arbitration or whether the arbitrator decides all outcomes. Regarding the overall question of what model and what features might best serve interest arbitration in Canada, there are four areas in which governments should support reviews (including research) with a view to strengthening the system and its outcomes.[1]

- To ensure that arbitration clearly serves the public interest, governments should consider updating the system by introducing certain criteria that arbitrators should consider – including the need to explain how each factor, whether judged relevant or not, was considered – and increasing the accountability of arbitrators by requiring that they explicitly consider and assess the submissions of the parties.

1 These conclusions are subject to the important caveat that the outcomes of ongoing jurisprudence could constrain the possibilities and choices regarding the arbitration model and process. For example, regarding the composition and use of rosters versus other practices for the appointment of arbitrators, in *C.U.P.E. v. Ontario (Minister of Labour)*, [2003] 1 SCR 539, 2003 SCC 29, the Supreme Court of Canada confirmed – in the particular context of the *Hospital Labour Disputes Arbitration Act* – that arbitrators should be impartial, have the requisite expertise and have "general acceptance in the labour relations community" (542).

- To ensure that, where required, third parties have the skill set to perform the roles of mediator and arbitrator and are accountable to the stakeholders in the industrial relations system, governments should support a review of the competencies and skills that mediators and interest arbitrators need, with a view to setting competency standards and developing (formal) training to enhance their skills.
- To minimize the systemic risk of the parties "capturing" arbitrators and of incentives to engage in the simple patterning of awards, as well as to maintain a degree of uncertainty in the system, governments should examine formally whether or not to establish an independent roster of mediators and arbitrators.
- Finally, governments should assess whether the arbitration system needs to be modified to further strengthen the role of mediation and/or more formally follow a two-stage mediation-arbitration (med-arb) process.

Trends in Arbitration as a Settlement Tool

Over the period between 2001 and 2014, among large bargaining units – agreements covering 500 or more employees – across Canada, 5.6 percent of settlements in the private sector and 7.9 percent of those in the public sector were determined by arbitration (Canada 2015). During this period, there were no discernable relationships between the size of the jurisdiction or unionization rates and the share of settlements determined through arbitration. Of course, the use of arbitration depends, in the first instance, on whether or not legislation provides for it. Across jurisdictions, usage of arbitration was highest in transportation, public administration, construction, education, health and social services – all industries in which certain work stoppages stand to have a significant effect on the economy or on public health and well-being.

It is instructive to examine the experience of Ontario, the Canadian jurisdiction with the largest number of arbitrated settlements. Considering the 2001–17 period across sectors, the percentage of settlements achieved through arbitration was higher between 2010 and 2017 than in the earlier period (Figure 1). Moreover, the share of arbitrated settlements and the percentage of employees affected by arbitration in Ontario over the 2001–17 period are quite higher in the (broader) public sector (Table 1). This is partly because arbitration is viewed as a somewhat indispensable alternative to strikes in broader public-sector industries that provide essential services, such as healthcare, policing or firefighting, or industries in which a wide segment of the public could be adversely affected by a prolonged work stoppage, such as education. Indeed, key industries are subject to compulsory arbitration.

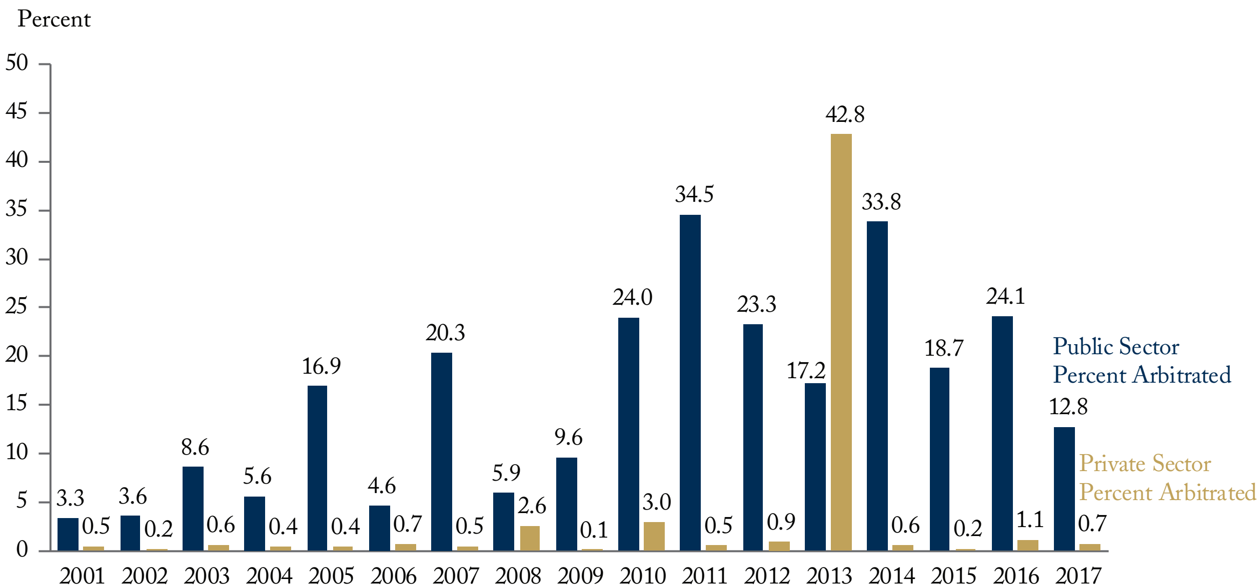
The Goals of Interest Arbitration

Beginning in the late 1960s, the federal government and the provinces enacted statutes granting public-sector workers – other than some municipal employees who were already covered by provincial labour relations acts – the right to bargain collectively. These statutes largely adopted the collective bargaining model used in the private sector. Many aspects of that private-sector model had straightforward implications in the public sector, but critical dissimilarities in the two sectors led to some incompatibilities, particularly with respect to the resolution of collective bargaining impasses.

Concerns with Public-Sector Strikes

Many governments have taken steps to prohibit or circumscribe the use of the strike in parts of the public sector because of two broad concerns. The first concern raised is the harm that public-sector strikes inflict on the public. In the private sector, the costs of a strike are primarily borne by the parties to the dispute. Those who want to obtain the goods or services provided by the parties to the dispute often have other available options. In the public

Figure 1: Proportion of Settlements Achieved through Interest Arbitration, Private and Public Sectors, Ontario, 2001–17



Notes: Data for 2017 cover only the period from January to August.
The result for the percentage of settlements arbitrated in the private sector for 2013 reflects the manner in which construction settlements were resolved in that particular year, with arbitration being applied across the construction sector.

Source: Data provided by the Ontario Ministry of Labour upon request.

sector, consumers of government services often do not have the option to obtain them elsewhere if government is their sole provider. This, it is argued, imposes greater costs on the public, which will have to cope without those services, or their availability at a diminished level, for the duration of the dispute. This concern is heightened if services are deemed essential, such as those in the area of public safety.

The second concern raised with public-sector strikes is that since such strikes might deprive the public of vital governmental services, government officials will feel immense public pressure to end the dispute by agreeing to the union's demands (Adell, Grant, and Ponak 2001; Wellington and Winter 1971). Even the threat of a strike might lead politicians, who depend on the public for their re-election, to capitulate to union demands in collective bargaining (see Malin 2013). This provides public-sector unions with immense bargaining power, the effect of which is the disproportionate allocation of public resources to the compensation and employment of public-sector workers. Further, to pay for the outsized settlements necessary to avoid public-sector work stoppages and maintain services, the level of taxes might need to be increased and those tax dollars increasingly (re) allocated to the compensation of unionized public-sector employees.

The question then becomes: do these concerns warrant the prohibition of strikes in the public sector?[2] With regard to the first concern, there are questions as to the severity of harm that is inflicted on the public through public-sector strikes, particularly depending on the type of workers involved (Malin 2013; Weiler 1980). For example, in their study of strikes involving nurses, municipal workers and transit workers, Adell, Grant, and Ponak (2001, 194) find that, generally, disputes involving these workers rarely immediately endangered public health and safety,[3] although they note that the prospect of such a dispute can provoke considerable public anxiety.

The second concern regarding excessive union power also has not substantially materialized (Keefe 2013). Although there was some initial support for the idea (see Edwards and Edwards 1982), recent empirical evidence for Canada is consistent with the argument that public-sector unions have been able to leverage wage premiums that are broadly comparable to those of their private-sector counterparts, even as their fringe benefits such as pensions, insurance and leaves are greater (see Gunderson 2010; Gunderson and Hyatt 2009; Keefe 2013; Thompson and Slinn 2013). Further, although estimates place a government wage premium of about 5–10 percent for public-sector workers over comparable private-sector workers, the premium varies for workers based on gender, the level of government and where the worker is situated in the occupational/wage distribution. In fact, some estimates show that there might be a wage penalty for certain workers in the public sector, including some managers and executives (Gunderson 2010; Mueller 1998, 2000).

Table 1: Proportion of Settlements Determined by Interest Arbitration, and Employees Covered, in Ontario, 2001-2017, by Sector

Sector	Share of All Settlements Determined through Arbitration	Share of Employees Covered under Arbitration Awards
	(*percent*)	
Private	5.5	4.4
Public	33.1	37.6
Total	9.7	12.5

Note: The 2017 data only include the period from January to August.

Source: Data provided by the Ontario Ministry of Labour upon request.

The use of interest arbitration as the primary substitute for the right to strike has been entrenched by the Supreme Court of Canada's decision in *Saskatchewan Federation of Labour v. Saskatchewan*. In this recent decision, the Court ruled that "the right to strike is an essential part of a meaningful collective bargaining process in our system of labour relations" and was, therefore,

2 Since one *raison d'être* of unions is to raise wages, and given that this necessarily involves the allocation of public resources to unionized public-sector employees – where there are alternative public uses for the resources and taxes might need to be raised – the policy issue is how to determine appropriate proportionality in limiting the application of strike activity.

3 Adell, Grant, and Ponak note that this outcome holds because "one or both of the parties will almost invariably take steps to ensure that a certain level of essential services is maintained" (2001, 188). Provision of essential services has been achieved, for example, through the use of "exempt" employees – that is, employees who are not permitted to be part of a bargaining unit, such as supervisors and certain professionals; and where a certain number of bargaining unit members are categorized as "designated" and therefore required to work in order to provide a minimal service level, while all others may engage in a work stoppage. This is not to suggest, however, that a risk of public harm does not exist; as examples, in transit and healthcare, in certain circumstances, the level of acceptable risk associated with a strike has been judged unacceptable (Adell, Grant, and Ponak 2001).

protected.[4] Although the Court did not preclude restrictions on the right to strike in certain circumstances, such as situations where essential services are provided, there must be some other meaningful dispute resolution mechanism – and interest arbitration has been and remains the "go to" mechanism used to "offset" limits on the right to strike (Chaykowski 2016, 498).

Labour Relations and the Policy Goals of Interest Arbitration

Industrial Peace

In the private sector, work stoppages impose costs on the parties that induce them to compromise to end the dispute. As well, the maintenance of industrial peace is generally equated with minimizing economic losses.

In the broader public sector, in contrast, the pre-eminent goal of a system of interest arbitration is the maintenance of the provision of essential services by ensuring industrial peace through avoiding strikes that are considered to pose too high a risk to the health and safety of the public. With regard to this goal, the use of compulsory arbitration, in lieu of the right to strike, does appear to reduce strike frequency when compared to other legal structures (Campolieti, Hebdon, and Dachis 2016; Currie and McConnell 1991, 1994).

If industrial peace is defined more broadly than simply work stoppages to include other types of job actions that can interrupt the delivery of essential services, then arbitration might not be as successful. Hebdon and Stern (1998) found that laws prohibiting strikes were associated with greater numbers of grievance filings and grievance arbitrations in Ontario's government and healthcare subsectors than was the case for other public-sector workers with the right to strike. While maintaining industrial peace, compulsory arbitration also might divert some of the conflict from the process of negotiating a collective agreement to its administration.

Voluntarism

One main tenet of the labour relations model found in Canada and the United States is voluntarism (see Chaykowski and Hickey 2013, 380–1), whereby labour law provides the framework within which the parties craft their own agreements voluntarily through direct negotiations. This is viewed as a positive policy objective because it is believed that the parties are more likely to adhere to the agreement if they craft the settlement themselves, rather than have it imposed upon them by a neutral third party. The superior outcome flows from the fact that the parties have a better understanding of their own needs and concerns, and can make more informed and, therefore, better compromises that advance their interests and that fit their circumstances than can someone external to the relationship (Farber and Katz 1979). In fact, the process of negotiations itself serves to reveal information about the priorities of the parties (Hicks 1966). Thus, having a third party impose an agreement might avoid a dispute, but it also might lead to a settlement that does not accord with the parties' expectations (Chaykowski et al. 2001).

The strike (or lockout), or the threat of one, is the main pressure tactic that forces the parties to make the compromises and tradeoffs necessary to achieve a settlement. Where strikes are prohibited, though, a good dispute resolution mechanism should encourage voluntary settlement; arbitration seeks to do this through the uncertainty over what the arbitrator's award will be. That is, the parties might be more willing to compromise in order to have a say in the terms of the final agreement, rather than assume the risk associated with having

4 *Saskatchewan Federation of Labour v. Saskatchewan*, 2015 SCC 4, [2015] 1 SCR 245, at para. 3.

the final agreement determined by an external party.[5] It is generally believed that steps to reduce the predictability of interest arbitration outcomes for the parties will further this goal of inducing voluntary settlement. With regard to this goal, current arbitration again appears to fall short, as compulsory arbitration legal structures have been shown to produce greater rates of impasse (fewer bargaining settlements) than do legal structures that specify other dispute resolution procedures as the terminal step (Anderson and Kochan 1977; Campolieti, Hebdon, and Dachis 2016; Currie 1989; Hebdon and Mazerolle 2003; Rose and Piczak 1996).

Procedural Justice

Procedural justice requires that the parties view the process of arbitration as being fair. Several factors can affect the perceptions of procedural fairness and, therefore, the legitimacy of arbitration:

- *Bias*: Arbitration might break down when the process is perceived to be either biased in favour of one side or unable to produce suitable outcomes (Adell, Grant, and Ponak 2001; Rose 2015). For example, the importance of the "general acceptance" of the arbitrator was highlighted in *C.U.P.E. v. Ontario (Minister of Labour)*, where the union challenged the legitimacy of arbitrator appointments on various grounds, including "apprehension of bias."[6]
- *Transparency*: A lack of transparency in the rationale for arbitration awards also might inhibit perceptions of procedural justice. Specifying the arbitral criteria that need to be considered in fashioning an award might increase transparency, but if the criteria are viewed as privileging one side over the other, this might reduce the acceptability of arbitration by the parties (Archibald 2003; Rose 2015).
- *Institutional differences*: The effectiveness of arbitration at providing procedural justice might be highly variable across jurisdictions or between even the parties to a bargaining relationship. To illustrate, Adell, Grant, and Ponak (2001) found that compulsory arbitration worked relatively well for nurses in the Ontario healthcare sector, but failed to prevent work stoppages among nurses in Alberta. The reason behind these divergent outcomes was the union's acceptance of the system in Ontario and its rejection in Alberta.

Balance

The policy goal of ensuring "balance" represents the principle that the interests of both parties to collective bargaining should be reflected in the process and outcome. In the private sector, the two main stakeholders are the employer and the union, and arbitration is required to ensure the interests of both are considered. In the broader public sector, however, the principle also includes the public interest.[7]

In replacing the right to strike, arbitration should strive to "safeguard employee interests" (Rose 2015). Similarly, it should also not overly disadvantage employers – for example, by restricting the employer's operational efficiency or by

5 Of course, differences in the degree of risk aversion between the parties would be expected to result in variations in the types and extent of any concessions that either side is prepared to make. For that reason, mechanisms that are designed to increase uncertainty might lead to different – but not necessarily better – outcomes where there is underlying asymmetry in risk aversion between the parties.

6 In particular, the decision noted: "In early 1998, the Minister appointed four retired judges to chair several arbitration boards.…The unions sought declarations that the Minister's actions denied natural justice and lacked institutional independence and impartiality"; see *C.U.P.E. v. Ontario (Minister of Labour)*, at 540–1.

7 In the private sector, there is a public interest in achieving lower strike activity, but cases, such as that of the rail industry, in which a private sector activity is deemed "essential" to the point where government imposes arbitration as an alternative to a strike – or legislates an end to a work stoppage – are quite unusual.

imposing labour costs that place the employer at a competitive disadvantage. Safeguarding the public interest is primarily associated with arbitration outcomes that do not, for example, place undue strain on public finances or burden the public with frequent work stoppages. What features of interest arbitration operate to advance the public interest?

Efficiency

The goal of efficiency requires that arbitration settle disputes quickly and at less cost than other systems of dispute resolution. With respect to costs, judging how well arbitration meets the goal of efficiency might depend on how costs are defined. If the focus is on dispute costs, as measured by the cost of arbitration hearings versus the cost of forgone wages in a strike (as a proxy for economic rent) and lost output, then compulsory arbitration does meet this goal, as the cost of strikes dwarfs that of arbitration, even when more disputes go to arbitration than lead to strikes.

However, although the lesser cost of arbitration is often highlighted as an advantage of the process, in the context of public-sector labour relations an arbitration regime might inhibit bargaining efficiency by slowing the speed of the process. Not only are compulsory arbitration regimes associated with higher rates of impasse or dispute, but arbitration hearings – with the requisite time and resources devoted to preparation, hearings, and the arbitrator's issuing of the award – are likely to take much longer than the average public-sector strike duration, over the 1978–2008 period, of 32.5 days (Campolieti, Hebdon, and Dachis 2016). Arbitration, therefore, appears to fulfill the goal of efficiency with respect to cost, but falls short when it comes to enhancing the time to produce a settlement.

Systems of Arbitration and the Use of Designation of Employees

A number of different types, or systems, of interest arbitration exist, some of which might accomplish the goals of arbitration more effectively than others.

Conventional Arbitration

In the predominant type of arbitration used in the settlement of interest disputes, known as conventional or traditional arbitration, the parties submit their proposals on each issue in dispute to the arbitrator, who is free to choose from either party's proposals or craft an original award. The flexibility afforded the arbitrator in this type of arbitration is one of its strengths. As noted above, however, using arbitration as a terminal step in a dispute resolution procedure results in higher rates of impasse. This is theorized to be due to the "chilling effect," whereby the belief of the parties that the arbitrator simply "splits the difference" between the two proposals inhibits concessions during the negotiations, since concessions will reduce the favourability of the award for the conceding party (Anderson and Kochan 1977). The chilling effect emanates from the perception of predictability in the creation of the arbitration award. The response to this shortcoming of arbitration has been to introduce more uncertainty into the process in order to elicit greater concessions.

Final Offer Arbitration

The best-known example of a modification to conventional arbitration in order to mitigate the chilling effect is final offer arbitration (FOA). This form of arbitration requires the arbitrator to select either of the "final offers" presented by the parties (see Feuille 1975; Stevens 1966). It is theorized that this will lead each of the parties to create more reasonable proposals in order to increase the likelihood that the arbitrator will select their final proposal/offer. FOA raises the stakes of going to arbitration because the parties risk losing on every issue if the arbitrator does not select their proposal. This heightened risk is expected to lead to greater concessionary behaviour and more voluntarily negotiated settlements. As well, it is possible to combine the conventional and FOA forms of arbitration such that, as is the case in Michigan, one is used to determine economic issues and the other is used for non-economic issues (Block 2013).[8] The evidence as to whether FOA is more successful than conventional arbitration at inducing more negotiated settlements is, however, mixed; see Devinatz and Budd (1997); Gunderson, Hebdon, and Hyatt (2009); Hebdon (1996).[9]

Conventional arbitration is used more often than FOA, perhaps, because there are many potential problems associated with FOA, including:

- the risk that the arbitrator will be forced to choose between two unreasonable proposals;
- the possibility that FOA might be harmful to relationships, as only one party emerges the winner (Gunderson, Hebdon, and Hyatt 2009),[10] a win/lose scenario that might reduce the likelihood that the party whose proposal was not selected will adhere to the settlement;[11] and
- the risk that the parties might be less likely to submit proposals that include innovations, a problem that emanates from the adherence of arbitrators to the conservatism principle – that is, where arbitrators avoid conferring breakthroughs in their awards since they believe that fundamental changes to the bargaining relationship should come from the parties (Rootham 2017, 278). This aspect of arbitrator decision-making, which leads to criticisms that arbitration stifles innovation, is exacerbated in FOA, as parties will be less likely to submit proposals that include innovations since this might lead the arbitrator to select the other party's proposal (Malin 2013, 156).

Arbitration Boards/Panels and Hybrid Arbitration Systems

Either conventional arbitration or FOA may be undertaken with a board (or panel)[12] of three arbitrators or a single arbitrator. With a board, the

8 FOA may be practised on either a total-package or an issue-by-issue basis. However, the more discretion the arbitrator has, such as the ability to choose among issues rather than packages, the less the procedure moderates arbitration's chilling effect on negotiations.

9 Based largely upon research on the use of arbitration in policing and firefighting in the United States, Lipsky and Katz (2006, 267) conclude: "It appears, however, that final offer arbitration does provide a greater incentive for the parties to settle on their own than does conventional arbitration: arbitration usage rates are significantly lower in states with final offer arbitration than they are in states with conventional arbitration." See also Katz and Kochan (1988, 283–4).

10 The concern is that a damaged relationship might affect efficiency negatively. Mas (2006) investigates the performance of police in relation to FOS arbitration outcomes in a regime where the parties were required to engage in collective bargaining for a specified period and strikes were prohibited – if a settlement was not achieved, then FOS arbitration was imposed – and finds a negative efficiency outcome: "Police performance declines sharply when officers lose arbitrations" (785).

11 This outcome might be mitigated, however, through another variant of FOA known as "double FOA." Here, each of the parties submits two roughly equal final offers to the arbitrator, who then selects between the union and management proposals. The side not chosen then gets to select from the two proposals of the side chosen by the arbitrator. This process might help the "losing" party feel as though it had some say in the outcome, and thereby aid in the award's acceptance.

12 In Canada, the term "board" is common, and typically refers to a slate of three, with a neutral and one member representing each of the two parties. In the United States, the term "panel" is commonly used, and can refer to a slate that includes a neutral with one or more representatives from either party (a "tripartite panel") or three neutrals; see Katz and Kochan (1988, 280).

union and management typically each appoints a nominee who serves to advance its interests. The neutral chair of the board is selected by mutual agreement of the parties, or by the minister of labour or the Labour Relations Board in the event of disagreement;[13] the chair needs to be someone acceptable to both parties and is qualified to serve in that role (Rootham 2017, 277). A board might be preferred because nominees appointed by the parties might bring more relevant labour relations and arbitration experience to the process (Barnes and Kelley 1975); moreover, a board might encourage the bargaining process, particularly where the panel members negotiate the issues among themselves (Block 2013).

On the other hand, concerns about the use of a tripartite board or panel, rather than a single arbitrator, include the potential for greater direct costs as well as delays in rendering awards.[14] There is, however, a dearth of research that compares arbitration outcomes with a board to those under a single arbitrator; also insufficiently examined is the effect on outcomes of a board of appointed neutrals versus a board consisting of two nominees and a neutral chair.[15]

There are also "hybrid" types of arbitration that combine mediation with arbitration, the most common form being the aforementioned mediation-arbitration. In med-arb, the parties undertake mediation with the aim of achieving a voluntary agreement, but if they are unsuccessful within a given period, the parties then undertake arbitration.[16] The expectation is that the uncertainty surrounding the outcome of arbitration, if mediation fails, will facilitate the mediation stage of this process. Within this procedure, the roles of mediator and arbitrator may be performed by the same person (a one-stage med-arb) or two individuals (a two-stage med-arb).

Some analysts maintain that the information the individual obtains in the mediation phase of a one-stage med-arb could facilitate the individual's role in the arbitration phase (if necessary) by allowing the arbitrator to gain a deeper understanding of the cause of the impasse. Others argue that, if one person plays both roles, then the individual might receive confidential information in his or her role as mediator that would be inappropriate to use in his or her subsequent role as arbitrator. Thus, a chilling effect might take place insofar as the parties might not divulge certain information in the mediation phase for fear that it might be used against them in the arbitration phase in a one-stage med-arb (Campolieti and Riddell 2018; Devinatz and Budd 1997). Further, in a one-stage med-arb, the parties might be able to obtain information on the third party's thinking, which might reduce the uncertainty surrounding both the award and the incentive to bargain (Farber and Katz 1979). In Ontario, whether conducted formally or informally as a part of an arbitration process, some form of mediation is quite common. There is concern,

13 For example, under the *Ontario Police Services Act*, the neutral chair is selected by an arbitration commission.

14 Delays could arise, for example, because scheduling of three board members might take longer than for a single person. Banks, Chaykowski, and Slotsve (2019) find that tripartite boards are associated with longer delays in the arbitration of rights disputes.

15 Highlighting the differences in the process under the two types of panel composition, Lipsky and Katz (2006, 269) point out: "A tripartite panel consisting of an impartial chairperson and an arbitrator appointed by each of the party's function in a measurably different fashion from a panel consisting of three impartial arbitrators. The former more closely approximates the negotiation approach to interest arbitration and the latter the judicial approach."

16 In practice, experienced arbitrators typically attempt to settle as many issues as possible at the outset of an arbitration proceeding; although not formally a med-arb process, this approach is expected to have some of the same effect. Conciliation is also a feature of most Canadian statutes, but as well as adds time to the process, it is sometimes viewed as ineffective (see, for example, Campolieti and Riddell 2018, 19).

however, about whether one individual has the skill set to play both roles effectively in either of these hybrid processes.

Alternative Models for Dealing with Essential Services

Many jurisdictions have been moving away from compulsory arbitration for public-sector workers (outside of public safety) and toward a designation model with a limited right to strike. Under the designation model, the parties negotiate an essential services agreement that determines the type and number of workers that are chosen as essential. In Ontario, for example, this includes corrections officers (from 1994 to 2016),[17] provincial employees (since 1994) and paramedics (since 2000) (Dachis and Hebdon 2010, table A1). These workers must remain on the job in the event of a work stoppage to maintain a level of service that ensures public health and safety. In circumstances where the parties are in disagreement, an independent administrative agency, usually the jurisdiction's labour relations board, may issue an order determining the number of designated workers (Doorey 2017, 173; Rootham 2017, 273–4).

In their study of essential service strikes, Adell, Grant, and Ponak (2001) ultimately conclude that the designation model is better than either the no-strike/compulsory arbitration model or unrestricted strike model in maintaining essential services, inducing voluntary settlements and producing outcomes acceptable to both parties.[18] There are, however, some issues of concern with the essential services designation model. Campolieti, Hebdon, and Dachis (2016) find that this model is associated with reduced wages, while Adell, Grant, and Ponak (2001) suggest that it could increase both the frequency and duration of strikes. Strikes might occur more often as unions adapt to the model by substituting tactics such as rotating strikes or work-to-rule in place of a full strike. Thus, similar to the case of interest arbitration, the conflict could manifest itself in other ways if disputes that produced the impasse are not resolved. Strikes also might last longer since services would continue, albeit at a diminished level, which would lessen public pressure for the work stoppage to end. Despite such concerns, however, Campolieti, Hebdon, and Dachis (2016) find that the essential service designation model is not (statistically) associated with either a greater likelihood of strikes or the increased duration of strikes relative to the unrestricted strike model.

The most serious issue with the essential services designation model is the need to get the level of essential services that must be maintained "correct." As Adell, Grant, and Ponak (2001, 192) note, if the percentage of the bargaining unit that is designated is too low, a work stoppage is likely to result in a significant disruption of essential services that could adversely affect public health and safety, but if the percentage is set too high, the union essentially loses its ability to apply economic pressure to the employer through a strike. With respect to this need for balance, some have advocated that, if the percentage of the bargaining unit that is designated as essential is above a certain threshold – beyond which the union would be deprived of its bargaining

17 The *Ontario Crown Employees Collective Bargaining Act* was amended in 2016 to establish a separate bargaining unit for corrections officers; the parties are subject to interest arbitration to determine unresolved matters in dispute.

18 In Adell, Grant, and Ponak (2001), the only criterion on which the designation model falls short, compared to the other two models, is in the efficiency of collective bargaining, as the essential services agreement prolongs the negotiation by adding it to the issue mix.

power – then the employees should have access to arbitration (Weiler 1980).[19]

There is also concern about the tendency, over time, for employers in the broader public sector to ratchet up the proportion of employees designated as essential, presumably with the intention of ensuring the provision of an adequate level of essential services. This has had the side effect, however – one that favours the employer – of diminishing the effectiveness of strikes (Rose 2016). This outcome creates a grey area in which strikes are not prohibited, but nonetheless are rendered a hollow option. Such erosion of the efficacy of strikes runs counter to the protections the Supreme Court of Canada placed, in its decision in *Saskatchewan Federation of Labour v. Saskatchewan*, on the right to engage in strike activity or, in the absence of the right to strike, the right to interest arbitration (or a similarly meaningful mechanism). Even under a designation model, the Court's decision in that case suggests that reliance upon arbitration might increase.

Legislated Criteria for Arbitration Awards

In the Ontario broader public sector, legislation establishing the process of interest arbitration specifies a number of arbitral criteria, including ability to pay; the economic situation; the terms and conditions of employment for comparators; and the ability to attract/retain employees. These criteria reflect, variously, the interests of employers and employees (the union). From a labour relations policy perspective, arbitral criteria serve to guide arbitrators in crafting an award that supports the goals of achieving efficiency and a balance of interests. However, there is also a significant overarching public interest in the terms and conditions of public-sector collective agreements – and interest arbitration awards – including with respect to achieving the goals of procedural justice, balancing the parties' interests and supporting efficiency, as well as in the economic outcomes of the process.

Unlike those in some other jurisdictions, arbitrators in Ontario are instructed to consider these criteria only if they are deemed relevant. Further, the criteria are not intended to restrict the arbitrator's discretion – indeed, the legislation explicitly states that the section which enumerates the criteria does not affect the power of the arbitrator(s). Thus, how strictly an arbitrator adheres to these criteria depends on the arbitrator's assessment of their relevance. The criteria enumerated in legislation that have received the most attention are the terms and conditions of employment of comparison groups in the public and private sectors, and the employer's ability to pay in light of its fiscal situation.

Comparability

Theoretically, to achieve an outcome that provides the benefits associated with voluntarism, arbitrators should try to make a determination that best approximates the agreement that the parties would have produced in a system of free collective bargaining with the right to resort to economic sanction. Referred to as the replication principle, this presents a decisive difficulty in that it is an unobserved counterfactual. In practice, a guiding

19 In fact, this is the approach that Ontario has taken with its ambulance services collective bargaining legislation. Under the *Ambulance Services Collective Bargaining Act*, a party may apply to the Ontario Labour Relations Board for a declaration if it believes that the essential services agreement deprives the party of a meaningful right to strike/lockout. The board is restricted, however, from issuing a declaration if at least 75 percent of the bargaining unit is not designated as essential. This order could be that the portion of the bargaining unit containing ambulance workers be directed to final and binding arbitration.

principle in arbitrator decision-making is the notion of comparability; this principle involves making comparisons with the terms and conditions of other workers performing similar work, which is empirically possible to observe (Adams 1981).

In striving to approximate the outcome that would result from applying the replication principle, arbitrators may turn to the comparability principle to infer what the contract outcome might have been had it been settled by the parties; that is, as based upon the "market" rate for that type of public work – notionally, "external comparability," as established through the voluntary settlements of other workers (Rootham 2017; Slater 2013).[20] Application of the comparability principle is also consistent with achieving other objectives, such as satisfying the arbitral criterion concerning the ability of the public employer to attract and retain qualified employees, including from the private sector, or arbitral objectives regarding horizontal equity – that is, related to "internal" comparability.[21]

A couple of major shortcomings, however, are associated with the use of the comparability principle. First, the use of comparisons to justify awards could result in an overall patterning of awards – sometimes referred to as the "parasitic effect" of interest arbitration (Adams 1981). This effect arises when an arbitrator's award forms the basis for subsequent awards (or even voluntary settlements), where the lead award is not one that would have prevailed in a dispute resolution system based on the right to strike and might be divorced from the "market." There are also concerns that the parasitic effect could lead to wage escalation in the broader public sector (Chaykowski and Hickey 2012), especially where arbitrators fail to give appropriate weight to individual circumstances. The fact that wage escalation in the public sector does not appear to have outstripped that in the private sector in the decades since interest arbitration was first introduced might moderate this concern.

Second, many public-sector occupations do not have a natural comparator in the private sector. This might lead the arbitrator to use a variety of approaches to determine comparability when deciding an award (Slater 2013). These could include external comparability, where the characteristics of the bargaining unit or workers are compared to those of "similar" workers under a different employer (for example, a different municipality); internal comparability, where the terms and conditions of employment are compared across different types of workers under the same employer; or comparability in relation to previous collective agreements settled in the relationship.

Ability to Pay

Ability to pay is a critical criterion because it relates directly to an individual employer's financial viability and, where the employer is publicly funded, to government fiscal sustainability. Ability to pay is therefore directly related to the broader public interest. Arbitrators, however, have largely rejected meaningful consideration of the public employer's ability to pay, despite the enumeration of ability to pay in legislation. Arbitrators' refusal to apply this principle might be due to a number of reasons (Rose 2015, 178):

20 A fundamental challenge is that, in practice, employers would be expected to take the position that arbitrators ought to take into account terms and conditions of employment that prevail for comparable workers performing similar work in both the unionized and the non-unionized segments of their industry; in contrast, unions are expected to advocate for unionized comparator groups.

21 Slater (2013, 406) describes internal comparability: "For municipal employees, this usually means employees of other cities of a similar size, often within the same state. 'Internal' comparables involve arguably similar employees of the same employer. This issue is often labeled 'internal consistency.'"

- Arbitrators might view public employers' purported *inability* to pay as "unwillingness to pay," since governments can redirect budgetary funds from other expenditures, increase taxes or reduce certain service levels in order to offset labour costs. Thus, although governments might be unwilling to exercise these options, public-sector employees should not be expected to "subsidize" public services through inferior terms and conditions of employment.[22]
- Arbitrators might view the inclusion of this criterion in legislation as public officials simply seeking to avoid accountability associated with making hard decisions regarding raising taxes or curtailing service levels in order to support public-sector compensation levels.
- Arbitrators might perceive elevating the importance of the public employer's ability to pay as infringing upon their independence, leading employees/unions to view the arbitrator more as an instrument of government fiscal policy than as an impartial umpire with the ability to protect their interests.

The various Ontario statutes that govern the use of interest arbitration in public-sector labour relations do not currently require certain criteria to be applied and assigned definite relative weights in arbitral decision-making.[23] Some other governments in Canada and some US states, in contrast, have been willing to place greater restrictions on arbitral discretion in ways that advantage the employer in the process (Block 2013; Rose 2000, 2015). Available evidence suggests, however, that legislative changes in Canada to emphasize the ability-to-pay criterion have had no effect on the size of arbitrated wage settlements (Campolieti, Hebdon, and Dachis 2016). If the goal of increasing the emphasis on ability to pay was to reduce the size of settlements produced from arbitration, it appears to have been unsuccessful.

Key Concerns about Interest Arbitration

Ability to Mitigate Conflict

One key concern about interest arbitration is whether it is effective at resolving disputes that brought parties to an impasse or merely suppresses conflicts temporarily or redirects them to other forms of conflict, at other times. There is some evidence that arbitration results in the latter.[24] Compulsory arbitration legal structures are associated with lower strike frequency (see Campolieti, Hebdon, and Dachis 2016; Currie and McConnell 1991), although Adell, Grant, and Ponak (2001) found that compulsory arbitration might not reduce the frequency of strikes if the parties – the union, in particular – do not accept the system as a legitimate mechanism for the settlement of interest disputes. On balance, the available evidence does not permit one to discern clearly the effects of arbitration in alleviating conflict versus diverting it.

Chilling Effects

Another key concern is the "chilling effect" that arbitration might have on collective bargaining. Numerous studies have found that rates of impasse/dispute under legal structures that require arbitration are higher than under legal structures that have other dispute resolution procedures as the terminal step (Anderson and Kochan 1977; Campolieti, Hebdon, and Dachis

22 See Chaykowski and Hickey (2012) and the arbitration awards cited therein.

23 In contrast, Slater (2013, 404) notes that, in the United States, "some statutes specifically instruct arbitrators to give certain criteria the most weight."

24 Hebdon and Stern (1998) found that strike bans/compulsory interest arbitration were associated with increases in mid-contract grievance activity and job actions (for example, slowdowns), and that this was exacerbated under final offer arbitration. See also Hebdon and Mazerolle (2003, 670–1) for a discussion of potential for the redirection of conflict.

2016; Currie 1989; Hebdon and Mazerolle 2003; Rose and Piczak 1996). The chilling effect is mainly concerned with the effect of arbitration on the current round of bargaining, but it is also hypothesized that arbitration can affect future rounds of bargaining.

There are several reasons why the parties might have a dependence on arbitration – referred to as a "narcotic effect."[25] First, the parties learn over time that it is easier and less costly to have an arbitrator settle their differences than to do so themselves through difficult collective bargaining, resulting in greater rates of impasse and reliance on arbitration (Anderson 1981, 131). Second, with each use, the parties develop a better understanding of the process and the arbitrator's reasoning; this reduces the uncertainty surrounding the process that is supposed to induce voluntary settlements (Farber and Katz 1979). Third, the ability to "save face" by placing the blame of a "bad result" on the arbitrator might induce union elected officials to use arbitration to avoid political accountability for the difficult decisions that might best be made in collective bargaining (McCall 1990).

Substantive Outcomes: Wages

There is also concern over whether wage increases in arbitration awards are more generous than those found in voluntarily negotiated agreements – and in the public sector more generally. For comparisons within legal structures – for example, where there is a choice between striking or resorting to arbitration – there is some, albeit limited, evidence from the Canadian federal level that arbitrated settlements (in the years just following the introduction of bargaining rights) became comparable, over time, to voluntarily negotiated ones (see Anderson and Kochan 1977).[26]

Looking across different legal structures (with different dispute resolution regimes), evidence suggests that systems with arbitration as the final step in the procedure are associated with a small wage premium (approximately 1.0–2.5 percent) as compared to systems that have a strike as the final step (Currie and McConnell 1991; Gunderson, Hebdon, and Hyatt 1996). Campolieti, Hebdon, and Dachis (2016, 20), examining a more recent period than previous Canadian studies, find wage gains under compulsory arbitration statutes not to be statistically significantly different from those produced under right-to-strike statutes, but they attribute this finding to the public-sector wage restraint of the early 1990s. When they control for this period, they find that a compulsory arbitration legal structure is associated with a statistically significant wage premium that is comparable to findings of previous studies (18). Thus, in Canada, it appears that there might be a price to pay for

25 The empirical literature in Canada has found evidence of the existence of a narcotic effect (see, for example, Anderson and Kochan 1977; Currie 1989). US studies have produced more mixed results (see, for example, Butler and Ehrenberg 1981; Champlin, Bognanno, and Schumann 1997; Kochan et al. 2010). Although Campolieti, Hebdon, and Dachis (2016, 13–14) find evidence for Canada consistent with a narcotic effect, they note that their findings are also consistent with the persistence of conflict.

26 The authors attribute these findings to arbitrators' conservative decision-making and to the use of comparability, whereby weaker bargaining units that were unable to exercise significant economic or political leverage used arbitration to achieve the gains that were won by bargaining units that were able to use such leverage. Thus, access to arbitration aided weaker bargaining units in following a pattern, but did not produce any gains beyond those negotiated voluntarily.

substituting interest arbitration for the right to strike.[27]

Conclusions and Recommendations

There is a wide range of potential models for an interest arbitration system. Studies that have examined the effects of certain models – for example, final offer arbitration versus conventional arbitration – are not definitive, however, for two reasons. First, evidence on all aspects of arbitration models – such as the extent of "arbitrator capturing" by the parties – is simply not available. Second, much of the extant research applies to the United States, where aspects of public-sector labour relations and law can be quite different than in Canada – and in industrial relations, institutional factors can matter a great deal. Consequently, the results of these US studies might not necessarily be conclusively applied to the Canadian context. The available research nonetheless provides some important guidance. With these caveats in mind, four areas of potential reform to the arbitration system would be applicable across many Canadian jurisdictions.

Change the Process and Parameters of Arbitration

If mediation plays a prominent role in the arbitration process, and the arbitrator first attempts to mediate a settlement before adjudicating, then the threat of an imposed outcome stands to increase the likelihood of a voluntary settlement. The push toward voluntary settlements, therefore, would be expected to allow for innovative solutions, to alleviate conflict instead of diverting it and to increase the parties' accountability to their constituents (Chaykowski et al. 2001; Malin 2013). The use of mediation prior to the arbitration process permits another round of tradeoffs in order to craft a voluntary settlement and avoid the prospect of an adverse arbitration outcome (see Campolieti and Riddell 2018; Malin 2013). These considerations suggest that a mediation-arbitration model should deliver superior outcomes, and this points to encouraging the use of some form of that model.

With a med-arb process, several further challenges would need to be addressed. For example, the parties might withhold information at the mediation stage in order to gain a later advantage in arbitration, or they might be reluctant to share information with the mediator, knowing that it could be used later in the crafting of an arbitration award (Campolieti and Riddell 2018, 5). Indeed, unwillingness to share information could *increase* the likelihood of going to arbitration (5–6). As well, the parties might perceive the mediation process as "coercive" (5). There is, in fact, a dearth of empirical evidence on the efficacy of med-arb,[28] although Campolieti and Riddell, examining

27 Although there have been relatively few studies in Canada regarding arbitration and wage outcomes, those that exist have been able to make use of large databases that cover a broad range of occupations. In contrast, the greater number of US studies have a narrower focus (primarily on police and firefighting) and the evidence from these studies is somewhat mixed, with some finding arbitration associated with higher wages and others finding no discernable effect on wages. See, for example, Ashenfelter and Hyslop (2001); Bloom (1981); Feuille, Delaney, and Hendricks (1985); Kochan et al. (2010); Kochan and Wheeler (1975); and Olson (1980).
It is worthwhile noting that the emphasis in US research on arbitration among police and firefighters has reflected, at least historically, the fact that, "[i]n most of the states, the driving power behind the enactment of an arbitration statute has come primarily from police and firefighter unions" (Lester 1984, 1). In Canada, the demand for arbitration in the public sector has tended to extend well beyond police and firefighting.

28 The available US evidence is limited, somewhat mixed in its results and subject to some methodological limitations. For example, widely cited papers by Lester (1984) and Stern (1984) regarding med-arb reach somewhat opposite conclusions.

its use and arbitration rates in Ontario policing and firefighting, find that “the introduction of mediation-arbitration is significantly associated with increased use of arbitration by firefighters relative to the police” (2018, 1).

Although some problems (such as the chilling effect) associated with one-stage med-arb, where the same person conducts both processes, could be addressed through the use of two-stage med-arb, whereby different experts conduct the two processes, other potential problems remain. As examples, where the parties have developed a narcotic effect, they might be less likely to take the mediation phase seriously because they have come to depend upon the arbitration process. Or the parties, once in mediation, might behave strategically – for example, with regard to information sharing – which also would increase the likelihood of going to arbitration. In these circumstances, the parties would need to be incentivized to vest more fully in the mediation stage. Therefore, taken altogether,

- *governments should assess whether the arbitration system should be modified so that it follows a two-stage process, monitor whether the modified system yields improved outcomes (for example, decreased use of arbitration)*[29] *and assess whether the mediation phase can be modified to incentivize the parties to vest more fully in the process*.

Ensure the Public Interest Is Addressed

Although collective bargaining, or interest arbitration, might advance the interests of employers and unions, the settlements and outcomes might not always be in the public interest.[30] In fact, under the current system, there appear to be few, if any, incentives for employers and unions to internalize the public interest in their negotiations process.[31] There is, however, a direct public interest in such issues as ability to pay, the financial sustainability of the provision of public services and government debt loads. These issues also intersect with factors such as the application of the “replication principle” and the “comparability” criterion.

The main way in which the public interest is internalized in the arbitration process is by appealing in legislation for arbitrators to take account of such factors. Yet, in Ontario, the legislation permits arbitrators full discretion in their focus and weighting of the criteria they choose to apply. Perhaps not surprisingly, arbitrators routinely decline to take account of certain criteria (notably, ability to pay) despite the fact that legislation highlights the criteria deemed to be important (see Chaykowski and Hickey 2012, 40–54; Rose 2000), while governments seem reluctant to stipulate that certain key criteria must be applied.[32]

As a result, the current model appears to create a wedge between the private interests of the parties and the public interest. This also has the unintended side-effect of pressuring governments to act in an ad hoc – and sometimes unilateral – fashion to end disputes, which can yield poor outcomes as a matter of labour relations and labour policy. These considerations point to the need to ensure that

29 The available research regarding the efficacy of alternative approaches to med-arb is not definitive, so it does not assist in informing us whether changes necessarily would lead to better or worse outcomes.

30 As examples, widespread high wage outcomes in the private sector could lead to increases in the aggregate costs of labour inputs, which could lead to cost-push inflation, while high wage settlements in the public sector could place pressure on government budgets.

31 There appears to be little, if any, research in Canada on the issue of the degree of alignment between the public interest and the interests of employers and unions in public-sector bargaining or arbitration outcomes.

32 It is worthwhile noting that more work needs to be done to clarify certain potential criteria – ability to pay would be one such candidate. In addition, a key issue that should be carefully addressed is that of the best approach to enforcement – especially in light of arbitrators’ established track record of ignoring certain criteria that have been stipulated in legislation.

the public interest is embodied in the outcomes of interest arbitrations by establishing key criteria and increasing arbitrator accountability. Accordingly,

- *governments should demand that arbitrators consider certain arbitral criteria,[33] including an explanation of how each factor was considered, even those judged irrelevant; enumerated criteria should include those that have a substantive public interest component, but any changes should not otherwise restrict arbitrators' discretion, so as to maintain a level of unpredictability in the process.*

In addition,

- *governments should strengthen the accountability of arbitrators by explicitly requiring them to consider and assess the parties' submissions;[34] one potentially important effect of this would be to encourage the parties to increase, over time, the quality of the substantive evidence they provide arbitrators.*

These changes would explicitly address the need to take account of the public interest and be expected to increase the uncertainty that the parties experience in interest arbitration, creating greater incentives for the parties to reach a settlement through bargaining and, failing that, serving to incentivize the parties to reach a settlement at the mediation stage. Finally, the changes would directly increase the accountability of the arbitrator to the parties and the public.

Develop the Human Capital and Skills of Arbitrators and Mediators

One major concern is whether third parties have the skill set to perform the role of mediator, arbitrator or both.[35] Arbitrators in industrial relations historically have also practised facilitative mediation aimed at aiding in the resolution of disputes. An analytical review of the skills that mediators and arbitrators, respectively, need would benefit the system, including in the context of two-stage med-arb, where both a mediator and an arbitrator are required.[36]

Increasing the accountability of arbitrators – for example, by requiring them to consider and assess the parties' submissions – requires that their skills be sufficient to the task. Some of the factors that arbitrators could be required to consider would necessitate a sound basis of understanding in economics, accounting and statistics, as examples. Therefore,

- *government should conduct a review of the competencies and skills that mediators and arbitrators need, respectively, with a view to identifying skill requirements, setting competency standards and*

33 It is worth emphasizing that this recommendation is not meant to imply that simply specifying more criteria is necessarily an improvement; rather, the emphasis should be on identifying significant criteria that have a vital bearing on the public interest, including the interests of the parties. In a similar vein, it is not necessarily the case that placing any limits on arbitral discretion – by mandating certain criteria – necessarily has negative consequences.

34 The Ontario government attempted to introduce reforms to the arbitration process in the broader public sector through Bill 55, the *Strong Action for Ontario Act* (*Budget Measures*), 2012, which included requirements for written submissions as well as arbitrator rationales, but these changes were never given effect.

35 The need to engage in training and development and to establish competency standards is not a new idea. For more information, see Horton (1975). Yet the mediation and arbitration professions remain one of the few areas where formal training and competency-based standards are not required. See also Zack (1978).

36 As Campolieti and Riddell (2018, 17) emphasize, "the general point that arbitration (a process of evaluation) and mediation (a process of participation and self-determination) involve very different skill sets has been raised many times in the literature."

developing (formal) training to enhance skills.[37]

Avoid Arbitrator Capturing, Incentives to Pattern and Predictability

In the current adversarial labour relations system, there is a concern about the parties' having an influence on the choice of arbitrator;[38] in turn, arbitrators have a predictable self-interest in being selected by the parties over time.[39] Several potential problems are attendant to this system that could create a wedge between the private interests of the parties and the public interest:[40]

- arbitrator "capturing," where the arbitrator has an incentive to "split the difference" in crafting the award in order to achieve a middle ground that does not alienate either party;
- increased patterning of awards, where the arbitrator has an incentive to craft a settlement that patterns – that is, avoids significantly diverging from recent settlement patterns – hence the heavy weight often placed on the comparability criterion, with the risk of an upward bias in monetary awards over time; and
- predictability, where repeat usage leads the parties to develop a better understanding of the process, expectations and reasoning of a particular arbitrator, a dynamic that reduces the uncertainty surrounding the process that operates to induce higher settlement rates.

A common argument for having the parties agree on the arbitrator and for appointing the same arbitrator in subsequent arbitrations is that the arbitrator comes to "best know" institutional characteristics about the parties that "matter" in industrial relations – for example, issues that preoccupy the parties, their labour relations history, the labour relations dynamic in play or

37 One anecdotal observation is that there appears to be no "obvious" competency/skills deficit among arbitrators; unfortunately, there is no research on the subject of the skill sets of mediators and arbitrators to guide our understanding of whether or not such a deficit exists. The fundamental principle, however, is that there should be an objective indicator that key competencies have been mastered, just as in other professions such as engineering, urban planning, medicine, nursing or law. The central issues are, first, whether mediators and arbitrators currently have the necessary set of competencies and whether their capabilities in each competency are sufficient; and, second, where current skill sets meet an agreed-upon standard, whether skills can be further enhanced, thereby supporting better mediation and arbitration outcomes. Although the mediation and arbitration professions do not have a tradition of formal professional standards reviews, a review focused on competency and skill requirements would bring the mediation/arbitration professions in line with every other profession that has significant responsibilities (Horton 1975, 507). Finally, anecdotally, in Ontario concerns have been expressed about ensuring there is an adequate "next generation" supply of skilled, high-quality arbitrators. This recommendation accordingly represents yet another reason to invest in training and development and simultaneously would provide an opportunity to advance standards in the profession.

38 In the Ontario police and fire sectors, there are fairly well-established practices for the assignment of arbitrators; in police, the choice of arbitrators tends to be the next available person drawn from a list established by the independent Ontario Police Arbitration Commission; for fire, the parties regularly (overwhelmingly) rely upon a select group of arbitrators to handle most cases (Campolieti and Riddell 2018, 3–4, 17).

39 One observation is that "capturing" is more likely to be an issue for arbitrators who undertake rights arbitration. In many jurisdictions, however, arbitrators may undertake both rights and interest arbitration in their practices. A further observation that, in some jurisdictions, the pool of interest arbitrators is small and that they are highly used, is quite consistent with arbitrators behaving so as not to not alienate either party (for example, by splitting the difference), as well as with other factors, including an inadequate supply of skilled arbitrators.

40 There is no Canadian empirical research evidence regarding the extent of capturing or the extent to which arbitrators split the difference in their awards; anecdotally, however, this has been identified as a concern. Similarly, there is no empirical research evidence regarding the predictability issue. Patterning, however, is a common outcome by virtue of the fact that arbitrators use the comparability principle and industry norms.

the nature of the workplaces.[41] In fact, these are sound reasons to appoint the same mediator (not arbitrator) in a two-step med-arb process, since the mediator is attempting to bring the parties together on an agreement. The parties can and do place comprehensive submissions before interest arbitrators, and the scope of these submissions could be readily broadened, as required, to include discussion of any institutional considerations deemed appropriate. Arbitrators thus could be assigned in a manner that reduces the potential for capturing, the incentives simply to pattern awards, and predictability. A straightforward approach to addressing these concerns would be to

- *establish an independent roster of mediators and arbitrators,*[42] *with substantial and meaningful input from unions and employers in a manner consistent with any requirements set out by the courts*[43] *and administered from government in a manner that did not create a conflict of interest with its role as employer (for example, at arm's length through a board).*[44]

Interest arbitration is central to the Canadian industrial relations system, especially in broader public-sector industries where many services are either essential to the well-being of the public or no ready substitutes for the services exist in the event of a strike or lockout. Overall, although the current system of arbitration appears to serve the stakeholders fairly well, there remain concerns about how well it serves the public interest. In determining the balance between promoting collectively bargained settlements, permitting strikes, taking measures to limit costly strikes and relying upon arbitration, it is incumbent upon policymakers to be mindful of the central role that collective bargaining and work stoppages play, and to ensure that interest arbitration is an effective, albeit last resort, mechanism.[45]

41 These factors arguably are much more relevant in the context of *rights arbitration*, not interest arbitration.

42 An important implementation issue is whether the arbitration process should rely upon a single arbitrator, a board consisting of two nominees (from the union and employer sides, respectively) and a neutral or a panel of three neutrals. One anecdotal criticism of the use of a single neutral (with nominees) is that the nominees, unsurprisingly, tend to "take sides" on key issues, leaving these issues to be decided by the neutral. Taken together, either a single neutral arbitrator or a panel of neutral arbitrators (in conjunction with the roster) likely would be better able to avoid the problems associated with the current approaches.

43 For example, the legal considerations identified in *C.U.P.E. v. Ontario (Minister of Labour)*. In operationalizing the allocation of arbitrators from the roster, the objective would be to avoid having a mechanism that permitted the parties repeatedly to choose the same arbitrator; one approach to avoiding this outcome is random selection for each case (subject to availability). Such an approach also would underscore the need for a sufficiently large roster of arbitrators, all of whom would be acceptable to the parties.

44 In following this recommendation, it would be useful to examine current practices regarding the use of arbitrator rosters across jurisdictions.

45 Other factors, including reforms to institutional arrangements such as bargaining structures or government funding arrangements with service providers would be expected to affect the parties' overall reliance on arbitration.

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CONFIDENTIAL LABOUR RELATIONS STRATEGY APPENDIX

Pursuant to the OEB's direction in its decision in EB-2019-0082, this Appendix is being filed as part of Hydro One's go-forward plan to achieve market levels of compensation. The Appendix outlines the key elements of Hydro One's labour relations strategy for upcoming rounds of collective bargaining. It highlights various considerations, factors that impact Hydro One's negotiating power, and other points which inform Hydro One's labour relations strategy. This Appendix includes discussion of Hydro One's: objectives in upcoming rounds of bargaining; specific points of focus (including compensation-related changes intended to be pursued); and views or assumptions in respect of certain negotiating approaches.

A copy of this Appendix has been filed confidentially with the OEB in accordance with the *Practice Direction on Confidential Filings*.

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PENSION AND OPEB COSTS

This exhibit describes Hydro One's pension and other post-employment benefit costs (OPEB) for the 2023-2027 period, in respect of the Transmission and Distribution businesses, and the manner in which those costs have been forecasted for purposes of recovery. As pension and OPEB costs are an important part of the overall compensation that is provided to attract and retain skilled employees for the purpose of providing regulated service, Hydro One has historically been permitted to recover such costs through rates, including most recently for the Distribution business in EB-2017-0049 and for the Transmission business in EB-2019-0082. Hydro One's pension and OPEB costs over the test period have been appropriately forecasted in a manner consistent with prior OEB approvals and based on expert actuarial valuation.

1.0 PENSION COSTS OVERVIEW

Until January 1, 2016, the only Hydro One pension plan was a defined benefit plan (the DB Plan). Company contributions to the DB Plan are based on actuarial valuation reports, which must be performed by actuaries at least every three years. Forecasting for future years is based on such Tri-Annual Valuation reports and actual or projected levels of members and pensionable earnings as applicable.

As discussed under Section 2.3 below, Hydro One's pension plan would need to have a funded ratio of at least 105% calculated on a wind-up basis to be in a position to take a pension contribution holiday in a given year. Hydro One's DB Plan is 73% funded on a wind-up basis. Furthermore, under the current collective agreements, Hydro One has a commitment to contribute an amount to the DB Plan that is at least equal to its employees' contributions. Therefore, Hydro One is not in a position to take a pension contribution holiday and contributions cannot be reduced to zero in a given year.

Effective January 1, 2016, Hydro One introduced a second pension plan, which is a defined contribution pension plan (the DC Plan). The DC Plan is only available to persons who are not eligible to participate in the DB Plan. Members of the DC Plan have an option to contribute 4%, 5%, or 6% of their pensionable earnings into the DC Plan, with matching contributions by Hydro One up to an annual contribution limit. Exhibit E-06-01 provides further information regarding Hydro One's efforts to reduce pension costs.

2.0 DB PLAN

The following sections describe the DB Plan and its governance, the actuarial valuations which determine contribution rates under the DB Plan, cost recovery for the DB Plan, as well as DB Plan performance.

2.1 DB Plan Description and Governance

The DB Plan is a contributory, defined-benefit pension plan. The DB Plan is registered pursuant to the *Pension Benefits Act* (Ontario) and the *Income Tax Act* (Canada) and is not subject to income tax. Plan members include eligible represented employees of the Power Workers Union (PWU) and the Society of United Professionals (SUP), as well as non-represented Management Compensation Plan (MCP) employees, who were hired and met the eligibility requirements to join the plan no later than September 30, 2015, along with pensioners who were previously employees, and pensioners who are beneficiaries or surviving spouses of employees or pensioners.

The DB Plan covers Hydro One Limited and its subsidiaries including Hydro One Inc. Hydro One Inc. is the DB Plan sponsor and administers the pension assets and obligations of the DB Plan. The DB Plan therefore does not segregate assets into separate accounts for individual participating entities from the Hydro One group of companies, nor is the accrual cost of the DB Plan allocated to, or funded separately by entities within the consolidated group. Rather, Hydro One Networks Inc. and other subsidiaries of Hydro One Inc. are participants in the DB Plan. As such, while the DB Plan is accounted for as a defined benefit plan at the level of Hydro One Inc., for Hydro One Networks Inc. the DB Plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded on Hydro One Networks' financial statements. This is consistent with pension accounting for utilities whose employees participate in the Ontario Municipal Employees Retirement System (OMERS) pension plan.

2.2 DB Plan Actuarial Valuation

As discussed earlier, for DB plans, there is a requirement to complete and file a full actuarial valuation at a minimum every 3 years. Management can, at its discretion, file these valuations more frequently. The Tri-Annual Actuarial Valuation report for the DB Plan as at December 31, 2018 (provided as Attachment 1 to this exhibit) establishes the contribution rate for 2019, 2020 and 2021. In September 2019, Hydro One filed this actuarial valuation with the Financial Services Regulatory Authority of Ontario (FSRA), formerly FSCO. Hydro One’s next Tri-Annual Actuarial Valuation for the DB Plan is required as at December 31, 2021 and must be filed by September 30, 2022. The valuation results will depend on investment returns, changes in benefits, and actuarial assumptions.

The December 31, 2018 valuation showed that the DB Plan is in a significant deficit position of $2,595M on a wind-up basis[1] as of December 31, 2018.[2] Based on that valuation, starting in 2019, the required contribution rate for the DB Plan (employer normal actuarial cost as a % of payroll) was set at 11.4% of base pensionable earnings.

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.

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[1] See footnote 11

[2] This valuation also showed that the DB Plan had a surplus of $1,425M on a going-concern basis, however, as explained in section 2.3 below, whether or not there is a surplus on a going-concern basis is not relevant to the question of whether a contribution is required in a given year by Hydro One.

Management prudently monitors the health of the DB Plan to determine the optimal timing of filing actuarial valuations based on the prescribed requirements (at a minimum a Tri-Annual valuation). 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 (see Exhibit G-01-01).

2.3 DB Plan Cost Recovery

Hydro One Inc. recognizes pension expense on a cash basis. 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. Additionally, the cash basis reflects the statutory amounts that Hydro One has to contribute to the DB Plan. If Hydro One Inc. were to switch to the accrual basis, Hydro One Networks would need to recover the current pension benefit regulatory asset[3] over a 15 year period (which is the estimated average remaining service life of active employees), thus resulting in the accrual basis costs being higher than the cash basis costs. The pension benefit regulatory asset balance as at December 31, 2020 of $1.7B, which represents the cumulative life to date difference between the cash basis and the accrual basis of the DB Plan, is a direct offset of the pension liability as assessed by the actuaries.

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[3] Pension Benefit Regulatory Asset refers to a regulatory asset that Hydro One Inc. recognizes on the balance sheet on the basis of the OEB's approval of pension costs on a cash basis.

The OEB has consistently allowed cash payments related to pension obligations to be recovered through rates in numerous prior Hydro One Networks Transmission and Distribution proceedings.[4] In the most recent proceeding for Transmission Revenue Requirement for 2020 to 2022 (EB-2019-0082) the OEB reaffirmed its approval of the cash basis.

> *Hydro One's use of the cash method for pensions and the accrual method for OPEBs for cost recovery is a continuation of the approach approved in Hydro One's last transmission proceeding, and is consistent with the approach approved for Hydro One's distribution business. The OEB's policy on pensions noted that for stability and predictability, maintaining a consistent method used to determine recovery over time may be one reason for not adopting the accrual method for rate setting.*[5]

Tables 1a and 1b present analysis of the cash vs. accrual basis for pension costs for Transmission and Distribution for the DB Plan over the 2023 to 2027 test period.

Table 1a - Transmission Cash vs Accrual Basis Pension Costs ($M)

	2023		2024		2025		2026		2027	
Pension Costs	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**
OM&A	11	19	11	18	11	16	12	15	12	15
Capital	33	56	35	54	35	49	35	46	38	45
Recovery of Reg Asset (1)		48		48		48		48		48
Total	**45**	**123**	**46**	**120**	**46**	**114**	**47**	**109**	**49**	**108**

(1) Represents recovery of the $714M Pension Regulatory Asset at Dec. 31, 2020, with an assumption that 43% of the Pension Regulatory Asset is attributable to Hydro One Transmission and is recovered over a period of 15 years to 2035.

[4] RP-1998-0001; RP 2005-0020/EB-2005-0378; EB-2006-0501; EB-2008-0272: EB-2010-0002; EB-2012-0031; EB-2013-0416; EB-2014-0140; EB-2016-0160; EB-2017-0049; EB-2019-0082.
[5] EB-2019-0082, Decision and Order, April 23, 2020, p. 145

Table 1b - Distribution Cash vs Accrual Basis Pension Costs ($M)

	2023		2024		2025		2026		2027	
Pension Costs	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**
OM&A	20	33	20	31	20	29	20	27	21	25
Capital	39	66	41	63	41	58	42	55	43	52
Recovery of Reg Asset (1)		63		63		63		63		63
Total	**59**	**162**	**60**	**157**	**61**	**150**	**62**	**145**	**64**	**140**

(1) Represents recovery of the $947M Pension Regulatory Asset at Dec. 31, 2020, with an assumption that 57% of the Pension Regulatory Asset is attributable to Hydro One Transmission and is recovered over a period of 15 years to 2035.

Hydro One Networks' pension cost is calculated by applying the contribution rate on base pensionable earnings of its employees that participate in the DB Plan.[6] The pension costs that Hydro One Networks proposes to recover through rates for the DB Plan, for Transmission and Distribution for 2023 to 2027, are provided in Table 2 below. The DB pension contributions are based on projected employer contributions as provided by Willis Towers Watson (WTW); the supporting document is provided as Attachment 2 to this Exhibit.

Table 2 - 2023-2027 Forecast DB Pension Costs ($M)[7]

2023 - Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	11	20
Capital	$M	33	39
Total	**$M**	**45**	**59**

[6] In years when minimum special payments or solvency payments are required under the Tri-Annual Valuation in effect, these are allocated in proportion to Hydro One Networks pension cost to the total pension cost of Hydro One Inc.
[7] The DB Plan valuation/projection that Hydro One undertakes includes Hydro One Limited and all of its regulated and non-regulated affiliates. The tables provided only present Transmission and Distribution.

2024 - Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	11	20
Capital	$M	35	41
Total	**$M**	**46**	**60**

2025 - Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	11	20
Capital	$M	35	41
Total	**$M**	**46**	**61**

2026 - Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	12	20
Capital	$M	35	42
Total	**$M**	**47**	**62**

2027 - Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	12	21
Capital	$M	38	43
Total	**$M**	**49**	**64**

In the EB-2017-0049 Decision, the OEB denied Hydro One's request to recover pension costs "based on the magnitude of the current surplus".[8] The OEB stated that it was reducing Hydro One's OM&A budget for reasons which included that there was "a significant surplus in the pension plan and that there was no justification for continued inclusion of additional pension contributions in rates".[9] It therefore appeared to Hydro One that the OEB may have erred in

[8] EB-2017-0049, Decision and Order, March 7, 2019, p. 96
[9] EB-2017-0049, Decision and Order, March 7, 2019, p. 94

finding that a surplus on a going-concern and solvency basis[10] allowed Hydro One to take a pension contribution holiday. In response to Hydro One's review and variance motion in EB-2019-0122 (the R&V Motion), the OEB clarified that the reductions in relation to pension contribution costs in the EB-2017-0049 Decision were made regardless of whether Hydro One was legally obligated to make pension contributions and, instead, were intended as part of the overall reductions to Hydro One's OM&A and capital envelopes.

Furthermore, in the EB-2019-0082 proceeding, with respect to the Transmission-related pension costs, Hydro One Networks explained that, based on changes to the law relating to DB pension plan contribution holidays and the funded status of the DB Plan at that time, Hydro One would not legally be permitted to take a pension contribution holiday in 2020, 2021 or 2022 (test years of the proceeding). More particularly, Hydro One Networks explained that under the Pension Benefits Act (PBA) and the regulations thereunder, it was previously the case that an employer could take a contribution holiday if their plan was fully funded on both a going concern basis and on a solvency basis if a cost certificate was filed annually confirming the plan to be in a surplus position. However, 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.[11] As such, the OEB in EB-2019-0082

[10] Going concern basis valuations assume that a pension plan will continue indefinitely. The value of benefits is calculated using long-term assumptions that reflect the investment policy of the pension fund. Solvency basis valuations assume that the plan was terminated on a specific date. The value of benefits is calculated assuming members' benefits are settled through either a purchase of annuities or the transfer of commuted values on that specified date. The assumptions therefore reflect the estimated cost of annuities and the prescribed assumptions for commuted values and the interest rates tend to fluctuate on a monthly basis.

[11] Wind-up basis valuations assume the plan is terminated and wound up on a specified date with all members' benefits being settled through either a purchase of annuities or the transfer of commuted values and the interest rates tend to fluctuate on a monthly basis. The assumptions therefore reflect the estimated cost of annuities and the prescribed assumptions for commuted values. The value of all benefits, including future indexation of benefits, is included in a wind up valuation.

allowed the recovery of Hydro One's Transmission-related pension costs consistent with historical practice.

> *"The OEB finds that the pension and OPEB amounts requested by Hydro One for 2020 are supported by sufficient evidence and will allow the recovery of these amounts."*[12]

A 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.

2.4 DB Plan Performance

As noted above, Hydro One Inc. is the DB Plan sponsor and administers the pension assets and obligations of the DB Plan, in which Hydro One Networks is a participant. As at December 31, 2020, the DB Plan had a reported net asset value of $8,144M as per the audited financial statements and about 13,592 members. Approximately 43% of the DB Plan's members are active. The remaining DB Plan members are inactive, either retired, surviving spouses or beneficiaries of retirees, former employees eligible for a deferred pension, or members on long-term disability.

The going concern and solvency funded statuses are the primary ways that Hydro One can assess the Plan's success at providing benefit security to Plan members and contribution funding stability to Hydro One. Funding ratios greater than 100% indicate that the Plan holds more than

[12] EB-2019-0082, Decision and Order, April 23, 2020, p. 145

a sufficient amount of assets to meet the long-term obligations of the Plan. The Plan ended 2020 with a going concern funded ratio of 110% (2019: 111%) and a solvency funded ratio of 111% (2019: 111%).

3.0 DEFINED CONTRIBUTION PLAN

As indicated above, effective January 1, 2016, Hydro One introduced a DC Plan. The DC Plan covers Hydro One Limited and its subsidiaries. The DC Plan is registered with the Financial Services Regulatory Authority of Ontario and is a Registered Pension Trust as defined by the *Income Tax Act* (Canada) and as such is exempt from income taxes. The DC Plan is available for all new full-time and part-time MCP employees, who meet the eligibility requirements to join a pension plan on or after October 1, 2015 and who are not eligible to participate in the DB Plan. Members are able to join the DC Plan on the later of January 1, 2016 or the date they are made probationary or regular employees.

The DC Plan allows eligible employees to contribute up to 6% of their pensionable earnings with a 100% match of contributions by Hydro One. The value of the DC plan is determined by the sum of employer and employee contributions, plus investment earnings. Employee and employer contributions are invested by the DC Plan members among a range of investment options available through Sun Life, the DC Plan’s record keeper. As at December 31, 2020, the DC Plan’s assets were approximately $12M.

Pension benefits are paid upon termination or retirement and may be taken in the form of a life annuity from an insurer for those members who have achieved 55 years of age or a lump sum transfer equivalent to the accumulated value of the member’s account.

Death benefits are available for the spouse or beneficiary(ies) on the death of an active member, and may be taken in the form of a life annuity from an insurer or a lump sum payment equivalent to the accumulated value of the member’s account.

The forecast DC pension contributions in Table 3 below are based on projected employer contributions provided by WTW; the supporting document is provided as Attachment 2 to this exhibit.

Table 3 - 2023-2027 Forecast DC Pension Costs ($M)

2023 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.4	0.7
Capital	$M	1.2	1.4
Total	**$M**	**1.6**	**2.1**

2024 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.4	0.7
Capital	$M	1.3	1.5
Total	**$M**	**1.7**	**2.3**

2025 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.5	0.8
Capital	$M	1.4	1.6
Total	**$M**	**1.8**	**2.4**

2026 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.5	0.9
Capital	$M	1.5	1.8
Total	**$M**	**2.0**	**2.6**

2027 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.5	0.9
Capital	$M	1.6	1.8
Total	**$M**	**2.1**	**2.7**

4.0 OTHER POST-EMPLOYMENT BENEFIT (OPEB) COSTS

OPEBs cover Hydro One Limited and its subsidiaries including Hydro One Inc. These benefits cover eligible represented employees of the PWU and SUP, as well as MCP employees, pensioners who were previously employees, and pensioners who are beneficiaries or surviving spouses of employees or pensioners.

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. Paid benefit amounts are for retirees, drawn against the liability that was incurred by the company during their years of service.

Tables 4a and 4b summarize historical and forecast OPEB costs included in rates for each of the Transmission and Distribution businesses.

Table 4a - Transmission OPEB Costs Included in Rates ($M)

OPEBs	Pre 2018	2018	2019	2020	2021	2022	2023	Total
Amounts included in Transmission rates:								
OM&A	411	21	15	37	38	39	31	592
Capital (Note 1)	335	10	16	18	20	20	25	444
Deferral Account		22	19					41
Sub-total	**746**	**53**	**50**	**55**	**58**	**59**	**56**	**1,077**
Paid benefit amounts	247	21	21	28	30	30	31	408
Net excess amount included in rates greater than amounts actually paid	499	32	29	27	28	28	25	669

Note 1 – The capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess amount in each year noted does not represent the excess recovery in that year.

Table 4b - Distribution OPEB Costs Included in Rates ($M)

OPEBs	Pre 2018	2018	2019	2020	2021	2022	2023	Total
Amounts included in Distribution rates:								
OM&A	537	26	26	26	25	26	45	711
Capital (Note 1)	403	12	13	13	12	14	29	496
Deferral Account		13	15	15	15	16		74
Sub-total	**939**	**51**	**54**	**54**	**52**	**56**	**74**	**1,280**
Paid benefit amounts	408	27	26	28	28	30	35	582
Net excess amount included in rates greater than amounts actually paid	531	24	28	26	24	26	39	698

Note 1 – The capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess amount in each year noted does not represent the excess recovery in that year

Under US GAAP, the non-service cost component of OPEBs can no longer be capitalized unless the regulator allows for the continued capitalization.[13] In the EB-2019-0082 Decision, the OEB concluded that the non-service cost component of Hydro One's OPEB costs shall be recognized as OM&A for both its transmission and distribution businesses. As such, Hydro One has not been tracking any amounts in the OPEB Cost Deferral Account for Transmission beyond 2019 and intends to stop tracking these amounts for Distribution starting in 2023 (presented as Deferral Account in Table 4a and 4b above). Please refer to Exhibit G-01-01 for additional details.

[13] In the case of the Federal Energy Regulatory Commission (FERC), it is allowing FERC-regulated utilities, which are subject to USGAAP and the changes in ASU 2017-07, to continue to capitalize both the service and non-service cost components of pensions and OPEBs.

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HYDRO ONE INC.

HYDRO ONE PENSION PLAN

Actuarial Valuation as at December 31, 2018

September 19, 2019

Registration Number: 1059104

WillisTowersWatson

DISCLAIMERS

This document is an actuarial valuation report of a pension plan. It is technical in nature and the reader should seek expert advice to fully understand it. The actuarial results presented here are based on numerous economic and demographic assumptions as to future events. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future actuarial valuations.

This report is based on the terms of engagement listed in Appendix A.

This report is based on the premise that all the plan's assets, including any letters of credit, are available to meet the plan's liabilities included in this valuation.

This report is based on the premise that the plan remains a going concern. This report does not address the disposition of any surplus assets remaining in the event of plan windup. If an applicable pension regulator or other entity with jurisdiction directs otherwise, certain financial measures contained in this report, including contribution requirements, may be affected.

The results presented in this report have been developed using a particular set of actuarial assumptions. Other results could have been developed by selecting different actuarial assumptions. The results presented in this report are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events.

Future contribution levels may change as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which have been anticipated at this time.

The results were developed with various data as at the valuation date that were provided to us: plan membership data, plan assets data, plan provisions and statement of investment policy. Towers Watson Canada Inc. (“Willis Towers Watson”) has relied on these data after verifying them and assessing their reasonableness. However, Willis Towers Watson has not independently audited these data.

The information contained in this report was prepared for Hydro One Inc., for its internal use and for filing with the Pension Authorities, in connection with the actuarial valuation of the plan prepared by Willis Towers Watson. This report is not intended, nor necessarily suitable, for other parties or for other purposes. Furthermore, some results in this report are based on assumptions mandated by legislation. These results may not be appropriate for purposes other than those for which they were prepared. Willis Towers Watson is available to provide additional information with respect to this report to the above-mentioned intended users upon request.

The numbers in this report are not rounded. The fact that numbers are not rounded does not imply a greater level of precision than if the numbers had been rounded.

Definitions:

Pension Authorities means the Financial Services Commission of Ontario and the Canada Revenue Agency ("CRA").

Pension Legislation means the *Pension Benefits Act (Ontario)* and Regulation thereto and the *Income Tax Act (Canada)* and Regulations thereto ("ITA").

Table of Contents

Introduction

Purpose

This report with respect to the Hydro One Pension Plan has been prepared for Hydro One Inc., the plan administrator, and presents the results of the actuarial valuation of the plan as at December 31, 2018.

The principal purposes of the report are:

- to present information on the financial position of the plan on going concern, solvency and hypothetical windup bases;
- to provide the basis for employer contributions.

Significant Events since Previous Actuarial Valuation (December 31, 2017)

Effective May 14, 2018, a new policy asset mix was adopted by Hydro One. This policy will be implemented over the next several years, when the appropriate investment opportunities are available. Notably this includes a shift towards real-estate and infrastructure and the removal of specific regional equity and fixed income mandates. This report reflects the new policy asset mix.

In November 2018, an asset transfer application in respect of Customer Service Operations (CSO) employees who transferred from Inergi LP to Hydro One was filed with the Pension Authorities. At the time this report is being prepared, the application has not yet been approved by the Pension Authorities and therefore, the impact of the past service transfer of assets and liabilities has not been reflected in this report. A financial update as of December 31, 2018 in respect of the asset transfer, as required under section 12 of the Ontario Regulation 310/13, is included as an Addendum to this report.

There have been no changes to the plan provisions and actuarial standards having an impact on the valuation results. Changes to the going concern basis are described in Appendix C. Changes to the solvency basis are described in Appendix D.

Subsequent Events

We completed this actuarial valuation on July 30, 2019.

On May 21, 2019, amendments to the Pension legislation were released. These amendments are intended to clarify certain details related to the new funding framework that took effect on May 1, 2018. The impact of these amendments, notably as it relates to the definition of “open” plan in the calculation of the Provision for Adverse Deviations, has been reflected in this report.

In June 2019, a cost certificate effective January 1, 2019 was filed with the Financial Services Regulatory Authority of Ontario. The present report takes precedence over the January 1, 2019 cost certificate.

Except as noted above, to the best of our knowledge and on the basis of our discussions with Hydro One Inc., no events which would have a material financial effect on the actuarial valuation occurred between the actuarial valuation date and the date this actuarial valuation was completed.

Next Valuation

The next actuarial valuation of the plan must be performed with an effective date not later than December 31, 2021.

Section 1: Going Concern Financial Position

1.1 Statement of Financial Position

	December 31, 2018	December 31, 2017
Going Concern Value of Assets	$ 7,202,478,000	$ 6,932,459,000
Actuarial Liability		
Active and disabled members	$ 1,662,138,096	$ 1,894,495,063
Retired members and beneficiaries	4,083,736,181	4,188,945,730
Terminated vested members	31,732,267	37,189,476
Total actuarial liability	$ 5,777,606,544	$ 6,120,630,269
Actuarial Surplus (Unfunded Actuarial Liability)	$ 1,424,871,456	$ 811,828,731
Prior Year Credit Balance	(48,000,000)	(48,000,000)
Actuarial Surplus (Unfunded Actuarial Liability) After Prior Year Credit Balance	$ 1,376,871,456	$ 763,828,731
Funded Ratio[1]	124%	112%
Provision for Adverse Deviations (PfAD)	$ 350,805,224	N/A
Actuarial Surplus (Unfunded Actuarial Liability) After Prior Year Credit Balance and PfAD	$ 1,026,066,232	763,828,731
Excess Actuarial Surplus[2] $	0	0

Notes:

[1] After reflecting prior year credit balance.
[2] Considered to be nil if there is a hypothetical windup or solvency deficit.

Comment:

- The prior year credit balance is employer contributions made prior to the actuarial valuation date that are in excess of the minimum required and are set aside as a reserve for application towards future contribution requirements.

1.2 Reconciliation of Financial Position

Actuarial surplus (unfunded actuarial liability) as at December 31, 2017 before reflecting the Prior Year Credit Balance		$ 811,828,731
Net special payments		0
Application of:		
■ Actuarial surplus	$ 0	
■ Prior year credit balance	0	0
Expected interest on:		
■ Actuarial surplus (unfunded actuarial liability)	$ 43,838,751	
■ Net special payments	0	
■ Application of actuarial surplus	0	
■ Application of prior year credit balance	0	43,838,751
Plan experience:		
■ Investment gains (losses)	$ 132,768,855	
■ Salary and YMPE gains (losses)	9,968,737	
■ Retirement gains (losses)	(14,059,141)	
■ Withdrawal gains (losses)	(6,623,303)	
■ Mortality gains (losses)	(7,702,027)	
■ Gains (losses) from contractual pension increases	(16,001,483)	
■ Miscellaneous liability gains (losses)	(14,211,650)	84,139,988
Change in actuarial basis		485,063,986
Actuarial surplus (unfunded actuarial liability) as at December 31, 2018 before reflecting the Prior Year Credit Balance and PfAD		$ 1,424,871,456

1.3 Contributions (Ensuing Year)

	December 31, 2018	December 31, 2017
Employer Normal Actuarial Cost		
Normal actuarial cost in respect of benefits	$ 113,346,619	$ 120,445,195
Provision for Adverse Deviations (PfAD)	6,671,594	N/A
Estimated member contributions	(53,554,752)	(49,552,747)
Employer normal actuarial cost	$ 66,463,461	$ 70,892,448
Estimated payroll	584,820,060	533,584,509
Employer normal actuarial cost as % of payroll	11.4%	13.3%

Reconciliation of Employer Normal Actuarial Cost Rule

Employer normal actuarial cost as a % of payroll at December 31, 2017	13.3 %
■ Changes in membership profile	(0.1)%
■ Changes in actuarial basis	(3.0)%
■ Change in the PfAD level	1.2 %
Employer normal actuarial cost as a % of payroll at December 31, 2018	11.4 %

1.4 Reconciliation of Prior Year Credit Balance (cash basis)

Prior year credit balance as at December 31, 2017		$ 48,000,000
Actual employer contributions:		
■ Employer normal actuarial cost	$ 75,042,000	
■ Going concern amortization payments	0	
■ Solvency amortization payments	0	
■ Transfer deficiency payments	0	
■ Prior year credit balance	0	
■ Other contributions	0	75,042,000
Minimum employer contributions required:		
■ Employer normal actuarial cost	$ (75,042,000)	
■ Going concern amortization payments	0	
■ Solvency amortization payments	0	
■ Transfer deficiency payments	0	
■ Other contributions	0	(75,042,000)
Application against unfunded actuarial liability		0
Prior year credit balance as at December 31, 2018		$ 48,000,000

Section 2: Solvency and Hypothetical Windup Financial Position

2.1 Statement of Solvency and Hypothetical Windup Financial Position

	December 31, 2018	December 31, 2017
Solvency Value of Assets		
Market value of assets	$ 7,208,634,000	$ 7,305,522,000
Provision for plan windup expenses	(7,000,000)	(7,000,000)
Total solvency value of assets	$ 7,201,634,000	$ 7,298,522,000
Solvency Liability		
Active and disabled members	$ 2,068,058,939	$ 2,172,760,741
Retired members and beneficiaries	4,433,823,741	4,334,621,102
Terminated vested members	37,708,259	40,324,067
Total solvency liability	$ 6,539,590,939	$ 6,547,705,910
Solvency Surplus (Unfunded Solvency Liability)	$ 662,043,061	$ 750,816,090
Prior Year Credit Balance	$ 48,000,000	$ 48,000,000
Solvency ratio	Not less than 100%	Not less than 100%
Value of excluded benefits	$ 3,256,931,443	$ 3,482,126,137
Total hypothetical windup liability	9,796,522,382	10,029,832,047
Hypothetical Windup Surplus (Unfunded Hypothetical Windup Liability)	$ (2,594,888,382)	$ (2,731,331,047)
Lesser of estimated employer contributions for the period until the next actuarial valuation and the prior year credit balance	48,000,000	48,000,000
Transfer ratio	73%	73%

	December 31, 2018	December 31, 2017
PBGF Information		
Ontario PBGF liability	$ 6,539,590,939	$ 6,547,705,910
Ontario asset ratio	Not less than 100%	Not less than 100%
Ontario portion of the fund	$ 7,208,634,000	$ 7,305,522,000
PBGF assessment base	$ 0	$ 0
Ontario additional PBGF liability	$ 0	$ 0

Comments:

- The solvency actuarial valuation results presented in this report are determined under a scenario where, following a plan windup, the employer continues its operations.
- The hypothetical windup valuation results presented in this report are determined under a scenario where, following a plan windup, the employer continues its operations.
- As the transfer ratio is less than 1.00, transfer deficiencies must be paid over a maximum period of five years unless the cumulative transfer deficiencies are within the limits prescribed by the Pension Legislation or the employer remits additional contributions in respect of the transfer deficiencies. Pursuant to Regulations 19(4) or 19(5) to the Pension Legislation, approval of the Chief Executive Officer will be required to make commuted value transfers if there has been a significant decline in the transfer ratio after the actuarial valuation date.

2.2 Determination of the Statutory Solvency Excess (Deficiency)

In calculating the statutory solvency excess (deficiency), various adjustments can be made to the solvency financial position.

	December 31, 2018	December 31, 2017
Solvency surplus (unfunded solvency liability)	$ 662,043,061	$ 750,816,090
Adjustments to solvency position:		
■ Present value of existing amortization payments	$ 0	$ 0
■ Smoothing of asset value	(6,156,000)	(373,063,000)
■ Adjustment to reflect reduced solvency deficiency[1]	991,252,410	N/A
■ Averaging of liability discount rate	(68,758,462)	201,718,938
■ Prior year credit balance	(48,000,000)	(48,000,000)
■ Total	$ 868,337,948	$ (219,344,062)
Statutory solvency excess (deficiency)	$ 1,530,381,009	$ 531,472,028

Note:

[1] Reflects 15% of the solvency liabilities based on the discount rates after averaging.

Section 3: Contributions

3.1 Estimated Minimum Employer Contribution (Ensuing Years)

Year		2019		2020		2021
Employer Normal Actuarial Cost (including the PfAD)	$	66,463,461	$	65,993,735	$	65,248,200
Amortization Payments						
■ Going concern		0		0		0
■ Solvency		0		0		0
■ Sub-total	$	0	$	0	$	0
Application of Prior Year Credit Balance [1]		0		0		0
Application of available actuarial surplus		0		0		0
Estimated Minimum Employer Contribution	$	66,463,461	$	65,993,735	$	65,248,200

Note:

1 As at the actuarial valuation date a $48,000,000 Prior Year Credit Balance exists, which may be applied to reduce Employer contributions in 2019, 2020 or 2021.

3.2 Estimated Maximum Employer Contribution (Ensuing Year)

		December 31, 2018
Employer Normal Actuarial Cost	$	66,463,461
Greater of the Unfunded Actuarial Liability and the Unfunded Hypothetical Windup Liability		2,594,888,382
Estimated Maximum Employer Contribution	$	2,661,351,843

3.3 Timing of Contributions

Employer normal cost and member contributions: monthly and within 30 days of the month to which they pertain.

Amortization payments: monthly before the end of the month to which they pertain (or replaced by an equivalent letter of credit), if applicable.

Adjustment to contributions made since the valuation date: within 60 days from the date that this report is filed with the Pension Authorities.

Section 4: Actuarial Opinion

In our opinion, for the purposes of the going concern, solvency and hypothetical windup valuations:

- the membership data on which the actuarial valuations are based are sufficient and reliable,
- the assumptions are appropriate, and
- the methods employed in the actuarial valuations are appropriate.

This report has been prepared, and our opinion has been given, in accordance with accepted actuarial practice in Canada. The actuarial valuations have been conducted in accordance with our understanding of the funding and solvency standards prescribed by the Pension Legislation.

Towers Watson Canada Inc.

Davis Gonsalves

Davis Gonsalves
Fellow of the Canadian Institute of Actuaries

Suzanne Jacques

Suzanne Jacques
Fellow of the Canadian Institute of Actuaries

Toronto, Ontario
September 19, 2019

Appendix A: Significant Terms of Engagement and Certificate of the Plan Administrator

A.1 Significant Terms of Engagement

For purposes of preparing this actuarial valuation report, the plan administrator has directed that:

- The actuarial valuation is to be prepared as at December 31, 2018.
- No margins for adverse deviations are to be used.
- For the purpose of determining the going concern discount rate, the investment policy dated May 14, 2018, which is the most up-to-date version, should be considered. There are no expectations that the target asset class distribution will be modified in the future.
- For purposes of determining the Provision for Adverse Deviations level as at December 31, 2018, the actual asset allocation based on the December 31, 2018 audited financial statements and additional information related to the investment categories provided directly by the plan administrator should be used.
- For purposes of determining the Provision for Adverse Deviations level, the plan is to be considered open to new entrants, as defined in the Pension legislation.
- The going concern value of assets is to be determined using the averaging technique described in the Asset Valuation Method section in Appendix C.
- The going concern valuation should use the projected unit credit actuarial cost method.
- For purposes of determining the solvency liabilities of the plan, certain benefits are to be excluded without requiring an election from the employer.
- The solvency and hypothetical windup valuation results are to be determined under a scenario where the employer continues to operate and certain expenses are paid from the pension fund (consistent with past practice) while the employer pays other plan expenses.
- This report is to be prepared on the basis that the employer is entitled to apply the available actuarial surplus, if any, to meet its contribution requirements under the plan.

Should these directions from the plan administrator be amended or withdrawn, Willis Towers Watson reserves the right to amend or withdraw this report.

A.2 Certificate of the Plan Administrator

I hereby certify that to the best of my knowledge and belief:

- the significant terms of engagement contained in Appendix A of this report are accurate and reflect the plan administrator's judgement of the plan provisions and/or an appropriate basis for the actuarial valuation of the plan;
- the information on plan assets, including the information on the investment policy and intended changes to the asset mix distribution after the valuation date, if any, forwarded to Towers Watson Canada Inc. and summarized in Appendix B of this report is complete and accurate;
- the data forwarded to Towers Watson Canada Inc. and summarized in Appendix E of this report are a complete and accurate description of all persons who are members of the plan, including beneficiaries who are in receipt of a retirement income, in respect of service up to the date of the actuarial valuation;
- the summary of plan provisions contained in Appendix F of this report is accurate;
- for purposes of determining the Provision for Adverse Deviations level, the fixed income allocation for each asset class shown in Appendix G is appropriate; and
- except as noted in the Introduction of the report, there have been no events which occurred between the actuarial valuation date and the date this actuarial valuation was completed that may have a material financial effect on the actuarial valuation.

	September 24, 2019
Signature	Date
Robert Cultraro	SVP, Chief Investment and Pension Officer
Name	Title

Appendix B: Assets

B.1 Statement of Market Value

		December 31, 2018		December 31, 2017
■ Total invested assets	$	7,208,634,000	$	7,305,522,000
Net outstanding amounts:				
■ Contributions receivable				
- Employer normal cost	$	0	$	0
- Members contributions		0		0
- Amortization payments		0		0
- Others		0		0
■ Benefits payable		0		0
■ Expenses and other payables		0		0
■ Total net outstanding amounts	$	0	$	0
Total Assets	$	7,208,634,000	$	7,305,522,000

Comment:

- The data relating to the invested assets are based on the financial statements issued by KPMG. The data relating to net outstanding amounts were furnished by Hydro One Inc.

B.2 Asset Class Distribution

The following table shows the target asset allocation stipulated by the plan's investment policy in respect of major asset classes and the actual asset allocation as at December 31, 2018.

	Target asset allocation	Actual asset allocation as at December 31, 2018
Global equities	40.0%	47.8%
Private equities	5.0%	2.7%
Real estate and infrastructure	20.0%	9.2%
Bonds and debentures	33.0%	38.3%
Cash and short-term investments	2.0%	2.0%
Total	100.0%	100.0%

B.3 Reconciliation of Invested Assets (Market Value)

Assets as at January 1, 2018		$ 7,305,522,000
Receipts:		
■ Contributions:		
- Employer normal actuarial cost	$ 75,042,000	
- Employer amortization payments	0	
- Member required contributions	52,525,000	
- Past service contributions	451,000	
- Provision for non-investment expenses	0	$ 128,018,000
■ Investment return, net of investment expenses		161,011,000
■ Total receipts		$ 289,029,000
Disbursements:		
■ Benefit payments:		
- Pension payments	$ (324,564,000)	
- Lump sum settlements	(34,403,000)	
- Other benefit payments	0	$ (358,967,000)
■ Non-investment expenses		(26,950,000)
■ Total disbursements		$ (385,917,000)
Assets as at December 31, 2018		$ 7,208,634,000

Comments:

- This reconciliation is based on the financial statements issued by KPMG.
- The rate of return earned on the market value of assets, net of all expenses, from December 31, 2017 to December 31, 2018 is approximately 1.9% per annum.

B.4 Development of the Going Concern Value of Assets

	Adjusted Market Value Beginning from:				
	December 31, 2014	December 31, 2015	December 31, 2016	December 31, 2017	December 31, 2018
Adjusted market value as at December 31, 2014	$ 6,311,204,000				
Net cash flow for 2015	(117,373,000)				
Assumed investment return	362,695,000				
Adjusted market value as at December 31, 2015	6,556,526,000	$ 6,745,869,000			
Net cash flow for 2016	(182,014,000)	(182,014,000)			
Assumed investment return	349,203,000	359,427,000			
Adjusted market value as at December 31, 2016	6,723,715,000	6,923,282,000	$ 6,909,437,000		
Net cash flow for 2017	(235,047,000)	(235,047,000)	(235,047,000)		
Assumed investment return	350,209,000	360,786,000	360,052,000		
Adjusted market value as at December 31, 2017	6,838,877,000	7,049,021,000	7,034,442,000	$ 7,305,522,000	
Net cash flow for 2018	(230,949,000)	(230,949,000)	(230,949,000)	(230,949,000)	
Assumed investment return	363,146,000	374,493,000	373,706,000	388,345,000	
Adjusted market value as at December 31, 2018	$ 6,971,074,000	$ 7,192,565,000	$ 7,177,199,000	$ 7,462,918,000	$ 7,208,634,000
Going Concern Value of Assets					
Average of the five adjusted market values as at December 31, 2018					$ 7,202,478,000
Net outstanding amounts					0
Going concern value of assets as at December 31, 2018					$ 7,202,478,000

Comment:

- The rate of return earned on the going concern value of assets, net of all expenses, from December 31, 2017 to December 31, 2018 is approximately 7.4% per annum.

Appendix C: Actuarial Basis - Going Concern Valuation

C.1 Methods

Asset Valuation Method

The going concern value of assets was calculated as the average of the market value of invested assets at the valuation date and the four previous years' adjusted market values. The market values at December 31 of each of the four preceding years were accumulated to the valuation date with net cash flow (i.e., contributions less benefit payments) and assumed investment return. Net cash flow was assumed to occur uniformly throughout each year. Assumed investment return for a year was calculated assuming that each year, the assets earned interest at the going concern discount rate in effect for that year. Finally, this 5-year average of adjusted market values was then adjusted for net outstanding amounts.

The objective of the asset valuation method is to produce a smoother pattern of going-concern surplus (deficit) and hence a smoother pattern of contributions, consistent with the long-term nature of a going concern valuation.

Such smoothing is achieved by use of an averaging process which systematically recognizes investment returns different from expectations over a 5-year period, with 20% recognized at the valuation date and the remainder at a rate of 20% per year. This method will be expected to average periods of outperformance with periods of underperformance.

The expected return of the going concern discount rate has been selected to equal the expected return on the assets over long periods of time, with a margin for adverse deviations. As such, it is anticipated that, on average, the asset valuation method will tend to produce a result that is somewhat less than the market value of assets.

Actuarial Cost Method

The actuarial liability and the normal actuarial cost were calculated using the projected unit credit cost method (benefit accrual).

C.2 Actuarial Assumptions

	December 31, 2018	December 31, 2017
Economic Assumptions (per annum)		
Liability discount rate	6.00%	5.40%
Rate of inflation	2.00%	Same
Rate of salary increase	2.50% plus Merit and Promotion (see Table 1)[1]	2.50% plus Merit and Promotion (see Table 1)[2]
Escalation of YMPE under Canada/Québec Pension Plan[3]	3.00%	Same
Escalation of *Income Tax Act (Canada)* maximum pension limit[4]	3.00%	Same
Interest on members' contributions	2.00%	Same
Demographic Assumptions		
Mortality	95% of the 2014 Private Sector Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	Same
Retirement from active membership	Age and service related rates (see Table 2)	Same
Pension commencement after termination of employment	Age 65	Same
Withdrawal	Age-related rates (see Table 3)	Same
Disability incidence/recovery	Age-related rates (see Table 4)	Same
Other		
Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	Same
Provision for non-investment expenses	None; return on plan assets is net of all expenses	Same

Notes:

[1] For PWU members for 2019 and 2020, 1.5% p.a. increase plus merit and promotion (per applicable collective bargaining agreement).

[2] For Society for 2018, 0.5% increase plus merit and promotion (per applicable collective bargaining agreement).

[3] The YMPE of $57,400 for 2019 is the starting value for the YMPE projection as at the current actuarial valuation and is indexed starting in 2020.

[4] The *Income Tax Act (Canada)* maximum pension limit of $3,025.56 per year of service in 2019 is the starting value for maximum pension limit projection as at the current valuation and is indexed starting in 2020.

Table 1 — Merit and Promotion Scale

Age	First 4 Years of Employment	Subsequent Years
Under 25	7.5%	2.0%
25 - 29	5.5%	2.0%
30 - 34	3.5%	2.0%
35 - 39	3.5%	1.5%
40 – 44	3.5%	1.5%
45 - 49	2.0%	1.0%
50 - 54	2.0%	1.0%
55 - 59	1.0%	0.5%
60 & over	1.0%	0.0%

Table 2 — Retirement Rates

Age	Eligible for Unreduced Retirement: Based on points (82 or 85)	Eligible for Unreduced Retirement: 35 years of service and over	Not Eligible for Unreduced Retirement
Under 55	10%	30%	0%
55 to 59	15%	30%	5%
60 to 64	12%	30%	7%
65	50%	30%	20%
66 to 69	25%	30%	15%
70 and over	100%	100%	100%

Table 3 — Withdrawal Rates

Service (years)	Male & Female
Under 20	1%
20 and over	0%

Table 4 — Sample Disability Rates

Age	Male & Female
Under 25	0.100%
25	0.100%
30	0.105%
35	0.110%
40	0.115%
45	0.120%
50	0.295%
55	1.000%
60 and above	1.878%

C.3 Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the going concern valuation is summarized below.

The going concern assumptions do not include margins for adverse deviations as a separate Provision for Adverse Deviations has been applied to the actuarial liability and normal actuarial cost.

Liability discount rate

The assumption is an estimate of the expected long-term return on plan assets adjusted as follows:

■ Expected long-term return on plan assets before adjustments	6.06 %
■ Investment management fees	(0.04)%
■ Adjustment for non-investment expenses paid by the plan	(0.07)%
■ Rounding effect	0.05 %
■ Expected long-term return on plan assets after adjustments and margin	6.00 %

Rate of inflation

Estimate of future rates of inflation considering economic and financial market conditions at the valuation date.

Rate of salary increase

■ Assumed rate of inflation per annum	2.00%
■ Effect of real economic growth and productivity gains in the economy	0.50%
■ Individual employee merit and promotion based on a scale which varies by age and service	
■ Total rate of salary increase	2.50% plus Merit and Promotion (see Table 1)

Escalation of YMPE under C/QPP and ITA limit

Indexed annually based on increases in the Industrial Aggregate Wage index for Canada, assumed to be a rate of inflation of 2.00% per annum, plus 1.00% per annum for the effect of real economic growth and productivity gains in the economy.

Mortality

Base mortality rates from the CPM2014Priv table, with a multiplier of 95% based on a review of the experience of the plan's actual mortality experience over the period 2007-2015 are considered reasonable for the actuarial valuation. Applying improvement scale CPM-B generationally provides allowance for improvements in mortality after 2014 and is considered reasonable for projecting mortality experience into the future.

Retirement from active membership

The rates of retirement were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations. All members are assumed to commence their pension at retirement date.

Pension commencement after termination of employment

All terminated members are assumed to commence their pension at the age that produces the highest liability.

Withdrawal

The rates of withdrawal were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations.

Percentage of involuntary terminations of employment

No allowance has been made for involuntary terminations of employment since assuming otherwise would not have a material impact on the actuarial valuation results.

Disability incidence/recovery

The rates of disability incidence/recovery are based on a prior assessment performed by Mercer (Canada) Limited. The use of a different assumption would not have material impact on the actuarial valuation results.

Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form

When provided, the actual data for the spouse and form of payment were used for retired members. For other members, the assumed percentage of members with a spouse is based on the percentages for the general population and an assessment of future expectations for members of the plan.

Years male spouse older than female spouse

When provided, the actual data for the spouse were used for retired members. For other members, the assumption is based on surveys of the age difference in the general population, a review of plan data for the years 2007 to 2015, and an assessment of future expectations for members of the plan.

Provision for non-investment expenses

The liability discount rate is net of all expenses. The assumed level of expenses reflected in the liability discount rate is based on recent experience of the plan and an assessment of future expectations.

Appendix D: Actuarial Basis - Solvency and Hypothetical Windup Valuations

D.1 Methods

Asset Valuation Method

The market value of assets, adjusted for net outstanding amounts, has been used for the solvency and windup valuations. The resulting value has been reduced by a provision for plan windup expenses.

The adjustment in respect of the smoothing of solvency assets for purposes of determining the statutory solvency deficiency was calculated as the difference between the going concern value of assets used for the going concern valuation and the market value of assets.

Liability Calculation Method

The solvency and hypothetical windup liabilities for members were calculated using the traditional unit credit cost method.

Other Considerations

The solvency and hypothetical windup valuations have been prepared on a hypothetical basis. In the event of an actual plan windup, the plan assets may have to be allocated between various classes of plan members or beneficiaries as required by applicable Pension Legislation. Such potential allocation has not been performed as part of these solvency and hypothetical windup valuations.

D.2 Solvency Incremental Cost Actuarial Method

To calculate the Solvency Incremental Cost ("SIC"), we used the same method as for the solvency valuation.

No new entrants have been considered on the basis that such assumptions would not have a material impact on the SIC. The benefits and members' contributions were projected using the going concern valuation assumptions and the plan provisions.

We adjusted the expected settlement method at the end of the projection period to reflect demographic evolution. Regardless of that change, we used the discount rate applicable to the settlement method at the valuation date for each member.

The liability discount rates (before averaging) are assumed to remain at their current level over the projection period.

D.3 Actuarial Assumptions

	December 31, 2018	December 31, 2017
Economic Assumptions (per annum)		
Liability discount rate		
■ Annuity purchase (non-indexed)	3.20%	3.10%
■ Annuity purchase (fully-indexed)	0.08%	-0.13%
■ Annuity purchase (partially-indexed)[1]	0.85%	0.68%
■ Commuted value transfer (non-indexed)	3.20% for 10 years, 3.40% thereafter	2.60% for 10 years, 3.40% thereafter
■ Commuted value transfer (fully-indexed)	1.70% for 10 years, 1.80% thereafter	1.40% for 10 years, 1.60% thereafter
■ Commuted value transfer (partially-indexed)[1]	2.07% for 10 years, 2.17% thereafter	1.70% for 10 years, 2.00% thereafter
Liability discount rate (after averaging for solvency)		
■ Annuity purchase	3.14%	3.37%
■ Commuted value transfer	2.52% for 10 years, 3.56% thereafter	2.48% for 10 years, 3.80% thereafter
Discount rate for determining amortization payments	N/A	Same
Escalation of *Income Tax Act* (Canada) maximum pension limitation [2]	1.14% for 10 years, 1.91% thereafter	1.10% for 10 years, 2.04% thereafter
Demographic Assumptions		
Mortality	CPM2014 Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	Same
Retirement/pension commencement	Described in section D.4	Same

	December 31, 2018	December 31, 2017
Other		
Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	Same
Percentage of members receiving settlement by commuted value transfer [3]	Retired members and beneficiaries: 0% Other members: ■ Not eligible for retirement: 60% ■ Eligible for retirement: 20%	Same
Provision for expenses		
■ Solvency and Hypothetical windup	$7,000,000	Same

Notes:

1 Applicable to New Society and New Management members only.

2 The *Income Tax Act (Canada)* maximum pension limit is $3,025.56 per year of service in 2019 and is indexed starting in 2020.

3 The balance are assumed to receive settlement by annuity purchase.

D.4 Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the solvency and hypothetical windup valuations is summarized below.

The actuarial assumptions used in the solvency and hypothetical windup valuations do not include margins for adverse deviations.

Liability discount rate

Portion of the solvency and hypothetical windup liabilities expected to be settled by a group annuity purchase: based on the CIA annuity purchase guidance applicable at the valuation date which corresponds to an approximation of the annuity purchase rate. The duration of the liabilities assumed to be settled through the purchase of non-indexed annuities is 11.9.

Portion of the solvency and hypothetical windup liabilities expected to be settled by commuted value transfer: determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at the valuation date.

Liability discount rate for solvency (after averaging)

The average discount rates for calculation of the statutory solvency deficiency are based on the following:

- Benefits that are expected to be settled by a group annuity purchase, the average of the annualized approximate annuity purchase rates at December 31, 2018 and the four previous year-ends[1], determined as follows:

December 31, 2014	3.18%
December 31, 2015	3.10%
December 31, 2016	3.10%
December 31, 2017	3.10%
December 31, 2018	3.20%
Average	3.14%

Note:

[1] The approximate annuity purchase interest rates prior to October 1, 2015 have been adjusted to reflect the change in the mortality table assumption applicable to the determination of liabilities settled by group annuity purchase.

- Benefits that are expected to be settled by commuted value transfers, the average of the interest rates determined under the *Standards of Practice for Pension Commuted Values,* published by the Canadian Institute of Actuaries, at December 31, 2018 and the four previous year-ends[1], determined as follows:

	Rate for 10 years	Rate after 10 years
December 31, 2014	2.50%	3.80%
December 31, 2015	2.10%	3.70%
December 31, 2016	2.20%	3.50%
December 31, 2017	2.60%	3.40%
December 31, 2018	3.20%	3.40%
Average	2.52%	3.56%

Note:

[1] The *Standards of Practice for Pension Commuted Values* effective on December 31, 2018 are assumed to have always been in effect when determining the interest rates prior to October 1, 2015.

Escalation of *Income Tax Act (Canada)* maximum pension limitation

The maximum pension limitation under the Income Tax Act (Canada) is scheduled to be indexed annually based on assumed increases in the Industrial Aggregate Wage index. This assumption has been determined as the underlying inflation rates from the rates applicable to benefits expected to be settled by commuted value transfers (after averaging for solvency). For simplicity, this assumption has also been used for the benefits that are expected to be settled by a group annuity purchase.

Pre-retirement and Post-retirement pension increases

For the solvency valuation, as permitted under the Pension Legislation, post-retirement pension increases are assumed to be nil. For the hypothetical windup valuation, the assumption has been determined by applying the post-retirement increase provision specified in the plan to the inflation assumption.

Mortality

For the benefits that are expected to be settled by a group annuity purchase: based on CIA annuity purchase guidance.

For benefits that are expected to be settled by commuted value transfer: prescribed table. No pre-retirement mortality has been assumed in order to approximate the value of pre-retirement death benefits.

Retirement/pension commencement

For active and disabled members:

- Members eligible to retire: pension commences at the age that produces the highest actuarial value (including statutory grow-in rights).
- Members with age plus continuous service greater than or equal to 55 years: pension commences at the age that produces the highest actuarial value of pension (including statutory grow-in rights).
- Other members: age that produces the highest actuarial value.

For deferred vested members:

- Members are assumed to retire at the earliest age at which they qualify for an unreduced pension.

For the benefits that are expected to be settled by a group annuity purchase, this is consistent with the expected assumption that will be used by insurers to price the group annuity. For benefits that are expected to be settled by commuted value transfers, this assumption is in accordance with the Canadian Institute of Actuaries' Standards of Practice for Pension Commuted Values.

Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form

See rationale for going concern assumptions in Appendix C.

Years male spouse older than female spouse

See rationale for going concern assumptions in Appendix C.

Percentage of members receiving settlement by commuted value transfer

This assumption has been determined by considering the benefit provisions of the plan, legislative requirements to offer specific settlement options to various classes of members, and, in particular, the options to be provided to members upon plan windup.

The assumption also reflects the expectation that members further from retirement are more likely to elect to settle their pension benefit by a commuted value transfer, while members closer to retirement are more likely to elect to settle their pension benefit through a group annuity purchase where this option is available. In addition, the assumption reflects past plan experience for terminating and retiring members.

Provision for expenses

Allowance was made for normal administrative, actuarial, legal and other costs which would be incurred if the plan were to be wound up (excluding costs relating to the resolution of surplus or deficit issues). The actuarial valuation is premised on a scenario in which the employer continues to operate after the windup date. In establishing the allowance for plan windup costs, certain administrative costs were assumed to be paid from the pension fund (consistent with past practice) while other costs were assumed to be borne directly by the employer.

Appendix E: Membership Data

	December 31, 2018	December 31, 2017
Active members		
■ Number	5,417	5,165
■ Average age	43.8	43.7
■ Average service	11.9	12.6
■ Annual payroll	$ 573,175,762	$ 548,752,740
■ Average salary	$ 105,811	$ 106,244
■ Accumulated contributions with interest	$ 400,687,906	$ 381,013,270
Disabled members		
■ Number	182	143
■ Average age	53.3	54.2
■ Average service	18.7	22.3
■ Annual payroll	$ 16,744,522	$ 12,955,921
■ Average salary	$ 92,003	$ 90,601
■ Accumulated contributions with interest	$ 11,946,420	$ 9,899,469
Retired members		
■ Number	5,775	5,698
■ Average age	71.9	71.6
■ Total annual pension	$ 261,518,671	$ 250,806,450
■ Average annual pension[1]	$ 45,285	$ 44,017
■ Total temporary annual pension	$ 21,738,013	$ 21,816,672
Beneficiaries and Survivors		
■ Number	1,717	1,751
■ Average age	81.1	81.4
■ Total annual pension	$ 46,592,190	$ 46,336,455
■ Average annual pension[1]	$ 27,136	$ 26,463
■ Total temporary annual pension	$ 344,094	$ 351,395

	December 31, 2018		December 31, 2017	
Terminated vested members				
■ Number		302		305
■ Average age		53.7		54.2
■ Total annual pension[2]	$	3,038,183	$	3,080,065
■ Average annual pension	$	10,060	$	10,099

Notes:

[1] Excluding temporary annual pension.

[2] Prior to application of Income Tax Act maximum pension limits.

The following distribution relates to active and disabled members. The following meanings have been assigned to:

- Age: Age as at December 31, 2018
- Credited Service: Credited service as at December 31, 2018
- Earnings: Pensionable earnings for the year beginning January 1, 2019

		Credited Service								
Age		*0 - 4*	*5 - 9*	*10 - 14*	*15 - 19*	*20 - 24*	*25 - 29*	*30 - 34*	*35 +*	*Total*
< 25	Number									42
	Average Earnings	84,431								84,431
25 - 29	Number		59							398
	Average Earnings	91,997								92,766
	42									
30 - 34	Number	355	561	127						1,043
	Average Earnings	91,068		109,839						100,405
	339	97,185								
35 - 39	Number	207	359	356	22					944
	Average Earnings	92,228		111,347	121,683					104,868
		104,178								
40 - 44	Number	151	185	213	116	1				666
	Average Earnings	86,011		109,575	116,637	*				*
		104,701								
45 - 49	Number	117	116	177	68	8	49	1		536
	Average Earnings	93,056	109,799	114,077	118,620	125,441	112,855			*
		111,479								
50 - 54	Number	95	94	153	91	12	210	161		816
	Average Earnings	89,642	105,980	109,810	114,431	126,092	117,518			109,964
							*			
55 - 59	Number	75	80	121	91	11	114	223	31	746
	Average Earnings	89,170	115,637	105,968	113,125	135,158	109,903		116,391	110,222
							110,849			
60 - 64	Number	36	39	64	44	6	43	48	47	327
	Average Earnings	90,734	108,265	107,969	110,287	*	108,463		118,425	*
							114,558			
65 +	Number		8	18	11		4	17	18	81
	Average Earnings	83,518	106,951	111,716	100,185		125,881		111,647	111,026
							108,201			
Total	Number		1,501	1,229	443	38	420	450	96	5,599
	Average Earnings	90,659	106,207	110,386	114,978	133,883	114,060		116,498	105,362
	5						123,168			

1,422

Average Age = 44.1

Average Credited Service = 12.1

112,913

Review of Membership Data

The membership data were supplied by Hydro One Inc's third-party administrator, Morneau Shepell, as at December 31, 2018.

Elements of the data review included the following:

- ensuring that the data were intelligible (i.e., that an appropriate number of records was obtained, that the appropriate data fields were provided and that the data fields contained valid information);
- preparation and review of membership reconciliations to ascertain whether the complete membership of the plan appeared to be accounted for;
- review of consistency of individual data items and statistical summaries between the current actuarial valuation and the previous actuarial valuation;
- review of reasonableness of individual data items, statistical summaries and changes in such information since the previous actuarial valuation date; and
- comparison of the membership data and the plan's financial statements for consistency.

However, the tests conducted as part of the membership data review may not have captured certain deficiencies in the data. We have also relied on the certification of the plan administrator as to the quality of the data.

Membership Reconciliation

	Actives	Disabled	Terminated vested	Retired	Beneficiaries and survivors	Total
As at December 31, 2017	5,165	143	305	5,698	1,751	13,062
■ New entrants (including re-employed)	299	0	0	0	0	299
■ Transfers from Inergi LP	242	30	0	0	0	272
■ From disabled	6	(6)	0	0	0	0
■ To disabled	(31)	31	0	0	0	0
■ Terminated (with lump sum payment)	(43)	0	(10)	0	0	(53)
■ Termination (with vested pension entitlement)	(32)	0	32	0	0	0
■ Retirement	(186)	(14)	(23)	223	0	0
■ Deceased (without beneficiary)	(1)	(2)	0	(57)	(132)	(192)
■ Deceased (with beneficiary)	(2)	0	(1)	(89)	92	0
■ New ex-spouse	0	0	0	0	3	3
■ Data corrections	0	0	(1)	0	3	2
■ Net change	252	39	(3)	77	(34)	331
As at December 31, 2018	5,417	182	302	5,775	1,717	13,393

Appendix F: Summary of Plan Provisions

The following is an outline of the principal features of the plan which are of financial significance to valuing the plan benefits. This summary is based on the plan document as at November 7, 2016 and amendments up to and including the valuation date, as provided by Hydro One Inc. It is not a complete description of the plan terms and should not be relied upon for administration or interpretation of benefits. For a detailed description of the benefits, please refer to the plan document.

F.1 DB Provisions

Membership

The following categories of employees are members of the Pension Plan:

a) All regular employees (see Note 1a and Note 1b);

b) Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982;

c) Continuing construction employees who were members admitted to the Ontario Electricity Financial Corporation Pension Plan and its predecessors;

d) Employees who became continuing construction clerical employees after July 29,1982 and before August 8, 1984;

e) Employees who have completed three months of continuous employment as a probationary employee (see Note 1a and Note 1b).

Note 1a: Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 are eligible after completing three months of continuous employment but are not required to join the Pension Plan.

Note 1b: Management employees who were not eligible to elect to become a member of the Pension Plan on or after September 30, 2015 are no longer eligible to join the Pension Plan.

Any other employee who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the Year’s Maximum Pensionable Earnings (“YMPE”), as defined under the Canada Pension Plan in each of the two previous consecutive calendar years, may elect to become a member of the Pension Plan.

Normal Retirement Date

a) Female members whose continuous employment commenced prior to January 1, 1976: The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her 65th birthday.

b) All other members: The first day of the month coincident with or next following the attainment of age 65.

Amount of Accrued Pension

Life Pension

a) 2% of the member's "high three-year average" (see Note 6) for each year of credited service, subject to a maximum of 35 years (see Note 2 and Note 3).

Note 2: For Management employees hired on or after January 1, 2004, and Society represented employees hired on or after November 17, 2005 the reference to "high three-year average" is changed to "high five-year average" for pensionable service while a Management or Society-represented employee.

Note 3: For members represented by PWU and the Society, for service accrued after March 31, 2025 for current employees and new hires, the benefit calculated will be determined using "high five-year average" (updated from "high three-year average" used for service accrued until March 31, 2025) as outlined in the respective collective agreements.

LESS

b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 6) for each year of credited service included in (a) above subsequent to December 31, 1965, subject to a maximum of 35 years – see Note 4.

Note 4: Effective July 1, 2001, for members of the PWU, and effective January 1, 2004, for Society represented members hired before November 17, 2005; the factor is reduced from 0.625% to 0.50%.

Bridge Pension (see Note 5)

0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 6) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. This is generally payable until age 65.

The bridge benefit is reduced for early retirement in accordance with the same early retirement reduction provision applicable to the early retirement life pension described below.

Note 5: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, no bridge pension is payable for pensionable service while a Management or Society-represented employee. Effective January 1, 2018, Society represented employees hired on or after November 17, 2005 will be entitled to a bridge benefit equal to 0.625% up to the average YMPE for each year of service from January 1, 2018 onward while the member is earning a benefit under the basic formula.

Note 6: "High three-year average"/ "high five-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the 36/60 consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPE's during the 60 consecutive months when the base earnings were highest.

Early Retirement

<u>Age Plus Service</u> (See Note 7 and Note 8)

A member may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the member's age and years of continuous employment is equal to or greater than 82 or the member has 35 years of continuous employment, whichever occurs first (see Note 7).

Note 7: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, retirement without reduction is available when the sum of the employee's age and years of pensionable service is equal to or greater than 85 or the employee has 35 years of pensionable service, whichever occurs first.

Note 8: For members represented by PWU, for service accrued after March 31, 2025, the early retirement criteria for an unreduced pension will be changed from the sum of the employee's age and years of pensionable service is equal to or greater than 82 to the 85 as outlined in the collective agreement.

<u>25 or More Years of Continuous Employment</u> (see Note 9)

A member who does not qualify for the early retirement provisions above who is at least age 55 and has 25 or more years of continuous employment may retire prior to age 60, in which case the member's accrued pension is reduced by 3% for each year by which early retirement precedes age 60. These reductions also apply to members who elected a deferred pension when they left the Pension Plan and had 25 or more years of continuous employment.

<u>Female Members with More Than 15 Years or Other Members with 15 or More Years but Less than 25 Years of Continuous Employment</u> (see Note 9)

A female member whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other member with 15 or more years but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the member's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the member's normal retirement date.

These reductions apply with respect to a female member whose employment commenced prior to 1976 and who has a deferred pension and at least 25 years of continuous employment at retirement. For any other members who have a deferred vested pension and have fewer than 25 years of continuous employment and are at least age 55 when they request that the pension payments begin, the deferred vested pension will be actuarially reduced (unless the member was eligible for an unreduced early retirement provision in effect when the member terminated active employment).

Other Members

A member, who does not qualify under any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. If the retirement occurred prior to July 1, 2012, the member is also required to have at least two years of Pension Plan membership. In such a case, the pension is the actuarial equivalent of the member's deferred pension provided that the reduction shall not be less than the minimum early retirement reduction required under the *Income Tax Act* (Canada).

Terminated Members with Deferred Pensions

A terminated member with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination. In addition, if the member's employment is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the *Pension Benefits Act* (Ontario) ("PBA"), resulting in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination.

Note 9: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 all references to "continuous employment" are to be replaced with "pensionable service" for service while a Management or Society-represented employee.

Postponed Retirement

Members who work past their normal retirement date shall continue to accrue benefits until December 1st of the calendar year they reach age 71 (or the Income Tax Act age limit, if different), they reach the 35 year service limit, or they terminate employment, whichever occurs first. If a member reaches 35 years of service and ceases contributions to the Pension Plan, service after 35 years is not counted in the calculation of the member's pension, but the pension is calculated using the member's base earnings up to the date of postponed retirement. If the member works past age 71, the member's pension will commence to be paid not later than December 1st of the year in which the member turns age 71.

Pension Increases

Pension increases of 100% (see Note 10) of the increase in the Consumer Product Index (“CPI”) (Ontario), for the 12-month period ending in June of the previous year , will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions to an annual maximum of 8% each year after 1999. Any excess will be carried forward to use in future years up to the 8% limit.

Note 10: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, pension increases of 75% CPI (Ontario) for the 12-month period ending in June of the previous year will be given every January 1, to an annual maximum increase of 6%, with no carry forward.

Disability

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Employee Contributions

Members represented by the Management hired on or after January 1, 2004 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2018,

i. 7.75% of base annual earnings up to the YMPE; and
ii. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

i. 8.25% of base annual earnings up to the YMPE; and
ii. 10.75% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Management hired before January 1, 2004 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2018,

iii. 8.00% of base annual earnings up to the YMPE; and
iv. 10.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

iii. 8.75% of base annual earnings up to the YMPE; and
iv. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired on or after November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2018,

v. 7.75% of base annual earnings up to the YMPE; and

vi. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

v. 8.25% of base annual earnings up to the YMPE; and

vi. 10.75% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired before November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2018,

vii. 8.25% of base annual earnings up to the YMPE; and

viii. 10.25% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

vii. 8.75% of base annual earnings up to the YMPE; and

viii. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Note 11: For Society represented members hired before November 17, 2005, contributions increase by 0.5% in the event that after January 1, 2004 a valuation report reveals that the solvency assets are lower than 106% of the solvency liabilities. Effective April 1, 2018 this clause is no longer applicable.

Members represented by the PWU contribute at the following rates until they complete 35 years of credited service:

On and after December 31, 2017,

ix. 8.75% of base annual earnings up to the YMPE; and

x. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Death Before Retirement

<u>No Surviving Spouse or Eligible Dependent Children</u>

Fewer than two years of Pension Plan membership (Deaths prior to July 1, 2012)

The member's beneficiary or estate receives a cash refund of the member's contributions plus interest.

Two or more years of Pension Plan membership

The beneficiary or estate will receive the following:

- For pre-1987 service: a cash refund of the member's contributions plus interest.
- For post-1986 service: a lump sum equal to the commuted value of the member's pension earned since 1986, plus a refund of any excess contributions.

For deaths occurring on or after July 1, 2012, the beneficiary or estate will be entitled to the death benefits described above regardless of the member's length of service.

Surviving Spouse (see Note 12)

Fewer than two years of Pension Plan membership and less than 10 years of continuous employment

The beneficiary or estate receives a cash refund of the member's contributions plus interest.

Fewer than two years of Pension Plan membership and more than 10 years of continuous employment

The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned to the date of death.

More than two years of Pension Plan membership, but less than 10 years of continuous employment

For pre-1987 service: The beneficiary or estate receives a cash refund of the member's contributions plus interest.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:

  a. a lump-sum payment equal to the commuted value of the pension earned after 1986, or
  b. an immediate or deferred pension with a commuted value equal to pension earned after 1986.

More than two years of Pension Plan membership, and more than 10 years of continuous employment

For pre-1987 service: The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned prior to 1987.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:
- a lump-sum payment equal to the commuted value of the pension earned after 1986, or
- an immediate or deferred pension with a commuted value equal to pension earned after 1986. The immediate pension will not be less than 66.67% of the pension earned after 1986.

Note 12: For deaths occurring on or after July 1, 2012, the surviving spouse's entitlement to death benefits for post-1986 service shall be determined without reference to whether the member had more or less than two years of Pension Plan membership. In addition, for deaths occurring on or after July 1, 2012, if the surviving spouse is entitled to the death benefits in respect of the member's post-1986 service, the surviving spouse is also entitled to an amount equal to the member's contributions, with interest, in respect of pre-1987 service, rather than the designated beneficiary or estate.

<u>Dependent Children, No Surviving Spouse</u>

If the member completed 10 years of continuous employment, the survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest. A payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.

Death After Retirement

A survivor's pension, being an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse, subject to other options chosen at the time of retirement. If the survivor spouse subsequently dies and is survived by the dependent children, or the member does not have a surviving spouse and is survived only by dependent children, the 66.67% survivor pension is split among the dependent children and is payable to age 18 (longer if disabled or in full-time attendance at a school or university).

If the member does not have a surviving spouse at retirement, the normal form of pension is a pension payable for life with a guarantee of 60 payments.

Optional forms of pension are available on an actuarially equivalent basis.

Termination of Employment (see Note 14)

Less Than One Year of Pension Plan Membership

A cash refund of the member's contributions plus interest.

More Than One Year But Fewer Than Two Years of Pension Plan Membership

The member is entitled to elect a cash refund of the member's contributions plus interest, or may leave the earned pension benefit in the Pension Plan to be paid upon retirement.

More Than Two Years but fewer than 10 Years of Pension Plan Membership and, <u>either</u> under Age 45, or Fewer Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to a cash refund of the member's contributions plus interest, or may leave all of the earned pension benefit in the Pension Plan until retirement.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More Than Two Years but fewer than 10 Years of Pension Plan Membership, and Age 45 or Older with More Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) 75% of the commuted value of the pension and receive a refund of 25% of the commuted value of your earned pension; or to leave 75% of the earned pension benefit in the Pension Plan until retirement, and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More Than 10 Years of Pension Plan Membership, But Younger Than Age 45

For service from 1965 to 1986: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More than 10 Years of Pension Plan Membership and Age 45 or Older

For pre-1965 service: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value.

For service from 1965 to 1986: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value; or to transfer (see Note 13) the greater of the commuted value of 75% of the earned pension or the member's contributions with interest and receive a refund of 25% of the commuted value of the earned pension.

For post 1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer the commuted value of the earned pension.

If a member is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the PBA, which could result in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination. If grow-in benefits apply, this may affect the value of the benefits the member is entitled to receive on termination of employment or retirement.

Note 13: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Note 14: In respect of terminations occurring on or after July 1, 2012, a member is entitled to the earned pension benefits for all service regardless of length of Pension Plan membership, continuous employment or age.

Excess Contributions

Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the vested deferred pension accrued after 1986 is refunded to the member (or to the spouse, beneficiary or estate, as applicable in the case of death before retirement).

Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987. (See Note 15)

Note 15: For terminations occurring on or after July 1, 2012, entitlement to excess contributions in respect of pre-1987 service shall be determined without reference to age or years of continuous employment.

Maximum Benefits

The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act (Canada).

Appendix G: Sensitivity Analysis and Other Disclosures

G.1 Sensitivity Information

Amounts determined with a discount rate 1% lower:

Going concern actuarial liability	$ 6,604,180,023
■ As percent increase	14.3%
Solvency actuarial liability	$ 7,463,167,347
■ As percent increase	14.1%
Total normal actuarial cost in respect of benefits	$ 148,002,361
■ As percent increase	30.6%
Employer normal actuarial cost as a percentage of payroll	16.3%

G.2 Solvency Incremental Cost

Solvency Incremental Cost (up to next valuation date)	$ 587,004,649

G.3 Provision for Adverse Deviations Level

Actual Asset Allocation for Fixed Income Assets

The information below as at December 31, 2018 has been used to determine the Provision for Adverse Deviation level.

	Actual asset allocation	Fixed income allocation	Non-fixed income allocation	Fixed income weight
Asset classes				
- Global Equities	47.78%	0%	47.78%	0%
- Private Equities	1.93%	0.965%	0.965%	50%
- Venture Capital	0.73%	0.365%	0.365%	50%
- Real estate and Infrastructure	9.23%	4.615%	4.615%	50%
- Bonds and debentures (below minimum rating)	0.01%	0.005%	0.005%	50%
- Bonds and debentures	38.31%	38.31%	0%	100%
- Cash & short-term investments	2.01%	2.01%	0%	100%
Total	100%	46.27%	53.73%	

Benchmark Discount Rate

Components	Rate
CANSIM V39056	2.18%
Risk Premium on Non-Fixed Income Assets[1]	2.69%
Risk Premium on Fixed Income Assets[2]	0.69%
Diversification Allowance	0.50%
Benchmark Discount Rate	6.06%

Note:

[1] 5.00% of the non-fixed proportion of the assets.

[2] 1.50% of the fixed proportion of the assets.

Provision for Adverse Deviations Level

Components	Provision for Adverse Deviation level
Fixed	4.00%
Asset mix based	3.37%
Benchmark discount rate based[1]	0.00%
Provision for Adverse Deviations Level[2]	7.37%

Notes:

[1] Reflects going concern discount rate less benchmark discount rate (subject to a minimum of zero), multiplied by the going concern liabilities duration (refer to sub-section G.1)

[2] The Provision for Adverse Deviations is applied to the going concern actuarial liability and total normal cost, excluding any portion for future indexation.

Hydro One Inc.

Hydro One Pension Plan

Addendum to the Actuarial Valuation as at December 31, 2018

Registration Number: 1059104

This addendum has been prepared in conjuction with the actuarial valuation of the Plan as at December 31, 2018 and is intended to satisfy the requirements of section 12 of the Ontario Regulation 310/13 to the *Pension Benefits Act (Ontario)* in connection with the application as of March 1, 2018 for the transfer of assets and liabilities of the following pension plans to the Plan:

- Inergi LP Customer Service Operations Pension Plan ("Inergi CSO Plan"), Registration Number 1285733; and
- the Vertex Customer Management (Canada) Limited Pension Plan ("Vertex Plan"), Registration Number 1099993*.*

As of the date of filing this valuation report regulatory approval from the Chief Executive Officer of the Financial Services Regulatory Authority of Ontario of the transfer of assets and liabilities described above is pending. As such, the purpose of this addendum is to provide a financial update of the transfer of assets and liabilities as of December 31, 2018 on a going concern and solvency valuation basis.

Methods and Assumptions

A summary of the methods and assumptions used to develop the amounts herein, can be found in Appendicies C and D of this actuarial valuation report.

Assets

Information relating to the Plan assets can be found in Appendix B of this actuarial valuation report. Information relating to the assets for the Inergi CSO Plan and Vertex Plan was provided by Aon Consulting Inc. on August 14, 2019 and August 20, 2019, respectively.

Membership Data

A summary of the data for the Plan can be found in Appendix E of this actuarial valuation report. For the Inergi CSO Plan and Vertex Plan, the data was provided by AON Consulting Inc. for the purposes of preparing the March 1, 2018 asset transfer valuation report and was adjusted to reflect known retirements and terminations between March 1, 2018 and December 31, 2018. A summary of the membership data can be found on page 3 of this addendum.

Plan Provisions

A summary of the plan provisions can be found in the March 1, 2018 asset transfer actuarial valuation report.

December 31, 2018 Financial Update

The going concern and solvency results at December 31, 2018 are provided below.

	December 31, 2018		
	Inergi CSO Plan	**Vertex Plan**	**Hydro One Pension Plan (Post Transfer)[2]**
Going Concern Position			
Going concern value of assets	$ 19,614,791	$ 85,582,264	$7,307,675,055
Going concern liability	$ 12,641,339	$ 75,483,106	$5,865,730,989
Actuarial Surplus (Unfunded Actuarial Liability)	$ 6,973,452	$ 10,099,158	$1,441,944,066
Funded Ratio	155%	113%	125%
Provison for Adverse Deviation (PfAD)	$ 737,161	$ 4,201,742	$ 355,744,127
Prior Year Credit Balance (PYCB)	0	0	(48,000,000)
Actuarial Surplus (Unfunded Actuarial Liability) After PYCB and PfAD	$ 6,236,291	$ 5,897,416	$1,038,199,940
Solvency Financial Position			
Solvency value of assets	$ 19,614,791	$ 85,582,264	$7,306,831,055[1]
Solvency liability	$ 17,136,299	$ 92,647,303	$ 6,649,374,541
Solvency Surplus (Unfunded Solvency Liability)	$ 2,478,492	$ (7,065,039)	$ 657,456,514
Prior Year Credit Balance	$ 0	$ 0	$ (48,000,000)
Solvency ratio	Not less than 100%	92%	Not less than 100%

Notes:

[1] Reflects $7,000,000 of assumed windup expenses.

[2] For convience, the going concern and solvency position of the Plan post transfer is also shown.

Summary of Membership Data

	Inergi CSO Plan	Vertex Plan
Active Members		
Number	240	223
Average Age (years)	46.3	46.7
Average Credited Service (years)	2.5	9.8
Average Salary	$ 70,526	$ 72,587
Disabled Members		
Number	23	16
Average Age (years)	54.1	54.2
Average Credited Service (years)	9.0	11.4
Average Salary	$ 72,956	$ 75,411
Deferred Vested Members		
Number	9	22
Average Age (years)	47.3	48.2
Average Annual Accrued Pension	$ 2,991	$ 7,667
Retired Members		
Number	17	49
Average Age (years)	61.2	64.3
Average Annual Pension In Pay	$ 2,894	$ 33,817
Outstanding Commuted Values		
Number	N/A	26
Total outstanding commuted values	N/A	$ 4,237,246

Actuarial Information Summary

See the instructions for completing this form. If an item does not apply, enter N/A.

Part I – Plan Information and Contributions

A. 001. Name of registered pension plan
Hydro One Pension Plan

B. 002. Registration number

Canada Revenue Agency: 1059104 Other:

C. 003. Is this plan a designated plan? ☐ Yes ☑ No

D. 004. Valuation date of report Year Month Day: 2018 12 31

E. 005. End date of period covered by report Year Month Day: 2021 12 30

F. 006. Purpose of the report (indicate all reasons for which the report was prepared)

☐ Initial report for a newly established plan
☑ Regular (triennial or annual) report for an ongoing plan
☐ Interim report in respect of an amendment to an ongoing plan
☐ Partial termination
☐ Termination
☐ Conversion
☐ Other (explain)

G. Contributions (prior to application of any credits or surplus) for covered period

Periods (see instructions)	Period 1	Period 2	Period 3	Period 4
007. Period start date (YYYY-MM-DD)	2019-01-01	2020-01-01	2021-01-01	
008. Period end date (YYYY-MM-DD)	2019-12-31	2020-12-31	2021-12-30	
Normal cost (defined benefit provision) 009. Members	53,554,752	52,850,402	51,617,771	
010. Employer	66,463,461	65,993,735	65,248,200	
010a. Explicit expense allowance included in employer normal cost above				
Normal cost (money purchase provision) 011. Members				
012. Employer				
Special payments Special payments for going-concern unfunded liability and solvency deficiency 013. Employer	0	0	0	
013a. Members	0	0	0	
Fixed contributions 014. Estimated dollar amounts of fixed employer and, if applicable, member contributions (defined benefit provision)				
014a. Estimated dollar amounts of fixed employer and, if applicable, member contributions (money purchase provision)				

Part II – Membership and Actuarial Information

H. Membership information	Number	Average age	Average pensionable service	Average salary	Average annual pension
015. Active members	5,599	44.10	12.10	105,362	N/A
016. Retired members	7,492	74.00	N/A	N/A	41,125
017. Other participants	302	53.70	N/A	N/A	10,060

I. Actuarial basis for going-concern valuation (see instructions)

020. Asset valuation method

☐ Market ☑ Smoothed Market ☐ Book ☐ Book and Market combination ☐ Other (specify)

021. Liability valuation method

☑ Accrued benefit (unit credit) ☐ Entry age normal ☐ Individual level premium ☐ Aggregate ☐ Attained Age

☐ Other (specify)

I. Actuarial basis for going-concern valuation (continued)

Selected actuarial assumptions

Where a flat rate is used, enter the rate under Ultimate rate and N/A under Initial rate and Number of years.

Valuation Interest rate	Initial rate (%)	Number of years	Ultimate rate (%)
025. Active members	N/A	N/A	6.00
026. Retired members	N/A	N/A	6.00
027. Rate of indexation	N/A	N/A	2.00
028. Rate of general wage and salary increase	N/A	N/A	2.50
029. YMPE escalation rate	N/A	N/A	3.00
030. Income Tax Regulations' maximum pension limit escalation	N/A	N/A	3.00
031. Rate of CPI increase	N/A	N/A	2.00

032. Components of going-concern valuation interest rate on line **025** and/or **026**

a) Expected investment return on plan assets, excluding additional return from active investment management .... 6.06 %

b) Expected additional return from active investment management .... 0.00 %

c) Expected expenses paid from the fund for active investment management .... 0.00 %

d) Expected investment expenses other than those reported on line **032 (c)** .... -0.04 %

e) Other expected expenses including administrative expenses .... -0.07 %

f) Effect of rebalancing and diversification, if any .... 0.00 %

g) Margins for adverse deviations .... 0.00 %

h) Other components .... 0.05 %

i) Net going concern valuation interest rate .... 6.00 %

035. Year Income Tax Regulations' maximum pension limit escalation commences 2019

036. Mortality table

☐ 1994 GAM Static ☐ 1994 Group Annuity Reserving (GAR) ☐ 1994 UP ☐ 80% of 1983 GAM ☐ CPM2014

☐ CPM2014Publ ☑ CPM2014Priv ☐ Other (specify) ______

036a. Improvement scale

Has a projection of mortality improvement been made? .... ☑ Yes ☐ No

i) Has an assumption of generational mortality improvements been made? .... ☑ Yes ☐ No

ii) If applicable, what is the year in which the mortality improvements have been projected? .... ____

iii) Which scale have you used?

☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) ______

036b. Adjustment to the mortality table

i) Has an adjustment to the mortality table been made? .... ☑ Yes ☐ No

ii) If **yes**, which percentage did you apply to .... Male 0.95 Female 0.95

037. Allowance for promotion, seniority, and merit increases

☐ Included in (line **028**) above ☑ Separate scale based on age or service ☐ No allowance

038. Allowance for expenses

038a. Allowance for investment expenses

☑ Implicit ☐ Explicit ☐ Both explicit and implicit

038b. Allowance for administrative expenses

☑ Implicit ☐ Explicit ☐ Both explicit and implicit

039. If a multi-employer plan, number of hours of work per member per plan year ....

040. Was a withdrawal scale used? .... ☑ Yes ☐ No

041. Were variable retirement rates used? .... ☑ Yes ☐ No

042. If **no**, what is the assumed retirement age? .... ______

J. Actuarial basis for solvency valuation

Valuation interest rate	Initial rate (%)	Select period	Ultimate rate (%)
		10	
046. Benefits to be settled by lump sum transfer	3.20		3.40
046. Benefits to be settled by purchase of deferred annuity	N/A	N/A	3.20
047. Benefits to be settled by purchase of immediate annuity	N/A	N/A	3.20
048. Rate of indexation	N/A	N/A	N/A

049. Mortality table

Lump sum: ☐ 1994 UP Generational ☐ CPM2014Priv ☑ CPM2014 ☐ CPM2014Publ ☐ Other (specify)

Annuity Purchase: ☐ 1994 UP Generational ☐ CPM2014Priv ☑ CPM2014 ☐ CPM2014Publ ☐ Other (specify)

049a. Improvement scale used

Lump sum: ☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) ☐ None

Annuity Purchase: ☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) ☐

K. Balance sheet information (DB provisions, see instructions)

050. Market value of assets, adjusted for receivables and payables	7,208,634,000
051. Amount of contributions receivable included in market value above	
Going-concern valuation	
052. Going-concern assets	7,202,478,000
053. Optional ancillary contributions account balance included in going-concern assets above for a flexible pension plan (if applicable)	0
Going-concern liabilities	
060. For active members	1,662,138,096
061. For retired members	4,083,736,181
062. For other participants	31,732,267
	0
064. Reserves	
064a. Expenses	0
064b. Ad-hoc indexing	0
064c. Provision for adverse deviation	350,805,224
064d. Other (Specify)	
070. Net funded position—surplus/deficit	1,074,068,232
071. Additional voluntary contributions	0
072. Money purchase assets (if applicable)	0

Solvency valuation

Complete lines 080 to 100 only if the report contains an explicit solvency valuation

Solvency assets	
080. Solvency assets with adjustment for expense provision, if any	7,201,634,000
081. Amount of wind-up expense provision reflected in line 080	7,000,000
082. Optional ancillary contributions account balance included in solvency assets above for a flexible pension plan (if applicable)	
Solvency liabilities	
090. For active members	2,068,058,938
091. For retired members	4,433,823,741
092. For other participants	37,708,259
093. For optional ancillary benefits to be provided under a flexible pension plan (if applicable)	0
094. Reserves	
094a. Expenses	0
094b. Other (Specify)	
100. Net solvency position—surplus/deficit	662,043,061
101. Incremental cost	567,004,645

If the plan provides benefit increases coming into effect during the period covered by the report but after the valuation date, have those increases been reflected in:

102. The going-concern liabilities in lines **060** to **064**? ☐ Yes ☐ No ☑ N/A

103. The solvency liabilities in lines **090** to **094**? ☐ Yes ☐ No ☑ N/A

Discount rate sensitivity

	Change in percentage using discount rate 1% lower	Change in amount using discount rate 1% lower	Change in amount using discount rate 1% higher
104. Going-concern liabilities	14.30	826,573,479	
105. Normal cost	30.60	34,655,742	
106. Solvency liabilities	14.10	923,576,408	

107. Duration of the portion of the liabilities assumed to be settled through the purchase of annuities. 11.90

L. Actuarial gains or losses

110. Was a gain/loss analysis done? ☑ Yes ☐ No

111. If line **110** is **yes**, indicate the date of the last filed funding valuation report and the net funded position as of that date Year Month Day 2017 12 31 811,828,731

If line **110** is yes, indicate amount of gain or loss due to:

112. interest on surplus (unfunded liability)	43,838,751
113. special payments made	0
114. amount used for contribution holiday	0
115. change in actuarial assumptions	485,063,986
116. change in the asset valuation method	0
117. change in liability valuation method	0
118. plan amendments/changes	0
119. investment experience	132,768,855
120. retirement experience	(14,059,141)
121. mortality experience	(7,702,027)
122. withdrawal experience	(6,623,303)
123. salary increase experience	9,968,737
124. optional ancillary contributions forfeited	

Are there major contributing sources other than lines **112** to **124** above (if yes, specify)

125. contractual pension increases	(16,001,483)
126. Provision for Adverse Deviation	(350,805,224)
127. all other sources (combined)	(14,211,650)

M. Subsequent events

135. Are there any subsequent event(s) that have not been reflected in the valuation? (refer to SOP) ☐ Yes ☑ No

N. Statements of opinion

136. Does the report include the statements of opinion required by the SOP (data, assumptions, methods, accepted actuarial practice)? ☑ Yes ☐ No

136a. Are any of the actuary's statements of opinion qualified? ☐ Yes ☑ No

Part III – Information required by the Financial Services Commission of Ontario

O. Additional valuation information

For purposes of Part III, the Regulation refers to the Regulation 909, R.R.O. 1990, as amended except as otherwise provided.

Going-concern valuation

137. Are benefits under the pension plan provided by an annuity purchase? ☐ Yes ☑ No

138. If line 137 is **yes**,

a) Enter the total asset value of the buy-in annuities as reported in the actuarial valuation report

b) Enter the total liabilities related to the buy-in annuities as reported in the actuarial valuation report

c) Enter the total asset value of the non-discharged buy-out annuities as reported in the actuarial valuation report

d) Enter the total liabilities related to the non-discharged buy-out annuities as reported in the actuarial valuation report

e) Have any annuities been discharged under OPBA section 43.1 since last valuation date? ☐ Yes ☐ No

If yes,

i) How many annuity discharge transactions have been made since the last valuation date?

ii) Enter the total premium of the buy-out annuities if the purchase was made since the last valuation date

iii) Enter the going-concern liabilities related to the annuity discharge at the time of purchase.

iv) Enter the top-up contributions required as per section 4 of Ontario Regulation 193/18.

139.1. Is the plan required to report the amount of Available Actuarial Surplus? ☑ Yes ☐ No

i) If yes, enter the amount of Available Actuarial Surplus: 0

139.2. Breakdown of the total special payyments with respect to the going-concern unfunded liability and plan amendment

Special payments with respect to:	Period 1	Period 2	Period 3	Period 4	Present value of the special payments on the going-concern basis
Going-concern unfunded liability 139.2a Members	0	0	0		0
139.2b Employer	0	0	0		0
Plan amendment 139.2c Members	0	0	0		0
139.2d Employer	0	0	0		0

Provision for Adverse Deviations

139.3. Is the Provision for Adverse Deviations of the plan zero or deemed to be zero? ☐ Yes ☑ No

If no, complete lines **139.4** to **139.9**

139.4. Is the plan closed as determined in subsection 11.2(2) component A of the Regulation? ☐ Yes ☑ No

139.5 Combined target asset allocation for fixed income assets as determined in subsection 11.2(4) component J of the Regulation: 46.27 %

139.6 Plan's duration of going-concern liabilities in subsection 11.2(5) of the Regulation: 15.00

139.7 Total Provision for Adverse Deviation (%): 7.37 %

139.8 Amount of Provision for Adverse Deviation included normal cost (line **9**, **10** and **10a**): 6,671,594.00

139.9. a) Does the plan provide future escalated adjustments? ☑ Yes ☐ No

If 139.9(a) is yes,

b) Are the future costs of escalated adjustments Included in the calculation of the Provision for Adverse Deviation amounts on lines **064c** and **139.8**? ☐ Yes ☑ No

If 139.9(b) is no,

c) Enter the going-concern liability related to the future escalated adjustments: ,017,698,491

d) Enter the normal cost related to the future escalated adjustments: 22,822,962

Solvency valuation

140.1 If line **137** is **yes**,

a) Enter the total asset value of the buy-in annuities as reported in the actuarial valuation report ....

b) Enter the total liabilities related to the buy-in annuities as reported in the actuarial valuation report ....

c) Enter the total asset value of the non-discharged buy-out annuities as reported in the actuarial valuation report ....

d) Enter the total liabilities related to the non-discharged buy-out annuities as reported in the actuarial valuation report ....

e) If line **138(e)** is **yes**,
i) Enter the solvency liabilities related to the discharge at the time of purchase..........

140.2 Enter the total value of any reduced solvency deficiency payments (or solvency deficiency payments if applicable) that are guaranteed by letter(s) of credit..........

140.3 Enter the expiry date of the letter of credit, if any .... Year | Month | Day

140.4 Solvency asset adjustment .... -6,156,000

140.5 Solvency liability adjustment.......... -68,758,462

140.6 Reduced solvency deficiency.......... 991,252,410

140.7 Solvency ratio as per the Regulation (express in decimal format) 1.0900

140.8 Components of the solvency special payments on lines **013** and **013a**

Special payments with respect to reduced solvency deficiency	Period 1	Period 2	Period 3	Period 4	Present value of the special payments on the solvency basis
140.8a Members	0	0	0		0
140.8b Employer	0	0	0		0

141. Have any of the excludable benefits been excluded?.......... ☑ Yes ☐ No ☐ N/A

142. If line **141** is **yes**, enter the total amount of liabilities being excluded 3,256,931,443

144. (i) Has an averaging method been applied to the market value of assets in determining the solvency asset adjustment?.......... ☑ Yes ☐ No

a) If **yes**, indicate the positive or negative amount by which the solvency assets are adjusted as a result of applying the averaging method.......... (6,156,000)

(ii) Has the averaging method used in determining the solvency asset adjustment changed since the last valuation? ☐ Yes ☑ No

If **yes**, complete **(ii)a** or **(ii)b**, as appropriate:

a) The change in method increases the solvency asset adjustment by the amount of..........

b) The change in method decreases the solvency asset adjustment by the amount of ....

P. Miscellaneous

145. Prior year credit balance.......... 48,000,000

146. Transfer ratio (express in decimal format).......... 0.7300

Guarantee fund assessment

147. PBGF liabilities 6,539,590,939

148. PBGF assessment base.......... 0

149. Amount of additional liability for plant closure and/or permanent layoff benefits as described in E of subsection 37(4) of the Regulation 0

149a. Number of Ontario plan beneficiaries.......... 13,393

Part IV – Information required by the Canada Revenue Agency

R. Additional Information

173. Surplus/deficit determined at the valuation date as per the instructions:

173a. Going-concern basis	1,074,066,232
173b. Wind-up basis	-2,594,888382
173c. For designated plans, maximum funding valuation basis	

174. Excess surplus determined at the valuation date:

174a. Going-concern basis	
174b. For designated plans, maximum funding valuation basis	

175. For designated plans, employer normal cost determined under the maximum funding valuation basis:

Period 1	
Period 2	
Period 3	
Period 4	

176. Minimum surplus required under applicable pension benefit legislation before contribution holiday:

176a. Going-concern basis	
176b. Wind-up basis	

177. Maximum amount that could be claimed as eligible employer contribution(s) – defined benefit provisions – under subsection 147.2(2) of the Income Tax Act:

177a. Unfunded liability	2,594,888,382
177b. Normal cost:	
Period 1	66,463,461
Period 2	65,993,735
Period 3	65,248,200
Period 4	

178. Do you have any employees contributing over the limit stipulated under paragraph 8503(4) of the Income Tax Regulations? ☑ Yes ☐ No

Part V – Information required by Retraite Québec

S. Additional information

185. Date on which the valuation report was prepared ____________
186. Value of additional liabilities arising from an improvement on a funding basis ____________
187. Value of additional liabilities arising from an improvement on a solvency basis ____________
188. Surplus assets that can be allocated to fund contributions ____________
189. Special payments ____________
190. Total of the letters of credit taken into account in the assets on a funding basis ____________
191. Insured annuities from an insurer taken into account in the actuarial valuation on a solvency basis ____________

T. Additional information for plans whose employer is a municipality, a municipal housing bureau, or an educational institution at the university level

For service prior to the establishment of the stabilization fund

192. Reserve on a funding basis ____________

	Present value	Amortization payments			
		Period 1	Period 2	Period 3	Period 4
193. Deficiency attributable to the employer					
194. Funding deficiency 194a. Payable by the members					
194b. Payable by the employer					

For service following the establishment of the stabilization fund

195. Stabilization fund value ____________

	Stabilization contributions			
	Period 1	Period 2	Period 3	Period 4
196. Members				
197. Employer				

	Present value	Amortization payments			
		Period 1	Period 2	Period 3	Period 4
198. Technical funding deficiency 198a. Payable by the members					
198b. Payable by the employer					

U. Additional information for pension plans other than those mentioned in Section T, and for which solvency funding does not apply.

199. Target level (as a percentage) of the required stabilization provision ....

	Current service stabilization contributions			
	Period 1	**Period 2**	**Period 3**	**Period 4**
200. Members				
201. Employer				

	Present Value	Amortization payments			
		Period 1	**Period 2**	**Period 3**	**Period 4**
202. Technical funding deficiency					
202a. Payable by the members					
202b. Payable by the employer					
203. Stabilization funding deficiency					
203a. Payable by the members					
203b. Payable by the employer					
204. Improvement funding deficiency					
204a. Payable by the members					
204b. Payable by the employer					

Part VI – Certification by Actuary

As the actuary who signed the funding valuation report (the report), I certify that this completed form accurately reflects the information provided in the report.

Dated this 30 (day) day of September (month), 2019 (year)

Suzanne Jacques
Signature of actuary

Suzanne Jacques
Print or type name of actuary

Towers Watson Canada Inc.
Name of firm

(416)960-7460
Telephone

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Email*

*** Optional information. The Canada Revenue Agency will not communicate on plan specific matters with clients by email, since we cannot guarantee the confidentiality of emailed information.**

Personal information is collected under the authority of section 147.2 of the Income Tax Act and is used for the administration of a registered pension plan. It may also be used for any purpose related to the administration or enforcement of the Act such as audit and compliance. Information may also be shared or verified under information-sharing agreements to the extent authorized by law. Under the Privacy Act, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source canada.ca/cra-info-source, Personal Information Bank CRA PPU 226.

WillisTowersWatson

February 26, 2021

Our Ref: 601835/3140218

Hydro One Inc.
483 Bay Street, South Tower
Toronto, Ontario M5G 2P5

REVISED HYDRO ONE INC. (“HYDRO ONE”) PROJECTED 2021 – 2027 BENEFIT COST UNDER FASB ASC 715-20-50

As requested, we have prepared the projected benefit cost for 2021 to 2027 under FASB Accounting Standards Codification Topic 715-20-50 (“US GAAP”) for the following pension and benefits plans sponsored by Hydro One. *As instructed by Hydro One, note that the Hydro One PRB projections have been revised to remove certain retirees that were not entitled to medical and dental benefits*:

- Hydro One Pension Plan (the “RPP”);
- Hydro One Defined Contribution Plan (the “DCPP”);
- Hydro One Supplementary Pension Plan (the “SPS/DSPS”);
- Hydro One Supplemental Defined Contribution Plan (the “Notional DCPP”);
- Hydro One Non-Pension Post Retirement Benefits (the “Hydro One PRB” and the “Inergi PRB”); and
- Hydro One Post-Employment Benefits (the “PEB”).

It is intended that this letter is read in conjunction with our December 31, 2020 year-end disclosure reports (the “2020 Year-end Reports”) for all benefit plans listed above.

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Key Results - Projected Benefit Cost ($millions)

Based on the assumptions and approaches set out later in this letter, the projected benefit cost for the various arrangements are as follows:

	2021	2022	2023	2024	2025	2026	2027
RPP	$193.9	$187.2	$180.0	$172.3	$158.7	$149.0	$142.8
SPS/DSPS	$7.8	$7.4	$7.2	$7.0	$6.7	$6.5	$6.3
DCPP	$3.2	$3.7	$4.2	$4.5	$4.8	$5.2	$5.5
Notional DCPP	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3
Hydro One PRB	$94.6	$102.7	$107.9	$112.6	$117.3	$122.2	$126.9
Inergi PRB	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
PEB	$21.9	$22.8	$23.5	$24.1	$24.9	$25.7	$26.4
Total	**$322.1**	**$324.5**	**$323.5**	**$321.3**	**$313.2**	**$309.4**	**$308.7**

Detailed schedules providing the development of the benefit cost by year for each plan, other than for the DCPP, can be found in the enclosed Appendices. As requested, we have also included the allocation of projected benefit costs to the active and inactive members of the plans (other than for the DCPP and Notional DCPP) and an allocation of the projected benefit costs in respect of the Inergi and Non-Inergi obligations of the PRB plan. Appendices A and B provide projection details as follows:

- Appendix A – Projections for RPP, SPS/DSPS and Notional DCPP; and
- Appendix B – Projections for Hydro One PRB, Inergi PRB, and PEB.

Assumptions

All assumptions remain unchanged when compared to the assumptions used in the 2020 Year-end Reports, with the exception of an assumption of new entrants disclosed in this letter. A summary of the assumptions can be found in Appendix C.

Discount Rate Sensitivity – Projected Benefit Cost ($millions)

The projected benefit cost each year as a result of a 0.5% decrease in the accounting discount rates for the projection period are as follows (no other assumptions are assumed to change):

	2022	2023	2024	2025	2026	2027
RPP	$286.5	$276.4	$265.6	$248.0	$235.1	$226.5
SPS/DSPS	$7.8	$7.5	$7.3	$6.9	$6.7	$6.5
DCPP	$3.7	$4.2	$4.5	$4.8	$5.2	$5.5
Notional DCPP	$0.2	$0.2	$0.3	$0.3	$0.3	$0.3
Hydro One PRB	$111.4	$116.6	$121.1	$125.8	$130.9	$135.9
Inergi PRB	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6
PEB	$23.1	$23.8	$24.4	$25.1	$25.9	$26.6
Total	**$433.3**	**$429.3**	**$423.8**	**$411.5**	**$404.7**	**$401.9**

Membership Data

Summaries of data upon which these projections were based can be found in the following documents:

RPP: Hydro One Pension Plan actuarial valuation report as at December 31, 2018 dated September 19, 2019 (the "Funding Report") and the the Addendum to the Funding Report;

SPS/DSPS: Hydro One Supplementary Pension Plan December 31, 2019 actuarial report dated September 2020 (the "LOC Report");

DCPP and Notional DCPP: Provided by Hydro One on January 6, 2021 and February 3, 2021;

Hydro One PRB and Inergi PRB: - Presentation to Hydro One dated February 2021 with respect to valuation results as at January 1, 2020 (the "PRB Presentation"); and

PEB - Presentation to Hydro One dated February 2021 with respect to valuation results as at December 31, 2020 (the "PEB Presentation").

In addition, information regarding new entrant assumptions can be found under the Methodology section of this letter.

Plan Provisions

Summaries of the provisions for the different plans other than the DCPP and Notional DCPP, can be found in the Funding Report, LOC Report, PRB Presentation and the PEB Presentation.

DCPP

For Management employees hired on or after September 30, 2015, they are no longer entitled to the DB plan and they accrue benefits on a Defined Contribution (DC) basis. Members may elect to contribute 4%, 5% or 6% of pensionable earnings. Hydro One matches 100% of member contributions. The estimated annual pension expense for the DCPP is equal to the estimated annual contributions to the plan based on the profile of existing and new management employees (see Methodology section below) and assuming all members contribute 6% of pensionable earnings.

It was assumed that members of the DCPP will continue to be eligible for the Hydro One PRB Plan, with the provisions in place as of the date of this letter.

Notional DCPP

The Notional DCPP provides for Company contributions in excess of the Income Tax Act limit for members who participate in the DCPP. These notional contributions are allocated to the respective members and they accrue with deemed investment returns on a periodic basis.

Methodology

Funding Contributions - RPP

Hydro One funding contributions until December 31, 2021 are assumed to be equal to estimated normal cost outlined in the Funding Report, adjusted for expected future new entrants. From January 1, 2022 to December 31, 2027, Hydro One funding contributions are assumed to be equal to the estimated normal cost extrapolated from the results in the Funding Report with the following adjustments to the assumptions:

- a going concern discount rate of 4.9% p.a.;
- a decrease in the inflation, YMPE / ITA increase and indexation increase assumption of 25 bps (relative to the Funding Report);
- the salary scale used in 2020 Year-end Reports; and
- a Provision for Adverse Deviation (“PfAD”) of 7.3%; and
- expected future new entrants decribed in this letter.

The going concern discount rate and PfAD were determined based on December 31, 2020 market condtions.

Additionally, we have assumed that the exisiting prior year credit balance will be applied as follows: $12 million in each of 2021 and 2022, with the remaining applied in 2023.

We have assumed that no special funding payments would be required over the projection period. It is important to note that the minimum required contributions following the next filed actuarial valuation may be significantly different due to a number of factors, including experience gains and losses and future changes to liability measurement assumptions.

Assets

The market value of assets as at December 31, 2020 for the RPP was provided by Hydro One on January 9, 2021. The estimated market value of assets over the projection period has been extrapolated from the market value of assets as at December 31, 2020. The extrapolations are based on estimated contributions (including the use of the remaining Prior Year Credit Balance in 2021, 2022 and 2023), benefit payments in the intervening period and a return on assets assumption of 5.40% per annum.

As instructed by Hydro One, the estimated member contributions to be made to the RPP during the projection period are in accordance with the rates outlined in the Funding Report. We have not reflected future increases in employee contributions beyond those described that may come into effect in future years.

Consistent with Hydro One's actual disclosures at December 31, 2020, we have included the value of the Refundable Tax Account balance for the SPS/DSPS in our calculations. In addition, we have included the expected letter of credit fee in the expense calculations over the projection period.

Hydro One PRB, Inergi PRB and the PEB are not funded and have no assets.

Benefit Obligations and Service Cost

The projected benefit obligations and service cost over the period (December 31, 2021 to December 31, 2027) for the RPP have been estimated based on the most recent membership data as set out in the Funding Report projected to each December 31 using the assumptions set out in this letter. For PRB and PEB, the projected benefit obligations and service cost have been estimated based on the most recent membership data as set out in the PRB and PEB presentations respectively, with the adjustments which have been outlined in this letter. In addition, it was assumed that some active members terminating or retiring would be replaced by new entrants. As directed by Hydro One, we have assumed the following with respect to new entrants:

For the RPP:

	Percentage of New Entrants in Category	Average Age	Average Earnings
Power Workers Union Members	42%	30	$80,000
Society Members	58%	33	$90,000
Management Members	0%	N/A	N/A

As instructed by Hydro One, the RPP active membership in aggregate, is assumed to change at the following rates:

	2021	2022	2023	2024	2025	2026	2027
Population Change %	-1.35%	4.48%	0.43%	-0.20%	-0.34%	-0.08%	0.04%

For the DCPP and Notional DCPP:

For each year commencing January 1, 2021, new Management members are assumed to be hired externally. Each member is assumed to have average earnings of $120,000. No terminations or retirements were assumed over the projection period.

As instructed by Hydro One, the DCPP active membership in aggregate, is assumed to increase at the following rates:

	2021	2022	2023	2024	2025	2026	2027
Population Change %	41.8%	13.2%	7.1%	3.8%	4.5%	4.9%	3.2%

For the Notional DCPP no new entrants are assumed.

For the SPS/DSPS:

The projected benefit obligations and service cost over the projection period for the SPS/DSPS have been estimated based on the most recent membership data as set out in the LOC Report, projected using the demographic assumptions set out 2019 Year-end Reports.

For the PRB plan:

	Percentage of New Entrants in Category	Average Age	Average Earnings
Power Workers Union Members	14%	41	$100,000
Society Members	68%	36	$100,000
Management Members	18%	39	$117,000

For the Hydro One PRB plan and the PEB, the active membership in aggregate, is assumed to change at the following rates:

	2021	2022	2023	2024	2025	2026	2027
Population Change %	5.9%	1.0%	0.2%	-0.2%	0.2%	0.3%	-0.1%

The active membership projection of the Hydro One PRB plan and the PEB reflects the open nature of the plans to all employee groups for DB and DC groups.

The projected benefit obligations and service cost over the projection period for the Inergi PRB have been estimated based on the most recent membership data as set out in the PRB Presentation, with the adjustments which have been outlined in this letter. Given that this is a closed group, active membership will decline over time in accordance with the demographic assumptions.

Except as noted above, please refer to the 2020 Year-end Reports for additional details on methodology and accounting policies.

Allocation of Benefit Cost

Active and Inactive Split

As instructed by Hydro One, the projected benefit cost over the projection period is allocated to the active and inactive members of the plans as follows:

Current Service Cost	Allocated to active members
Interest Cost and EROA -	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Amortization of net actuarial (gains)/losses	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year -
Past service cost for RPP	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year -
Past service cost for SPS/DSPS -	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of that calendar year with the exception of certain past service costs for SPS/DSPS that are entirely in respect of former executives and are fully allocated to the inactive membership -
Past service cost for the PRB plans	Entirely allocated to active members

Notes Concerning our Calculations

There are a number of factors not reflected in this report that could potentially result in the benefit costs being different than expected including, but not limited to, changes to pension or benefit plan provisions other than those mentioned in this letter, experience revealed in any new valuation of the plans, contributions to the pension fund significantly different than expected, any significant event such as material downsizing or acquisition/divestiture, change in accounting standards or additional changes to the assumptions or methodology.

Actuarial Certification

The calculations herein have been made in accordance with US GAAP with which we are familiar. The - assumptions used were selected by Hydro One management for the purpose of preparing this letter, - following discussions with Willis Towers Watson, and they are in accordance with accepted actuarial practice. In our opinion, the data on which the calculations are based are sufficient and reliable for the purpose of these estimates. This letter and attachments have been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

The results presented in this letter have been developed using a particular set of actuarial assumptions and methods. Other results could have been developed by selecting different actuarial assumptions and methods.

Willis Towers Watson

February 23, 2021

The results presented in this letter are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events. The actual benefit cost levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which has been anticipated at this time. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future accounting valuations.

Effects of COVID-19 on the financial markets, regulations, and experience are uncertain and still evolving. The results in the attached exhibit make no allowances for the effects of COVID-19. There may be significant effects on plan experience and/or assumptions, both demographic and economic used for future measurements.

As at the date of this letter, other than mentioned above, we are not aware of any subsequent events that would have a material impact on the results of the projected benefit cost.

The information contained in this letter was prepared for Hydro One, for its internal budgeting purposes and in conjunction with the joint rate application to the Ontario Energy Board. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard.

The undersigned consultants with actuarial credentials meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinions contained herein. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Canada Inc.

Should you have any questions, please do not hesitate to contact us.

TOWERS WATSON CANADA INC.

In respect of the pension plans:

Suzanne Jacques, FCIA, FSA

Davis Gonsalves, FCIA, FSA

In respect of the post-retirement and post-employment plans:

Ross Cristiano, FCIA, FSA

Andrea Firmani, FCIA, FSA

Enclosures

cc: - Samir Chhelavda, Arthur McGlashan, Kamil Baig — Hydro One Inc.
David Kenny, Tiffany Kuo, Michael Vo, Susan Liao, Anica Curcic — Willis Towers Watson

Appendix C - Statement of Assumptions (RPP and SPS/DSPS)

The rates in the following table are on a per annum basis.

Measurement Date	**December 31, 2020 (as per year-end disclosures) and End of December 31 During Projection Period (2021-2027)**
Economic Assumptions	
Discount Rates: -	
• RPP	2.60% -
• SPS/DSPS	2.60% -
Going Concern Discount Rate for Determining Contributions – RPP only -	4.90% -
Provision for Adverse Deviation for Determining Contributions – RPP only -	7.30% -
Expected Long-term Return on Plan Assets (EROA) – RPP only [1] -	5.40% -
Consumer Price Index (Inflation)	1.75% -
YMPE Increases	2.75% -
Increase in maximum pension under the Income Tax Act -	2.75% -
Salary increases	Refer to Table 1 and Table 2 for details
Demographic assumptions	
Mortality	95% CPM2014 Private Table projected with Scale B
Retirement rates [2]	Table 3
Termination rates [2]	Table 4
Disability rates	Table 5
Other assumptions	
Eligible spouse at retirement	90%
Spousal age difference	Male 3 years older

Notes:
[1] Return on asset assumption is net of any expenses paid by the trust.

[2] No terminations or retirements were assumed under the DCPP. For the Notional DCPP, terminations and retirements are assumed to be 5% of the Projected Benefit Obligation the beginning of each year. In addition, we have also reflected a known payment stream remaining for one terminated member in the plan ending in 2023.

Hydro One Pension Plan **APPENDIX A.1**

Projected 2021 to 2027 Accounting Under US GAAP

Figures in $000s

		Projections						
		2021	2022	2023	2024	2025	2026	2027
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	9,763,046	9,962,794	10,177,862	10,400,320	10,631,609	10,866,447	11,109,699
	Employer service cost (BOY)	239,854	254,273	261,002	267,486	268,249	272,997	281,448
	Interest cost	256,963	262,512	268,237	274,167	280,181	286,401	292,956
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan Participants' contributions	57,662	60,803	62,655	64,521	66,230	68,115	70,402
	Benefits Paid	(354,731)	(362,520)	(369,436)	(374,885)	(379,822)	(384,261)	(388,010)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	9,962,794	10,177,862	10,400,320	10,631,609	10,866,447	11,109,699	11,366,495
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	8,078,550	8,269,850	8,502,214	8,756,619	9,024,350	9,303,601	9,597,727
	Expected return on plan assets	429,802	440,940	453,738	467,465	481,845	496,919	512,890
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	58,567	93,141	107,448	110,630	110,998	113,353	118,073
	Plan Participants' contributions	57,662	60,803	62,655	64,521	66,230	68,115	70,402
	Benefits paid	(354,731)	(362,520)	(369,436)	(374,885)	(379,822)	(384,261)	(388,010)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	8,269,850	8,502,214	8,756,619	9,024,350	9,303,601	9,597,727	9,911,082
C	**Amount recognized in the balance sheet**							
	Present value of obligations	9,962,794	10,177,862	10,400,320	10,631,609	10,866,447	11,109,699	11,366,495
	Fair value of plan assets	8,269,850	8,502,214	8,756,619	9,024,350	9,303,601	9,597,727	9,911,082
	Surplus (deficit)	(1,692,944)	(1,675,648)	(1,643,701)	(1,607,259)	(1,562,846)	(1,511,972)	(1,455,413)
	Unrecognized past service cost (benefit)	26,986	24,569	22,152	19,735	17,318	14,901	12,484
	Unrecognized net actuarial (gains)/losses	1,742,599	1,633,687	1,531,582	1,435,858	1,346,117	1,261,985	1,183,111
	Cumulative employer contributions in excess of benefit cost	76,641	(17,392)	(89,967)	(151,666)	(199,411)	(235,086)	(259,818)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	-	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(124,471)	(108,912)	(102,105)	(95,724)	(89,741)	(84,132)	(78,874)
	- Past service credits/(costs) amortized in year	(2,417)	(2,417)	(2,417)	(2,417)	(2,417)	(2,417)	(2,417)
	Sub-total	(126,888)	(111,329)	(104,522)	(98,141)	(92,158)	(86,549)	(81,291)
	Credit (charge) to OCI in year	126,888	111,329	104,522	98,141	92,158	86,549	81,291
D	**Components of Benefit Cost**							
	Employer service cost	239,854	254,273	261,002	267,486	268,249	272,997	281,448
	Interest cost	256,963	262,512	268,237	274,167	280,181	286,401	292,956
	Expected return on plan assets	(429,802)	(440,940)	(453,738)	(467,465)	(481,845)	(496,919)	(512,890)
	Net prior service (credit)/cost amortization	2,417	2,417	2,417	2,417	2,417	2,417	2,417
	Net (gains)/loss amortization	124,471	108,912	102,105	95,724	89,741	84,132	78,874
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	193,903	187,174	180,023	172,329	158,743	149,028	142,805
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	1,867,070	1,742,599	1,633,687	1,531,582	1,435,858	1,346,117	1,261,985
	EARSL	15.00	16.00	16.00	16.00	16.00	16.00	16.00
	Amortization of (gains)/losses	124,471	108,912	102,105	95,724	89,741	84,132	78,874
	Prior service (credit)/cost	29,403	26,986	24,569	22,152	19,735	17,318	14,901
	Amortization of prior service (credit)/cost	2,417	2,417	2,417	2,417	2,417	2,417	2,417
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	211,977	76,641	(17,392)	(89,967)	(151,666)	(199,411)	(235,086)
	Pension expense recognized in P&L in the financial year	(193,903)	(187,174)	(180,023)	(172,329)	(158,743)	(149,028)	(142,805)
	Employer contributions made in the financial year	58,567	93,141	107,448	110,630	110,998	113,353	118,073
	Benefits paid directly by company in the financial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	76,641	(17,392)	(89,967)	(151,666)	(199,411)	(235,086)	(259,818)
G	**Assumptions**							
	At beginning of period							
	Discount rate	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
	Expected rate of return on plan assets	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%

Hydro One Inc. Supplementary Pension Plan **APPENDIX A.2**
Projected 2021 to 2027 Accounting Under US GAAP

Figures in $000s

		Projections						
		2021	2022	2023	2024	2025	2026	2027
A	**Change in Benefit Obligation**							
	PBO at prior fiscal year end	145,058	144,541	143,798	142,822	141,581	140,057	138,301
	Employer service cost	1,070	1,020	964	897	813	764	748
	Interest cost	3,730	3,713	3,691	3,661	3,625	3,582	3,534
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits Paid from the Company	(5,317)	(5,476)	(5,631)	(5,799)	(5,962)	(6,102)	(6,233)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Benefit obligation - end of period	144,541	143,798	142,822	141,581	140,057	138,301	136,350
B	**Change in Plan Assets**							
	Fair value of assets at prior fiscal year end	5,130	5,344	5,558	5,772	5,986	6,200	6,414
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions - benefits paid	5,317	5,476	5,631	5,799	5,962	6,102	6,233
	Employer contributions - Letter of credit	428	428	428	428	428	428	428
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits paid from the company	(5,317)	(5,476)	(5,631)	(5,799)	(5,962)	(6,102)	(6,233)
	Transfer payments	-	-	-	-	-	-	-
	Taxes paid	(214)	(214)	(214)	(214)	(214)	(214)	(214)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Market value of plan assets - end of period	5,344	5,558	5,772	5,986	6,200	6,414	6,628
C	**Amount recognized in the balance sheet**							
	Present value of obligations	144,541	143,798	142,822	141,581	140,057	138,301	136,350
	Fair value of plan assets	5,344	5,558	5,772	5,986	6,200	6,414	6,628
	Surplus (deficit)	(139,197)	(138,240)	(137,050)	(135,595)	(133,857)	(131,887)	(129,722)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	36,398	33,909	31,576	29,388	27,337	25,414	23,612
	Cumulative employer contributions in excess of benefit cost	(102,799)	(104,331)	(105,474)	(106,207)	(106,520)	(106,473)	(106,110)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	214	214	214	214	214	214	214
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	214	214	214	214	214	214	214
	LESS							
	- Net actuarial gains/(losses) amortized in year	(2,615)	(2,275)	(2,119)	(1,974)	(1,837)	(1,709)	(1,588)
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	(2,615)	(2,275)	(2,119)	(1,974)	(1,837)	(1,709)	(1,588)
	Credit (charge) to OCI in year	2,829	2,489	2,333	2,188	2,051	1,923	1,802
D	**Components of Benefit cost**							
	Employer service cost	1,070	1,020	964	897	813	764	748
	Expected letter of credit fee	428	428	428	428	428	428	428
	Interest cost	3,730	3,713	3,691	3,661	3,625	3,582	3,534
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service cost amortization	-	-	-	-	-	-	-
	Net loss/(gain) amortization	2,615	2,275	2,119	1,974	1,837	1,709	1,588
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	7,843	7,436	7,202	6,960	6,703	6,483	6,298
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	39,227	36,398	33,909	31,576	29,388	27,337	25,414
	EARSL	15.00	16.00	16.00	16.00	16.00	16.00	16.00
	Amortization of (gains)/losses	2,615	2,275	2,119	1,974	1,837	1,709	1,588
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(100,701)	(102,799)	(104,331)	(105,474)	(106,207)	(106,520)	(106,473)
	Pension expense recognized in P&L in the financial year	(7,843)	(7,436)	(7,202)	(6,960)	(6,703)	(6,483)	(6,298)
	Employer contributions made in the financial year	428	428	428	428	428	428	428
	Benefits paid directly by company in the financial year	5,317	5,476	5,631	5,799	5,962	6,102	6,233
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(102,799)	(104,331)	(105,474)	(106,207)	(106,520)	(106,473)	(106,110)
G	**Assumptions**							
	At beginning of period							
	Discount rate	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Pension Plan (RPP) and Hydro One Inc. Supplementary Pension Plan (SPS/DSPS) **APPENDIX A.3**

Projected 2021 to 2027 Accounting Under US GAAP

Active / Inactive Split

Figures in $000s

RPP

	2021			2022			2023			2024			2025			2026			2027		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	0	239,854	239,854	0	254,273	254,273	0	261,002	261,002	0	267,486	267,486	0	268,249	268,249	0	272,997	272,997	0	281,448	281,448
Interest cost	159,317	97,646	256,963	162,757	99,755	262,512	165,770	102,467	268,237	168,064	106,103	274,167	169,790	110,391	280,181	170,981	115,420	286,401	171,672	121,284	292,956
Expected return on plan assets	(266,477)	(163,325)	(429,802)	(273,383)	(167,557)	(440,940)	(280,410)	(173,328)	(453,738)	(286,556)	(180,909)	(467,465)	(291,998)	(189,847)	(481,845)	(296,661)	(200,258)	(496,919)	(300,554)	(212,336)	(512,890)
Amortization of past service cost	893	1,524	2,417	974	1,443	2,417	1,104	1,313	2,417	1,186	1,231	2,417	1,309	1,108	2,417	1,429	988	2,417	1,576	841	2,417
Amortization of net (gain) loss	77,172	47,299	124,471	67,525	41,387	108,912	63,101	39,004	102,105	58,679	37,045	95,724	54,383	35,358	89,741	50,227	33,905	84,132	46,220	32,654	78,874
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Settlement (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefit cost recognized in the P&L account	(29,095)	222,998	193,903	(42,127)	229,301	187,174	(50,435)	230,458	180,023	(58,627)	230,956	172,329	(66,516)	225,259	158,743	(74,024)	223,052	149,028	(81,086)	223,891	142,805
Credit (charge) to OCI in year	78,065	48,823	126,888	68,499	42,830	111,329	64,205	40,317	104,522	59,865	38,276	98,141	55,692	36,466	92,158	51,656	34,893	86,549	47,796	33,495	81,291
Proportion	62.0%			62.0%			61.8%			61.3%			60.6%			59.7%			58.6%		
	37%			40%			46%			49%			54%			59%			65%		

SPS/DSPS

	2021			2022			2023			2024			2025			2026			2027		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	0	1,070	1,070	0	1,020	1,020	0	964	964	0	897	897	0	813	813	0	764	764	0	748	748
Expected letter of credit fee	361	67	428	363	65	428	365	63	428	367	61	428	371	57	428	372	56	428	374	54	428
Interest cost	3,144	586	3,730	3,149	564	3,713	3,148	543	3,691	3,137	524	3,661	3,143	482	3,625	3,116	466	3,582	3,085	449	3,534
Expected return on plan assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of past service cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of net (gain) loss	2,204	411	2,615	1,929	346	2,275	1,808	311	2,119	1,692	282	1,974	1,593	244	1,837	1,487	222	1,709	1,386	202	1,588
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Special Termination Benefit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefit cost recognized in the P&L account	5,709	2,134	7,843	5,441	1,995	7,436	5,321	1,881	7,202	5,196	1,764	6,960	5,107	1,596	6,703	4,975	1,508	6,483	4,845	1,453	6,298
Credit (charge) to OCI in year	2,204	411	2,615	1,929	346	2,275	1,808	311	2,119	1,692	282	1,974	1,593	244	1,837	1,487	222	1,709	1,386	202	1,588

Hydro One Supplemental Defined Contribution Plan **APPENDIX A.4**
Projected 2021 to 2027 Accounting Under US GAAP

Figures in $000s

		Projections						
		2021	2022	2023	2024	2025	2026	2027
A	**Change in Benefit Obligation**							
	PBO at prior fiscal year end	303	473	649	832	1,036	1,249	1,472
	Employer service cost	176	183	190	197	205	213	221
	Interest cost	20	30	39	49	60	72	83
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits Paid from the Company	(26)	(37)	(46)	(42)	(52)	(62)	(74)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Benefit obligation - end of period	473	649	832	1,036	1,249	1,472	1,702
B	**Change in Plan Assets**							
	Fair value of assets at prior fiscal year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions - benefits paid	26	37	46	42	52	62	74
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits Paid from the company	(26)	(37)	(46)	(42)	(52)	(62)	(74)
	Transfer payments	-	-	-	-	-	-	-
	Taxes paid	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Market value of plan assets - end of period	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	473	649	832	1,036	1,249	1,472	1,702
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit)	(473)	(649)	(832)	(1,036)	(1,249)	(1,472)	(1,702)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	30	28	26	24	22	21	20
	Cumulative employer contributions in excess of benefit cost	(443)	(621)	(806)	(1,012)	(1,227)	(1,451)	(1,682)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	-	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(2)	(2)	(2)	(2)	(2)	(1)	(1)
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	(2)	(2)	(2)	(2)	(2)	(1)	(1)
	Credit (charge) to OCI in year	2	2	2	2	2	1	1
D	**Components of Benefit cost**							
	Employer service cost	176	183	190	197	205	213	221
	Interest cost	20	30	39	49	60	72	83
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service cost amortization	-	-	-	-	-	-	-
	Net loss/(gain) amortization	2	2	2	2	2	1	1
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	198	215	231	248	267	286	305
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	32	30	28	26	24	22	21
	EARSL	15.00	16.00	16.00	16.00	16.00	16.00	16.00
	Amortization of (gains)/losses	2	2	2	2	2	1	1
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(271)	(443)	(621)	(806)	(1,012)	(1,227)	(1,451)
	Pension expense recognized in P&L in the financial year	(198)	(215)	(231)	(248)	(267)	(286)	(305)
	Employer contributions made in the financial year	-	-	-	-	-	-	-
	Benefits paid directly by company in the financial year	26	37	46	42	52	62	74
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(443)	(621)	(806)	(1,012)	(1,227)	(1,451)	(1,682)
G	**Assumptions**							
	At beginning of period							
	Discount rate	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Expected rate of return on plan assets	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%

Hydro One Limited Non-Pension Post Retirement Benefit - Hydro One Only
Projected 2021 to 2027 Accounting under US GAAP

APPENDIX B.1

Figures in $000s

		Projections						
		2021	2022	2023	2024	2025	2026	2027
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	1,560,031	1,609,746	1,665,792	1,725,671	1,788,923	1,855,434	1,925,424
	Employer service cost (BOY)	49,746	56,347	59,996	63,072	66,138	69,166	72,031
	Interest cost	41,317	42,759	44,293	45,913	47,617	49,408	51,285
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(41,348)	(43,060)	(44,410)	(45,733)	(47,244)	(48,584)	(49,943)
	Recognition of prior service	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	PBO at current fiscal year end	1,609,746	1,665,792	1,725,671	1,788,923	1,855,434	1,925,424	1,998,797
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	41,348	43,060	44,410	45,733	47,244	48,584	49,943
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(41,348)	(43,060)	(44,410)	(45,733)	(47,244)	(48,584)	(49,943)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	1,609,746	1,665,792	1,725,671	1,788,923	1,855,434	1,925,424	1,998,797
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(1,609,746)	(1,665,792)	(1,725,671)	(1,788,923)	(1,855,434)	(1,925,424)	(1,998,797)
	Unrecognized past service cost (benefit)	27,036	23,455	19,874	16,294	12,713	9,132	5,551
	Unrecognized net actuarial (gains)/losses	15,620	15,620	15,620	15,620	15,620	15,620	15,620
	Cumulative employer contributions in excess of benefit cost	(1,567,090)	(1,626,717)	(1,690,177)	(1,757,009)	(1,827,101)	(1,900,672)	(1,977,626)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	-	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	-	-	-	-	-	-	-
	- Past service credits/(costs) amortized in year	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)
	Sub-total	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)
	Credit (charge) to OCI in year	3,581	3,581	3,581	3,581	3,581	3,581	3,581
D	**Components of Benefit Cost**							
	Employer service cost	49,746	56,347	59,996	63,072	66,138	69,166	72,031
	Interest cost	41,317	42,759	44,293	45,913	47,617	49,408	51,285
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	3,581	3,581	3,581	3,581	3,581	3,581	3,581
	Net (gains)/loss amortization	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	Disclosed benefit cost	94,644	102,687	107,870	112,566	117,336	122,155	126,897
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	15,620	15,620	15,620	15,620	15,620	15,620	15,620
	EARSL	15.3	16.2	16.2	16.0	15.7	15.5	15.2
	Amortization of (gains)/losses	-	-	-	-	-	-	-
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(1,513,794)	(1,567,090)	(1,626,717)	(1,690,177)	(1,757,010)	(1,827,102)	(1,900,673)
	Benefit cost recognized in P&L in the financial year	(94,644)	(102,687)	(107,870)	(112,566)	(117,336)	(122,155)	(126,897)
	Employer contributions made in the financial year	41,348	43,060	44,410	45,733	47,244	48,584	49,943
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(1,567,090)	(1,626,717)	(1,690,177)	(1,757,010)	(1,827,102)	(1,900,673)	(1,977,627)
G	**Assumptions**							
	At beginning of period							
	Discount rate	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Limited Non-Pension Post Retirement Benefit - Inergi Only
Projected 2021 to 2027 Accounting under US GAAP

APPENDIX B.2

Figures in $000s

		Projections						
		2021	2022	2023	2024	2025	2026	2027
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	27,240	27,075	26,877	26,635	26,346	26,014	25,643
	Employer service cost (BOY)	-	-	-	-	-	-	-
	Interest cost	697	692	687	680	672	663	653
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(862)	(890)	(929)	(969)	(1,004)	(1,034)	(1,070)
	Recognition of prior service	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	PBO at current fiscal year end	27,075	26,877	26,635	26,346	26,014	25,643	25,226
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	862	890	929	969	1,004	1,034	1,070
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(862)	(890)	(929)	(969)	(1,004)	(1,034)	(1,070)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	27,075	26,877	26,635	26,346	26,014	25,643	25,226
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(27,075)	(26,877)	(26,635)	(26,346)	(26,014)	(25,643)	(25,226)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	(3,801)	(3,606)	(3,426)	(3,267)	(3,126)	(3,004)	(2,897)
	Cumulative employer contributions in excess of benefit cost	(30,876)	(30,483)	(30,061)	(29,613)	(29,140)	(28,647)	(28,123)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	-	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	189	195	180	159	141	122	107
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	189	195	180	159	141	122	107
	Credit (charge) to OCI in year	(189)	(195)	(180)	(159)	(141)	(122)	(107)
D	**Components of Benefit Cost**							
	Employer service cost	-	-	-	-	-	-	-
	Interest cost	697	692	687	680	672	663	653
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	(189)	(195)	(180)	(159)	(141)	(122)	(107)
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	Disclosed benefit cost	508	497	507	521	531	541	546
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	(3,990)	(3,801)	(3,606)	(3,426)	(3,267)	(3,126)	(3,004)
	EARSL	6.7	5.6	5.1	4.8	4.5	4.3	4.1
	Amortization of (gains)/losses	(189)	(195)	(180)	(159)	(141)	(122)	(107)
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(31,230)	(30,876)	(30,483)	(30,061)	(29,613)	(29,140)	(28,647)
	Benefit cost recognized in P&L in the financial year	(508)	(497)	(507)	(521)	(531)	(541)	(546)
	Employer contributions made in the financial year	862	890	929	969	1,004	1,034	1,070
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(30,876)	(30,483)	(30,061)	(29,613)	(29,140)	(28,647)	(28,123)
G	**Assumptions**							
	At beginning of period							
	Discount rate	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Limited Non-Pension Post Retirement Benefit - Hydro One + Inergi
Projected 2021 to 2027 Accounting under US GAAP

APPENDIX B.3

Figures in $000s

		Projections						
		2021	2022	2023	2024	2025	2026	2027
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	1,587,271	1,636,821	1,692,669	1,752,306	1,815,269	1,881,448	1,951,067
	Employer service cost (BOY)	49,746	56,347	59,996	63,072	66,138	69,166	72,031
	Interest cost	42,014	43,451	44,980	46,593	48,289	50,071	51,938
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(42,210)	(43,950)	(45,339)	(46,702)	(48,248)	(49,618)	(51,013)
	Recognition of prior service	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	PBO at current fiscal year end	1,636,821	1,692,669	1,752,306	1,815,269	1,881,448	1,951,067	2,024,023
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	42,210	43,950	45,339	46,702	48,248	49,618	51,013
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(42,210)	(43,950)	(45,339)	(46,702)	(48,248)	(49,618)	(51,013)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	1,636,821	1,692,669	1,752,306	1,815,269	1,881,448	1,951,067	2,024,023
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(1,636,821)	(1,692,669)	(1,752,306)	(1,815,269)	(1,881,448)	(1,951,067)	(2,024,023)
	Unrecognized past service cost (benefit)	27,036	23,455	19,874	16,294	12,713	9,132	5,551
	Unrecognized net actuarial (gains)/losses	11,819	12,014	12,194	12,353	12,494	12,616	12,723
	Cumulative employer contributions in excess of benefit cost	(1,597,966)	(1,657,200)	(1,720,238)	(1,786,622)	(1,856,241)	(1,929,319)	(2,005,749)
	Annual charges to OCI	-	-	-	-	-	-	-
	- Net actuarial gains/(losses) incurred in year	-	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-
	LESS	-	-	-	-	-	-	-
	- Net actuarial gains/(losses) amortized in year	189	195	180	159	141	122	107
	- Past service credits/(costs) amortized in year	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)	(3,581)
	Sub-total	(3,392)	(3,386)	(3,401)	(3,422)	(3,440)	(3,459)	(3,474)
	Credit (charge) to OCI in year	3,392	3,386	3,401	3,422	3,440	3,459	3,474
D	**Components of Benefit Cost**							
	Employer service cost	49,746	56,347	59,996	63,072	66,138	69,166	72,031
	Interest cost	42,014	43,451	44,980	46,593	48,289	50,071	51,938
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	3,581	3,581	3,581	3,581	3,581	3,581	3,581
	Net (gains)/loss amortization	(189)	(195)	(180)	(159)	(141)	(122)	(107)
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	Disclosed benefit cost	95,152	103,184	108,377	113,087	117,867	122,696	127,443
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	11,630	11,819	12,014	12,194	12,353	12,494	12,616
	EARSL	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Amortization of (gains)/losses	(189)	(195)	(180)	(159)	(141)	(122)	(107)
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(1,545,024)	(1,597,966)	(1,657,200)	(1,720,238)	(1,786,623)	(1,856,242)	(1,929,320)
	Benefit cost recognized in P&L in the financial year	(95,152)	(103,184)	(108,377)	(113,087)	(117,867)	(122,696)	(127,443)
	Employer contributions made in the financial year	42,210	43,950	45,339	46,702	48,248	49,618	51,013
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(1,597,966)	(1,657,200)	(1,720,238)	(1,786,623)	(1,856,242)	(1,929,320)	(2,005,750)
G	**Assumptions**							
	At beginning of period							
	Discount rate	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Limited Post Employment Benefits
Projected 2021 to 2027 Accounting under US GAAP

APPENDIX B.4

Figures in $000s

		Projections						
		2021	2022	2023	2024	2025	2026	2027
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	124,141	132,773	141,805	151,207	160,967	171,119	181,681
	Employer service cost (BOY)	18,378	18,990	19,463	19,862	20,346	20,857	21,289
	Interest cost	3,533	3,767	4,010	4,261	4,523	4,795	5,077
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(13,279)	(13,725)	(14,071)	(14,363)	(14,717)	(15,090)	(15,407)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	132,773	141,805	151,207	160,967	171,119	181,681	192,640
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	13,279	13,725	14,071	14,363	14,717	15,090	15,407
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(13,279)	(13,725)	(14,071)	(14,363)	(14,717)	(15,090)	(15,407)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	132,773	141,805	151,207	160,967	171,119	181,681	192,640
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(132,773)	(141,805)	(151,207)	(160,967)	(171,119)	(181,681)	(192,640)
	Unrecognized past service cost (benefit)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Unrecognized net actuarial (gains)/losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cumulative employer contributions in excess of benefit cost	(132,773)	(141,805)	(151,207)	(160,967)	(171,119)	(181,681)	(192,640)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	- Past service credits/(costs) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	LESS							
	- Net actuarial gains/(losses) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	- Past service credits/(costs) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Credit (charge) to OCI in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D	**Components of Benefit Cost**							
	Employer service cost	18,378	18,990	19,463	19,862	20,346	20,857	21,289
	Interest cost	3,533	3,767	4,010	4,261	4,523	4,795	5,077
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	21,911	22,757	23,473	24,123	24,869	25,652	26,366
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	EARSL	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Amortization of (gains)/losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(124,141)	(132,773)	(141,805)	(151,207)	(160,967)	(171,119)	(181,681)
	Benefit cost recognized in P&L in the financial year	(21,911)	(22,757)	(23,473)	(24,123)	(24,869)	(25,652)	(26,366)
	Employer contributions made in the financial year	13,279	13,725	14,071	14,363	14,717	15,090	15,407
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/diverstitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(132,773)	(141,805)	(151,207)	(160,967)	(171,119)	(181,681)	(192,640)
G	**Assumptions**							
	At beginning of period							
	Discount rate	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Limited Non-Pension Post Retirement Benefit **APPENDIX B.5**
Projected 2020 to 2027 Accounting under US GAAP
Active / Inactive Split
Figures in $000s

Projected OPRB Expense - Hydro One

	2021			2022			2023			2024			2025			2026			2027		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	-	49,746	49,746	-	56,347	56,347	-	59,996	59,996	-	63,072	63,072	-	66,138	66,138	-	69,166	69,166	-	72,031	72,031
Interest cost	22,022	19,295	41,317	22,705	20,054	42,759	23,431	20,862	44,293	24,012	21,901	45,913	24,475	23,142	47,617	25,000	24,408	49,408	25,386	25,899	51,285
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	1,909	1,672	3,581	1,901	1,679	3,581	1,894	1,687	3,581	1,873	1,708	3,581	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net transfers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	23,931	70,713	94,644	24,606	78,080	102,686	25,325	82,545	107,870	25,885	86,681	112,566	24,475	89,280	113,755	25,000	93,574	118,574	25,386	97,930	123,316
Credit (charge) to OCI in year	1,909	1,672	3,581	1,901	1,679	3,581	1,894	1,687	3,581	1,873	1,708	3,581	1,841	1,740	3,581	1,812	1,769	3,581	1,773	1,808	3,581

Projected OPRB Expense - Inergi

	2021			2022			2023			2024			2025			2026			2027		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest cost	606	91	697	617	75	692	622	65	687	624	56	680	625	47	672	625	38	663	622	31	653
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	(164)	(25)	(189)	(174)	(21)	(195)	(163)	(17)	(180)	(146)	(13)	(159)	(72)	(69)	(141)	(63)	(59)	(122)	(102)	(5)	(107)
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net transfers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	442	66	508	443	54	497	459	48	507	478	43	521	553	(22)	531	562	(21)	541	520	26	546
Credit (charge) to OCI in year	(164)	(25)	(189)	(174)	(21)	(195)	(163)	(17)	(180)	(146)	(13)	(159)	(72)	(69)	(141)	(71)	(70)	(141)	(60)	(62)	(122)

Projected OPRB Expense - Total (Hydro One Inc. + Inergi)

	2021			2022			2023			2024			2025			2026			2027		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	-	49,746	49,746	-	56,347	56,347	-	59,996	59,996	-	63,072	63,072	-	66,138	66,138	-	69,166	69,166	-	72,031	72,031
Interest cost	22,628	19,386	42,014	23,322	20,129	43,451	24,053	20,927	44,980	24,636	21,957	46,593	25,100	23,189	48,289	25,625	24,446	50,071	26,008	25,930	51,938
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	1,909	1,672	3,581	1,901	1,679	3,581	1,894	1,687	3,581	1,873	1,708	3,581	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	(164)	(25)	(189)	(174)	(21)	(195)	(163)	(17)	(180)	(146)	(13)	(159)	(72)	(69)	(141)	(63)	(59)	(122)	(102)	(5)	(107)
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net transfers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	24,373	70,779	95,152	25,049	78,134	103,183	25,784	82,593	108,377	26,363	86,724	113,087	25,028	89,258	114,286	25,562	93,553	119,115	25,906	97,956	123,862
Credit (charge) to OCI in year	1,744	1,648	3,392	1,728	1,658	3,386	1,731	1,670	3,401	1,727	1,695	3,422	1,769	1,671	3,440	1,741	1,699	3,440	1,713	1,746	3,459

Hydro One Limited Post Employment Benefit
Projected 2018 to 2024 Accounting under US GAAP
Active / Inactive Split
Figures in $000s

Projected PEB Expense

	2021			2022			2023			2024			2025			2026			2027		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	18,378	0	18,378	18,990	0	18,990	19,463	0	19,463	19,862	0	19,862	20,346	0	20,346	20,857	0	20,857	21,289	0	21,289
Interest cost	3,533	0	3,533	3,767	0	3,767	4,010	0	4,010	4,261	0	4,261	4,523	0	4,523	4,795	0	4,795	5,077	0	5,077
Expected return on plan assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of past service cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of net (gain) loss	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Settlement (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefit cost recognized in the P&L account	21,911	0	21,911	22,757	0	22,757	23,473	0	23,473	24,123	0	24,123	24,869	0	24,869	25,652	0	25,652	26,366	0	26,366
Credit (charge) to OCI in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Appendix C - Statement of Assumptions (Hydro One PRB and Inergi PRB)

The rates in the following table are on a per annum basis.

Measurement Date	**December 31, 2020 (as per year-end disclosures) and End of December 31 During Projection Period (2021-2027)**
Economic Assumptions	
Discount Rates: -	
• Hydro One PRB	2.60% -
• Inergi PRB	2.60% -
Salary increases	Refer to Table 1 and Table 2 for details
Health Care Trend Rates	
• Prescription Drug	4.25% per annum
• Other Medical	6.46% per annum in 2021 grading to 4.25% per annum after 2031
• Hospital and Dental	2.75% per annum
• Vision Care	1.75% per annum through 2028 and 0% thereafter
Per Capita Claim Costs	Please see Appendix A of the valuation report, “Post-Retirement Benefits Plans: Draft Actuarial Valuation Results as of January 1, 2020” dated February 2021 for per capita claim costs and the corresponding aging factors and expense / tax rates
Demographic assumptions	
Mortality	95% CPM2014 Private Table projected with Scale B
Retirement rates	Table 3
Termination rates	Table 4
Disability rates	Table 5
Other assumptions	
Eligible spouse at retirement	90%
Spousal age difference	Male 3 years older

Appendix C - Statement of Assumptions (PEB)

The rates in the following table are on a per annum basis.

Measurement Date	**December 31, 2020** **(as per year-end disclosures)** **and** **End of December 31** **During Projection Period** **(2021-2027)**
Economic Assumptions	
Discount Rates:	2.60%
Inflation on Disability Income Benefits	1.75%
Health Care Trend Rates	
• Medical	6.18% per annum in 2021 grading to 4.05% per annum after 2031
• Dental	4.25% per annum
Per Capita Claim Costs	
• Medical	$6,590 in 2020
• Dental	$1,410 in 2020
Demographic assumptions	
Mortality	UP94 table projected generationally using Scale AA
Disability termination rates	Based on the GLTD table from the 2009-2015 CIA Disability Termination Study
Incurred but not Reported (IBNR)	Estimated assuming a six month provision based on recent experience

Table 1 — Salary Increases due to Movement within the Salary Structure (M&P)

Age	First 4 Years of Employment	Subsequent Years
Under 25	7.5%	2.0%
25 - 29	5.5%	2.0%
30 - 34	3.5%	2.0%
35 - 39	3.5%	1.5%
40 – 44	3.5%	1.5%
45 - 49	2.0%	1.0%
50 - 54	2.0%	1.0%
55 - 59	1.0%	0.5%
60 & over	1.0%	0.0%

Table 2 — 2020 to 2027 fixed increases

Representation	2020	2021	2022	2023	2024	2025	2026	2027	2028 onward
Management	1.96%	2.33%	2.03%	2.00%	2.00%	2.00%	2.00%	2.00%	2.25%
Society	2.00%	2.33%	2.03%	2.00%	2.00%	2.00%	2.00%	2.00%	2.25%
PWU	1.96%	2.00%	2.20%	2.00%	2.00%	2.00%	2.00%	2.00%	2.25%

Table 3 — Retirement rates

	Eligible for Unreduced Retirement		
Age	Based on points (82 or 85)	35 years of service and over	Not Eligible for Unreduced Retirement
Under 55	10%	30%	0% -
55 to 59	15%	30%	5% -
60 to 64	12%	30%	7% -
65	50%	30%	20% -
66 to 69	25%	30%	15% -
70 and over	100%	100%	100% -

Table 4 — Termination rates

Service (years)	Male & Female
Under 20	1%
20 and over	0%

Table 5 — Disability Rates

Age	Male & Female
Under 30	0%
30 to 35	0.105%
35 to 40	0.110%
40 to 45	0.115%
45 to 50	0.120%
50 to 55	0.295%
55 to 59	1.000%
60 and above	1.878%

Appendix 2-KA
OPEBs (Other Post-Employment Benefits) Costs

A Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since the

Notes:
(Please add any information to explain the accounting basis used for OPEBs cost recovery in rate setting. If basis is

Hydro One utilizes the accrual method for accounting of Other Post-Employment Benefit (OPEBs) costs. The accrual method is appropriate because it reflects the costs incurred during the time period and, as such, more accurately attributes those costs to the appropriate ratepayers.

B Please complete the following table:

OPEBS	Pre 2018	2018	2019	2020	2021	2022	2023	Total
Amounts included in Tx Rates								
OM&A	$ 411	$ 21	$ 15	$ 37	$ 38	$ 39	$ 31	$ 592
Capital (**Note 1**)	$ 335	$ 10	$ 16	$ 18	$ 20	$ 20	$ 25	$ 444
Deferral Account		$ 22	$ 19					$ 41
Total	**$ 746**	**$ 53**	**$ 50**	**$ 55**	**$ 58**	**$ 59**	**$ 56**	**$ 1,077**
Paid benefit amounts	$ 247	$ 21	$ 21	$ 28	$ 30	$ 30	$ 31	$ 408
Net excess amount included in rates relative to amounts actually paid.	$ 499	$ 32	$ 29	$ 27	$ 28	$ 29	$ 25	$ 669

Note 1: Please see impacts to the capital component of OPEB costs as noted in Exhibit E-07-01.

C Please describe what the distributor has done with the recoveries in excess of cash payments:

The Capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net excess as noted does not represent the excess recovery in each year.

Appendix 2-KA
OPEBs (Other Post-Employment Benefits) Costs

A Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since the

Notes:
(Please add any information to explain the accounting basis used for OPEBs cost recovery in rate setting. If basis is

Hydro One utilizes the accrual method for accounting of Other Post-Employment Benefit (OPEBs) costs. The accrual method is appropriate because it reflects the costs incurred during the time period and, as such, more accurately attributes those costs to the appropriate ratepayers.

B Please complete the following table:

OPEBS	Pre 2018	2018	2019	2020	2021	2022	2023	Total
Amounts included in Dx Rates								
OM&A	$ 537	$ 26	$ 26	$ 26	$ 25	$ 26	$ 45	$ 711
Capital (**Note 1**)	$ 403	$ 12	$ 13	$ 13	$ 12	$ 14	$ 29	$ 496
Deferral Account		$ 13	$ 15	$ 15	$ 15	$ 16		$ 74
Total	**$ 939**	**$ 51**	**$ 54**	**$ 54**	**$ 52**	**$ 56**	**$ 74**	**$ 1,280**
Paid benefit amounts	$ 408	$ 27	$ 26	$ 28	$ 28	$ 30	$ 35	$ 582
Net excess amount included in rates relative to amounts actually paid.	$ 531	$ 24	$ 28	$ 26	$ 24	$ 26	$ 39	$ 698

Note 1: Please see impacts to the capital component of OPEB costs as noted in Exhibit E-07-01.

C Please describe what the distributor has done with the recoveries in excess of cash payments:

The Capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net excess as noted does not represent the excess recovery in each year.

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to describe Hydro One Networks' Transmission, Distribution and Common depreciation and amortization expenses for the 2023 to 2027 test years, and outline the methodology used to determine those amounts historically and for purposes of this Application.

1.1 TRANSMISSION BACKGROUND

The depreciation and amortization expense for Hydro One's 2007 and 2008 Transmission revenue requirements (EB-2006-0501) was supported by an independent study conducted by Foster Associates Inc. (Foster), completed in June 2006. Subsequently, Foster performed a series of studies or Technical Updates to its study to coincide with each of Hydro One's transmission revenue requirement applications, as follows:

- EB-2008-0272 – Study completed in August 2008 to support the 2009 and 2010 depreciation and amortization expense for the Transmission business;
- EB-2010-0002 – Depreciation Study or Technical Update was not carried out for 2011 or 2012 rates and depreciation rates were not changed from those previously approved;
- EB-2012-0031 – Study completed in May 2012 to support the 2013 and 2014 depreciation and amortization expense for the Transmission business;
- EB-2014-0140 – Study completed in August 2013 to support the 2015 and 2016 depreciation and amortization expense for the Transmission business;
- EB-2016-0160 – Study completed in April 2016 to support the 2017 to 2018 depreciation and amortization expense for the Transmission business; and,
- EB-2019-0082 – Study completed in August 2017 to support the 2020 to 2022 depreciation and amortization expense for the Transmission business.

The OEB accepted the costs flowing from each of the previous Depreciation Studies and Technical Updates for the purpose of supporting Transmission revenue requirements in each of the corresponding years.

The most recent depreciation rates for common assets were reviewed as part of the 2016 study and accepted by the OEB in EB-2016-0160 and adopted for both Transmission and Distribution.

1.2 DISTRIBUTION BACKGROUND

In RP-2005-0020/EB-2005-0378, Hydro One Distribution's depreciation rates were approved based on an independent depreciation study completed by Foster dated June 2005. Costs flowing from that depreciation study were accepted for the purpose of establishing Hydro One Distribution's revenue requirement in 2006. In 2013, Foster conducted an update to its depreciation study, which recommended continuation of the historical depreciation rates for purposes of the revenue requirements for the years 2015 to 2017. For purposes of EB-2017-0049, Hydro One requested that Foster prepare a new depreciation study in 2016 covering Hydro One Networks' distribution and common assets for the 2018 – 2022 test years (2016 Foster Distribution Study). That study recommended depreciation rates that, if implemented, would have increased Hydro One Distribution's depreciation expense significantly over the 2018 to 2022 rate setting period. As a result, Hydro One proposed to maintain its existing depreciation rates for Distribution and adopt the depreciation rates for common assets based on the study filed in EB-2016-0160 as discussed above, instead of adopting the rates identified in the 2016 Foster Distribution Study. Hydro One noted that this would avoid potential fluctuations in depreciation rates and the expenses recovered through rates. Hydro One's proposal was supported by Foster as indicated in the Letter of Transmittal attached to that study, and ultimately the OEB accepted this approach in its EB-2017-0049 decision, which applies to the Distribution business for the 2018 to 2022 rate years.

1.3 APPROACH TO 2023-2027 DEPRECIATION AND AMORTIZATION EXPENSES

In 2020, 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 is a U.S. based firm that has conducted over 275 depreciation studies for regulated and non-regulated electric, gas, steam, water, wastewater, cable and communications utilities across the U.S. and Canada since 2004. In its depreciation study for Hydro One, 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 and, by allowing all assets within an account to be considered as one group, it produces more stable depreciation rates from year to year through its averaging effects. Moreover, in Alliance's view, use of the BG methodology is more consistent with depreciation practices among other North American utilities. Alliance has also determined that almost all distribution plant account components were in the range of lives provided by Kinectrics, with exception to the SCADA equipment where Hydro One used shorter lives.[1] A copy of Alliance's depreciation study is provided in Attachment 1 to this exhibit.

2.0 DEPRECIATION EXPENSE

Tables 1 and 2, below, present each of the elements required to determine Hydro One's proposed depreciation expenses for Transmission and Distribution over the 2018 to 2027 period, which include the 2018 to 2021 historical period[2], the 2022 bridge year, and 2023 to 2027 test years.

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[1] Attachment 1, Exhibit E-08-01, p. 28
[2] 2021 is provided on a forecast basis

These include (a) Depreciation on Fixed Assets, which for the test years is based on the results from the new Alliance Depreciation Study, (b) Capitalized Depreciation, (c) Asset Removal Costs, and (d) Losses/Gains on Asset Disposition. Each of these elements are discussed below.

Detailed depreciation schedules are filed at Attachment 2 to this exhibit.

Table 1 - Transmission Depreciation Expense ($M)

	Historical Actuals										Bridge			Test Year				
	2018			2019	2020			2021			2022			2023	2024	2025	2026	2027
Transmission	**Actual**	**OEB-Approved**	**Difference**	**Actual**	**Actual**	**OEB-Approved**	**Difference**	**Forecast**	**OEB-Approved**	**Difference**	**Forecast**	**OEB-Approved**	**Difference**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Depreciation On Fixed Assets	387.3	402.0	(14.7)	406.6	410.9	419.9	(9.0)	440.2	436.4	3.8	461.2	457.2	4.0	481.8	509.3	538.2	566.6	592.2
Less Capitalized Depreciation	(13.0)	(12.8)	(0.2)	(13.1)	(14.4)	(13.3)	(1.1)	(14.5)	(13.5)	(1.0)	(14.5)	(13.6)	(0.9)	(14.8)	(14.9)	(15.1)	(15.2)	(15.3)
Asset Removal Costs	37.7	69.2	(31.5)	45.9	39.6	54.1	(14.5)	63.1	59.7	3.4	56.4	61.5	(5.1)	61.2	63.3	70.7	73.8	70.5
Losses/(Gains) On Asset Disposition	(0.5)	-	(0.5)	(0.5)	(2.4)	-	(2.4)	-	-	-	-	-	-	-	-	-	-	-
Total	**411.5**	**458.4**	**(46.9)**	**438.9**	**433.7**	**460.7**	**(27.0)**	**488.8**	**482.6**	**6.2**	**503.1**	**505.1**	**(2.0)**	**528.2**	**557.6**	**593.8**	**625.1**	**647.3**

1 **Table 2 - Distribution Depreciation Expense ($M)***

	Historical Actuals												Bridge			Test Year				
	2018			2019			2020			2021			2022			2023	2024	2025	2026	2027
Distribution	Actual	OEB-Approved	Difference	Actual	OEB-Approved	Difference	Actual	OEB-Approved	Difference	Forecast	OEB-Approved	Difference	Forecast	OEB-Approved	Difference	Forecast	Forecast	Forecast	Forecast	Forecast
Depreciation On Fixed Assets	344.9	345.2	(0.3)	351.7	353.6	(1.9)	355.4	361.9	(6.5)	370.1	379.9	(9.8)	384.9	393.6	(8.7)	402.9	425.0	460.6	496.6	528.7
Less Capitalized Depreciation	(18.0)	(19.3)	1.3	(18.3)	(20.1)	1.8	(17.7)	(20.8)	3.1	(17.9)	(20.8)	2.9	(17.9)	(20.8)	2.9	(18.2)	(18.3)	(18.5)	(18.7)	(18.9)
Asset Removal Costs	50.6	58.7	(8.1)	53.8	69.5	(15.7)	59.3	70.1	(10.8)	54.8	69.2	(14.4)	56.4	70.1	(13.7)	79.2	78.5	83.9	83.4	86.6
Losses/(Gains) On Asset Disposition	(1.3)	-	(1.3)	(1.2)	-	(1.2)	(0.5)	-	(0.5)	-	-	-	-	-	-	-	-	-	-	-
Total	**376.2**	**384.6**	**(8.4)**	**386.0**	**403.0**	**(17.0)**	**396.5**	**411.2**	**(14.7)**	**407.0**	**428.3**	**(21.3)**	**423.4**	**442.9**	**(19.5)**	**463.9**	**485.2**	**526.0**	**561.3**	**596.4**

**Note 1: 2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock). 2023-2027 figures are presented on a combined basis including Acquired Utilities.*

2.1 DEPRECIATION ON FIXED ASSETS

Hydro One has historically employed the half-year rule in calculating its depreciation expense for in-service additions, and has continued this practice for the test years. Depreciation rates are periodically reviewed by an external, independent fixed asset actuary and changes in depreciation rates are reflected for accounting purposes prospectively, consistent with their inclusion in electricity rates, subject to approval by the OEB. As noted above, Alliance has been retained to develop the proposed depreciation rates for Hydro One's Transmission, Distribution and Common Assets for the test period.

For costs relating to common assets, which are not directly attributable to the Transmission and Distribution business, Hydro One adopted and has consistently applied the OEB approved Shared Asset allocation methodology as detailed in Exhibit C-03-01. Depreciation and amortization expense are calculated for the Transmission and Distribution businesses based on asset allocation which uses the Shared Asset methodology for cost allocation.

The 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, which results in more assets that are subject to depreciation.

2.2 CAPITALIZED DEPRECIATION

Capitalized depreciation refers to depreciation on transport and work equipment, as well as other minor fixed assets (e.g. tools) that are charged to capital work projects. As such, capitalized depreciation is deducted from annual depreciation expense, as it is capitalized and treated as a capital expenditure.

2.3 ASSET REMOVAL COSTS

Fixed asset removal costs are grouped with depreciation expense and are recorded on an "as incurred" basis. These consist of the costs associated with removing old assets, such as the costs of digging up old foundations or removing old equipment.

Asset removal costs are included as a component of Hydro One's depreciation expense because, in an income statement, components are either classified by their nature or by their function. To report expenses by function means to report them according to the activity for which the expenses were incurred. The income statement will report expenses according to the following functional classifications: cost of power; operations, maintenance and administration; depreciation and amortization; and financing. This requires grouping similar expenses. Accordingly, asset removal costs are grouped together with depreciation and amortization due to their similar characteristics.

Most fixed asset removal costs are labour and equipment costs, rather than costs for materials. For both the Transmission and Distribution businesses, removal costs are driven by the nature and timing of work, where System Renewal type work which is driven by assets needs and customer outcomes drives most of these expenditures.

In EB-2019-0082, the OEB accepted Hydro One's proposal to establish the Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account for its Transmission business to record any differences between the asset removal cost forecasts that were included in the proposed depreciation expense for 2020 to 2022 and the actual asset removal costs incurred in each of those years, where differences would be calculated and booked to the account net of tax impact. In 2020, actual asset removal costs for Transmission were $14.5M lower than approved forecast levels and, as a result, the difference net of the tax impact was recognized in the variance account to be returned to rate payers. Please refer to Exhibit G-01-01 for further discussion on the Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account.

For the 2023-2027 test years, Hydro One is proposing to continue the account for Transmission, as well as to establish an equivalent new account for Distribution, as discussed further in Exhibit G-01-02.

2.4 LOSSES/(GAINS) ON ASSET DISPOSITION

Losses/gains on asset disposition relate to the sale of assets. Losses/gains on asset disposition are based on historical actuals and are not forecast for the bridge or test years. Hydro One has not historically recognized significant gains or losses as the company does not focus substantial efforts on selling assets as part of its normal course of business.

3.0 AMORTIZATION EXPENSE

Amortization expenses pertain to certain regulatory amounts for which the OEB has allowed Hydro One Transmission and Distribution to defer recovery until a future date. More particularly, Hydro One estimates its future Transmission and Distribution expenditures that are required to remediate past environmental contamination and to comply with current environmental legislation. Since these future expenditures are expected to be recovered in future rates, Hydro One has recognized the net present value of these estimated future expenditures as a regulatory asset on its balance sheet. The environmental regulatory asset balance is amortized on a basis consistent with the pattern of current expenditures expected to be incurred up to the year 2025. The combined work program to manage polychlorinated biphenyls (PCBs) and to carry out Hydro One's Land Assessment and Remediation (LAR) program is currently estimated to continue until the year 2025.

Hydro One Distribution first received approval from the OEB for this accounting treatment as part of the RP-2000-0023 Decision, and it has continued to be accepted in subsequent Distribution applications by the OEB. Hydro One Transmission's treatment of these costs was first presented in its Application for 2007-2008 Transmission Rates in EB-2006-0501, consistent with the Distribution treatment discussed above, and was accepted by the OEB in that proceeding and in subsequent applications. The treatment of these costs in this Application is consistent with the treatment in these prior Distribution and Transmission proceedings.

The increased spending in the bridge year is primarily due to increased PCB retro-fill activities as Hydro One is approaching Environment Canada's December 31, 2025 deadline to remove all but the lowest levels of PCBs in contaminated equipment.

Amortization schedules for test, bridge and historical years[3] are filed at Exhibit E-08-01 Attachment 2. Tables 3 and 4, below, reproduce the summary for Transmission and Distribution.

Table 3 - Transmission Amortization Expense ($M)

Description	Historical				Bridge	Test				
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Environmental Assets and Other	6.7	5.5	7.7	15.5	16.3	7.6	7.5	6.6	-	-

Table 4 - Distribution Amortization Expense ($M)

Description	Historical				Bridge	Test				
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Environmental Assets and Other	14.4	15.5	14.3	13.4	12.9	5.5	5.4	1.0	-	-

[3] 2021 is provided on a forecast basis.

4.0 TOTAL DEPRECIATION AND AMORTIZATION EXPENSE

Total Transmission and Distribution depreciation and amortization expenses for test, bridge and historical years are outlined in Tables 5 and 6 below.

Table 5 - Transmission Depreciation and Amortization Expense ($M)

Description	Historical				Bridge	Test				
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Total Depreciation Expenses	411.5	438.9	433.7	488.8	503.1	528.2	557.6	593.8	625.1	647.3
Total Amortization Expenses	6.7	5.5	7.7	15.5	16.3	7.6	7.5	6.6	-	-
Total	418.2	444.4	441.4	504.3	519.4	535.8	565.1	600.4	625.1	647.3

Table 6 - Distribution Depreciation and Amortization Expense ($M)*

Description	Historical				Bridge	Test				
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Total Depreciation Expenses	376.2	386.0	396.5	407.0	423.4	463.9	485.2	526.0	561.3	596.4
Total Amortization Expenses	14.4	15.5	14.3	13.4	12.9	5.5	5.4	1.0	-	-
Exclude Other Regulatory Amortization **	3.9	4.3	4.4	4.1	4.3	3.8	3.9	4.0	4.0	4.1
Total	386.7	397.2	406.4	416.3	432.0	465.6	486.7	523.0	557.3	592.3

**Note 1: 2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock). 2023-2027 figures are presented on a combined basis including Acquired Utilities.*
***Note 2: Depreciation on Provincial Funded Assets*

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April 26, 2021

Mr. Jonathan Myers
Torys LLP
79 Wellington St. W. 30th Floor.
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada

Re: Proposed Depreciation Rates Hydro One

Jonathan:

Alliance Consulting Group is pleased to submit our report of the 2019 Depreciation Study for Hydro One Networks, Inc. (Hydro One Networks). The attached report presents results of our review leading to a recommendation to adopt straight line, broad-group, remaining life rates and record depreciation expense for BU 210 (Transmission), BU 220 (Distribution), and BU 300 (Common) facilities.

The scope of our depreciation study process included:

- Collection of plant and reserve data
- Reconciliation of assembled database to Company records
- Discussion with Hydro One Networks plant accounting and operations personnel
- Estimation of projection lives and proposed retirement dispersion patterns
- Analysis and reallocation of recorded depreciation reserves, and
- Development of recommended depreciation rates for each category of plant for each business unit.

The results of our investigation are presented in the attached report. The Executive Summary provides an overview of the review and a discussion of the principal findings. The general discussion section presents information on depreciation definitions, survivor curves, actuarial analysis, and depreciation procedures. The detailed discussion discusses the life selection and analysis for each business unit and account. Finally, the appendices show the depreciation rate calculations, depreciation expense comparison, reserve comparison, and projection lives by business unit.

We wish to express our appreciation for this opportunity to be of service to Hydro One Networks and for the assistance provided to us. We would be pleased to discuss our report and review with you or others at your convenience.

Very truly yours,

Dane A. Watson

Dane A. Watson – Engagement Partner – Alliance Consulting Group

HYDRO ONE NETWORKS INC.

ELECTRIC UTILITY PLANT

DEPRECIATION RATE STUDY

BU 210, 220, AND 300

TRANSMISSION, DISTRIBUTION,

AND COMMON BUSINESS UNITS

AT DECEMBER 31, 2019

April 2021

hydro one

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

HYDRO ONE NETWORKS INC.
ELECTRIC UTILITY PLANT
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY
BU 210, 220, AND 300

TRANSMISSION, DISTRIBUTION,
AND COMMON BUSINESS UNITS
AT DECEMBER 31, 2019

Torys LLP, as legal counsel on behalf of Hydro One Networks Inc. ("Hydro One" or the "Company"), engaged Alliance Consulting Group ("Alliance") to conduct a depreciation study of the Company's electric utility plant depreciable assets as of December 31, 2019.

This study proposes depreciation accrual rates based on year end 2019 data that will be applied to plant balances developed in connection with a joint transmission and distribution Custom Incentive Rate ("CIR") application that will be filed with the Ontario Energy Board ("OEB") for purposes of establishing Hydro One's transmission revenue requirement and distribution rates for the 2023-2027 period (the "Joint Application"). For illustrative purposes, the tables below show the impact of the proposed depreciation accrual rates when applied to Hydro One's 2019 fixed asset values but do not reflect the changes that will occur for periods 2023 forward, which will be calculated once the rate application is prepared. Based on 2019 year-end values, which will differ from depreciation expense amounts in the filed application, this study would result in an overall decrease of $35 million in annual depreciation expenses for all accounts when using the proposed depreciation rates. This is in comparison to the existing annual depreciation accrual without including the existing true-up. A summary comparison of annual accrual by utility function is shown below. These amounts will differ from those computed in the CIR application when applied to 2023-2027 plant balances.

BU 210 Transmission Operations

Function	Plant at 12/31/2019	Existing Accrual	Proposed Accrual	Difference
Intangible	25,081,347	2,508,135	2,508,135	0
Transmission	16,766,760,553	306,201,391	284,873,007	(21,328,383)
General Depreciated	1,118,401,387	56,310,011	58,886,734	2,576,722
General Amortized	8,931,156	0	0	0
Total	17,919,174,444	365,019,537	346,267,876	(18,751,661)

BU 220 Distribution Operations

Function	Plant at 12/31/2019	Existing Accrual	Proposed Accrual	Difference
Intangible	304,187,590	30,418,759	30,418,759	0
Distribution	10,642,740,258	239,775,039	218,028,793	(21,746,245)
General Depreciated	338,255,204	20,445,568	18,703,368	(1,742,200)
General Amortized	41,261,340	1,880,251	1,880,251	0
Total	11,326,444,391	292,519,617	268,031,171	(23,488,445)

BU 300 Common Operations

Function	Plant at 12/31/2019	Existing Accrual	Proposed Accrual	Difference
Intangible	636,292,886	63,629,289	53,024,407	(10,604,882)
General Depreciated	234,456,029	(10,850,224)	6,984,546	17,834,770
General Amortized	241,134,350	42,682,280	42,692,682	10,402
Total	1,111,883,265	95,461,345	102,701,635	7,240,291

Total Hydro One	30,357,502,101	753,000,499	718,000,682	(34,999,815)

Appendix A shows the computation of depreciation rates based on 2019 year-end investment, and Appendix B shows a detailed comparison of the approved versus proposed depreciation rates and annual accruals by account for each utility function.

HYDRO ONE NETWORKS INC.

ELECTRIC UTILITY PLANT

DEPRECIATION RATE STUDY

BU 210, 220, AND 300

TRANSMISSION, DISTRIBUTION,

AND COMMON BUSINESS UNITS

AT DECEMBER 31, 2019

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PURPOSE

This review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Networks for its Transmission and Distribution Operations. The recommended rates are subject to acceptance by the Ontario Energy Board. Hydro One plant data through December 31, 2019 was used to compute the proposed depreciation rates. These proposed rates are being used to establish proposed transmission and distribution revenue requirements in the Joint Application for 2023-2027. In the Joint Application, these rates which are based on 2019, will be applied to the 2023-2027 investment balances. The account-based depreciation rates were designed to recover the total remaining undepreciated investment over the remaining life of Hydro One's property on a straight-line basis. Land and other non-depreciable property were excluded from this study.

Hydro One is Ontario's largest electricity transmission and distribution service provider. Hydro One distributes electricity across Ontario to nearly 1.4 million customers, or approximately 26 percent of the total numbers of customers in Ontario. Hydro One's transmission system accounts for approximately 98 percent of Ontario's electricity transmission capacity.

Hydro One Inc. ("HOI") has been in existence since 1999 and is the successor company to Ontario Hydro's electricity transmission and distribution businesses. Hydro One Limited ("HOL") was incorporated on August 31, 2015 under the Business Corporations Act (Ontario). On October 31, 2015, HOL acquired HOI, a company previously wholly owned by the Province of Ontario (the "Province"). At December 31, 2019, the Province held approximately 47.3 percent of the common shares of HOL. The principal businesses of HOL, which it carries out primarily through Hydro One Networks Inc., are the transmission and distribution of electricity to customers within Ontario.

STUDY RESULTS

Overall depreciation rates for all Hydro One depreciable property are shown in Appendix A. The amount of the change in depreciation expense in the application will depend on application of the depreciation rates established in this report to Hydro One's total forecast depreciable investment levels for that year. For illustrative purposes, a comparison is given based on data at year end 2019. These rates translate into an annual depreciation accrual of $718 million based on Hydro One's depreciable investment at December 31, 2019. The annual equivalent depreciation expense calculated by the same method using the approved rates was $753 million, resulting in a $35 million decrease in annual depreciation expense. Appendix A presents the calculation of the annual depreciation rates and resulting accrual. Appendix B presents a comparison of approved versus proposed rates and annual accruals by account. Appendix C presents a summary of life and mortality curve parameters by account. Appendix D presents a summary of book depreciation reserve as compared to the reallocated depreciation reserve for each business unit. Appendix E presents a summary of estimated component life for each plant account within Hydro One. Finally, Appendix F provides information on the background and qualifications of Alliance Consulting Group.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Basis of Depreciation Estimates

For all depreciable accounts, the straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

The advantage of the broad group system is that all assets within an account are considered to be one group. Broad group depreciation is widely used and produces stable depreciation rates from year to year because of its averaging effects. The broad group procedure “requires the least accounting records of annual additions and balances."[1] There are other depreciation systems that could be considered, such as vintage group depreciation or equal life group. The Company's prior depreciation studies used straight line, vintage group, remaining life as the depreciation system. Vintage group depreciation assumes that each vintage is a separate group, requiring that each vintage be analyzed separately to determine its average life. Then all vintages are composited to develop the average service life of the account. Given the stable results produced by broad group and its wider use across the utility industry, Alliance recommends changing the procedure to be more consistent with other utilities across North America. The computations of the annual functional depreciation rates are shown in Appendix A.

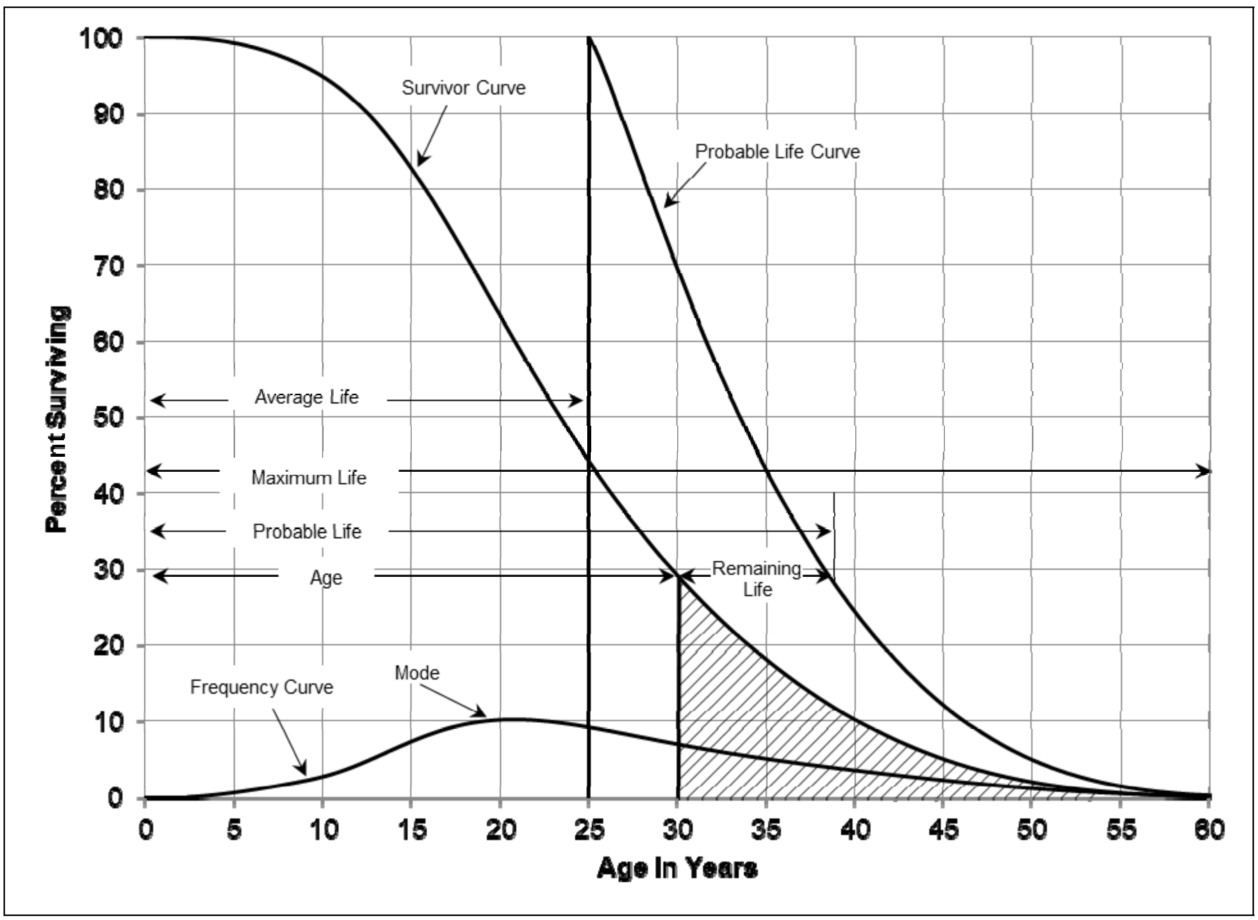
Actuarial analysis was used with each account within a function where sufficient data was available, and professional judgment was used to some degree on all accounts.

[1] Public Utility Depreciation Practices, National Association of Regulatory Utility Commissioners, 1996, p. 62.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The chart below shows a typical generalized survivor curve as well as some of the life characteristics that can be derived from the survivor curve.

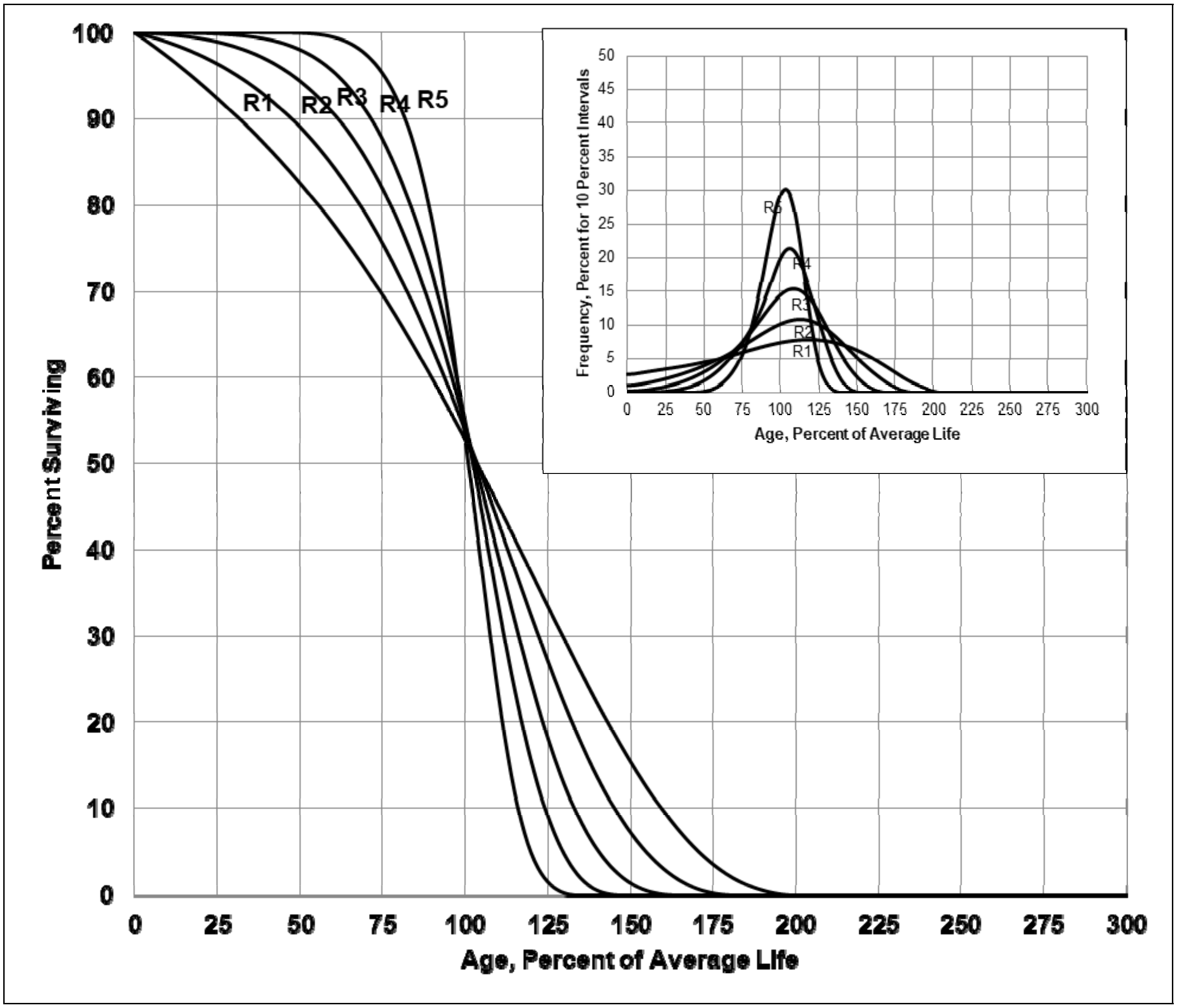
GENERALIZED SURVIVOR CURVE



The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property.

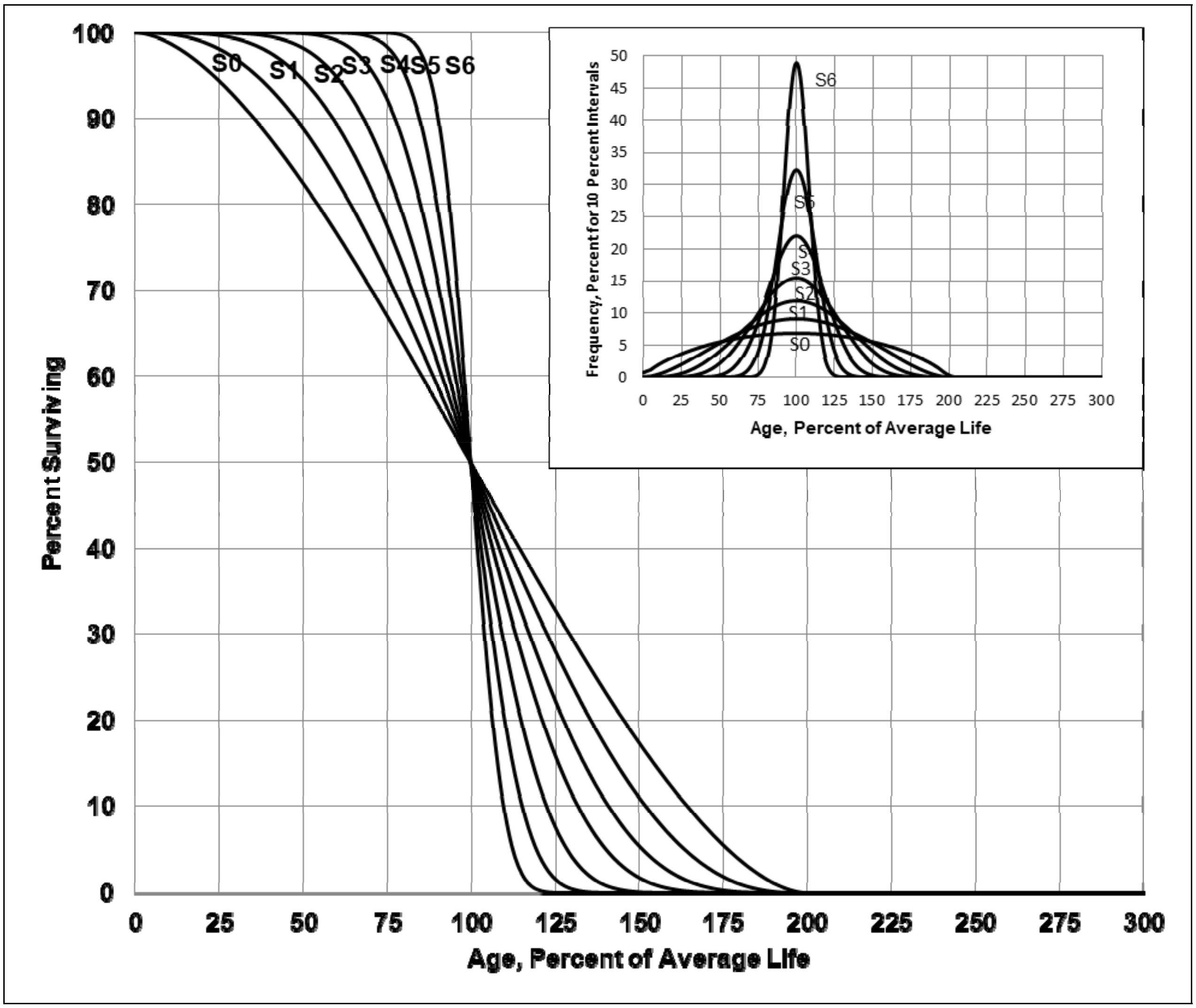
There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.

R-TYPE IOWA SURVIVOR CURVES



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. The higher the number of the curve, the greater the peak. A graph showing the S curves is shown below.

S-TYPE IOWA SURVIVOR CURVES



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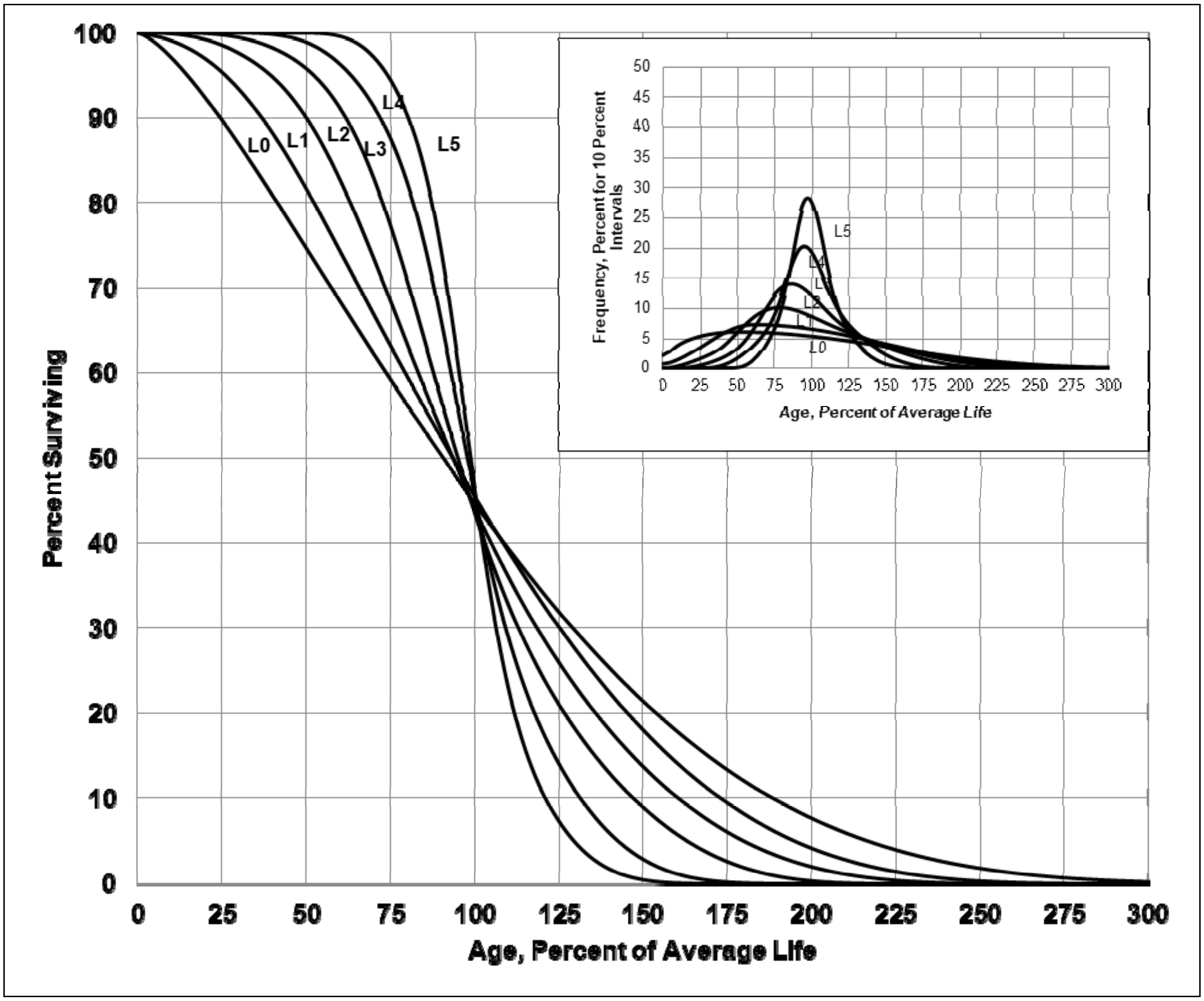
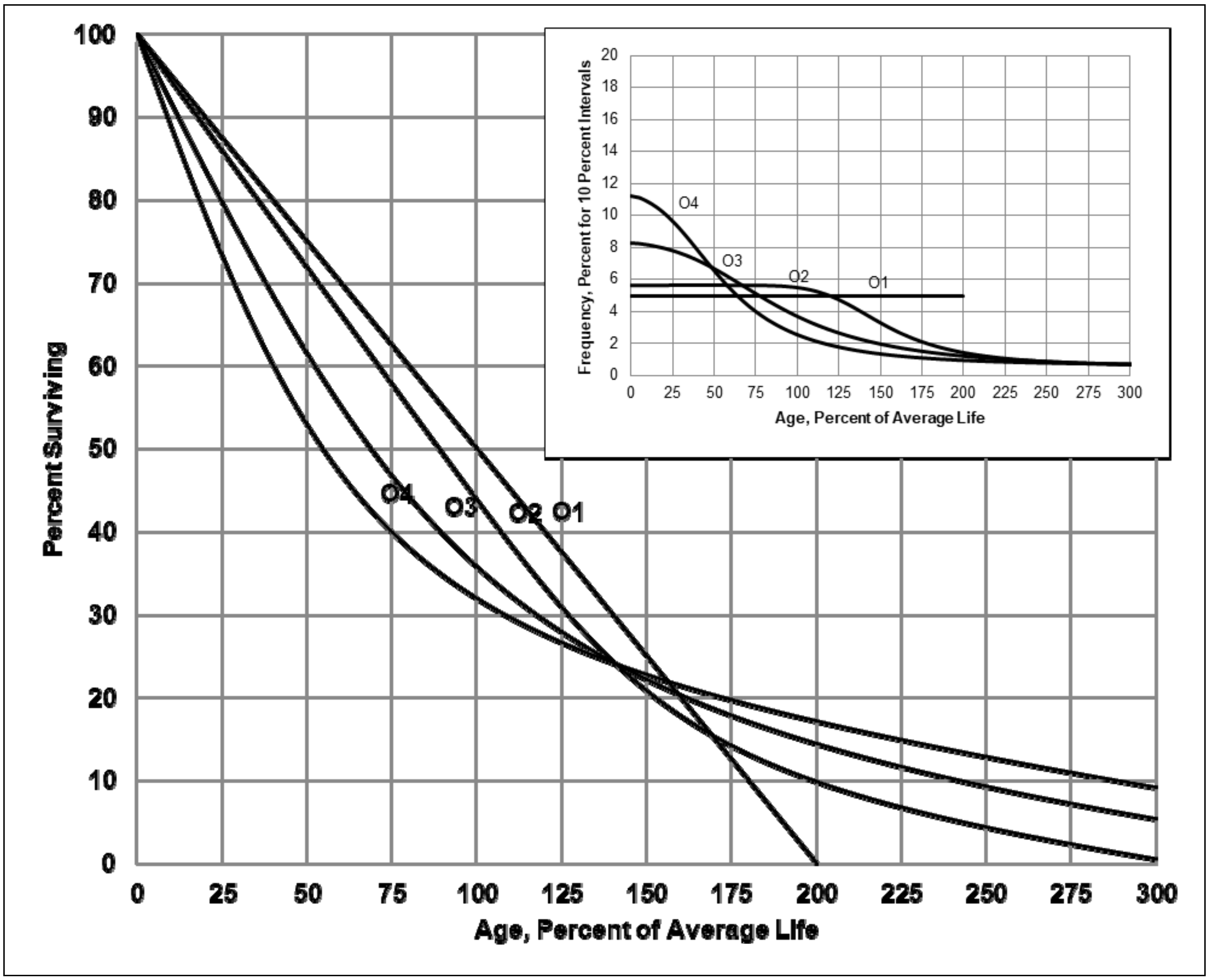
For distributions with the mode age less than the average life, a "L" designation (i.e., Left modal) is used. The family of “L” moded curves is shown below.

L-TYPE IOWA SURVIVOR CURVES



A special case of left modal dispersion is the "O" or origin modal curve family which was developed in the 1950s.

O-TYPE IOWA SURVIVOR CURVES



Given how long the O curves live, the O curves are seldom used in analyzing utility property in Alliance Consulting Group's experience. The O curves have been used for intellectual property.

Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency), while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data was available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Alliance Consulting Group is an international consulting firm formed in 2004 by Dane Watson. In addition to the partner, Alliance also has three full-time Senior Consultants, Dr. Karen Ponder, Ms. Rhonda Watts and Ms. Rebecca Richards as well as other support staff. Alliance is dedicated to providing quality consulting and expert services to the utility industry. Our professionals have more than 120 years of combined experience around the utility industry, and we have been employed in the industry as utility employees and consultants. The Alliance Consulting Group has performed over 275 depreciation studies for electric, gas, steam, water, wastewater, cable and communications utilities across North America since its founding by Mr. Watson in 2004. These utilities encompass regulated, non-regulated, municipal and federal agencies. The resumes of our personnel and a listing of our many engagements is provided in Appendix F. Given Alliance personnel's experience in accounting, fixed assets, engineering, and depreciation theory, we have an unparalleled expertise to incorporate in analyzing the Company's assets and recommending depreciation accrual rates.

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least, for example, any analysis requires choosing which bands to place more emphasis.

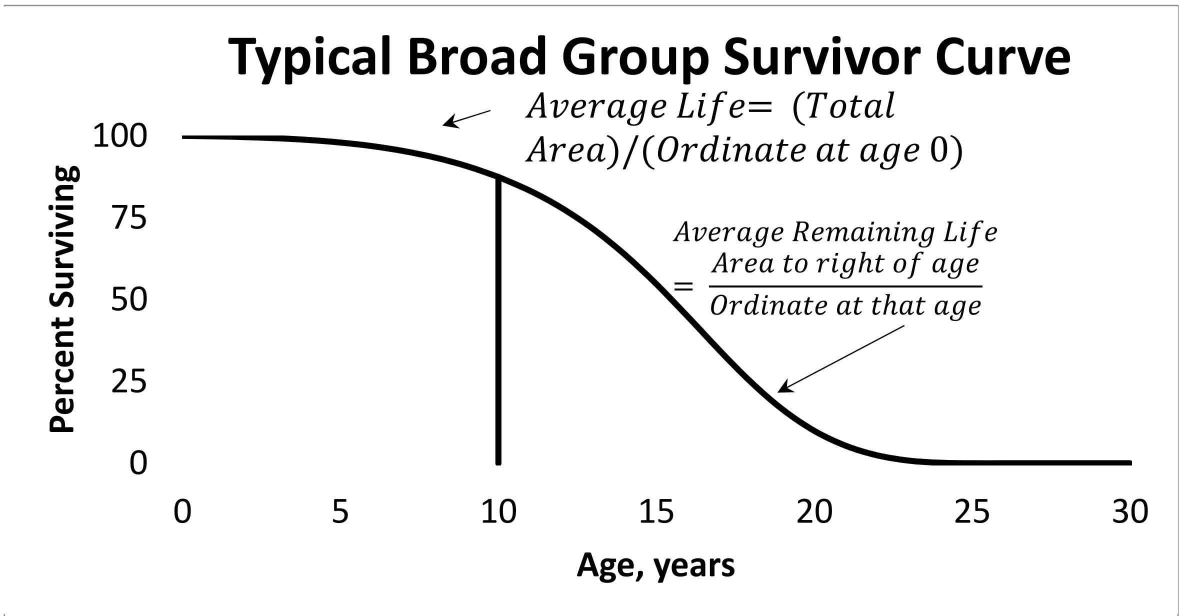
The establishment of appropriate average service lives and retirement dispersions for Hydro One's plant accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

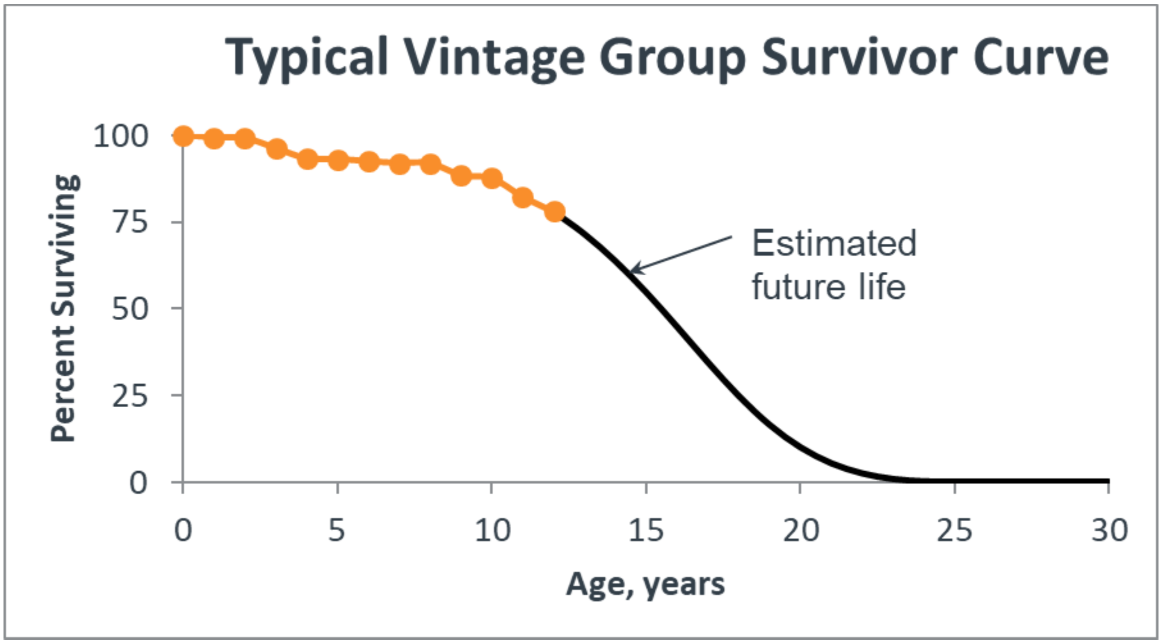
Average Life Group Depreciation

There are two depreciation "groupings" most commonly used in average life group depreciation: broad group and vintage group. Broad group ("BG") assumes that all units of plant in a plant account are considered to be one group. The BG produces stable results over many periods and, in Alliance Consulting Group's experience, is the most common depreciation system used across the industry. The vintage group ("VG") application assumes that each vintage within a plant account is a separate group. VG requires that each vintage group be analyzed separately to determine its average life, and then average lives of all vintages are composited to produce an average life for the group.

A typical broad group survivor curve is shown below.



VG uses the stub survivor curve of each vintage and determines remaining life from the proposed survivor curve. A typical vintage group curve model is shown below.



This study proposes to convert to the average life group, broad group depreciation system to group the assets within each account. In its last depreciation study, Hydro One was authorized to use the straight line, vintage group, remaining life ("SL-VG-RL") depreciation system. In Alliance's experience, the broad group procedure is much more commonly used across North America. Since Hydro One has limited transactional data from 2000-2019, the results from the VG procedure are more subject to fluctuations in computing individual vintage average service life if there are any anomalies in the data. Those changes in individual vintages could produce unstable results if there is incomplete data for an individual vintage. BG was selected as the depreciation system to use for Hydro One in this study given that it is more stable in the accrual rate computations and used by the majority of North American utilities.

Theoretical Depreciation Reserve and Reserve Rebalancing

The book depreciation reserve was derived from Company records at the individual account level. This study used a reserve model that relied on a prospective concept relating to future retirement and accrual patterns for property, given current life and salvage estimates. This study recommends and uses reserve reallocation to rebalance reserves within each business unit and function. Reserve reallocation is when the book reserve is re-spread within a functional group based on the theoretical reserve within each function. In the process of analyzing the Company's depreciation reserve, Alliance Consulting Group observed that the depreciation reserve positions of the accounts were generally not in line with the life characteristics found in the analysis of the Company's assets. To allow the relative reserve positions of each account within a function to mirror the life characteristics of the underlying assets, we reallocated the depreciation reserves for all accounts within each function. The depreciation reserve represents the amounts that have been collected as a systemic allocation of the cost of an asset over its useful life, including any net salvage that may be required to remove that asset from service upon retirement. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts in the function. Depreciation reserve allocation is a sound depreciation practice. The National Association of Regulatory Utility Commissioners endorsed the practice in its 1968 publication of *Public Utility Depreciation Practices*, explaining that reallocation of the depreciation reserve is appropriate "…where the change in the view concerning the life of property is so drastic as to indicate a serious difference between the theoretical and the book reserve."[2] Additionally, the 1996 edition of *Public Utility Depreciation Practices* states that "theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts."[3]

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2 *Public Utility Depreciation Practices*, Published by the National Association of Regulatory Utility Commissioners, 1968, page 48.
3 *Public Utility Depreciation Practices*, Published by the National Association of Regulatory Utility

The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

In the case of Hydro One, no net salvage is incorporated in depreciation accrual rates, consistent with other Canadian utilities. Reserve reallocation has been used in the Company's previous transmission and distribution depreciation studies.

Commissioners, 1996, page 188.

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis were evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documentation of the corresponding recommendations.

During the Phase 1 data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Also, as part of the Phase 1 data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the company's actual asset utilization and environment. Information that was gleaned in these discussions is found in the Detailed Discussion of this study in the life analysis sections.

Phase 2 is where the actuarial analysis is performed. Phases 2 and 3 overlap to a significant degree. The detailed property records information is used in Phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in Phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. No net salvage is incorporated in Hydro One's depreciation accrual rates, consistent with its accounting practices, with other Canadian utilities, and with its previous studies. Net salvage was not included in the Company's prior Transmission, Distribution and Common depreciation studies. This information was then carried forward into phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and mortality curve parameters. The historical analysis from Phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[4] documents the steps used in conducting this study. Depreciation Systems[5], page 289, documents the same basic processes in performing a depreciation study which are: statistical analysis, evaluation of statistical analysis, discussions with management and operational personnel, forecast assumptions, and documented recommendations.

[4] Public Utility Finance & Accounting, A Reader.

[5] Depreciation Systems, by Drs. W. C. Fitch and F.K. Wolf, Iowa State University Press, 1994, page 289.

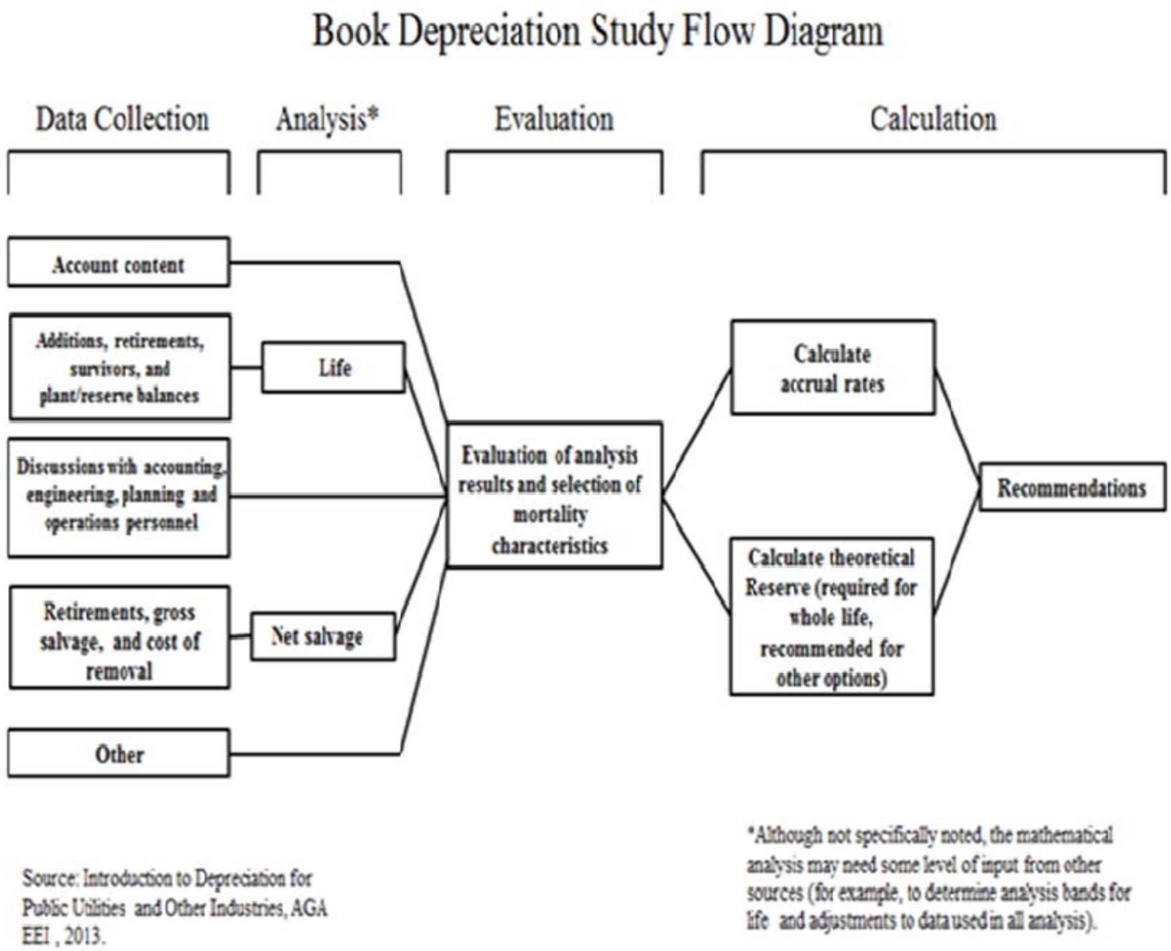


Figure 1

HYDRO ONE DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation Process

The proposed rates are based on plant and accumulated depreciation reserve balances at December 31, 2019 and will be applied to test year data developed in the Joint Application. Annual depreciation expense amounts for all accounts were calculated by the straight-line method, broad (average) life group procedure, remaining-life technique. These calculations are shown in Appendix A. The results of calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in Appendix D. Book depreciation reserves were based on Company individual accounts and the theoretical reserve computation was used to rebalance depreciation reserves and compute a composite remaining life for each account.

LIFE ANALYSIS

The retirement rate actuarial analysis method was applied to all accounts for Hydro One. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying widths. The historical observed life table was plotted and compared with various Iowa Curves to obtain the most appropriate match. A representative curve for each account is shown in the Life Analysis Section of this report.

Company history is compiled to develop observed survivor curves which are matched against the Iowa Curve families discussed earlier. An observed survivor curve that does not reach 0% surviving is a stub curve. Because the average life associated with a survivor curve is represented by the area under the complete survivor curve, the observed survivor curve must be smoothed and extended to 0% surviving. If more historical data is available to analyze, the observed survivor curve (stub curve) will be longer (i.e., getting closer to 0 percent surviving). Hence the more history available in the data, the more predictable and reliable the resulting Company observed survivor curve will be for selecting a complete survivor curve. It is desirable to have the stub curve drop below 50% surviving. The earliest experience year available where retirement history for each account was available was 2000, due to the 1999 demerger from Ontario Hydro and various system conversions that occurred over time. Many of the Company's assets have existing lives longer than 50 years, and the observed life tables may not reach the desired 50% surviving.

For each account on the overall band (i.e. placement from earliest vintage year which varied for each account through 2019), approved survivor curves from the prior study, if applicable, modified by subsequent orders, were used as a starting point. Then, using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (e.g., L, S. or R) as an obviously better match than others. The matching process relies on expert judgment to determine which portion of the curve to match. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed. Next placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa Curve in the top and mid-range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

Since Hydro One had aged data only going back to 1999, the short experience available for these long-lived accounts does not allow the observed life table to extend to a level that would allow the analyst to fully see the historical life-cycles for the assets being studied. To help better understand the historical characteristic of the assets being studied, interviews with Company subject matter experts (SMEs) provided valuable information to estimate life characteristics. Company SMEs also provided estimated component lives for various assets in each plant account. The component life analysis for each business unit is found in Appendix E. The data in this study includes all retirement activity that Hydro One has experienced between

2000-2019. By including all past events, this study expressly contemplates the range of natural disasters that Hydro One has experienced in the past, along with the associated impact on early retirement of damaged or destroyed assets. Over time, natural events such as storms, flooding, or wildfires can occur which may cause the early retirement of assets. Such events have occurred during the period from 2000-2019 in Company history and will recur in the future given climate change and unknown future events.

Alliance Consulting Group has developed the proposed life parameters given Hydro One's unique characteristics. At times, comparisons are made with other utilities. In 2010, Kinectrics presented Report No: K-418033-RA-001-R00 to the Ontario Energy Board, entitled Asset Depreciation Study. The Kinectrics report did not study Transmission function property. Kinectrics provided a range of lives for assets in the Distribution function for various components in each plant account. Since the components did not correlate on a one to one basis for every asset group it was not possible to examine every asset grouping listed in the 2010 report. After reviewing asset groupings, almost all distribution plant account components were in the range of lives provided by Kinectrics. One account differed between Kinectrics and Hydro One, where Hydro One has shorter lives for one property group, SCADA equipment. As used by Hydro One, SCADA equipment has been impacted by technology change. Since the Kinectrics report was published more than 10 years ago, the pace of technology continues to change and the Kinectrics range of lives may not be accurate in 2021.

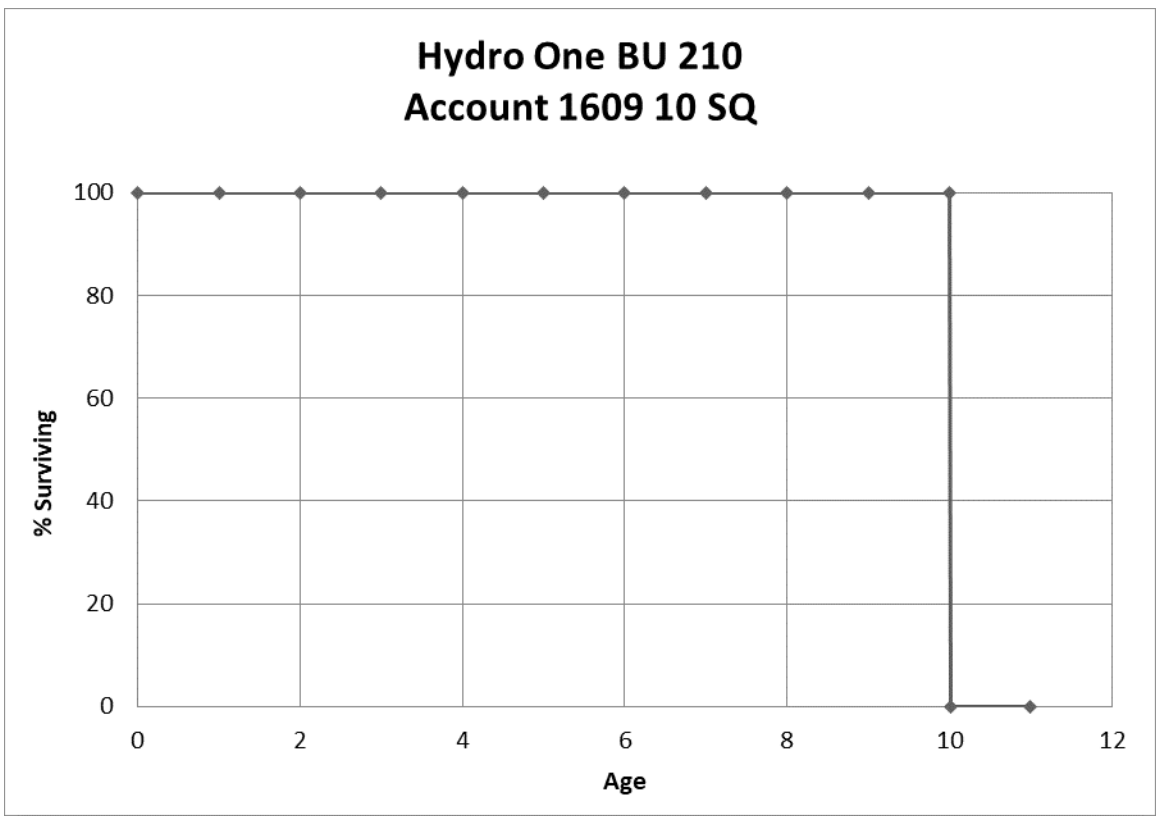
BU 210 TRANSMISSION OPERATIONS

INTANGIBLE FUNCTIONAL GROUP

Accounts in the intangible function are amortized. When those assets are fully accrued, amortization ceases. Any new assets added to an account are amortized using the life assigned to the account.

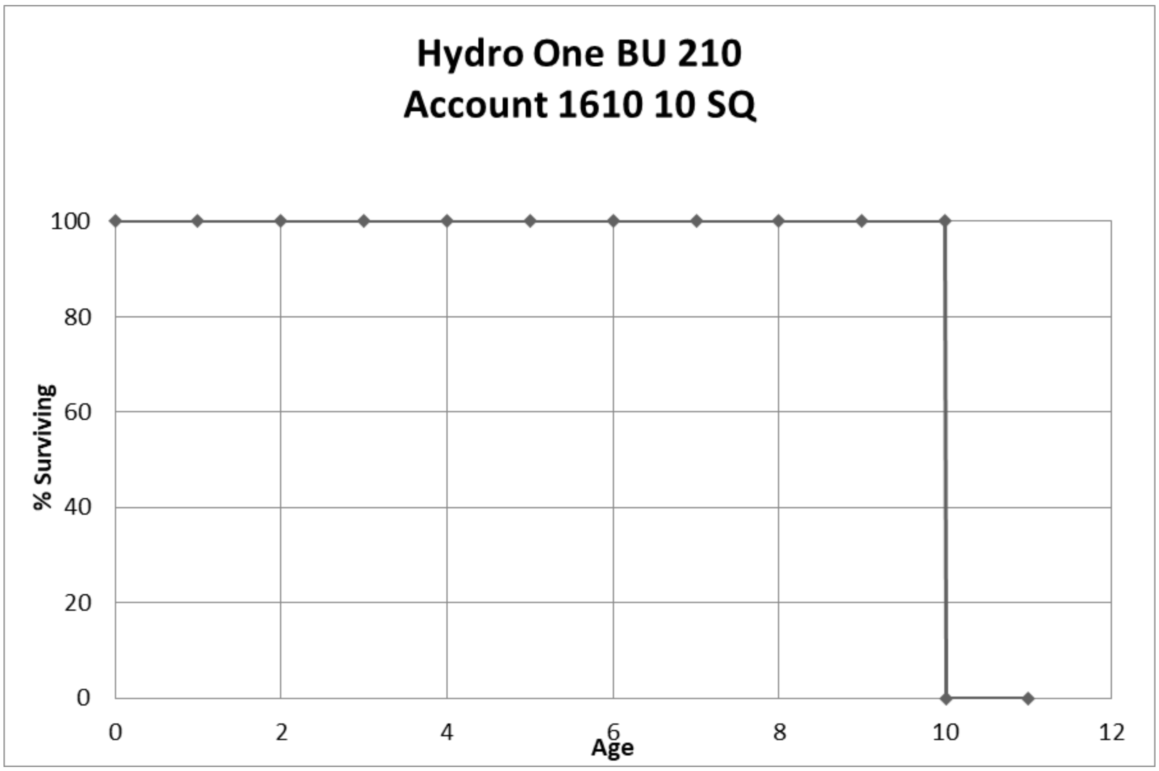
Account 1609 Capital Contributions (10 SQ)

This account consists of capital contributions for the Transmission Operations group. The plant balance in this account at December 31, 2019 is $8.7 million. Currently the amortization life of this account is 10 years. After reviewing plant lives with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 10-year life with a SQ dispersion.



Account 1610 Computer Software (10 SQ)

This account consists of computer software for the Transmission Operations group. Such assets include general system software and various fiber optic equipment. The plant balance in this account at December 31, 2019 is $16.3 million. Currently the amortization life of this account is 10 years. After reviewing plant lives with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 10-year life with a SQ dispersion.

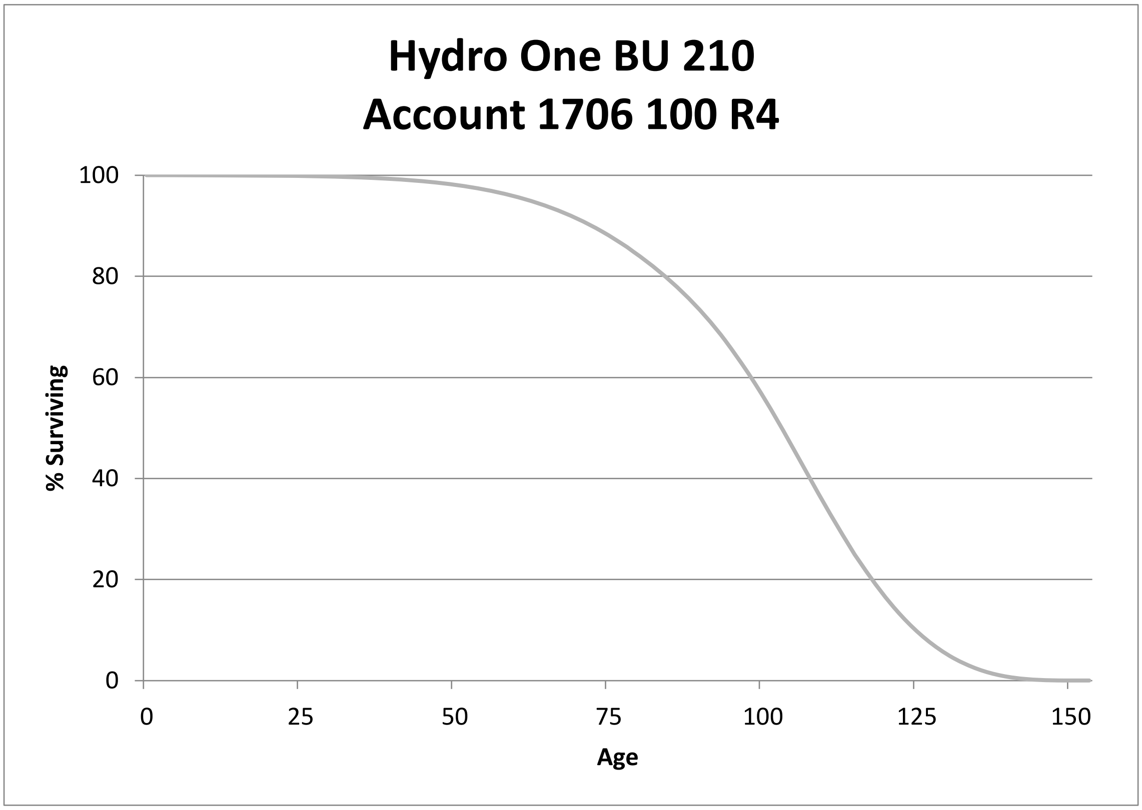


TRANSMISSION FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

Account 1706 Land Rights (100 R4)

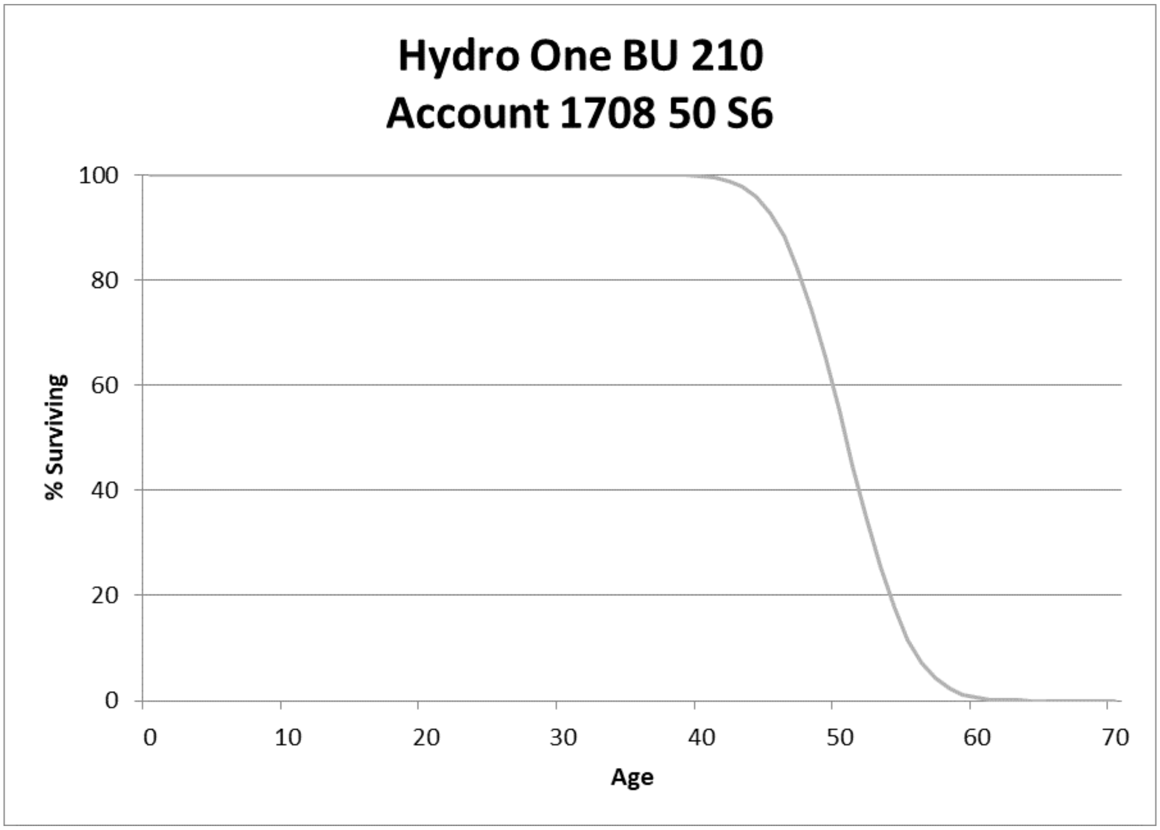
This account consists of land rights associated with Transmission Operations. Such assets include easements and site improvements. The plant balance in this account at December 31, 2019 is $257.3 million. Currently, the life of this account is 100 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the conclusion was that the existing 100-year life is still appropriate for this account. A change in dispersion is recommended to the R family, which is more predominant for transmission property in Alliance's experience. A representative graph for the life of the account is shown in the curve below, a 100-year life with an R4 dispersion.


Hydro One BU 210
Account 1706 100 R4
100
80
60
40
20
0
% Surviving
0
25
50
75
100
125
150
Age

32

Account 1708 Buildings and Fixtures (50 S6)

This account consists of various buildings and fixtures associated with Transmission Operations. Such assets include transmission station buildings, building components, cranes and hoists in buildings, underground cable in buildings, and other station structures. The plant balance in this account at December 31, 2019 is $603.0 million. Currently, the life of this account is 50 years with an S6 dispersion. Discussions with Company SMEs reveal that buildings in this account are a mixture of two different types: prefabricated and brick and mortar. Prefabricated structures are estimated to have a 40-year life from an operational perspective. Brick and mortar buildings will have a longer life. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 50-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 50-year life with an S6 dispersion.

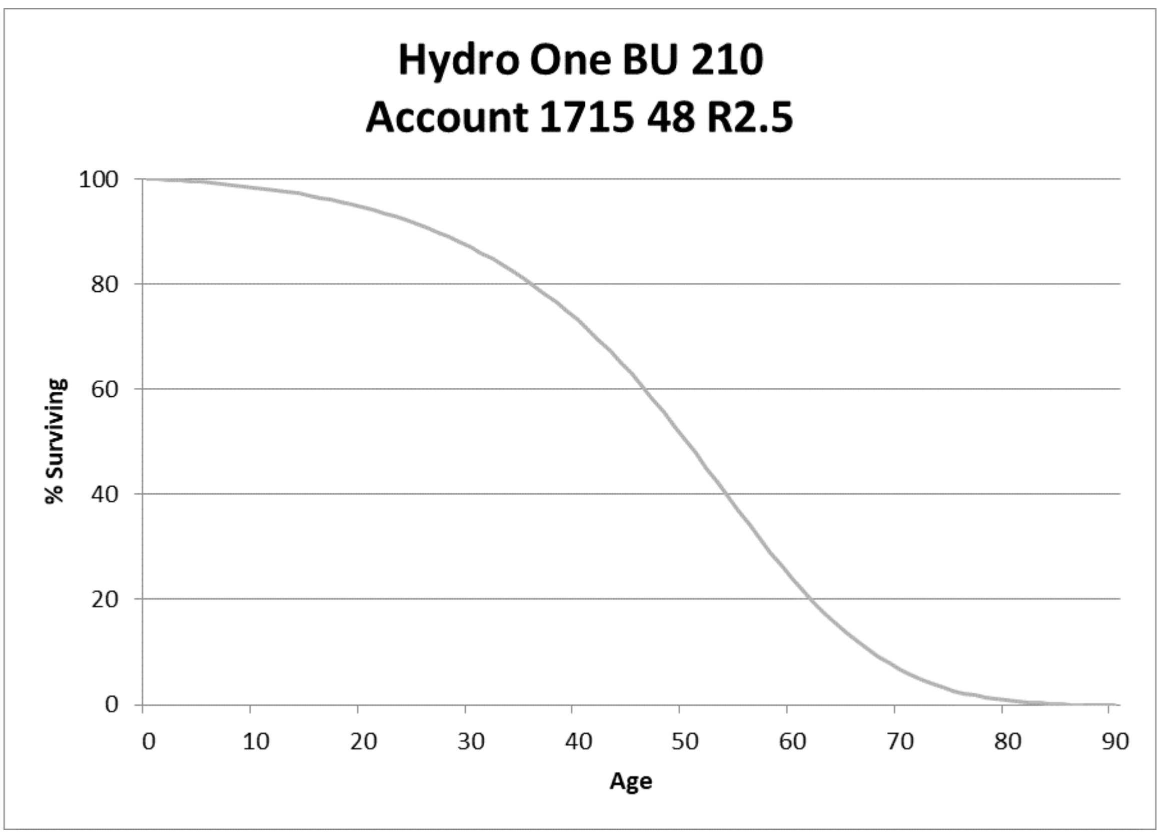


Account 1715 Station Equipment (48 R2.5)

This account consists of a variety of station equipment within Transmission Operations. Such assets include landscaping, fencing, foundations, capacitors, switch boards, control equipment, switching equipment, transformers, and regulators. The plant balance in this account at December 31, 2019 is $10.3 billion. Currently the life of this account is 45 years with an S2 dispersion. Company SMEs note that there are a wide variety of assets in this account that are impacted by differing forces and timing of retirement. Significant components are experiencing changes: breakers are changing to SF6, relays are moving analog to digital, and newer (second generation) IEDS have a longer life span. Newer equipment allows more ability to monitor load and aids in compliance and testing. Increasing levels of automation are being used on systems. Hydro One has standardized design and materials for transformers, and power transformers are now exhibiting a 45 to 55-

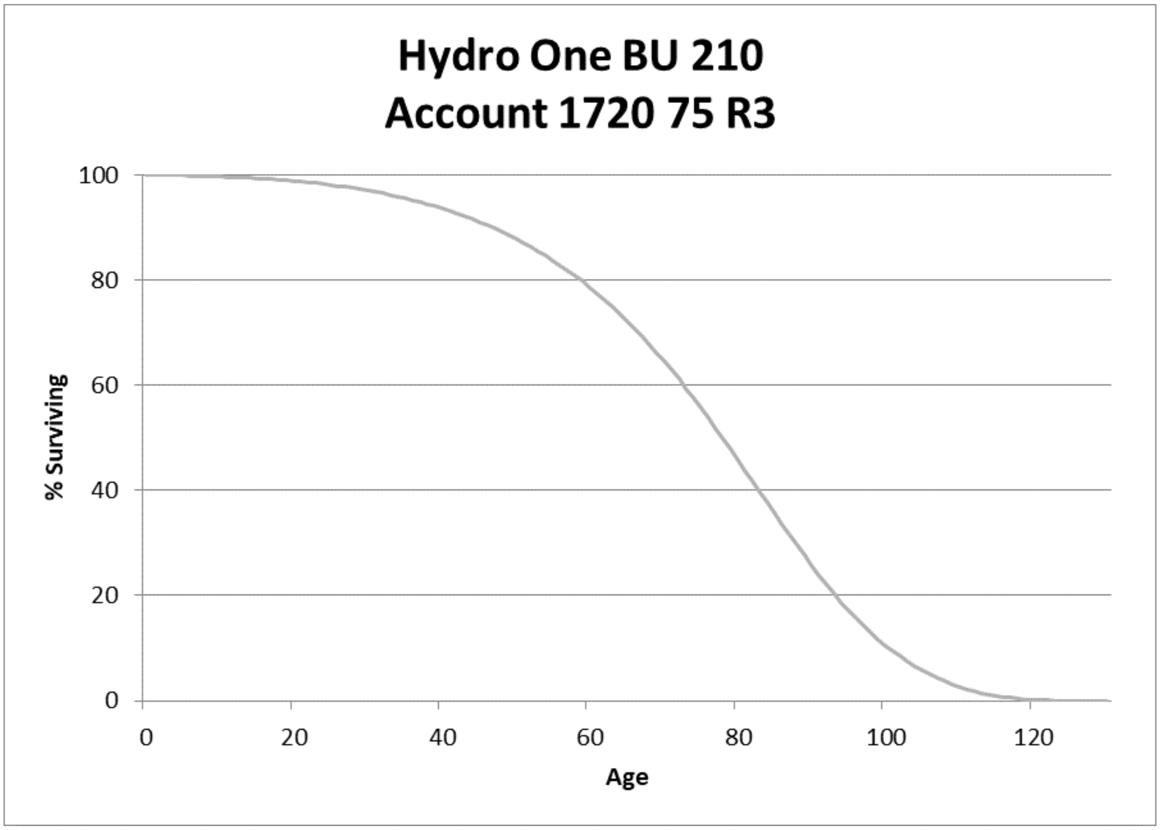
year life. SMEs report that the Company does not run assets to failure, and that the Company uses program maintenance, defect reports, and condition assessment to prevent failures. Various component life projections are shown in Appendix E-1.

Limited retirement activity exists to analyze the life of the account. Although there are forces decreasing the life of some assets, forces are also tending to extend the life of other assets. After seeking input from Company personnel and incorporating professional judgment, the determination was that a small extension of the life for this account is appropriate. In Alliance's experience, many transmission assets have an R dispersion life characteristic more frequently than the S family currently used. For these reasons, a 48-year life with an R2.5 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



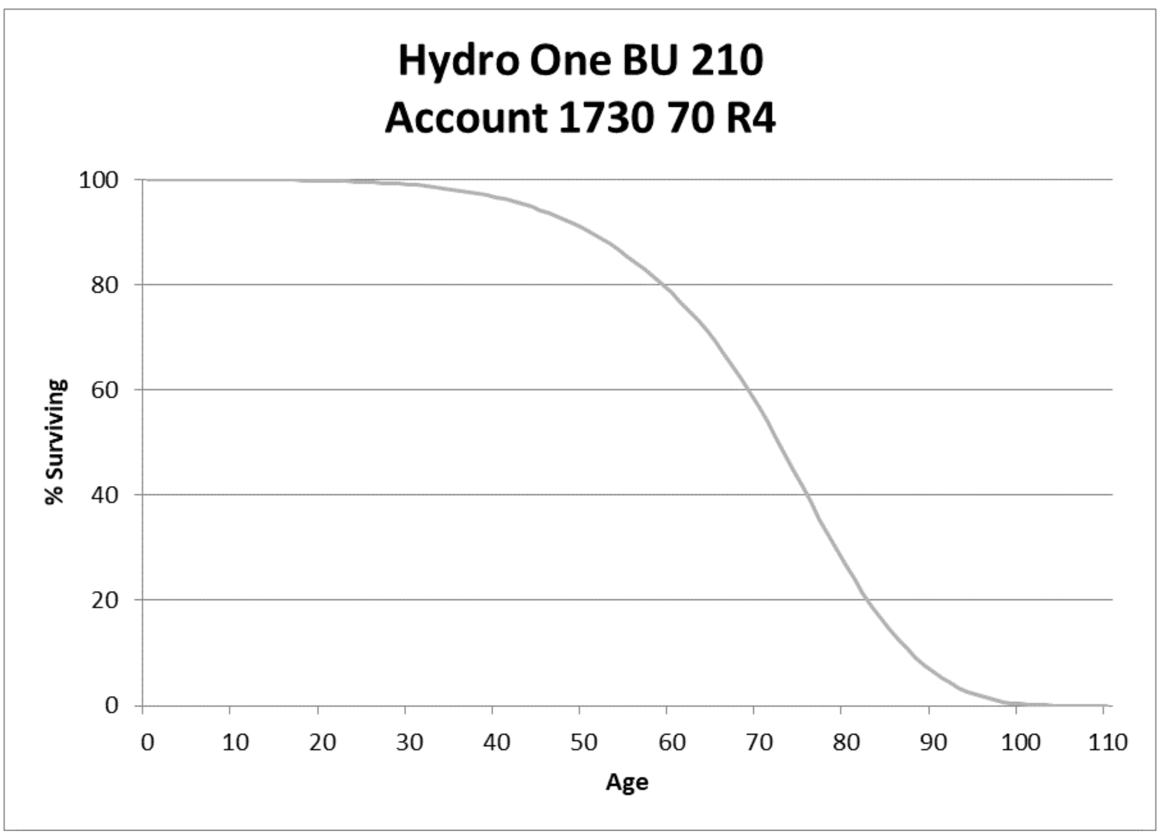
Account 1720 Towers and Fixtures (75 R3)

This account consists of towers and fixtures associated with Transmission Operations. Such assets include towers, steel poles, composite poles, crossarms, and anchors. The plant balance in this account at December 31, 2019 is $2.8 billion. Currently the life of this account is 75 years with an S2 dispersion. Limited retirement activity exists to analyze the life of the account. Company SMEs provided operational life expectations for major components within this account in Appendix E-1. Steel towers are estimated to have an operational life of 90 years, wood poles are estimated to have a 50-year life, steel poles are estimated to have a 90-year life, and composite poles are estimated to have an 80-year life. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is still appropriate for this account. In Alliance's experience, many transmission assets have an R dispersion life characteristic more frequently than the S family currently used. For the reasons listed above, a 75-year life with an R3 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 210
Account 1720 75 R3
100
80
60
40
20
0
% Surviving
0
20
40
60
80
100
120
Age

Account 1730 Overhead Conductors and Devices (70 R4)

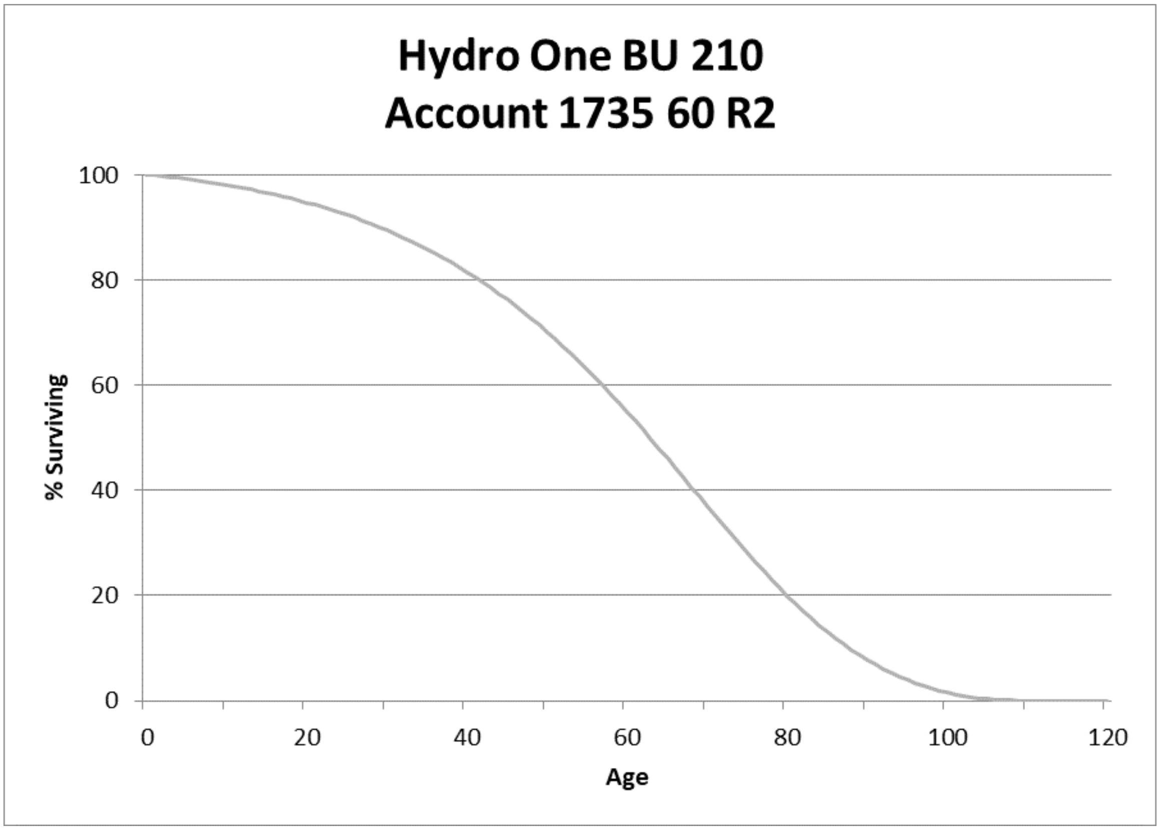
This account consists of various overhead and conductors associated with Transmission Operations. Such assets include insulators, ground wire, switches and devices, and overhead conductor and devices. The plant balance in this account at December 31, 2019 is $2.0 billion. Currently the life of this account is 65 years with an S3 dispersion. Limited retirement activity exists to analyze the life of the account. Operationally, the life of the conductor in this account could move a little closer to the expected life of the towers and poles. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing life should be extended for this account. In Alliance's experience, transmission assets have an R dispersion life characteristic more frequently than the S family currently used. For the reasons listed above, a 70-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



38

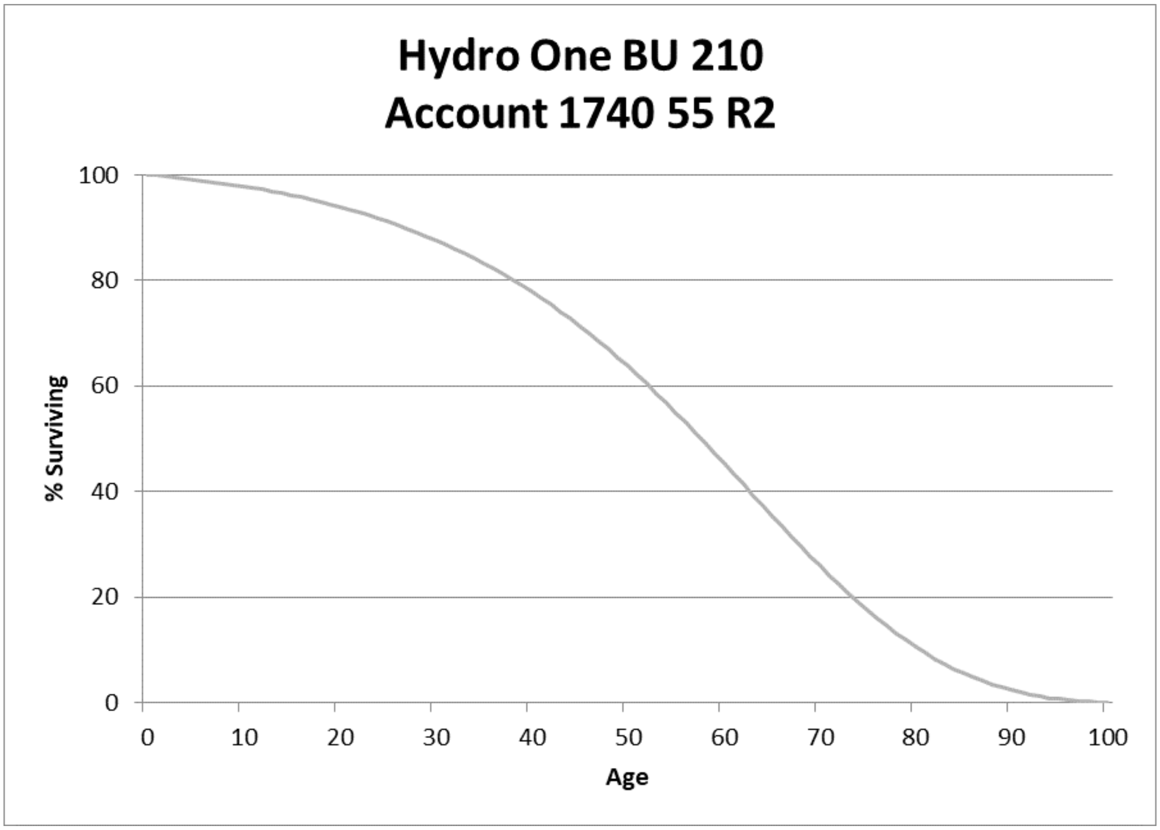
Account 1735 Underground Conduit (60 R2)

This account consists of various underground conduit used to deliver electric service for Transmission Operations. Such assets include transmission station buildings, cranes and hoists in buildings, underground cable in buildings, and other station structures. The plant balance in this account at December 31, 2019 is $310.3 million. Currently the life of this account is 55 years with an S2 dispersion. Limited retirement activity exists to analyze the life of the account. Company personnel believe there are some operational reasons that the conduit should have a slightly longer life in some cases than the cable within the conductor. After seeking input from Company personnel and incorporating professional judgment, the determination was that the life should be extended for this account. In Alliance's experience, transmission assets have an R dispersion life characteristic more frequently than the S family currently used. For the reasons listed above, a 60-year life with an R2 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



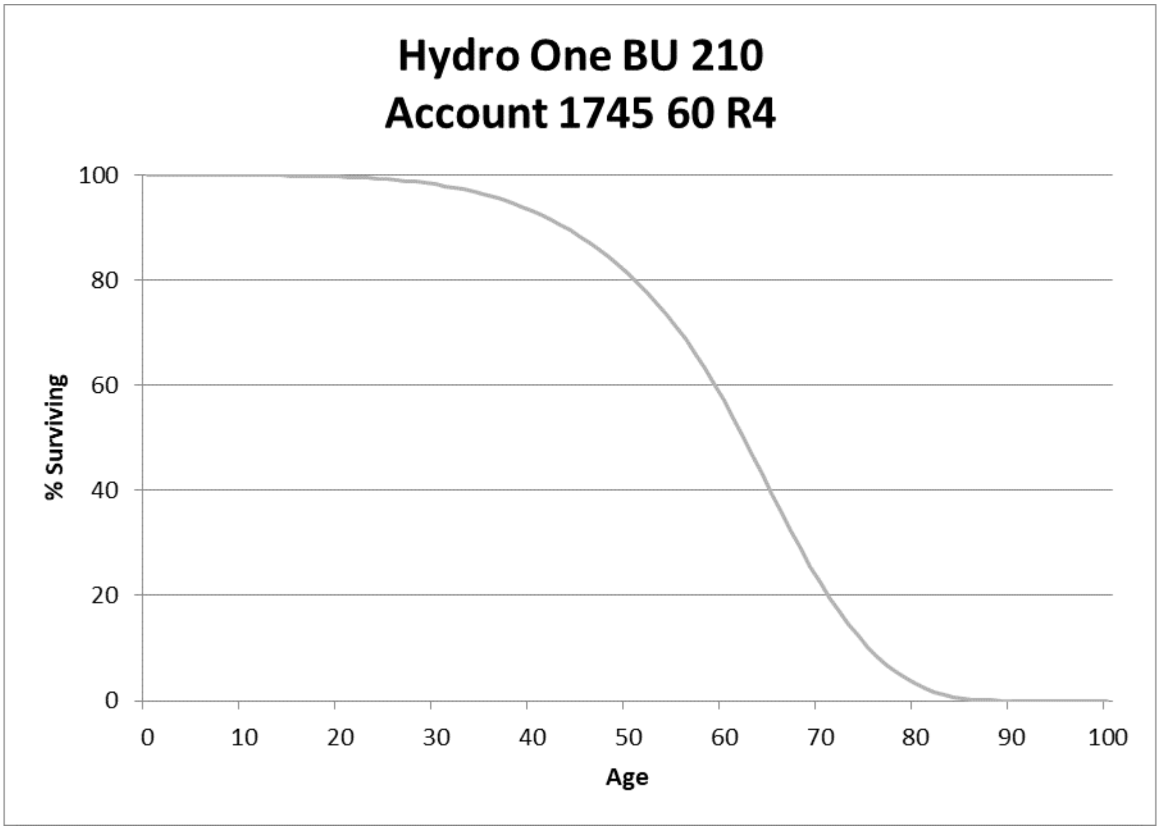
Account 1740 Underground Conductors and Devices (55 R2)

This account consists of various underground conductors and devices used to deliver electric service associated with Transmission Operations. The plant balance in this account at December 31, 2019 is $153.7 million. Currently the life of this account is 55 years with an S2 dispersion. The oldest assets in this account were installed from years 2000-2019, and limited retirement activity exists to analyze the life of the account. Since the observed life table only goes to 99 percent surviving, there is insufficient data to perform visual matching. Although there is some indication that the life being exhibited could be shorter than the existing 55 years, there is not enough retirement experience to move the life at this point. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 55-year life is still appropriate for this account. In Alliance's experience, transmission assets have an R dispersion life characteristic more frequently than the S family currently used. For the reasons listed above, a 55-year life with an R2 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



Account 1745 Road and Trails (60 R4)

This account consists of various roads and trails associated with Transmission Operations. Such assets include roads, clearing and surfaces areas used for transmission facilities. The plant balance in this account at December 31, 2019 is $308.5 million. Currently the life of this account is 50 years with an S2 dispersion. Compared to similar assets of other utilities, the existing 50-year life for this account is at the low end of the range. Limited retirement activity exists to analyze the life of the account. The component lives in Appendix E-1 show a longer life than is currently in place. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing life should be extended for this account. The currently used S curve assumes that items retire symmetrically around the average life of the group. In Alliance Consulting Group's experience, retirement characteristics of property in this account model the R family where more assets live longer than the average service life of the group. Based on professional experience we recommend shifting the life from the S family to the R family. For the reasons listed above, a 60-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 210
Account 1745 60 R4
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
Age

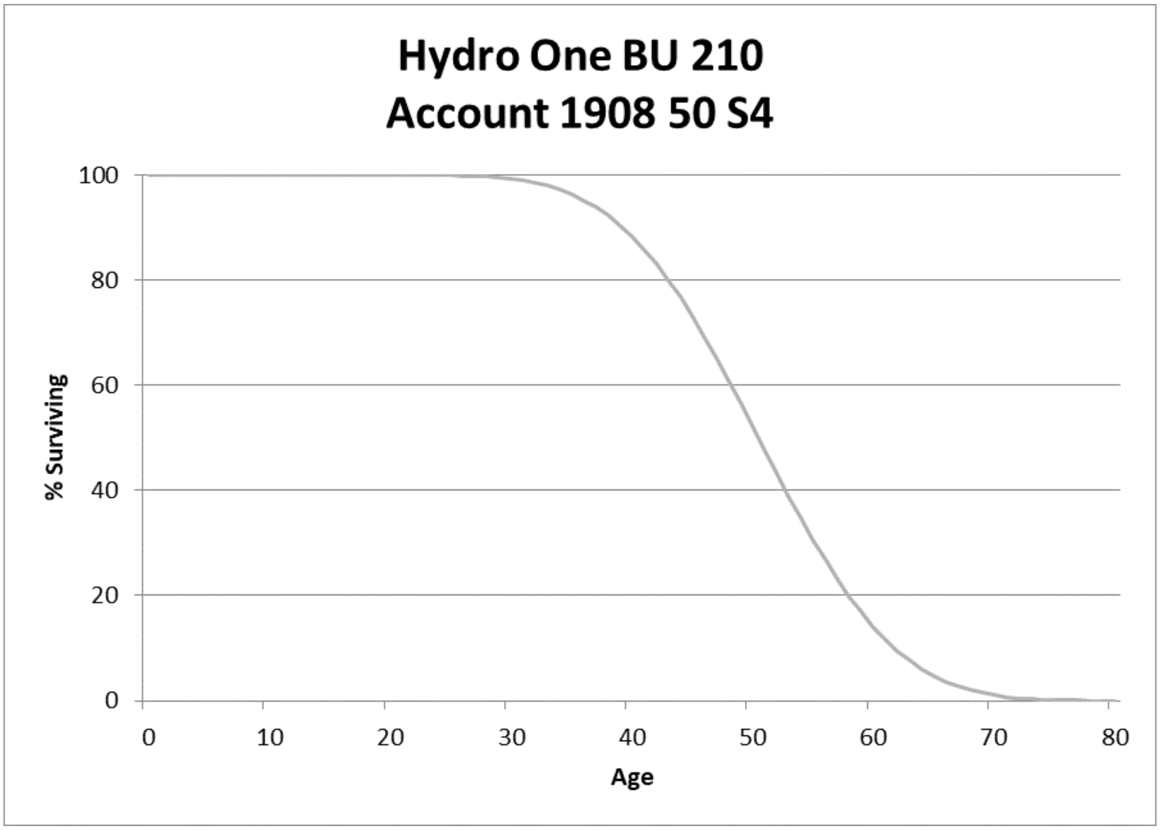
43

GENERAL DEPRECIATED FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

Account 1908 Buildings and Fixtures (50 S4)

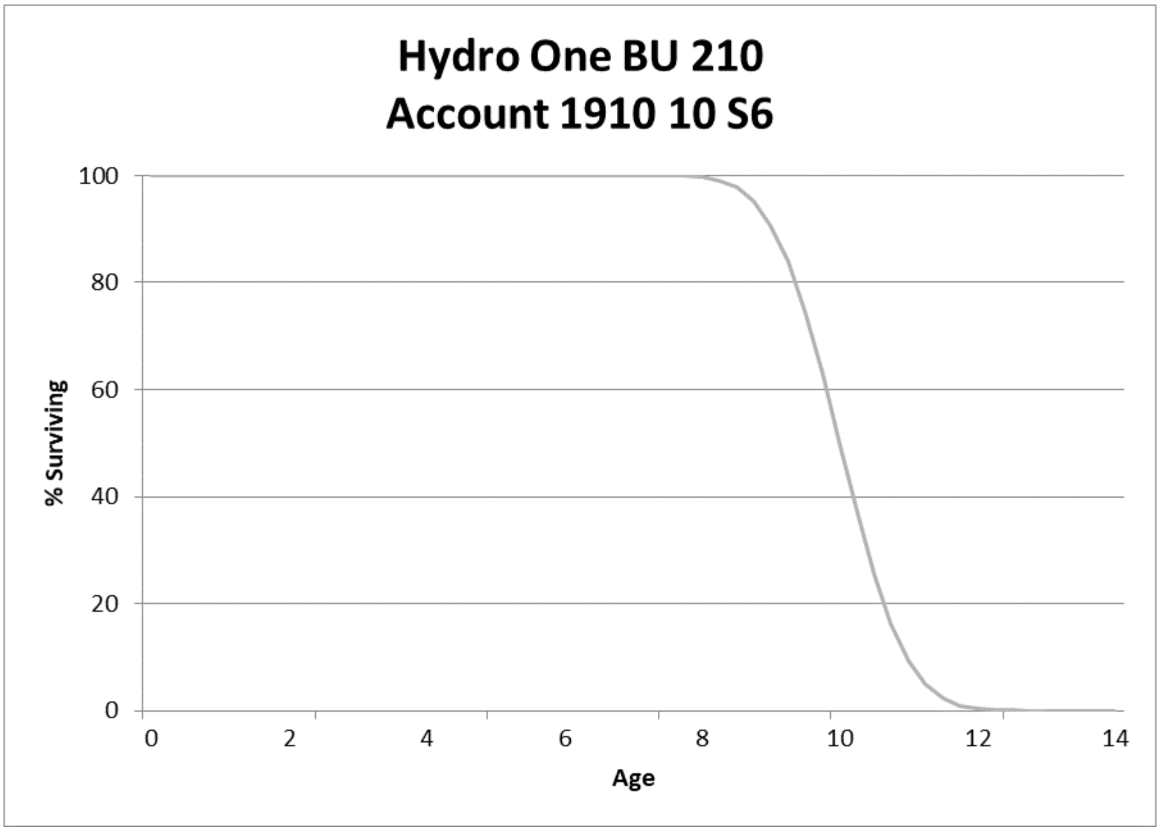
This account consists of various buildings and fixtures associated with Transmission Operations. Such assets include buildings, landscaping, fencing, roads and surfaces, and other structures. The plant balance in this account at December 31, 2019 is $151.6 million. Currently the life of this account is 45 years with an S4 dispersion. Limited retirement activity exists to analyze the life of the account. Based upon the component lives in Appendix E-1, the overall composite for this account is 48 years. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 45 year should be extended. A 50-year life with an S4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 210
Account 1908 50 S4
100
80
60
40
20
0
% Surviving
0
10
20
30
40
50
60
70
80
Age

45

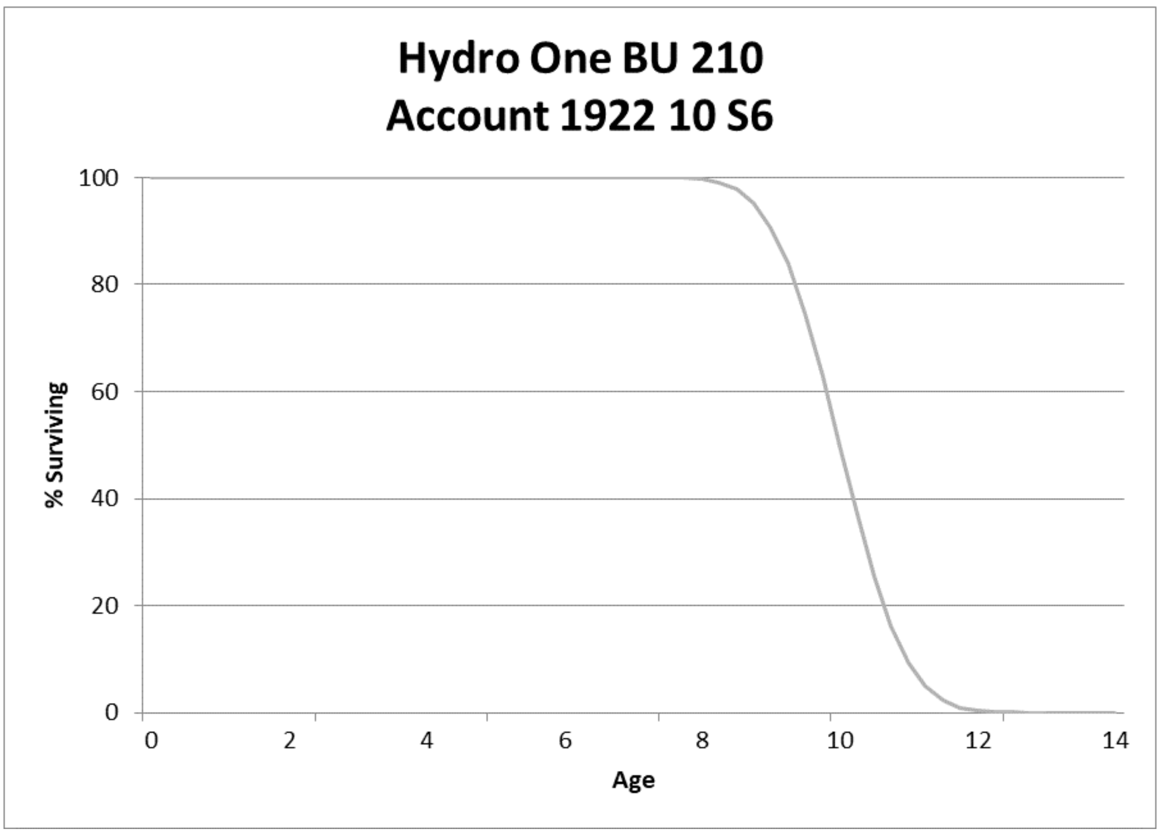
Account 1910 Leasehold Improvements (10 S6)

This account consists of various leasehold improvements made to leased buildings associated with Transmission Operations. The plant balance in this account at December 31, 2019 is $0.1 million. Currently the life of this account is 10 years with an S6 dispersion. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an S6 dispersion.



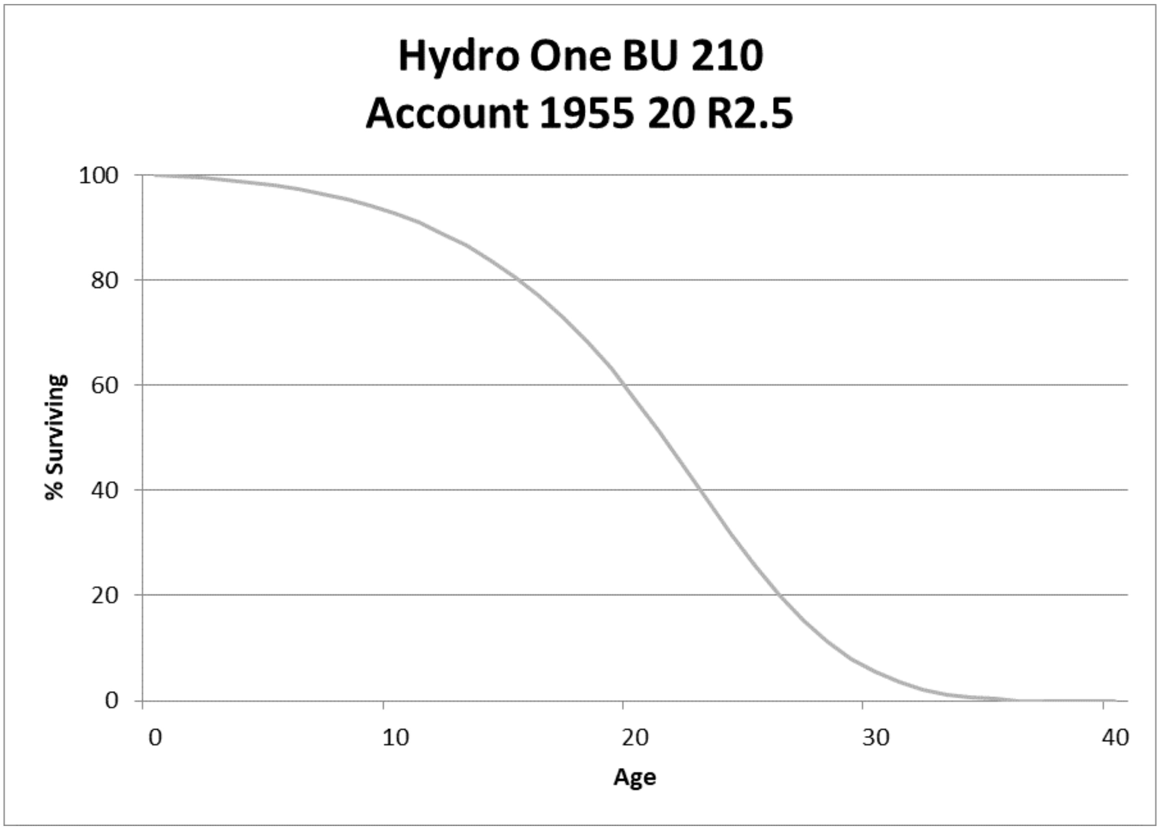
Account 1922 Computer Equipment - Hardware (10 S6)

This account consists of various major computer hardware equipment associated with Transmission Operations. Such assets include local area network cable, fiber optic equipment, and electrical devices. The plant balance in this account at December 31, 2019 is $15.2 million. Currently the life of this account is 10 years with an S6 dispersion. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an S6 dispersion.



Account 1955 Communication Equipment (20 R2.5)

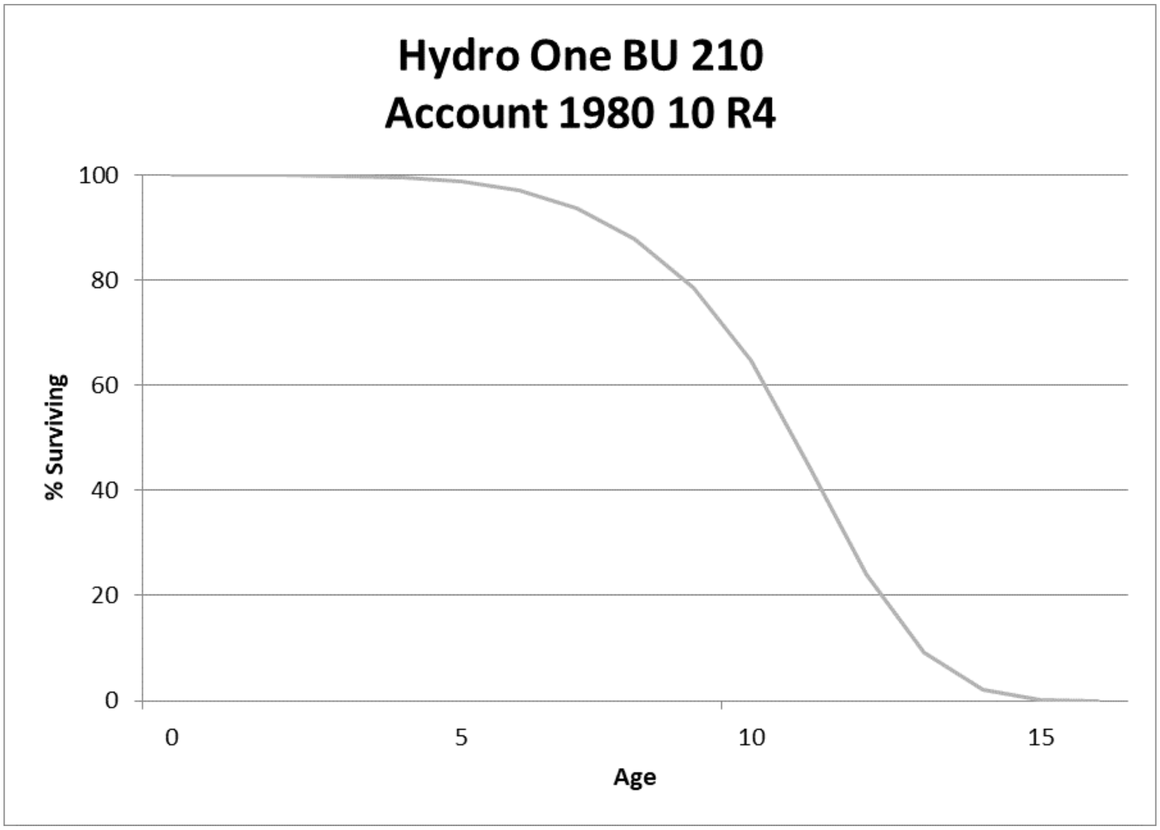
This account consists of various communication equipment associated with Transmission Operations. Such assets include telecom equipment, switching equipment, radios, optical wire, fiber optic cable, and power supply equipment. The plant balance in this account at December 31, 2019 is $499.4 million. Currently, the life of this account is 20 years with an L2 dispersion. Limited retirement activity exists to analyze the life of the account. Component lives in Appendix E-1 show a 20-year composite life. The currently used L curve assumes that items retire earlier than the average life of the group. In Alliance Consulting Group's experience, retirement characteristics of property in this account model the R family where more assets live longer than the average service life of the group. Based on professional experience we recommend shifting the life from the L family to the R family. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 20-year life is still appropriate for this account. For the reasons listed above, a 20-year life with an R2.5 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



Hydro One BU 210
Account 1955 20 R2.5
% Surviving
100
80
60
40
20
0
0
10
20
30
40
Age

Account 1980 System Supervisory Equipment (10 R4)

This account consists of system supervisory equipment associated with Transmission Operations. Such assets include power line equipment, software and hardware, and terminals. The plant balance in this account at December 31, 2019 is $452.2 million. Currently, the life of this account is 10 years with an L2 dispersion. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. The currently used L curve assumes that items retire earlier than the average life of the group. In Alliance Consulting Group's experience, retirement characteristics of property in this account model the R family where more assets live longer than the average service life of the group. Based on professional experience we recommend shifting the life from the L family to the R family. For the reasons listed above, a 10-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.

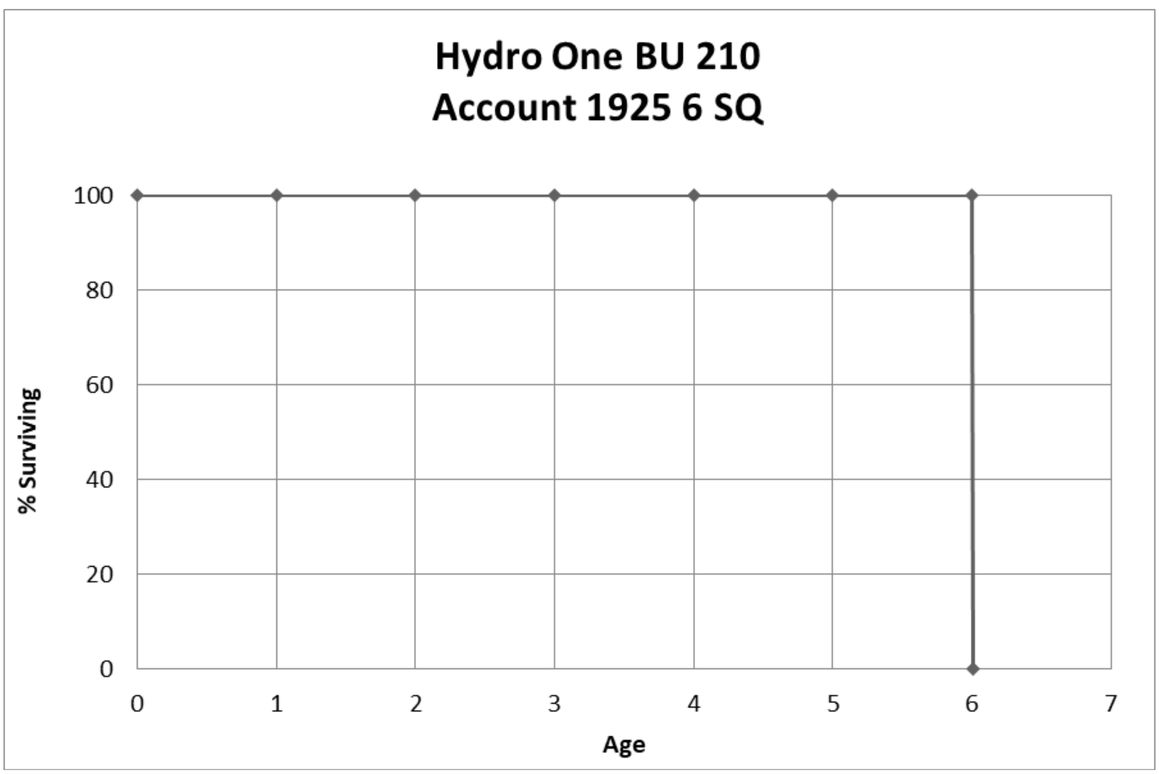

Hydro One BU 210
Account 1980 10 R4
% Surviving
100
80
60
40
20
0
0
5
10
15
Age

GENERAL AMORTIZED FUNCTIONAL GROUP

Accounts in the general amortized function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the life assigned to the account.

Account 1925 Computer Software (6 SQ)

This account consists of computer software for the Transmission Operations group. Such assets include general system software and various fiber optic equipment. The plant balance in this account at December 31, 2019 is $8.9 million. Currently the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 6-year life with an SQ dispersion.



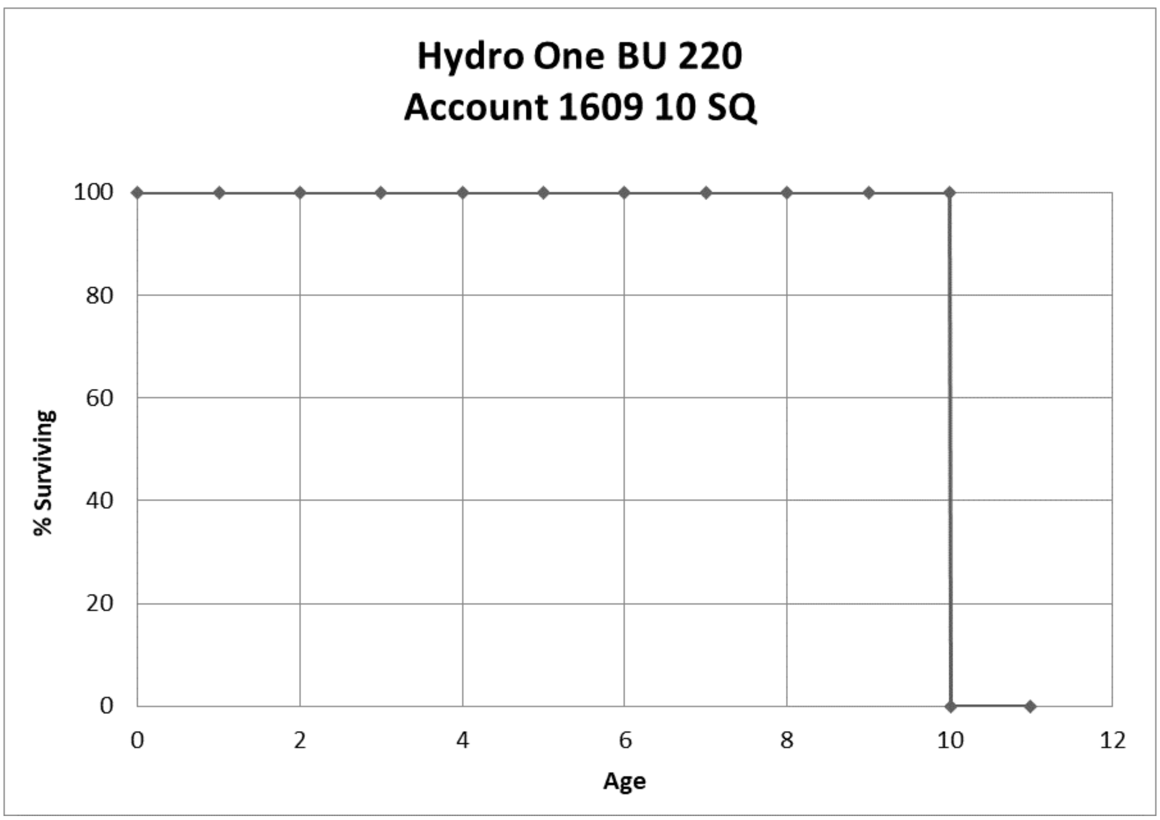
BU 220 DISTRIBUTION OPERATIONS

INTANGIBLE FUNCTIONAL GROUP

Accounts in the intangible function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the life assigned to the account.

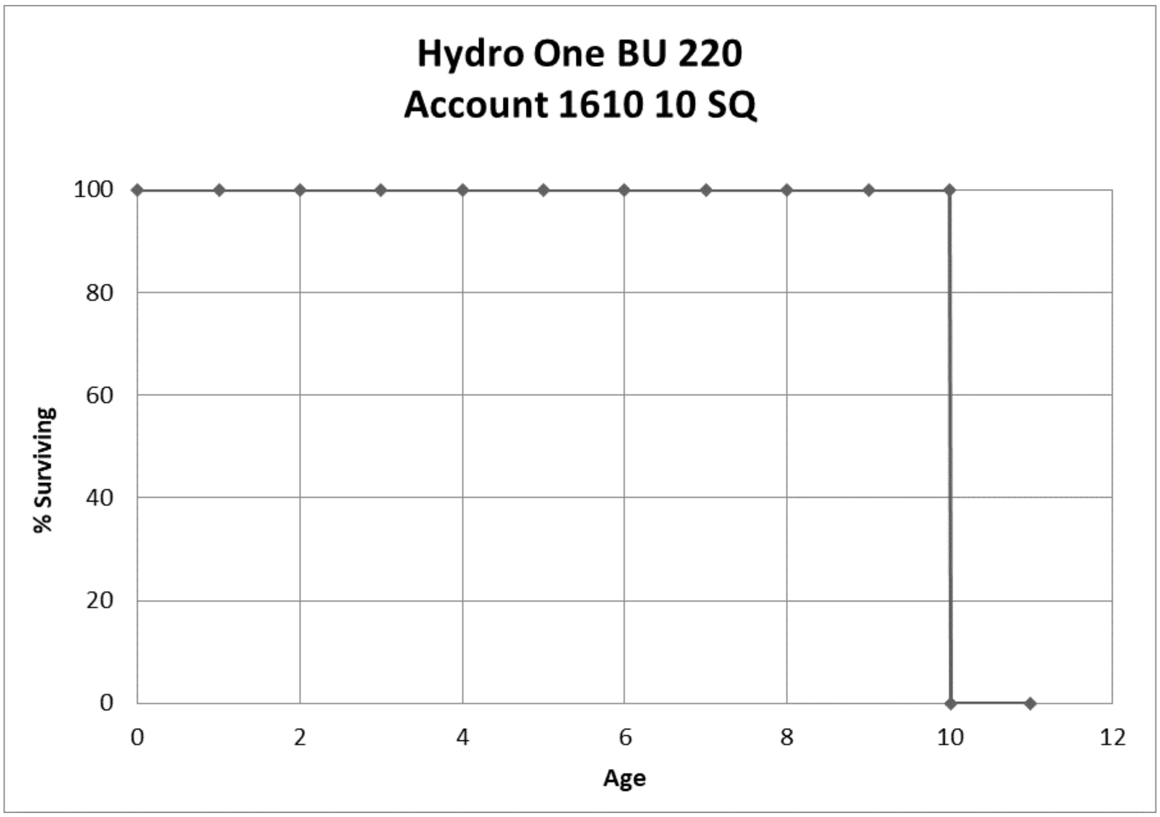
Account 1609 Capital Contributions (10 SQ)

This account consists of capital contributions for the Distribution Operations group. The plant balance in this account at December 31, 2019 is $48.6 million. Currently the amortization life of this account is 10 years. After reviewing the life with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 10-year life with an SQ dispersion.



Account 1610 Computer Software (10 SQ)

This account consists of computer software for the Distribution Operations group. Such assets include general system software. The plant balance in this account at December 31, 2019 is $255.5 million. Currently the amortization life of this account is 10 years. After reviewing plant lives with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 10-year life with an SQ dispersion.

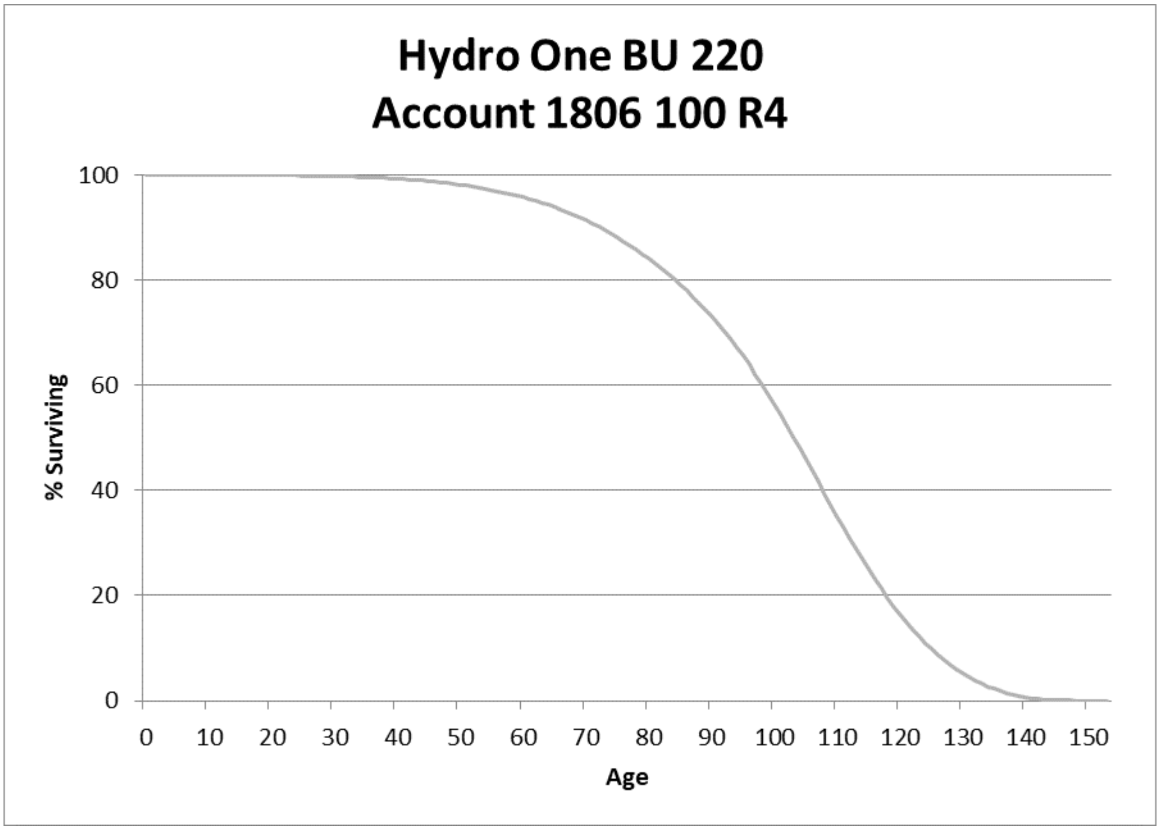


DISTRIBUTION FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

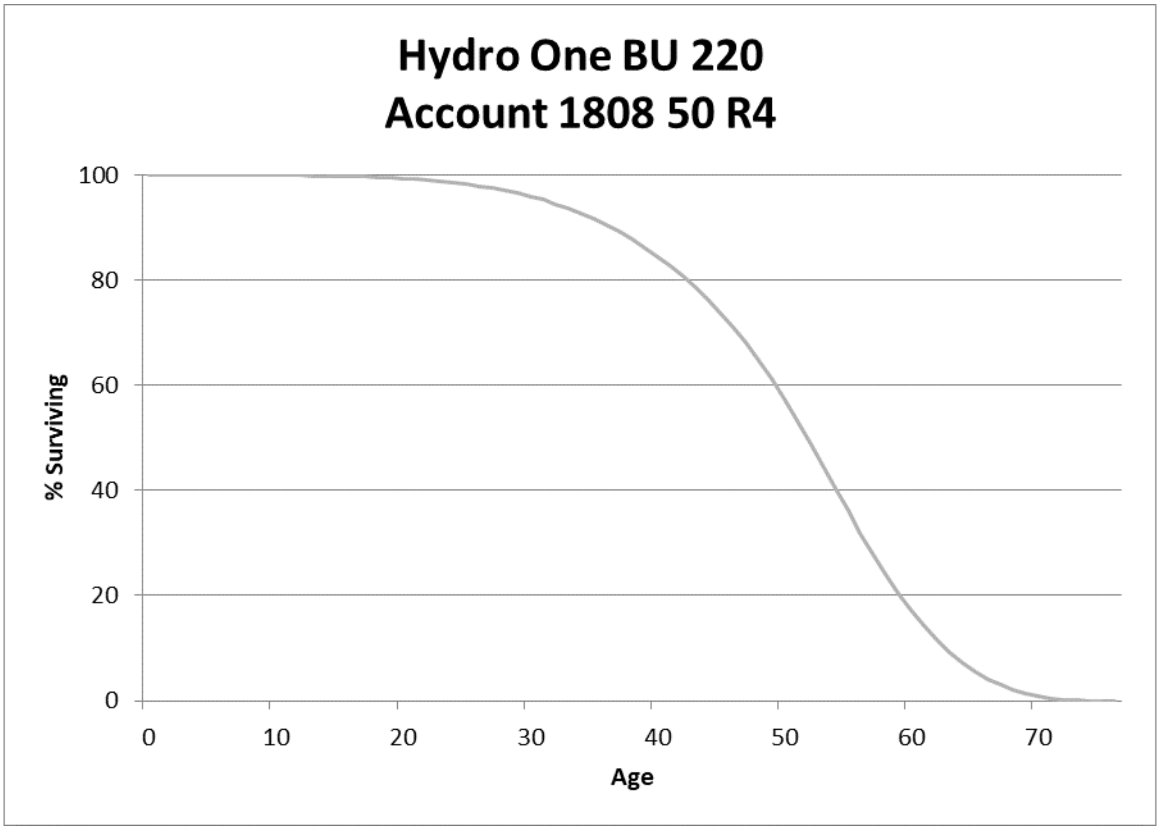
Account 1806 Land Rights (100 R4)

This account consists of land rights associated with Distribution Operations. Such assets include easements and site improvements. The plant balance in this account at December 31, 2019 is $240.4 million. Currently the life of this account is 100 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 100-year life is still appropriate for this account. The currently used S curve assumes that items retire symmetrically around the average life of the group. In Alliance Consulting Group's experience, retirement characteristics of property in this account model the R family where more assets live longer than the average service life of the group. Based on professional experience we recommend shifting the life from the S family to the R family. For the reasons listed above, a 100-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1806 100 R4
% Surviving
100
80
60
40
20
0
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150
Age

Account 1808 Buildings and Fixtures (50 R4)

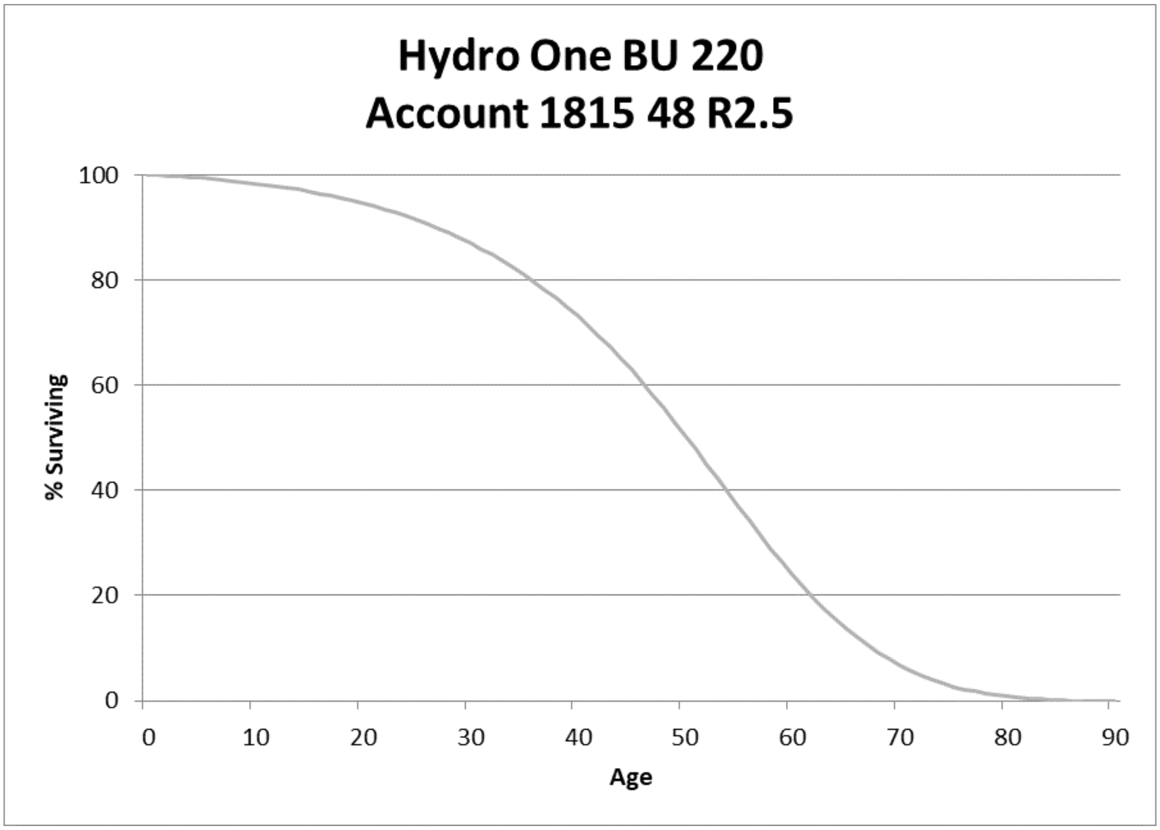
This account consists of various buildings and fixtures associated with Distribution Operations. Such assets include distribution station buildings, landscaping, and other station structures. The plant balance in this account at December 31, 2019 is $27.0 million. Currently the life of this account is 50 years with an S4 dispersion. Limited retirement activity exists to analyze the life of the account. A summary of component lives for such account is shown in Appendix E. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 50-year life is still appropriate for this account. The currently used S curve assumes that retirements in the account are symmetric about the average life. In Alliance Consulting Group's experience, retirement characteristics of property in this account model the R family where more assets live longer than the average service life of the group. Based on professional experience we recommend shifting the life from the S family to the R family. For the reasons listed above, a 50-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1808 50 R4
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
Age

58

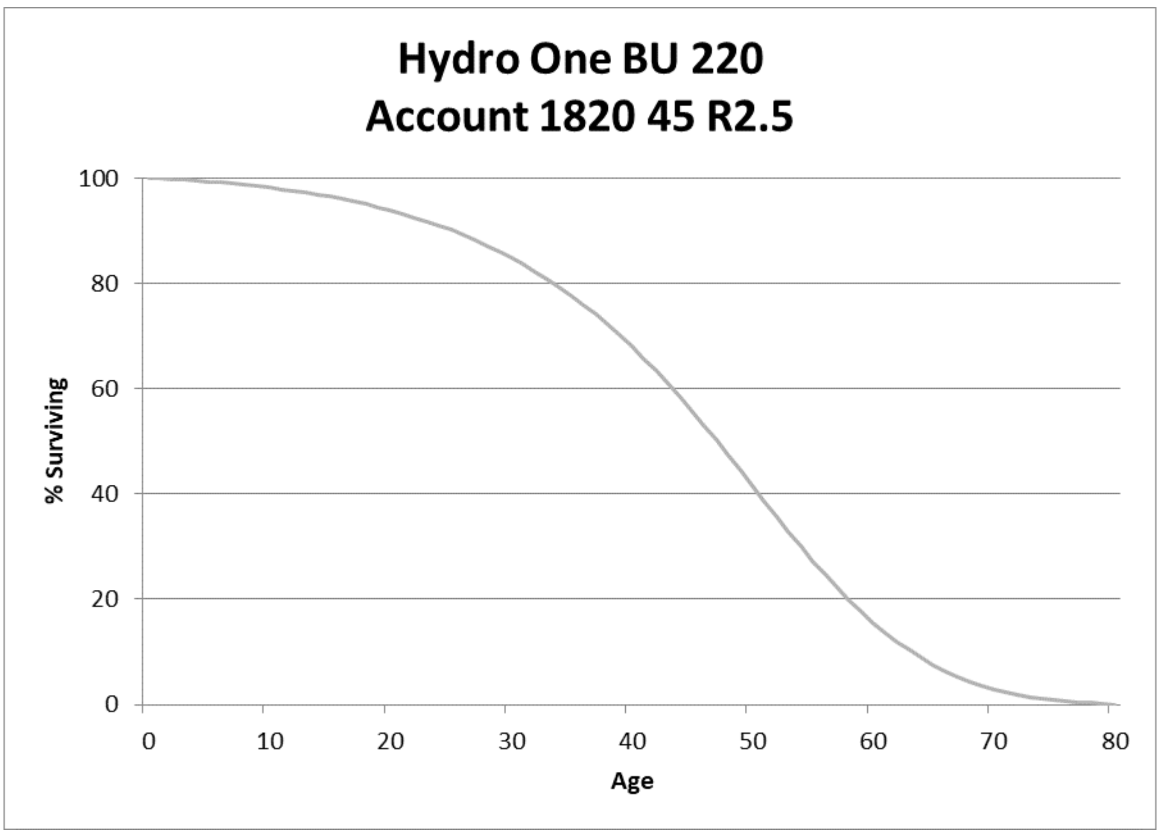
Account 1815 Transformer Station Equipment > 50 kV (48 R2.5)

This account consists of high side substation equipment associated with Distribution Operations. Such assets include site improvements, switchgear, foundations, fences gates, grounding systems, capacitors, and transformers. The plant balance in this account at December 31, 2019 is $231.5 million. Currently the life of this account is 40 years with an R2.5 dispersion. Limited retirement activity exists to analyze the life of the account. Currently, Transmission substations in BU 210 have a 45-year life that is being extended to 48 years. Company SMEs do not see any operational differential in life between the two business units for higher voltage level assets. Company subject matter experts recommend that assets in this account will have a similar life to Account 1715 in the Transmission Division, BU 210. After incorporating these recommendations, this study recommends increasing the life for this account to 48 years with an R2.5 dispersion. A representative graph for the life of the account is shown in the curve below.



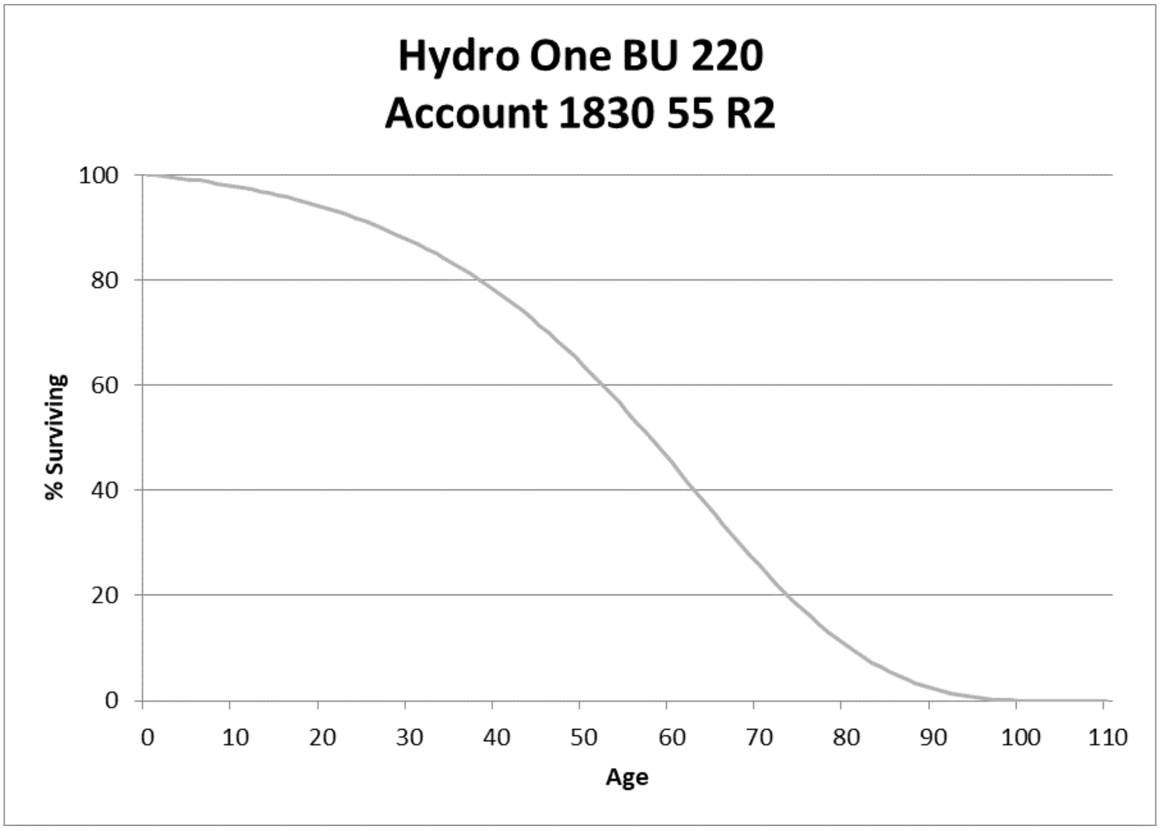
Account 1820 Distribution Station Equipment < 50 kV (45 R2.5)

This account consists of low side distribution substation equipment associated with Distribution Operations. Such assets include site improvements, foundations, fences, gates, regulators capacitors, switching, meters units, transformers, circuit breakers, and other switchgear. The plant balance in this account at December 31, 2019 is $799.8 million. Currently, the life of this account is 30 years with an R2.5 dispersion. Limited retirement activity exists to analyze the life of the account. Company experts do not believe that a differential of 10 years or more between this account and Account 1815 is operationally supportable. Company personnel state that meters are the largest component in these accounts other than transformers. They recommend changes in component lives to parallel with those in BU 210 Account 1715. In Distribution operations, Company personnel state that distribution assets are more condition-based than transmission assets, meaning that they are run to failure whereas the transmission assets receive time-based maintenance. Condition based assets will have a lower life in their operational experience. Some examples of run to fail assets in this account are: cables, service systems, switchboards, control cable, conduit, grounding systems, misc. regulators, and capacitors. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing life should be extended. For the reasons listed above, a 45-year life with an R2.5 dispersion is recommended for this account. A representative curve shape is shown below.



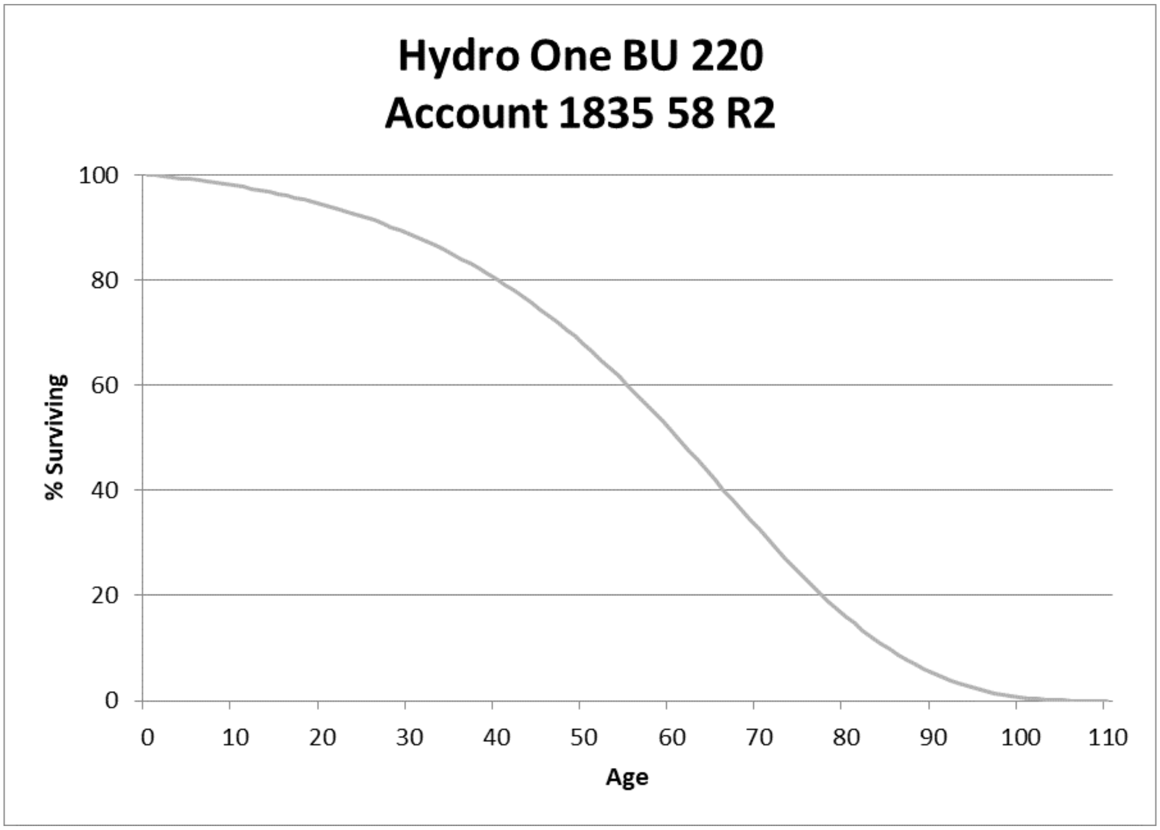
Account 1830 Poles Towers and Fixtures (55 R2)

This account consists of various poles, towers and fixtures associated with Distribution Operations. Such assets include steel towers, steel poles, supports, composite poles, and other support devices. The plant balance in this account at December 31, 2019 is $3.6 billion. Currently the life of this account is 55 years with an S2 dispersion. Limited retirement activity exists to analyze the life of the account. Pole refurbishment was noted to begin in September 2020. The Company will test and treat about 100,000 poles in 2020 out of the more than 1.6 million poles across the system. The program will involve testing and ground line treatments. It is estimated it will take about 15 years to complete the process. Previous programs focused more on visual inspection, and test and treat programs were not done from 2009 to 2020. Approximately 90% of Hydro One's poles are wood. Operations is hopeful that the pole refurbishment program will extend the life of poles. Since this is a new initiative, Company experts do not recommend moving the life of this account out at this time. As discussed with other operational accounts, the retirement characteristics of these assets are more in line with an R curve. Based on input from Company experts, this study recommends retention of the existing 55-year life, but with a change to an R2 dispersion. A representative curve shape is shown below.


Hydro One BU 220
Account 1830 55 R2
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
Age

Account 1835 Overhead Conductor and Devices (58 R2)

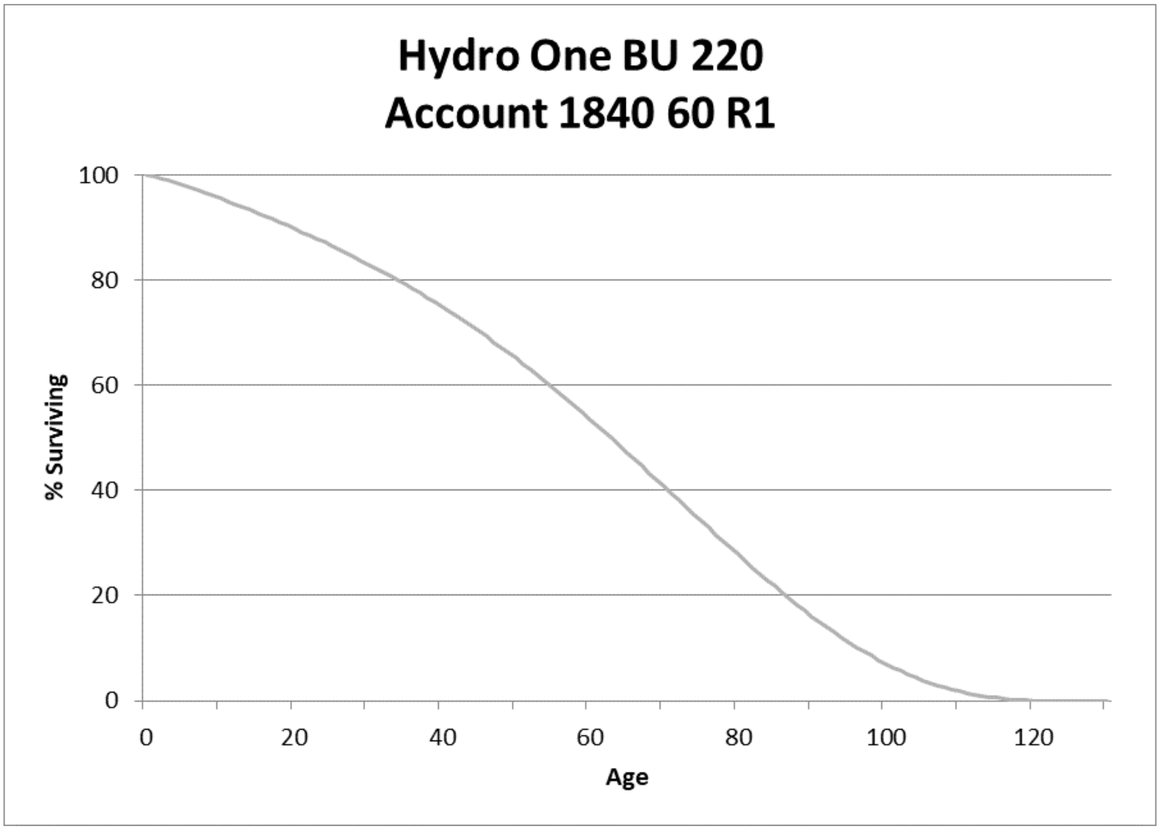
This account consists of overhead conductor and devices associated with Distribution Operations. Such assets include grounding system, ground wires, insulators, conductor, switches, voltage regulators, and capacitors. The plant balance in this account at December 31, 2019 is $2.1 billion. Currently, the life of this account is 55 years with an S2 dispersion. Limited retirement activity exists to analyze the life of the account. Company SMEs believe that conductor will have a slightly life longer than that of poles (which is 55 years). Company experts state that there are many reasons to replace conductor, including replacement due to sags or capacity. The Company is using more electronic devices that experts believe will have a shorter life than the mechanical switches used in the past. Electronic devices are approximately 5 percent of the total in Hydro One. Company experts do not see a reason to reduce the life of this account at this point based on the small dollar investment in electronics as compared to the cost of the conductor. Considering the recommendation for the life of conductor compared to poles, this study recommends a 58-year life with an R2 dispersion for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1835 58 R2
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
Age

65

Account 1840 Underground Conduit (60 R1)

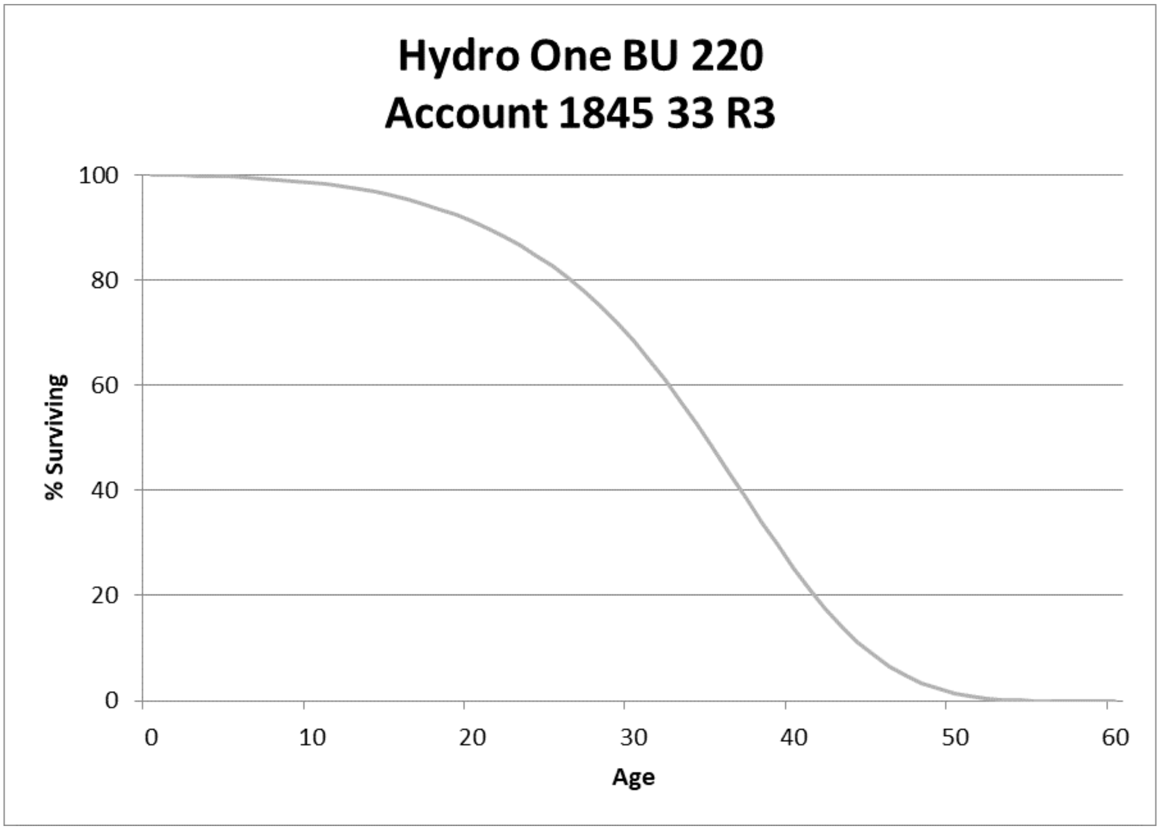
This account consists of underground conduit associated with Distribution Operations. The plant balance in this account at December 31, 2019 is $24.3 million. Currently, the life of this account is 50 years with an S2 dispersion. Limited retirement activity exists to analyze the life of the account. Company personnel report that conduit is found primarily in substation entries and in urban areas. Company experts believe higher levels of conduit will be installed in the future. Operations reports that material quality has improved in recent years with changes in specifications. Company personnel report that they generally run a spare conduit with installations, so that it is possible to pull and replace in same duct. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life should be extended for this account. As discussed with other operational accounts, the retirement characteristics of these assets are more in line with an R curve. For the reasons listed above, a 60-year life with an R1 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1840 60 R1
% Surviving
100
80
60
40
20
0
0
20
40
60
80
100
120
Age

67

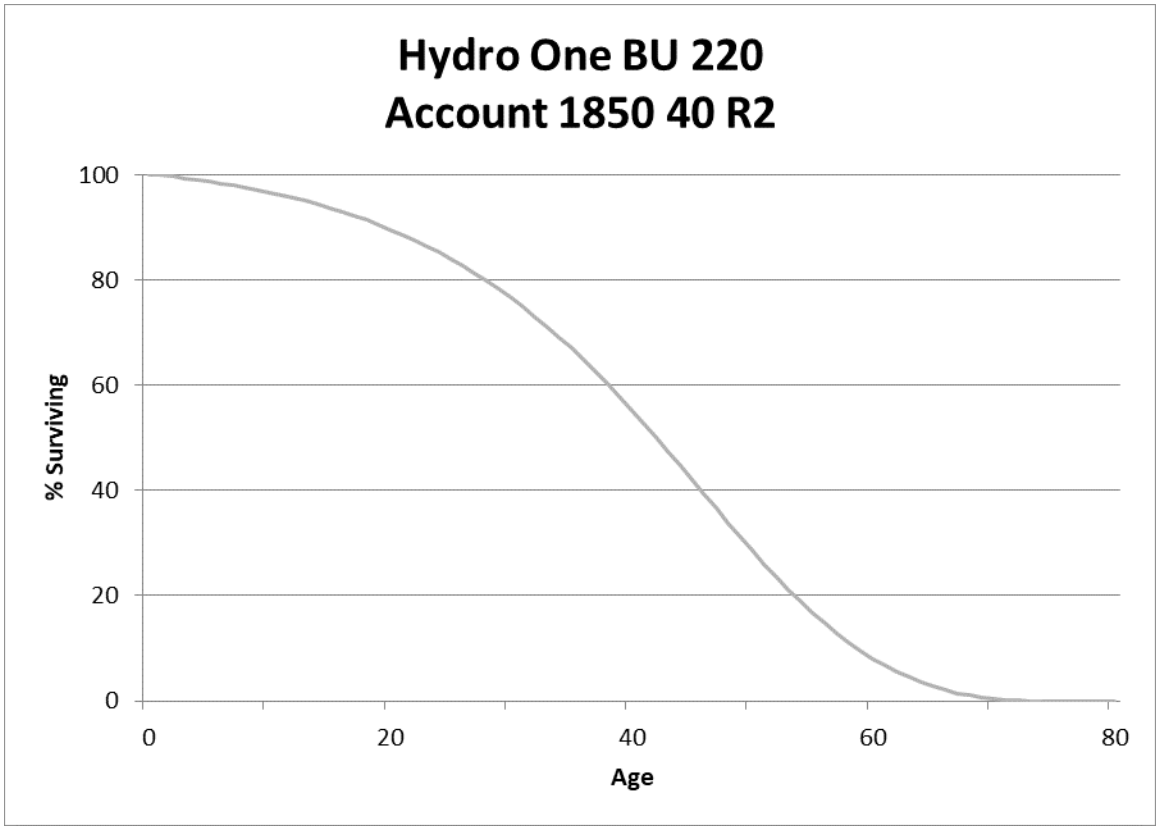
Account 1845 Underground Conductors and Devices (33 R3)

This account consists of various underground conductor and devices associated with Distribution Operations. Such assets include underground conductor, submarine cable, and fuse housing. The plant balance in this account at December 31, 2019 is $926.2 million. Currently, the life of this account is 30 years with an S3 dispersion. Limited retirement activity exists to analyze the life of the account. Company SMEs report that most conductor is direct buried. The reasons that conductor fails include insulation breaking down and dig-ins. In the Ontario environment, conductor has a much shorter life than conduit. The Company is piloting a cable cure program, which have not been installed in the past. Company personnel believe that new conductor will last slightly longer than older assets. After seeking input from Company personnel and incorporating professional judgment, the determination was that the life should be extended slightly for this account. For the reasons listed above, a 33-year life with an R3 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1845 33 R3
100
80
60
40
20
0
% Surviving
0
10
20
30
40
50
60
Age

Account 1850 Line Transformers (40 R2)

This account consists of various types of line transformers associated with Distribution Operations. Such assets include overhead transformers, underground transformers, capacitors, and other similar equipment. The plant balance in this account at December 31, 2019 is $2.1 billion. Currently, the life of this account is 40 years with an R2 dispersion. Limited retirement activity exists to analyze the life of the account. Company SMEs report that they are replacing all PCB transformers. They estimate that about 1-4% of the transformers will be impacted by the change out. Company personnel report that most replacements are approximately 40 years old. The Company runs a transformer until it fails, and no repair program is currently in place. Operations personnel report that the life of the transformer depends on its loading. Hydro One is loading transformers at around the same level as in the past. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 40-year life is still appropriate for this account. For the reasons listed above, retaining a 40-year life with an R2 dispersion is recommended for this account. A representative graph for this account is shown below.



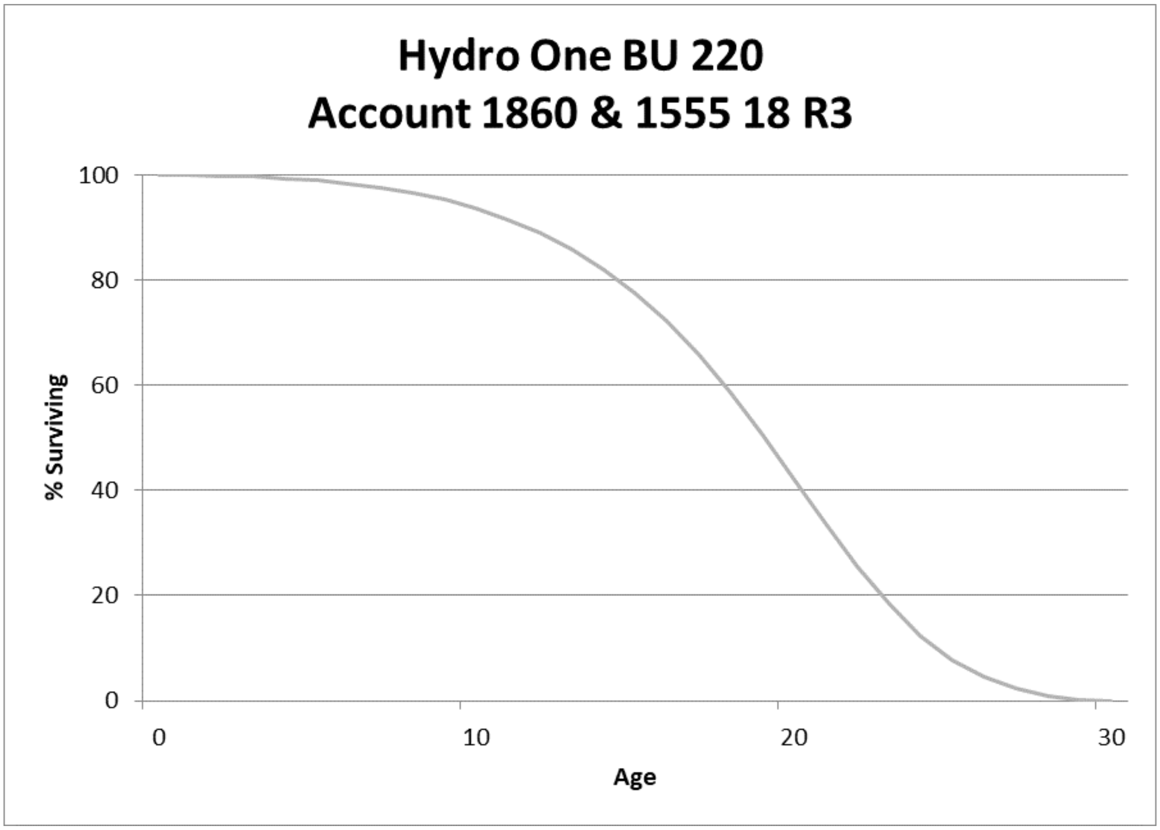
Hydro One BU 220
Account 1850 40 R2
100
80
60
40
20
0
% Surviving
0
20
40
60
80
Age

71

Account 1860, 1860S, and 1555 Smart Meters (18 R3)

Account 1860 consists of various meters associated with Distribution Operations. Such assets include watt meters, demand meters, and all other meter equipment. The plant balance in this account at December 31, 2019 is $265.0 million. Currently, the life of this account is 20 years with an R5 dispersion. Account 1860S and Account 1555 assets were modeled together. The total balance for all accounts was $330.3 million. Currently, the lives of these accounts are 15 years and 20 years with an R5 dispersion for 1555 and 1860, respectively. All old meters have been retired and accounts 1860, 1860S, and 1555 are combined. Hydro One began the move to smart meters in 2007. The meter fleet changed between 2007 and 2014, and the 15-year life used was from vendor information. Ontario was one of the first jurisdictions to completely switch to smart meters. Even in the short period, Hydro One's use of smart meters technology for this account changes and improves as product reliability improve. In 2020, the oldest meter is 13 years old. Company experts report that the quantity of failures is increasing, particularly among the oldest meters, which are failing at the highest rates. By 2022, the oldest meters will be retired. Capacitors and screen failures are the primary causes of retirement.

Hydro One will be deploying new meters to replace the oldest assets installed between 2007 and 2014. After replacement of the oldest assets, Company personnel believe that failure rates will decline, and that the life might begin to extend. Asset replacements have been budgeted in coming capital spending cycles. Accelerated replacement will be occurring. Company personnel believe the new meters will produce a slightly longer life than the previous vendor estimate of 15 years. New meters have a recommended life of 20 years. To incorporate the mixture of assets in this account, a life of 18 years is estimated on a combined basis. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 15-year life for smart meters should be extended. For the reasons listed above, an 18-year life with an R3 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.

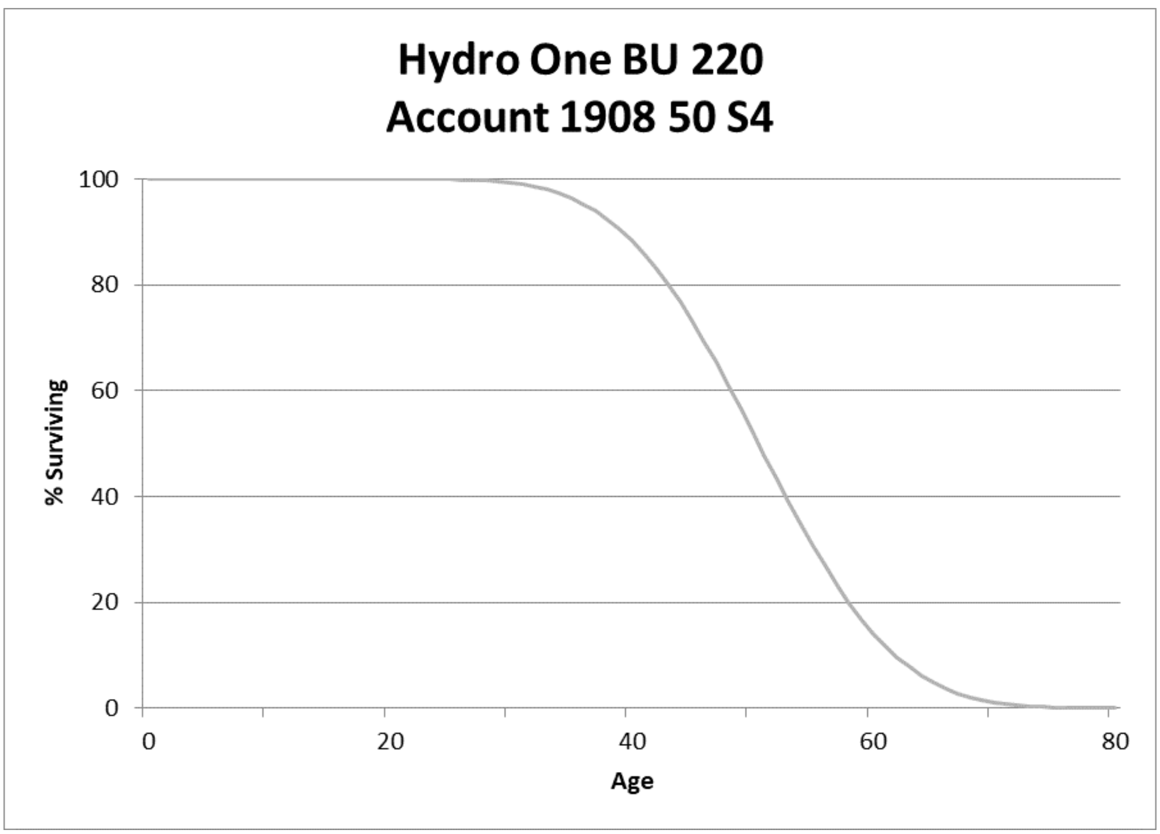


73

GENERAL DEPRECIATED FUNCTIONAL GROUP

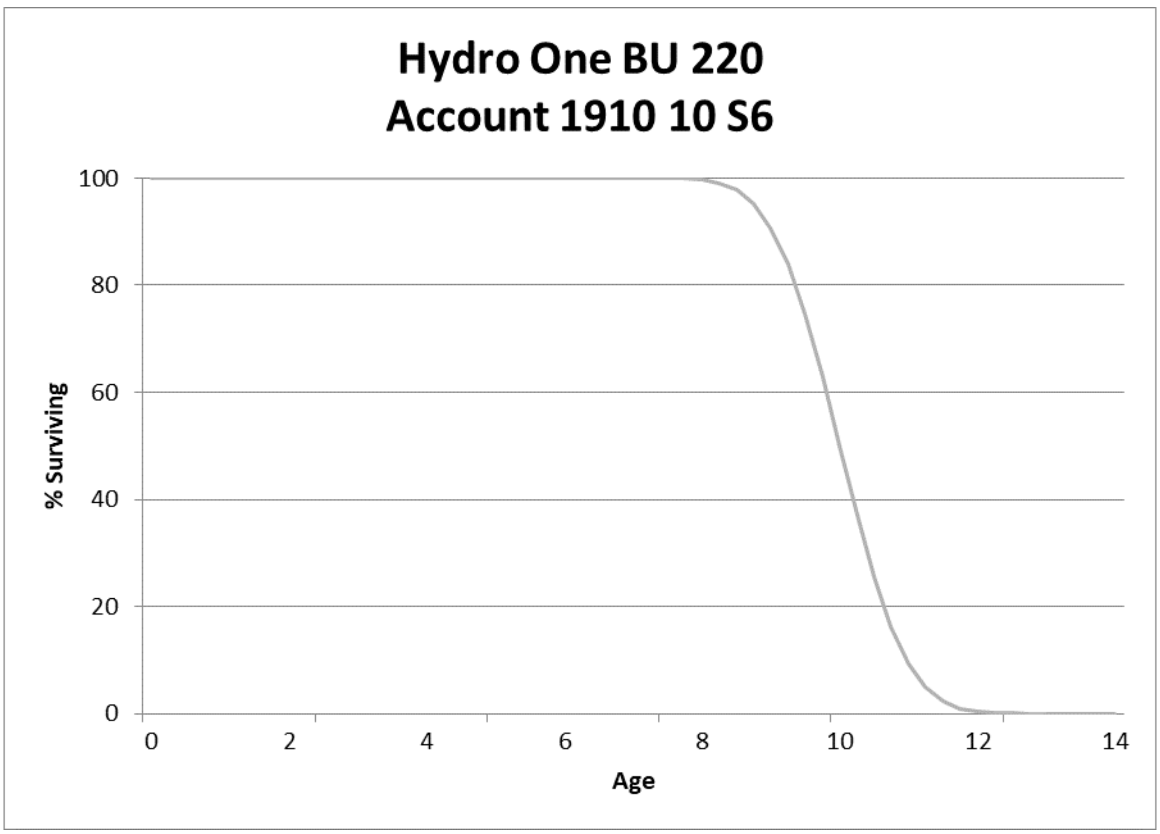
Account 1908 Buildings and Fixtures (50 S4)

This account consists of various buildings and fixtures associated with Distribution Operations. Such assets include distribution station buildings, landscaping, and other station structures. The plant balance in this account at December 31, 2019 is $147.7 million. Currently the life of this account is 50 years with an S4 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is still appropriate for this account. This study recommends retention of a 50-year life with an S4 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



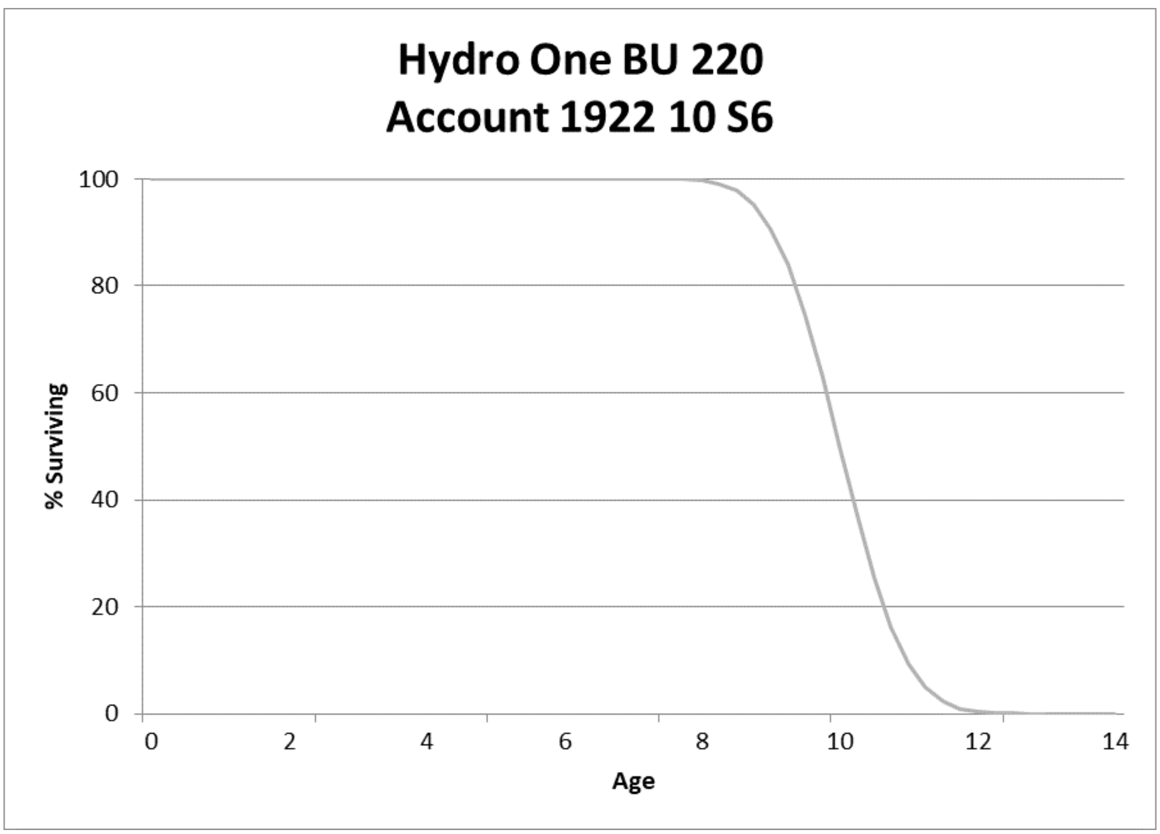
Account 1910 Leasehold Improvements (10 S6)

This account consists of various leasehold improvements made to leased buildings associated with Distribution Operations. The plant balance in this account at December 31, 2019 is $8.1 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. This study recommends retention of a 10-year life with an S6 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



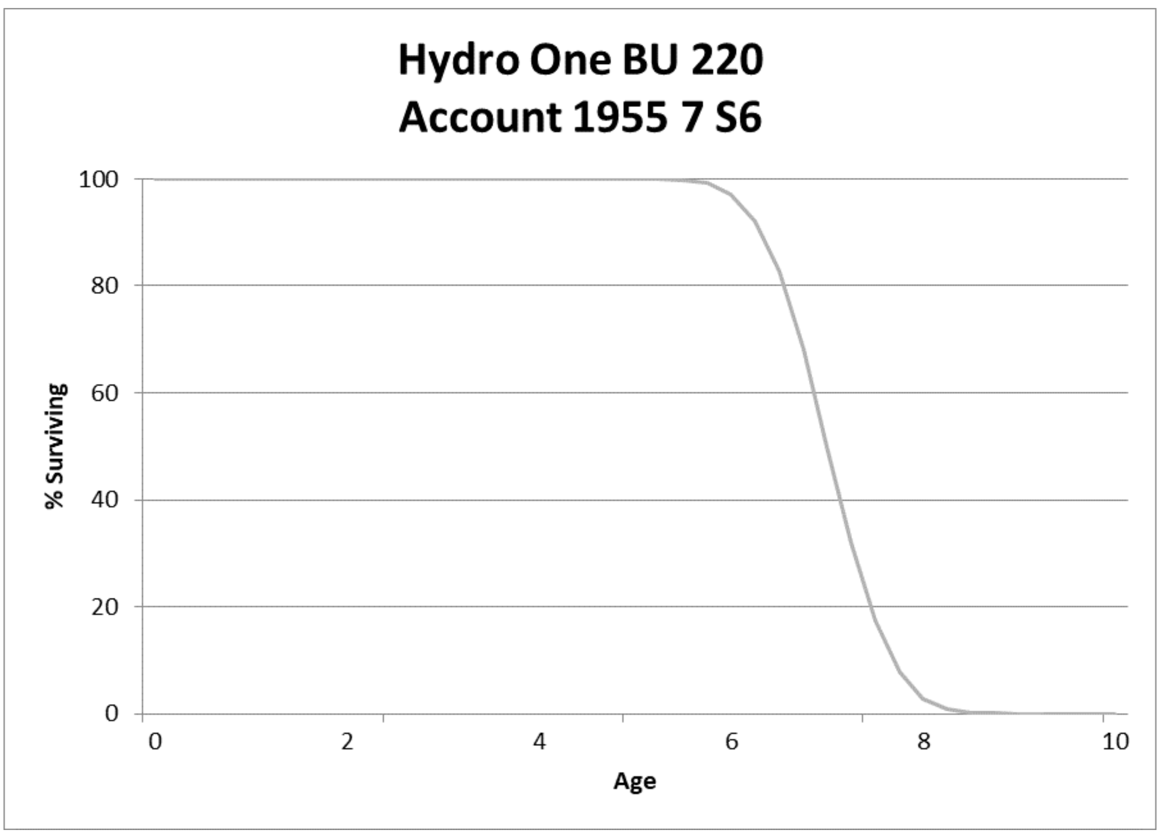
Account 1922 Computer Equipment - Hardware (10 S6)

This account consists of various computer hardware equipment associated with Distribution Operations. Such assets include local area network wire and devices and fiber optic cable. The plant balance in this account at December 31, 2019 is $4.7 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. This study recommends retention of a 10-year life with an S6 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



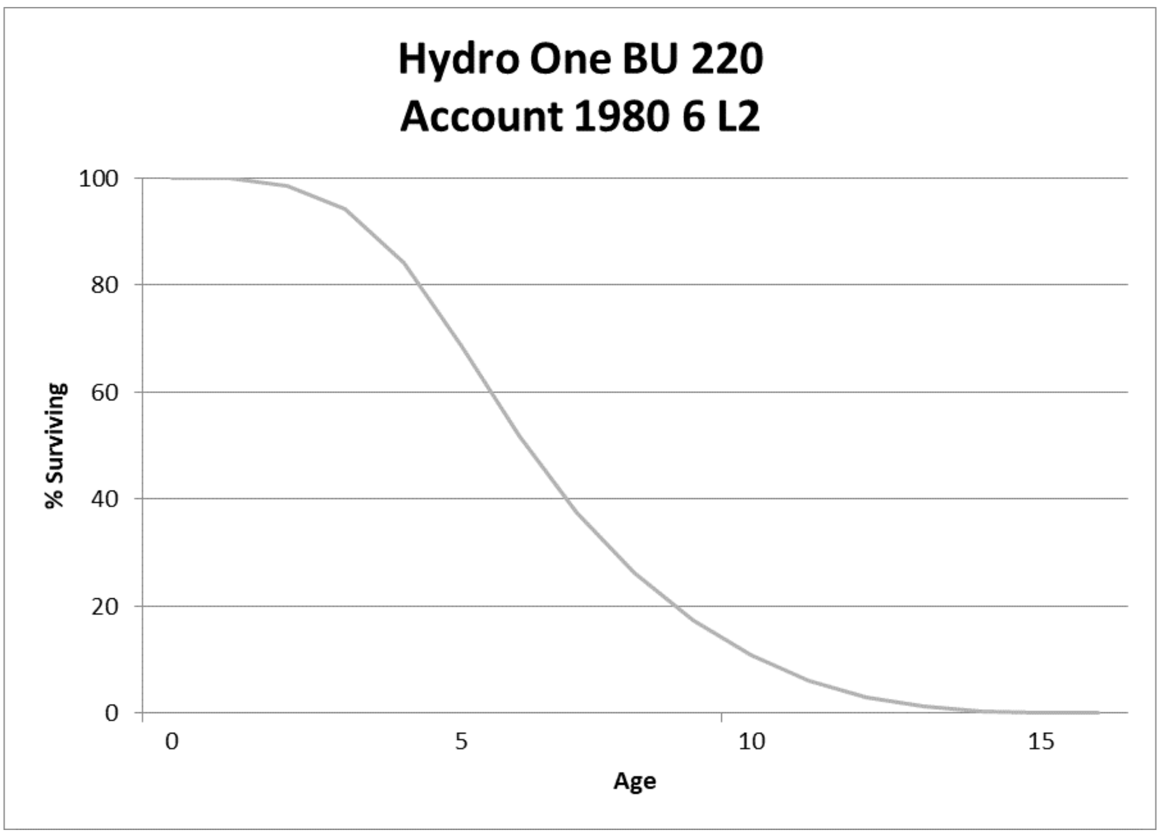
Account 1955 Communication Equipment (7 S6)

This account consists of various type of communication equipment associated with Distribution Operations. Such assets include fiber optic equipment, telecom equipment, radio equipment, and wire and power supply equipment. The plant balance in this account at December 31, 2019 is $29.1 million. Currently, the life of this account is 7 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 7-year life is still appropriate for this account. This study recommends retention of a 7-year life with an S6 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



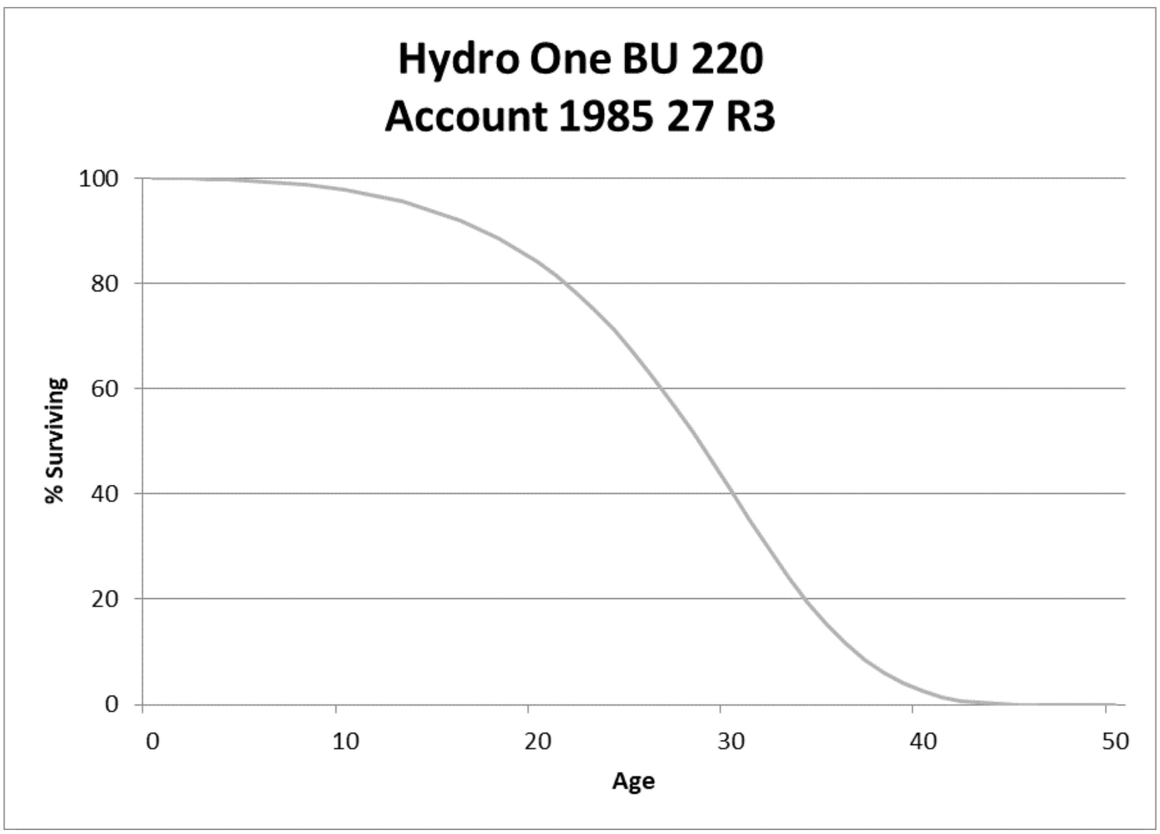
Account 1980 System Supervisory Equipment (6 L2)

This account consists of system supervisory equipment associated with Distribution Operations. Such assets include power lines, computer equipment, and related software. The plant balance in this account at December 31, 2019 is $133.3 million. Currently, the life of this account is 6 years with an L2 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 6-year life is still appropriate for this account. This study recommends retention of a 6-year life with an L2 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



Account 1985 Sentinel Lighting Rental Units (27 R3)

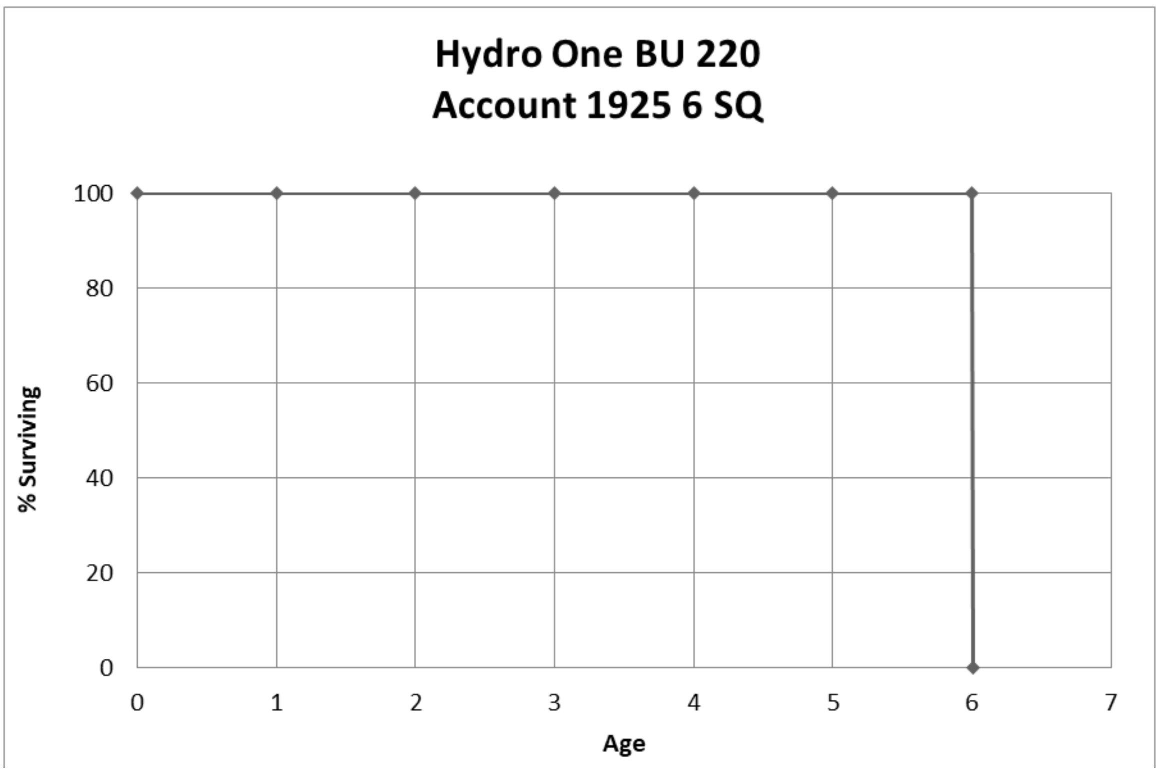
This account consists of sentinel lighting units with Distribution Operations. The plant balance in this account at December 31, 2019 is $15.3 million. Currently, the life of this account is 30 years with an R1.5 dispersion. Although limited retirement activity exists to analyze the life of the account, the actuarial analysis on this short-lived account was robust enough to indicate a reduction in life for this account. After seeking input from Company personnel, reviewing the analysis and incorporating professional judgment, the determination was that the existing year life should be shortened from its current level. This study recommends a 27-year life with an R3 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



GENERAL AMORTIZED FUNCTIONAL GROUP

Account 1925 Computer Software (6 SQ)

This account consists of computer software for the Distribution Operations group. Such assets include general system software. The plant balance in this account at December 31, 2019 is $41.3 million. Currently, the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 6-year life with an SQ dispersion.



BU 300 COMMON OPERATIONS

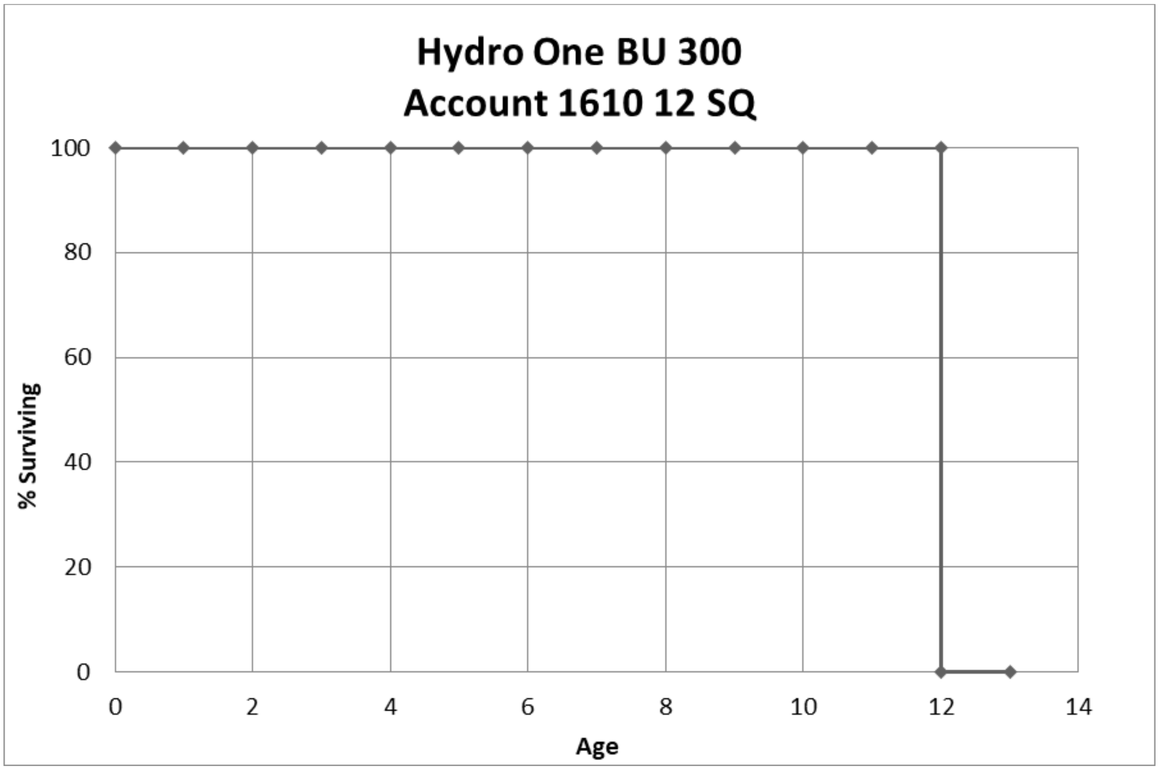
Common assets serve both the Transmission and Distribution Operations groups. The costs are allocated between each business unit.

INTANBIGLE FUNCTIONAL GROUP

Accounts in the intangible function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the assigned life of the account.

Account 1610 Computer Software (12 SQ)

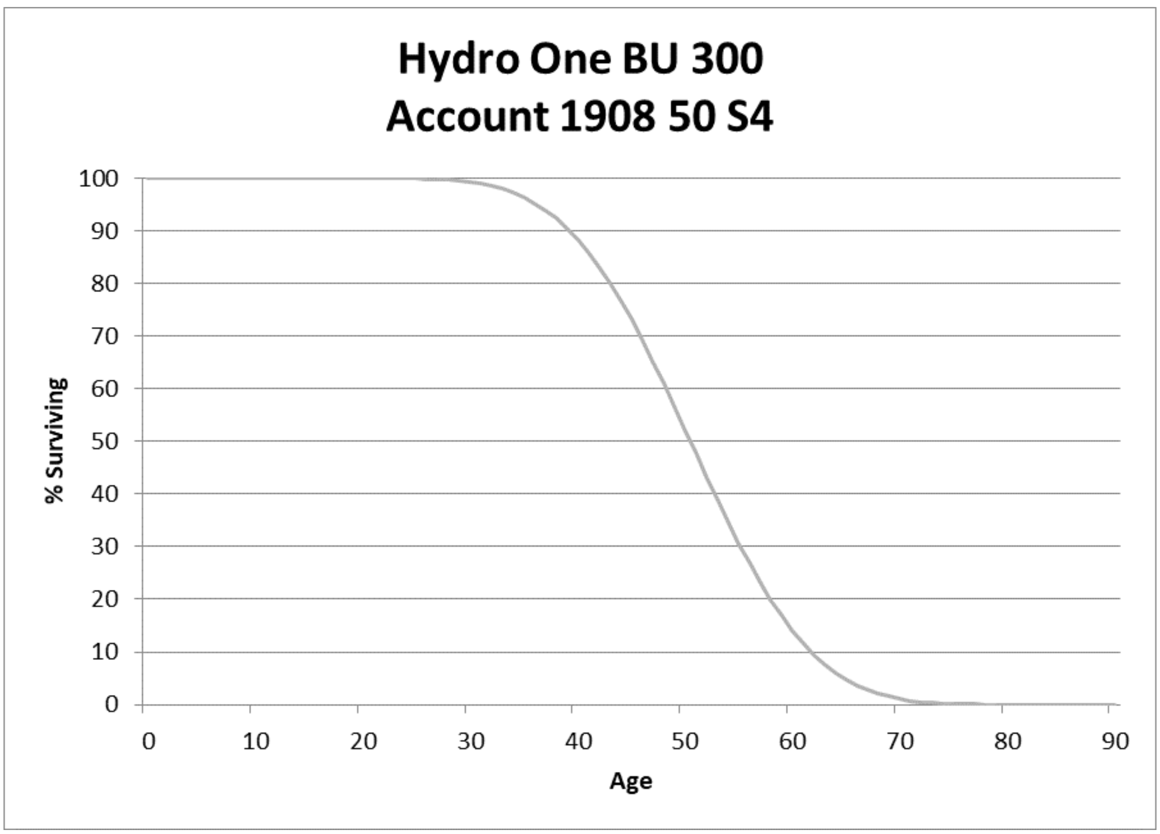
This account consists of computer software for general operations. Such assets include general system software. The plant balance in this account at December 31, 2019 is $636.3 million. Currently, the amortization life of this account is 10 years. The Company's major enterprise and cornerstone systems are booked in the account and allocated to transmission and distribution. Some of the systems are nearly 10 years old at this time with significant upgrades planned in the future. Given the continued use of these systems, a longer life is recommended in this account. After reviewing plant lives with Company personnel, the determination was that moving to a 12-year life is appropriate for this account. A representative of the life of the account is shown in the curve below, a 12-year life with an SQ dispersion.


Hydro One BU 300
Account 1610 12 SQ
100
80
60
40
20
0
% Surviving
0
2
4
6
8
10
12
14
Age

GENERAL DEPRECIATED FUNCTIONAL GROUP

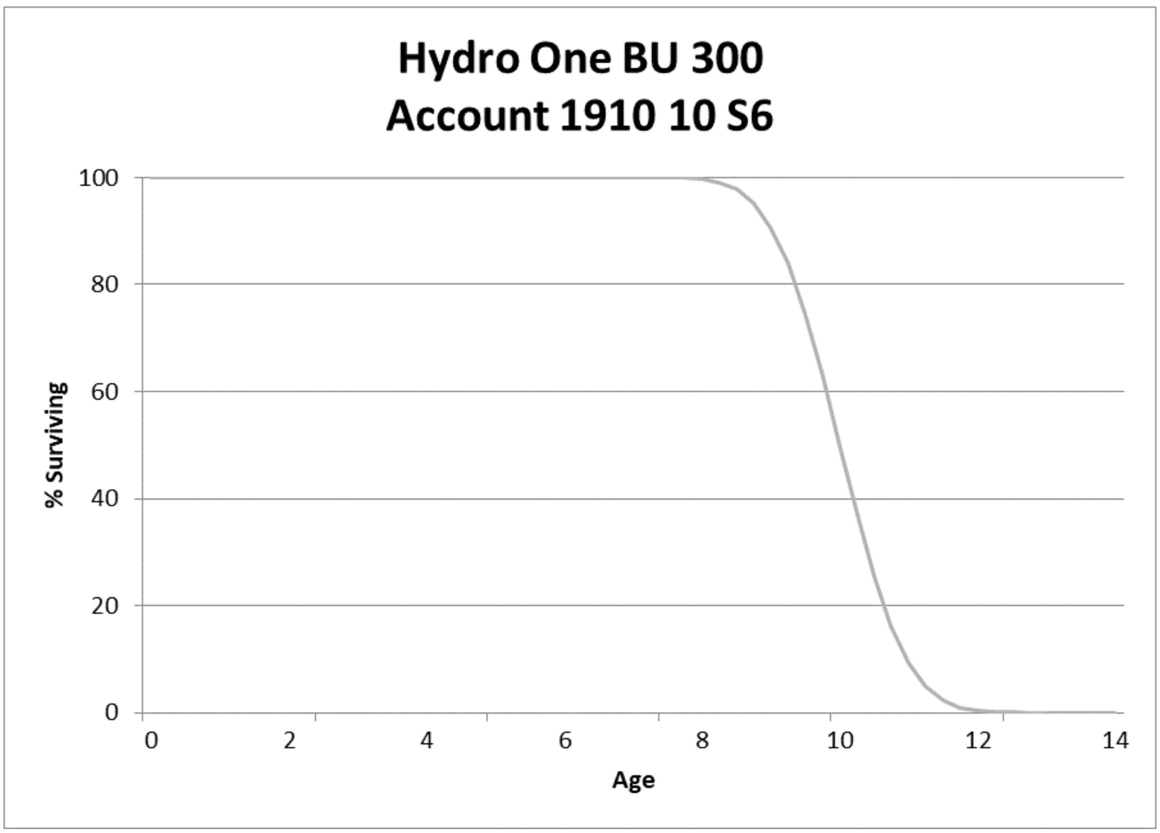
Account 1908 Buildings and Fixtures (50 S4)

This account consists of various general buildings and fixtures associated with Transmission and Distribution Operations. Such assets include buildings, road and surfaces, fences, auxiliary buildings, and road and surface areas. The plant balance in this account at December 31, 2019 is $130.8 million. Currently, the life of this account is 50 years with an S4 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 50-year life with an S4 dispersion.



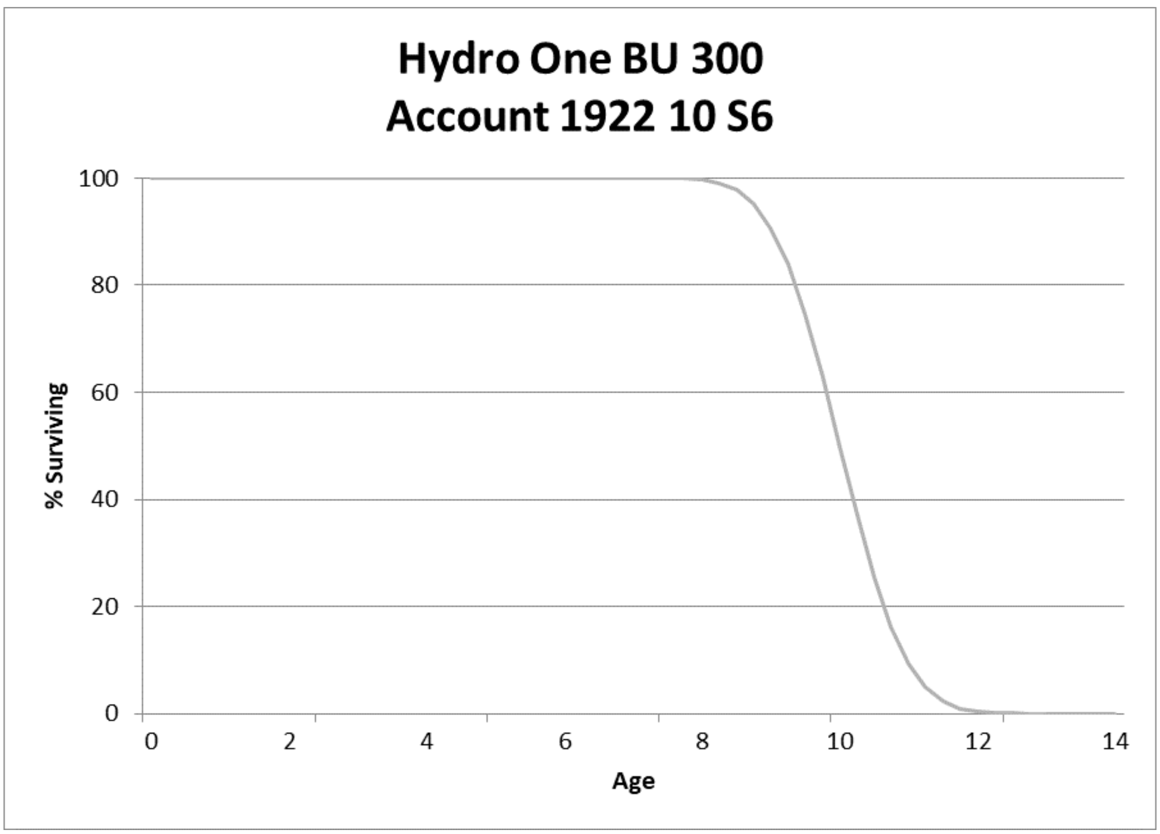
Account 1910 Leasehold Improvements (10 S6)

This account consists of various general leasehold improvements made to leased buildings associated with Transmission and Distribution Operations. The plant balance in this account at December 31, 2019 is $45.7 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an S6 dispersion.



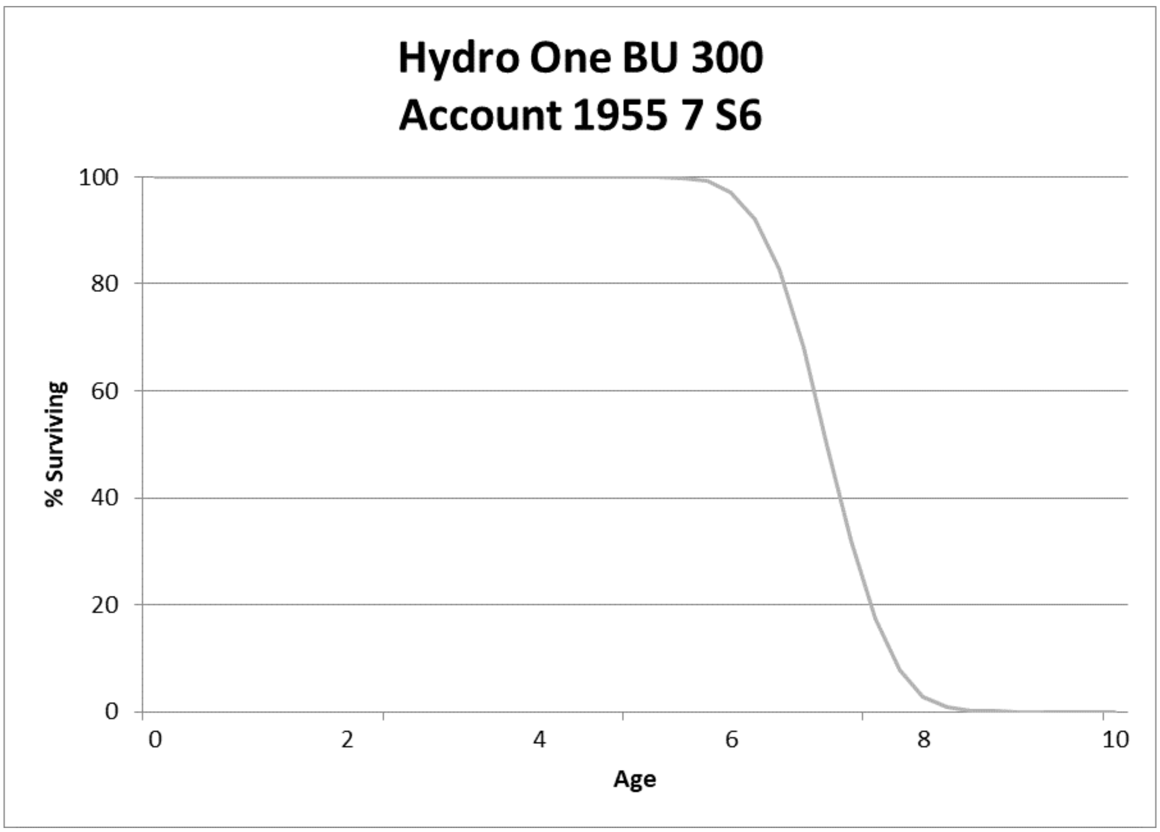
Account 1922 Computer Equipment - Hardware (10 S6)

This account consists of general computer hardware associated with Transmission and Distribution Operations. Such assets include local area network devices and cable. The plant balance in this account at December 31, 2019 is $15.9 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an S6 dispersion.



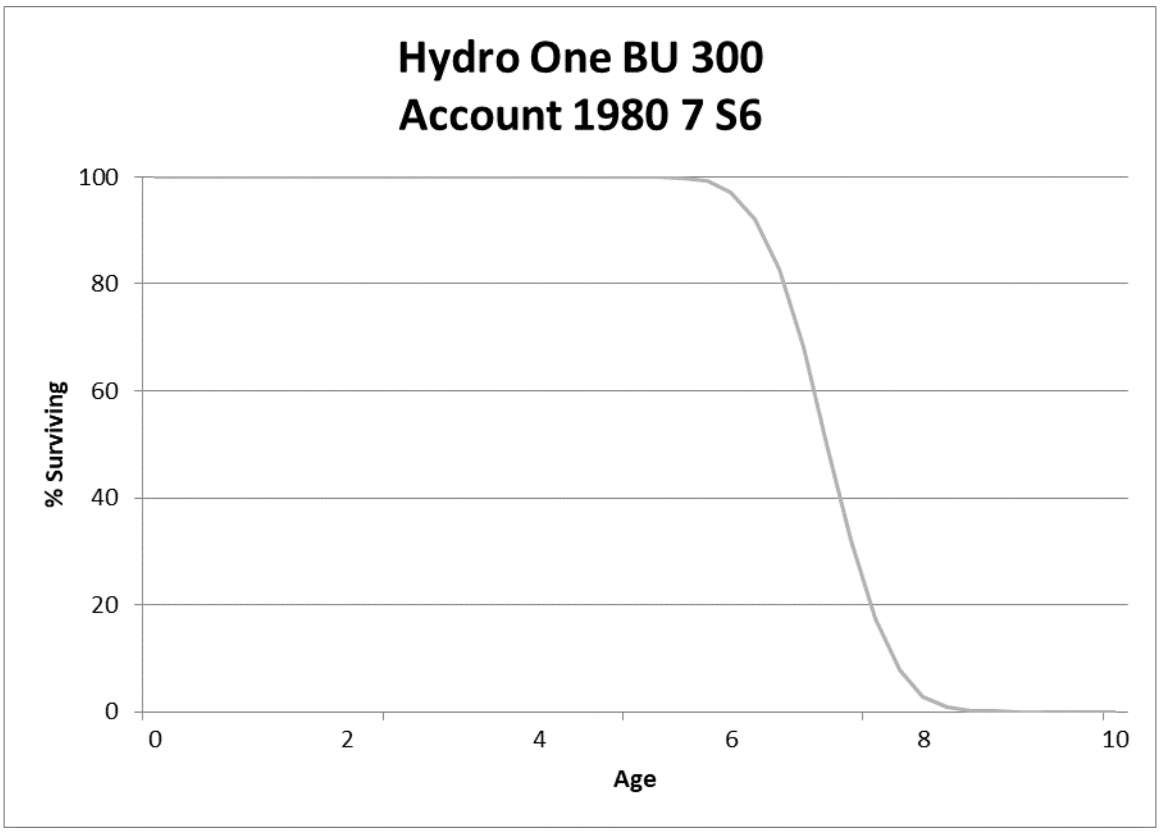
Account 1955 Communication Equipment (7 S6)

This account consists of various general communication equipment associated with Transmission and Distribution Operations. Such assets include telecom wire and equipment and radio equipment. The plant balance in this account at December 31, 2019 is $22.4 million. Currently, the life of this account is 7 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 7-year life with an S6 dispersion.



Account 1980 System Supervisory Equipment (7 S6)

This account consists of general system supervisory equipment associated with Transmission and Distribution Operations. Such assets include power line equipment, hardware, and computer software. The plant balance in this account at December 31, 2019 is $19.7 million. Currently, the life of this account is 7 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 7-year life with an S6 dispersion.

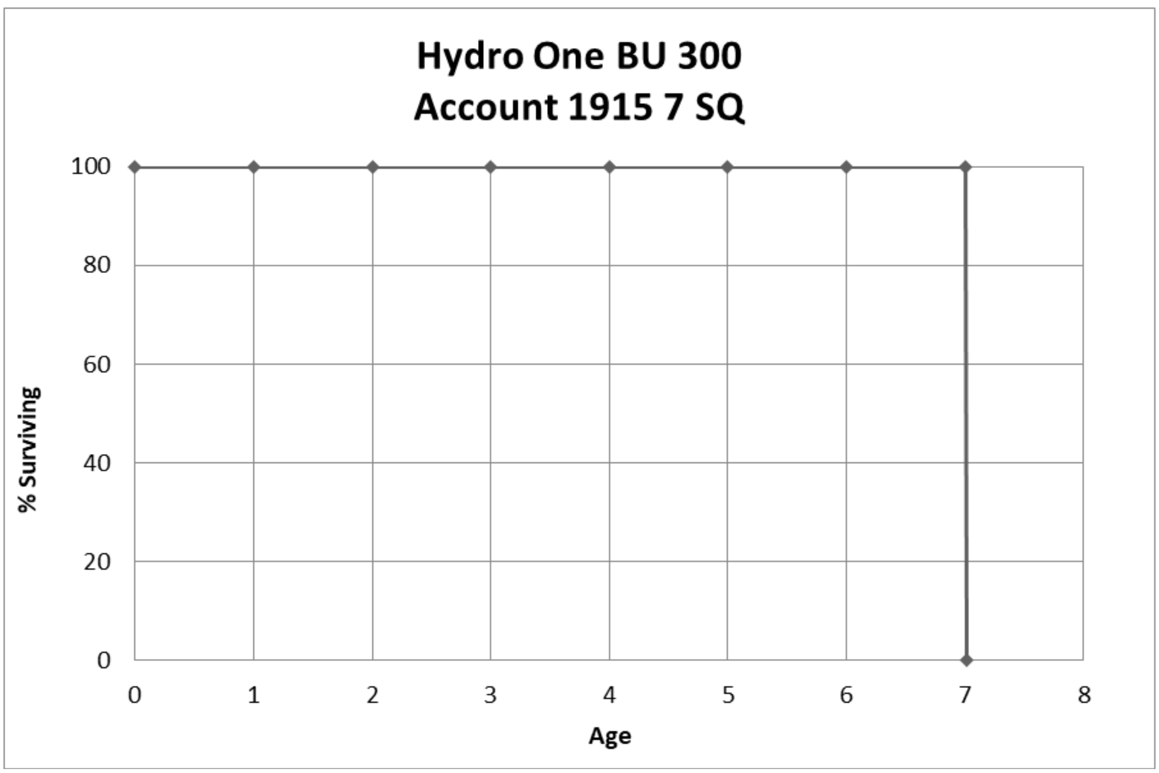


GENERAL AMORTIZED FUNCTIONAL GROUP

Accounts in the general amortized function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the assigned life of the account.

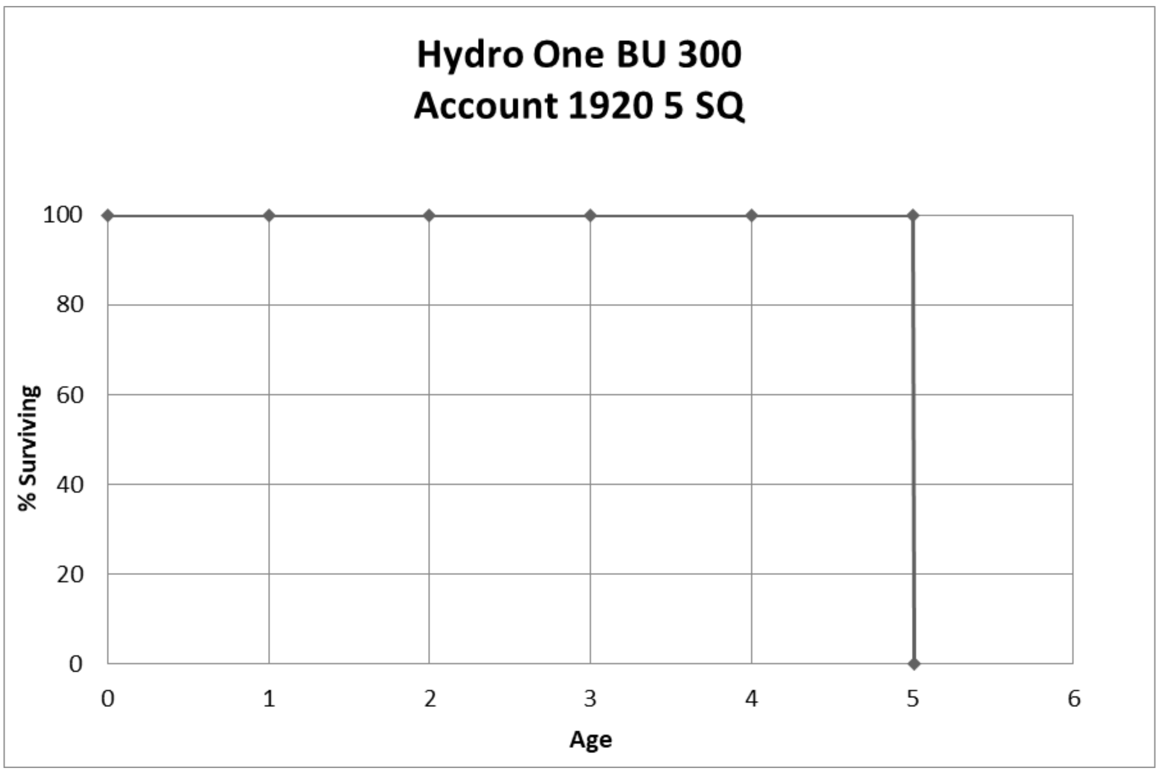
Account 1915 Office Furniture and Equipment (7 SQ)

This account consists of general office furniture and equipment. Such assets include desks, chairs, filing cabinets, etc. The plant balance in this account at December 31, 2019 is $10.6 million. Currently, the amortization life of this account is 7 years. After reviewing plant lives with Company personnel, the determination was that the existing 7-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



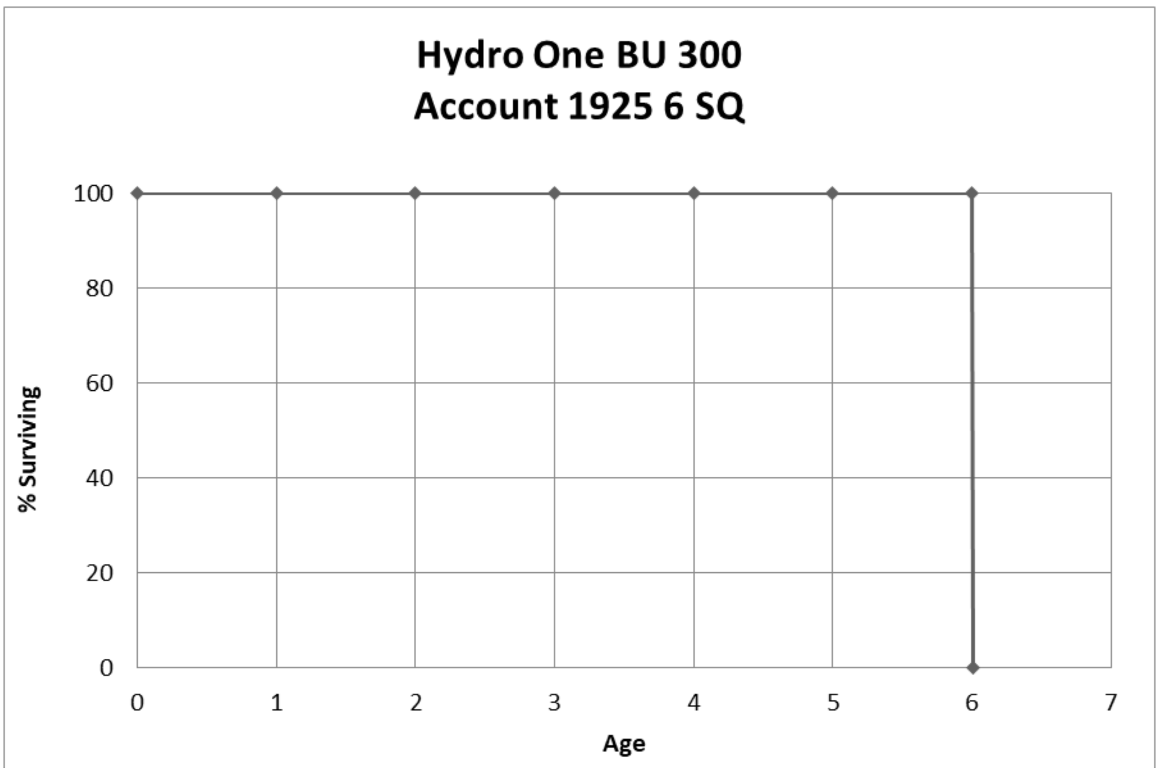
Account 1920 Computer Hardware - Minor (5 SQ)

This account consists of computer hardware, specifically computers, for general use. The plant balance in this account at December 31, 2019 is $67.7 million. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



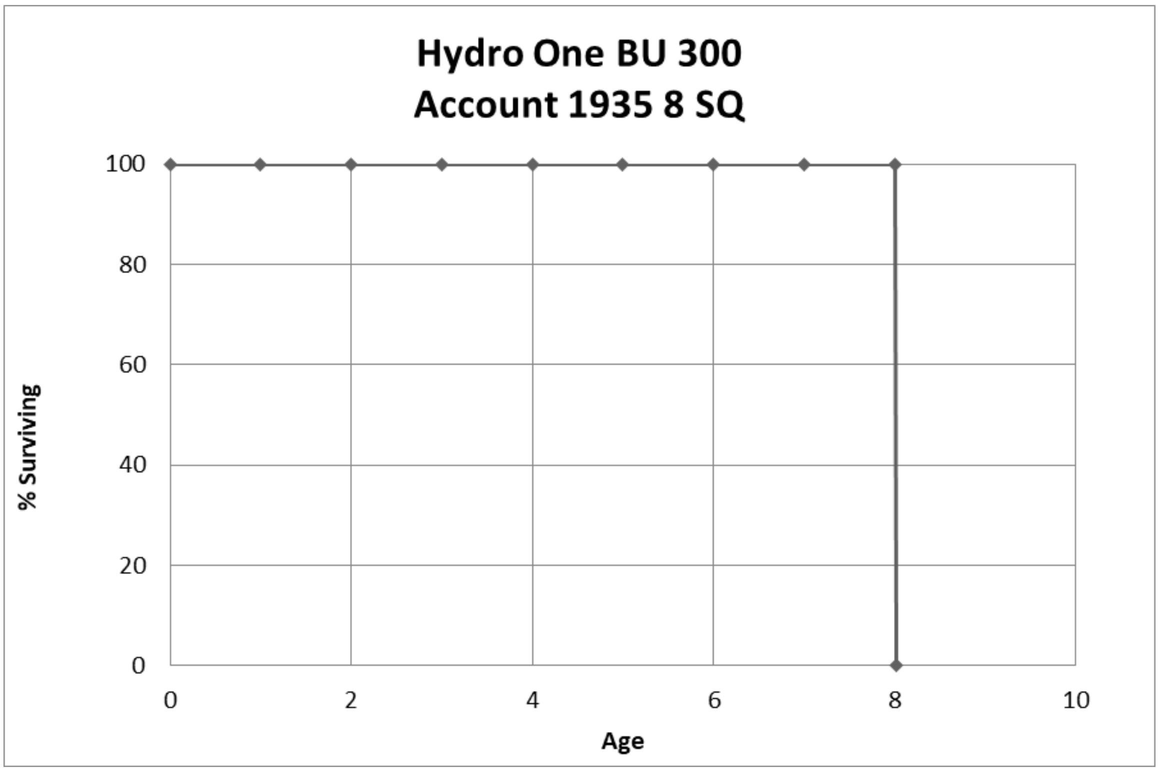
Account 1925 Computer Software (6 SQ)

This account consists of general computer software. Such assets include general system software and small amounts of associated hardware. The plant balance in this account at December 31, 2019 is $130.2 million. Currently, the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



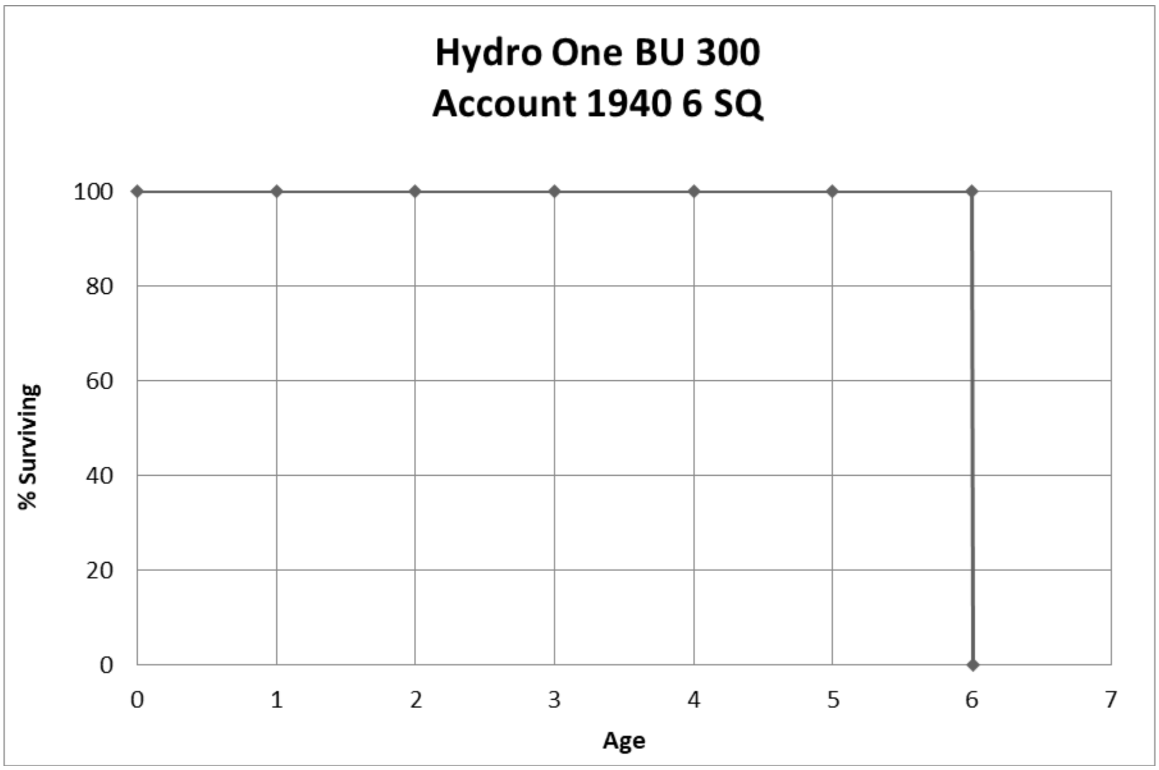
Account 1935 Stores Equipment (8 SQ)

This account consists of general stores equipment. Such assets include shelving and other stores assets. The plant balance in this account at December 31, 2019 is $0.4 million. Currently, the amortization life of this account is 8 years. After reviewing plant lives with Company personnel, the determination was that the existing 8-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



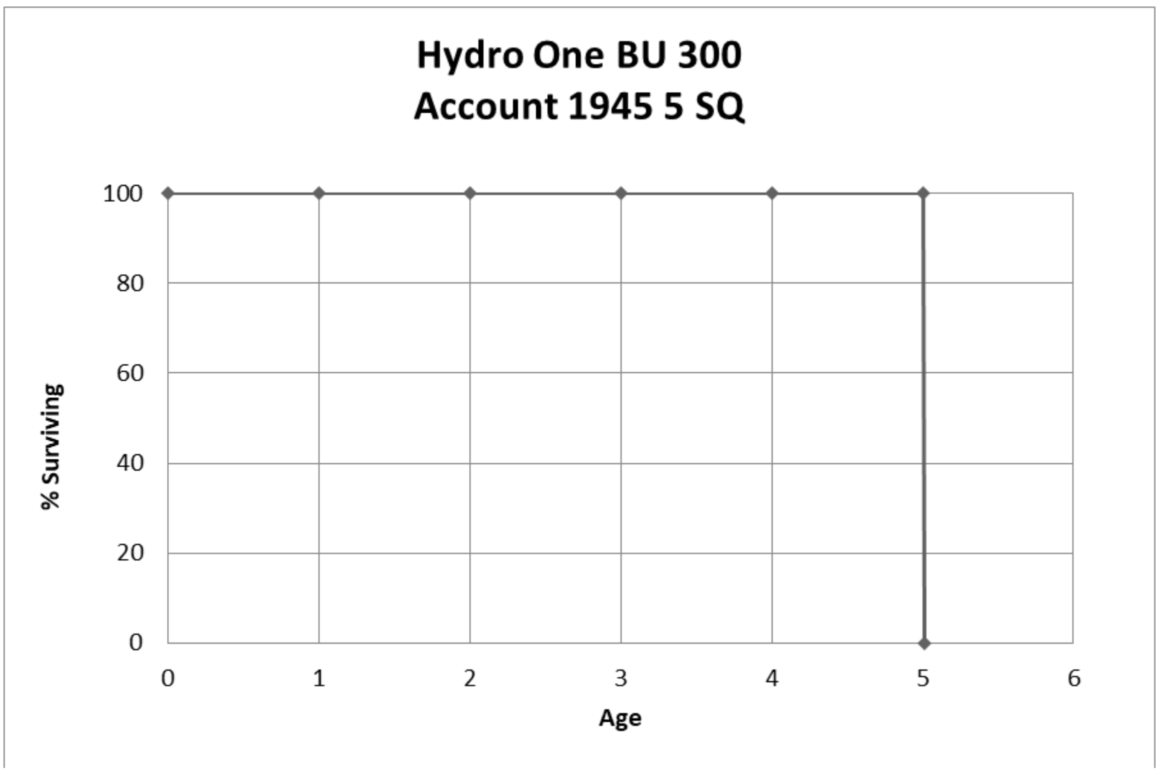
Account 1940 Tools Shop and Garage Equipment (6 SQ)

This account consists of general tools, shop, and garage equipment. The plant balance in this account at December 31, 2019 is $16.8 million. Currently, the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



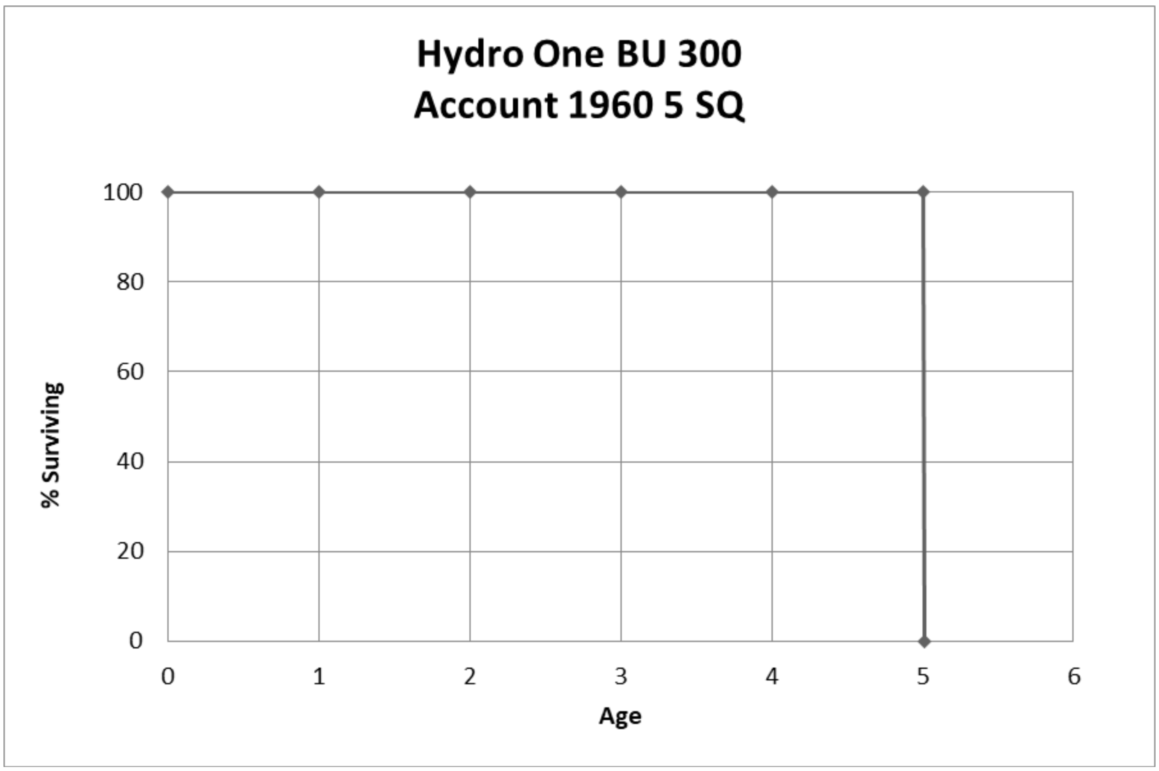
Account 1945 Measurement and Testing Equipment (5 SQ)

This account consists of general measuring and testing equipment. The plant balance in this account at December 31, 2019 is $12.1 million. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



Account 1960 Miscellaneous Equipment (5 SQ)

This account consists of general miscellaneous equipment. The plant balance in this account at December 31, 2019 is $3.4 million. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



APPENDIX A
Depreciation Rate Calculations

HYDRO ONE
BU 210 TRANSMISSION PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Allocated Reserve 12/31/2019	Unaccrued Balance	Remaining Life	Annual Accrual	Annual Accrual Rate
INTANGIBLE PLANT							
1609	Capital Contributions	8,740,895	815,204	7,925,690	9.07	874,089	10.00%
1610	Computer Software	16,340,452	2,491,028	13,849,424	8.48	1,634,045	10.00%
TRANSMISSION PLANT							
1706	Land Rights	257,330,714	91,691,253	165,639,461	70.32	2,355,424	0.92%
1708	Buildings and Fixtures	602,955,047	258,104,121	344,850,925	31.57	10,922,267	1.81%
1715	Station Equipment	10,331,573,044	3,470,648,634	6,860,924,410	34.48	198,962,916	1.93%
1720	Towers and Fixtures	2,783,289,839	876,789,671	1,906,500,168	55.32	34,462,083	1.24%
1730	Overhead Conductors and Devices	2,019,114,308	750,628,792	1,268,485,517	48.21	26,314,140	1.30%
1735	Undergound Conduit	310,338,976	141,977,003	168,361,974	37.14	4,533,470	1.46%
1740	Underground Conductors and Devices	153,702,365	28,246,268	125,456,097	46.58	2,693,258	1.75%
1745	Roads and Trails	308,456,260	129,735,928	178,720,332	38.61	4,629,450	1.50%
General Plant							
	Depreciable						
1908	Buildings and Fixtures	151,615,103	64,572,586	87,042,517	31.66	2,749,017	1.81%
1910	Leashold Improvements	100,228	100,228	0	0.00	0	10.00% *
1922	Computer Hardware- Major	15,167,911	10,469,221	4,698,690	3.91	1,201,464	7.92%
1955	Communication Equipment	499,352,541	309,378,029	189,974,511	9.28	20,466,767	4.10%
1980	System Supervisory Equipment	452,165,605	393,832,779	58,332,826	1.69	34,469,486	7.62%
	Amortizable						
1925	Computer Software Major	8,931,156	8,931,156	0	0.00	0	16.67% *
	Total	17,919,174,444	6,538,411,901	11,380,762,542		346,267,876	

* Fully Accrued Rate for new investment only

HYDRO ONE
BU 220 DISTRIBUTION PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Allocated Reserve 12/31/2019	Unaccrued Balance	Remaining Life	Annual Accrual	Annual Accrual Rate
INTANGIBLE PLANT							
1609	Capital Contributions	48,642,612	21,128,813	27,513,799	5.66	4,864,261	10.00%
1610	Computer Software	255,544,978	122,393,754	133,151,223	5.21	25,554,498	10.00%
DISTRIBUTION PLANT							
	Depreciable						
1805	Land						
1806	Land Rights	240,422,418	88,311,968	152,110,450	69.61	2,185,324	0.91%
1808	Building and Fixtures	27,043,692	5,083,754	21,959,938	42.17	520,737	1.93%
1815	Transformer Station Equipment > 50 kV	231,496,548	78,682,599	152,813,949	34.49	4,431,235	1.91%
1820	Distribution Station Equipment < 50 kV	799,777,839	258,008,331	541,769,508	32.96	16,436,065	2.06%
1830	Poles, Towers and Fixtures	3,647,830,496	1,008,950,927	2,638,879,569	42.41	62,219,855	1.71%
1835	Overhead Conductors and Devices	2,068,367,636	671,994,615	1,396,373,021	42.41	32,927,541	1.59%
1840	Underground Conduit	24,297,741	10,007,522	14,290,219	39.55	361,307	1.49%
1845	Underground Conductors and Devices	926,229,848	508,301,406	417,928,442	17.91	23,338,075	2.52%
1850	Line Transformers	2,081,972,509	793,560,796	1,288,411,713	27.36	47,089,100	2.26%
1860	Meters	264,973,413	43,119,808	221,853,605	15.58	14,243,122	5.38%
1860	Meters (Sustainment) (All transfer to 1860)			0			
1555	Smart Meters	330,328,119	205,884,574	124,443,545	8.72	14,276,433	4.32%
GENERAL PLANT							
	Depreciable						
1908	Building and Fixtures	147,672,903	61,246,363	86,426,539	33.55	2,576,324	1.74%
1910	Leasehold Improvements	8,149,230	7,080,431	1,068,799	2.34	456,172	5.60%
1922	Minor Computer Equipment- Hardware	4,733,131	4,572,019	161,112	0.71	161,112	3.40%
1955	Communication Equipment	29,086,977	27,249,838	1,837,139	0.64	1,837,139	6.32%
1980	System Supervisory Equipment	133,312,933	103,654,582	29,658,351	2.23	13,317,647	9.99%
1985	Sentinel Lighting Rental Units	15,300,030	11,450,642	3,849,388	10.84	354,975	2.32%
	Amortized						
1925	Computer Application Software	41,261,340	39,381,089	1,880,251	0.27	6,876,890	16.67%

HYDRO ONE
BU 300 COMMON PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Allocated Reserve 12/31/2019	Unaccrued Balance	Remaining Life		Annual Accrual	Annual Accrual Rate
INTANGIBLE PLANT								
1610	Computer Software	636,292,886	362,672,761	273,620,125	5.16		53,024,407	8.33%
GENERAL PLANT								
	Depreciable							
1908	Building and Fixtures	130,768,147	55,318,804	75,449,343	35.99		2,096,495	1.60%
1910	Leasehold Improvements	45,666,322	38,286,428	7,379,894	4.05		1,822,487	3.99%
1922	Computer Equipment- Hardware	15,899,996	12,882,437	3,017,559	4.43		681,154	4.28%
1955	Communication Equipment	22,440,010	22,086,197	353,813	1.63		217,643	0.97%
1980	System Supervisory Equipment	19,681,555	11,150,901	8,530,654	3.94		2,166,766	11.01%
	Amortized							
1915	Office Furniture and Equipment	10,563,024	6,838,830	3,724,194	2.47		1,509,003	14.29%
1920	Computer Hardware-Minor	67,662,865	30,371,747	37,291,118	2.76		13,532,573	20.00%
1925	Computer Software Major	130,222,116	117,919,572	12,302,544	0.57	(1)	21,703,686	16.67%
1935	Stores Equipment	415,591	231,097	184,493	3.55		51,949	12.50%
1940	Tools, Shop and Garage Equipment	16,760,402	10,713,938	6,046,464	2.16		2,793,400	16.67%
1945	Measuring and Testing Equipment	12,092,835	5,988,930	6,103,905	2.52		2,418,567	20.00%
1960	Miscellaneous Equipment	3,417,518	1,282,996	2,134,521	3.12		683,504	20.00%
		1,111,883,265	675,744,637	436,138,628			102,701,635	

Note 1: Since the remaining life of account 1925 is less than 1 year, accrual is set at 1/ average service life

APPENDIX B

Depreciation Expense Comparison

HYDRO ONE
BU 210 TRANSMISSION PLANT
COMPARISON OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Current Accrual Rate	Current Accrual Amount	Proposed Accrual Rate	Proposed Accrual Rate	Difference
INTANGIBLE PLANT							
1609	Capital Contributions	8,740,895	10.00%	874,089	10.00%	874,089	0
1610	Computer Software	16,340,452	10.00%	1,634,045	10.00%	1,634,045	0
TRANSMISSION PLANT							
1705	Land - Depreciable						
1706	Land Rights	257,330,714	0.96%	2,470,375	0.92%	2,355,424	(114,951)
1708	Buildings and Fixtures	602,955,047	1.83%	11,034,077	1.81%	10,922,267	(111,810)
1715	Station Equipment	10,331,573,044	2.08%	214,896,719	1.93%	198,962,916	(15,933,804)
1720	Towers and Fixtures	2,783,289,839	1.27%	35,347,781	1.24%	34,462,083	(885,698)
1730	Overhead Conductors and Devices	2,019,114,308	1.44%	29,075,246	1.30%	26,314,140	(2,761,106)
1735	Undergound Conduit	310,338,976	1.62%	5,027,491	1.46%	4,533,470	(494,021)
1740	Underground Conductors and Devices	153,702,365	1.80%	2,766,643	1.75%	2,693,258	(73,384)
1745	Roads and Trails	308,456,260	1.81%	5,583,058	1.50%	4,629,450	(953,608)
General Plant							
	Depreciable						
1905	Land - Depreciable						
1908	Buildings and Fixtures	151,615,103	2.10%	3,183,917	1.81%	2,749,017	(434,900)
1910	Leashold Improvements	100,228	-1.54%	0	10.00% *	0	0
1922	Computer Hardware- Major	15,167,911	9.28%	1,407,582	7.92%	1,201,464	(206,118)
1955	Communication Equipment	499,352,541	4.58%	22,870,346	4.10%	20,466,767	(2,403,579)
1980	System Supervisory Equipment	452,165,605	6.38%	28,848,166	7.62%	34,469,486	5,621,320
	Amortizable						
1925	Computer Software Major	8,931,156	16.67%	0	16.67% *	0	0
		17,919,174,444		365,019,537		346,267,876	(18,751,661)

* Account is fully accrued. Rate to be implemented when plant is added to this account.

HYDRO ONE
BU 220 DISTRIBUTION PLANT
COMPARISON OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Current Accrual Rate	Current Accrual Amount	Proposed Accrual Rate	Proposed Accrual Rate	Difference
INTANGIBLE PLANT							
1609	Capital Contributions	48,642,612	10.00%	4,864,261	10.00%	4,864,261	0
1610	Computer Software	255,544,978	10.00%	25,554,498	10.00%	25,554,498	0
DISTRIBUTION PLANT							
Depreciable							
1805	Land						
1806	Land Rights	240,422,418	0.94%	2,259,971	0.91%	2,185,324	(74,647)
1808	Building and Fixtures	27,043,692	1.82%	492,195	1.93%	520,737	28,541
1815	Transformer Station Equipment > 50 kV	231,496,548	2.23%	5,162,373	1.91%	4,431,235	(731,138)
1820	Distribution Station Equipment < 50 kV	799,777,839	2.70%	21,594,002	2.06%	16,436,065	(5,157,936)
1830	Poles, Towers and Fixtures	3,647,830,496	1.70%	62,013,118	1.71%	62,219,855	206,736
1835	Overhead Conductors and Devices	2,068,367,636	1.69%	34,955,413	1.59%	32,927,541	(2,027,873)
1840	Underground Conduit	24,297,741	1.71%	415,491	1.49%	361,307	(54,184)
1845	Underground Conductors and Devices	926,229,848	2.83%	26,212,305	2.52%	23,338,075	(2,874,230)
1850	Line Transformers	2,081,972,509	2.31%	48,093,565	2.26%	47,089,100	(1,004,465)
1860	Meters	264,973,413	6.63%	17,567,737	5.38%	14,243,122	(3,324,616)
1860	Meters (Sustainment) (All transfer to 1860)	0	6.63%	0	0.00%	0	0
1555	Smart Meters	330,328,119	6.36%	21,008,868	4.32%	14,276,433	(6,732,435)
GENERAL PLANT							
Depreciable							
1908	Building and Fixtures	147,672,903	1.84%	2,717,181	1.74%	2,576,324	(140,857)
1910	Leasehold Improvements	8,149,230	5.50%	448,208	5.60%	456,172	7,964
1922	Minor Computer Equipment- Hardware	4,733,131	-3.82%	(180,806)	14.29%	161,112	341,917 *
1955	Communication Equipment	29,086,977	-9.99%	(2,905,789)	16.67%	1,837,139	4,742,928 *
1980	System Supervisory Equipment	133,312,933	14.94%	19,916,952	9.99%	13,317,647	(6,599,305)
1985	Sentinel Lighting Rental Units	15,300,030	2.94%	449,821	2.32%	354,975	(94,846)
Amortized							
1925	Computer Application Software	41,261,340	16.66%	1,880,251	16.67%	1,880,251	0 *
	Total	11,326,444,391		292,519,617		269,031,171	(23,488,445)

* Account fully accrued in 2020. When new plant added use 10% for proposed rate for new assets only

HYDRO ONE
BU 300 COMMON PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Current Accrual Rate	Current Accrual Amount	Proposed Accrual Rate	Proposed Accrual Rate	Difference
INTANGIBLE PLANT							
1610	Computer Software	636,292,886	10.00%	63,629,289	8.33%	53,024,407	(10,604,881)
GENERAL PLANT							
	Depreciable						
1908	Building and Fixtures	130,768,147	1.53%	2,000,753	1.60%	2,096,495	95,742
1910	Leasehold Improvements	45,666,322	5.63%	2,571,014	3.99%	1,822,487	(748,527)
1922	Computer Equipment- Hardware	15,899,996	8.23%	1,308,570	4.28%	681,154	(627,415)
1955	Communication Equipment	22,440,010	-42.07%	(9,440,512)	0.97%	217,643	9,658,156
1980	System Supervisory Equipment	19,681,555	-37.04%	(7,290,048)	11.01%	2,166,766	9,456,814
	Amortized						
1915	Office Furniture and Equipment	10,563,024	14.28%	1,508,400	14.29%	1,509,003	604
1920	Computer Hardware-Minor	67,662,865	20.00%	13,532,573	20.00%	13,532,573	
1925	Computer Software Major	130,222,116	16.66%	21,695,004	16.67%	21,703,686	8,681
1935	Stores Equipment	415,591	12.50%	51,949	12.50%	51,949	
1940	Tools, Shop and Garage Equipment	16,760,402	16.66%	2,792,283	16.67%	2,793,400	1,117
1945	Measuring and Testing Equipment	12,092,835	20.00%	2,418,567	20.00%	2,418,567	
1960	Miscellaneous Equipment	3,417,518	20.00%	683,504	20.00%	683,504	
	Total	1,111,883,265	8.59%	95,461,345	9.24%	102,701,635	7,240,291

APPENDIX C

Depreciation Parameter Comparison

HYDRO ONE
CURRENT AT PROPOSED DEPRECIATION PARAMETERS
BU 210 TRANSMISSION AT DECEMBER 31, 2019

		Current				Proposed		
USofA	**USofA Description**	**Life**	**Curve**	**Rate**	**Procedure**	**Curve**	**Life**	**Procedure**
INTANGIBLE PLANT								
1609	Capital Contributions	10	SQ	10.00%	Amortize	10	SQ	Amortize
1610	Computer Software	10	SQ	10.00%	Amortize	10	SQ	Amortize
TRANSMISSION PLANT								
1705	Land - Depreciable	100	S6	0.96%	SL VG RL	NA	NA	SL BG RL
1706	Land Rights	100	S6	0.96%	SL VG RL	100	R4	SL BG RL
1708	Buildings and Fixtures	50	S6	1.83%	SL VG RL	50	S6	SL BG RL
1715	Station Equipment	45	S2	2.08%	SL VG RL	48	R2.5	SL BG RL
1720	Towers and Fixtures	75	S2	1.27%	SL VG RL	75	R3	SL BG RL
1730	Overhead Conductors and Devices	65	S3	1.44%	SL VG RL	70	R4	SL BG RL
1735	Undergound Conduit	55	S2	1.62%	SL VG RL	60	R2	SL BG RL
1740	Underground Conductors and Devices	55	S2	1.80%	SL VG RL	55	R2	SL BG RL
1745	Roads and Trails	50	S2	1.81%	SL VG RL	60	R4	SL BG RL
General Plant								
	Depreciable							
1905	Land - Depreciable	100	S6	0.98%	SL VG RL	NA	NA	
1908	Buildings and Fixtures	45	S4	2.10%	SL VG RL	50	S4	SL BG RL
1910	Leashold Improvements	10	S6	-1.54%	SL VG RL	10	S6	SL BG RL
1922	Computer Hardware- Major	10	S6	9.28%	SL VG RL	10	S6	SL BG RL
1955	Communication Equipment	20	L2	4.58%	SL VG RL	20	R2.5	SL BG RL
1980	System Supervisory Equipment	10	L2	6.38%	SL VG RL	10	R4	SL BG RL
	Amortizable							
1925	Computer Software Major	6	SQ	16.67%	Amortize	6	SQ	Amortize

BU 220 Current vs Proposed Parameters

		Current				Proposed		
USofA	Description	Curve	Life	Accrual Rate	System	Curve	Life	System
INTANGIBLE PLANT								
1609	Capital Contributions	10	SQ	10.00%	Amortization	10	SQ	Amortization
1610	Computer Software	10	SQ	10.00%	Amortization	10	SQ	Amortization
DISTRIBUTION PLANT								
	Depreciable							
1805	Land	50	S6	-0.18%	SL- VG-RL	NA	NA	
1806	Land Rights	100	S6	0.94%	SL- VG-RL	100	R4	SL- BG-RL
1808	Building and Fixtures	50	S4	1.82%	SL- VG-RL	50	R4	SL- BG-RL
1815	Transformer Station Equipment > 50 kV	40	R2.5	2.23%	SL- VG-RL	48	R2.5	SL- BG-RL
1820	Distribution Station Equipment < 50 kV	30	R2.5	2.70%	SL- VG-RL	45	R2.5	SL- BG-RL
1830	Poles, Towers and Fixtures	55	S2	1.70%	SL- VG-RL	55	R2	SL- BG-RL
1835	Overhead Conductors and Devices	55	S2	1.69%	SL- VG-RL	58	R2	SL- BG-RL
1840	Underground Conduit	50	S2	1.71%	SL- VG-RL	60	R1	SL- BG-RL
1845	Underground Conductors and Devices	30	S3	2.83%	SL- VG-RL	33	R3	SL- BG-RL
1850	Line Transformers	40	R2	2.31%	SL- VG-RL	40	R2	SL- BG-RL
1860	Meters	20	R5	4.89%	SL- VG-RL	18	R3	SL- BG-RL
1860	Meters (Sustainment) (All transfer to 1860)	15	R5	6.63%	SL- VG-RL	18	R3	SL- BG-RL
1555	Smart Meters	15	R5	6.36%	SL- VG-RL	18	R3	SL- BG-RL
GENERAL PLANT								
1908	Building and Fixtures	50	S4	1.84%	SL- VG-RL	50	S4	SL- BG-RL
1910	Leasehold Improvements	10	S6	5.50%	SL- VG-RL	10	S6	SL- BG-RL
1922	Minor Computer Equipment- Hardware	10	S6	-3.82%	SL- VG-RL	10	S6	SL- BG-RL
1955	Communication Equipment	7	S6	-9.99%	SL- VG-RL	7	S6	SL- BG-RL
1980	System Supervisory Equipment	6	L2	14.94%	SL- VG-RL	6	L2	SL- BG-RL
1985	Sentinel Lighting Rental Units	30	R1.5	2.94%	SL- VG-RL	27	R3	SL- BG-RL
	Amortized							
1925	Computer Application Software	6	SQ	16.66%	Amortization	6	SQ	Amortization

BU 300 Current vs Proposed Parameters

USofA		Current Curve Life	Current Rate	Current System	Proposed Curve Life	Proposed System
INTANGIBLE PLANT						
1610	Computer Software	10 SQ	10.00%	SL-VG-RL	12 SQ	Amortization
GENERAL PLANT						
Depreciable						
1908	Building and Fixtures	50 S4	1.53%	SL-VG-RL	50 S4	SL-BG-RL
1910	Leasehold Improvements	10 S6	5.63%	SL-VG-RL	10 S6	SL-BG-RL
1922	Computer Equipment- Hardware	10 S6	8.23%	SL-VG-RL	10 S6	SL-BG-RL
1955	Communication Equipment	7 S6	-42.07%	SL-VG-RL	7 S6	SL-BG-RL
1980	System Supervisory Equipment	7 S6	-37.04%	SL-VG-RL	7 S6	SL-BG-RL
Amortized						
1915	Office Furniture and Equipment	7 SQ	14.28%		7 SQ	Amortization
1920	Computer Hardware-Minor	5 SQ	20.00%		5 SQ	Amortization
1925	Computer Software Major	6 SQ	16.66%		6 SQ	Amortization
1935	Stores Equipment	8 SQ	12.50%		8 SQ	Amortization
1940	Tools, Shop and Garage Equipment	6 SQ	16.66%		6 SQ	Amortization
1945	Measuring and Testing Equipment	5 SQ	20.00%		5 SQ	Amortization
1960	Miscellaneous Equipment	5 SQ	20.00%		5 SQ	Amortization

APPENDIX D
Summary of Depreciation Book Reserve, Reallocated Depreciation Reserve, and Theoretical Depreciation Reserve

HYDRO ONE
BU 210 TRANSMISSION PLANT
COMPARISON OF PLANT AND ACCUMULATED DEPRECIATION
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Book Reserve	Allocated Reserve	Theoretical Reserve	Book - Allocated Reserve Difference
INTANGIBLE PLANT						
1609	Capital Contributions	8,740,895	993,019	815,204	815,204	177,815
1610	Computer Software	16,340,452	2,228,611	2,491,028	2,491,028	(262,417)
	Total Intangible	25,081,347	3,221,631	3,306,233	3,306,233	(84,602)
TRANSMISSION PLANT						
1705	Land - Depreciable					
1706	Land Rights	257,330,714	64,529,829	91,691,253	76,369,115	(27,161,424)
1708	Buildings and Fixtures	602,955,047	257,599,976	258,104,121	222,210,648	(504,145)
1715	Station Equipment	10,331,573,044	3,488,635,526	3,470,648,634	2,909,320,778	17,986,892
1720	Towers and Fixtures	2,783,289,839	913,200,613	876,789,671	730,273,051	36,410,943
1730	Overhead Conductors and Devices	2,019,114,308	682,292,689	750,628,792	628,652,056	(68,336,103)
1735	Undergound Conduit	310,338,976	135,895,617	141,977,003	118,251,825	(6,081,386)
1740	Underground Conductors and Devices	153,702,365	26,986,645	28,246,268	23,526,153	(1,259,622)
1745	Roads and Trails	308,456,260	180,556,112	129,735,928	109,989,905	50,820,184
	Suspense Activity		(2,128,553)	0	0	(2,128,553)
1705	Non Depreciable Land		253,214	0	0	253,214
	Total Transmission	16,766,760,553	5,747,821,670	5,747,821,670	4,818,593,530	(0)
General Plant						
	Depreciable					
1905N	Land Non Depreciable		582,963	0	0	582,963
1908	Buildings and Fixtures	151,615,103	59,221,096	64,572,586	55,602,894	(5,351,490)
1910	Leashold Improvements	100,228	94,752	100,228	100,228	(5,476)
1922	Computer Hardware- Major	15,167,911	8,512,298	10,469,221	9,236,037	(1,956,923)
1955	Communication Equipment	499,352,541	266,739,145	309,378,029	267,600,610	(42,638,884)
1980	System Supervisory Equipment	452,165,605	443,285,648	393,832,779	375,645,469	49,452,869
	Suspense Activity		1,544			1,544
	Total General	1,118,401,387	778,437,445	778,352,843	708,185,238	84,602
	Amortizable					
1925	Computer Software Major	8,931,156	8,931,156	8,931,156	8,931,156	0
	Total Amortizable	8,931,156	8,931,156	8,931,156	8,931,156	0
	Total Depreciable	17,919,174,444	6,538,411,901	6,538,411,901	5,539,016,157	0

HYDRO ONE
BU 220 DISTRIBUTION PLANT
COMPARISON OF PLANT AND ACCUMULATED DEPRECIATION
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Book Reserve 12/31/2019	Allocated Reserve	Theoretical Reserve	Book - Allocated Reserve Difference
INTANGIBLE PLANT						
1609	Capital Contributions	48,642,612	20,649,642	21,128,813	21,128,813	(479,171)
1610	Computer Software	255,544,978	120,873,652	122,393,754	122,393,754	(1,520,102)
DISTRIBUTION PLANT						
Depreciable						
1805	Land					
1806	Land Rights	240,422,418	83,772,336	88,311,968	73,075,310	(4,539,632)
1808	Building and Fixtures	27,043,692	4,535,373	5,083,754	4,234,550	(548,381)
1815	Transformer Station Equipment > 50 kV	231,496,548	86,541,540	78,682,599	65,177,690	7,858,941
1820	Distribution Station Equipment < 50 kV	799,777,839	322,877,955	258,008,331	213,945,221	64,869,625
1830	Poles, Towers and Fixtures	3,647,830,496	987,948,414	1,008,950,927	834,877,096	(21,002,513)
1835	Overhead Conductors and Devices	2,068,367,636	743,773,559	671,994,615	556,053,902	71,778,944
1840	Underground Conduit	24,297,741	14,971,891	10,007,522	8,280,902	4,964,369
1845	Underground Conductors and Devices	926,229,848	543,203,928	508,301,406	423,607,568	34,902,522
1850	Line Transformers	2,081,972,509	749,335,642	793,560,796	657,843,691	(44,225,155)
1860	Meters	264,973,413	16,413,730	43,119,808	35,680,253	(26,706,079)
1860	Meters (Sustainment) (All transfer to 1860)	0	5,175,673			5,175,673
1555	Smart Meters	330,328,119	133,807,017	205,884,574	170,362,854	(72,077,557)
1565	Smart Meters		(746,190)			(746,190)
Suspense			(19,704,568)			(19,704,568)
GENERAL PLANT						
Depreciable						
1908	Building and Fixtures	147,672,903	53,887,937	61,246,363	48,594,866	(7,358,426)
1910	Leasehold Improvements	8,149,230	5,576,275	7,080,431	6,239,885	(1,504,156)
1922	Minor Computer Equipment- Hardware	4,733,131	4,164,976	4,572,019	4,394,855	(407,043)
1955	Communication Equipment	29,086,977	19,763,440	27,249,838	26,423,497	(7,486,398)
1980	System Supervisory Equipment	133,312,933	127,458,917	103,654,582	83,831,697	23,804,335
1985	Sentinel Lighting Rental Units	15,300,030	8,819,430	11,450,642	9,155,017	(2,631,212)
	Suspense		(2,237,245)			(2,237,245)
1925	Computer Application Software	41,261,340	39,200,507	39,381,089	39,381,089	(180,581)
		11,326,444,391	4,070,063,832	4,070,063,832	3,404,682,512	0

HYDRO ONE
BU 300 COMMON PLANT
COMPARISON OF PLANT AND ACCUMULATED DEPRECIATION
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2019	Book Reserve	Allocated Reserve	Theoretical Reserve	Book - Allocated Reserve Difference
INTANGIBLE PLANT						
1610	Computer Software	636,292,886	402,672,668	362,672,761	362,672,761	39,999,908
GENERAL PLANT						
	Depreciable					
1908	Building and Fixtures	130,768,147	58,629,027	55,318,804	36,645,613	3,310,223
1910	Leasehold Improvements	45,666,322	22,677,387	38,286,428	27,174,410	(15,609,041)
1922	Computer Equipment- Hardware	15,899,996	9,253,698	12,882,437	8,856,192	(3,628,739)
1955	Communication Equipment	22,440,010	(1,483,048)	22,086,197	17,228,624	(23,569,244)
1980	System Supervisory Equipment	19,681,555	403,839	11,150,901	8,611,963	(10,747,063)
	Suspense		12,087,036			12,087,036
	Amortized					
1915	Office Furniture and Equipment	10,563,024	6,674,069	6,838,830	6,838,830	(164,761)
1920	Computer Hardware-Minor	67,662,865	26,989,978	30,371,747	30,371,747	(3,381,768)
1925	Computer Software Major	130,222,116	120,170,352	117,919,572	117,919,572	2,250,780
1935	Stores Equipment	415,591	218,046	231,097	231,097	(13,051)
1940	Tools, Shop and Garage Equipment	16,760,402	10,115,737	10,713,938	10,713,938	(598,201)
1945	Measuring and Testing Equipment	12,092,835	6,068,443	5,988,930	5,988,930	79,513
1960	Miscellaneous Equipment	3,417,518	1,267,404	1,282,996	1,282,996	(15,592)
	Total	1,111,883,265	675,744,637	675,744,637	634,536,673	

Allocation methodology assumes that for intangible plant and amortized plant the reallocated reserve equals the theoretical reserve.
Any excess or deficiency is allocated across the depreciable plant accounts.

APPENDIX E

Summary of Projection Lives by Business Unit

Hydro One 2019 Tx BU 210
Summary of Project Lives

Description	Current P-Life UsoA	Current P-Life Category	Recommended P-Life UsoA	Recommended P-Life Category	Plant UsoA	Plant Category
INTANGIBLE PLANT						
1609 Contributed Capital						
Contribued Capital		10		10		8,740,895
Total USoA 1609	10 SQ	10	10 SQ	10		8,740,895
1610 Computer Software						
1656 Genrl- Adm & Serv- Lan Fib Opt		10		10		1,894,826
1657 Genrl - Adm & Serv-Sys Software		10		10		1,569,069
Unknown		10		10		12,876,557
Total USoA 1610	10 SQ	10	10 SQ	10		16,340,452
TRANSMISSION PLANT						
1705D Land - Depreciable						
1210 Land Purch & Acqui (old Cap)		100		100		
Total USoA 1705D	100 S6	100		100		
1706 Land Rights						
1111 Rights & Easmnts <Landscaping>		100		100		2,959,657
1212 Easmnts & Rights		100		100		243,706,925
Land right		100		100		10,664,133
Total USoA 1706	100 S6	100	100 R4	100		257,330,714
1708 Buildings and Fixtures						
1120 Stn Building Components		50		50		470,950,497
1121 Cranes & Hoists In Bldgs		50		50		4,814,954
1260 Bldg W U/G Cable		50		50		31,740,987
1270 Serv Structures		50		50		25,538,801
Buildings & Fixtures		50		50		69,909,807
Total USoA 1708	50 S6	50	50 S6	50		602,955,047
1715 Station Equipment						
1111 Rights & Easmnts <Landscaping>		50		50		312
1112 Landscaping		50		50		30,684,868
1113 Site Imprv-Excl Fence		50		50		371,039,189
1123 Cost Equip Foundations		65		65		673,814,714
1127 Steel/Pipe Struc For Switch Eq		65		65		467,361,522
1128 Fences		30		30		143,923,281
1150 Rot Elec Eqp (No Wind'G)		65		65		18,782,246
1151 Rot Elec Eqp(Wind'Gs)		65		65		301,966
1152 Capacitors		30		30		151,444,578
1155 Regulators Incl Instal Cost		40		40		11,022,212
1159 Mobile Sub-Stations		30		30		3,350,897
1160 Misc Stn Eqp-Trsf/Volt Trsf		40		40		402,602,094
1161 Serv Swg-Ac/Dc-Light Trsf		55		55		280,546,279
1162 Control Cable & Conduit		60		60		470,546,755
1163 Grounding Systems		60		60		234,986,449
1164 Metering Units		15		15		63,979,446
1166 Switchboards		35		35		769,360,047
1167 Sup Cntrl-Prim H/Ware& Sys		20		20		651,570,657
1168 Sup Cntrl - Prim Appl S/Ware		20		20		23,822,684
1170 Service Systems		50		50		217,088,409
1175 Transf <=50Kv or <5Mva		50		50		71,177,422
1176 Trnsf <=115Kv or >5Mva		50		50		451,556,602
1177 Transf <=230Kv		50		50		466,856,199
1178 Transf >230Kv		50		50		333,436,542
1179 Transf Instal Cost		50		50		416,506,358

Hydro One 2019 Tx BU 210
Summary of Project Lives

Description	Current P-Life		Recommended P-Life		Plant	
	UsoA	Category	UsoA	Category	UsoA	Category
1181 Switching >=34.5Kv		45		45		212,571,500
1182 Switching >=115Kv		45		45		158,439,340
1183 Switching >=230Kv		45		45		183,049,683
1184 Sf6 Switchgear		45		45		411,887,025
1185 Reclosures		40		40		1,538,864
1186 Misc Switching		45		45		194,835,765
1187 Bus (Rigid & Strain)		45		45		341,903,275
1188 Cable		45		45		142,186,172
1190 Cct Breakers >=230Kv		45		45		329,577,808
1191 Cct Breakers >=115Kv		45		45		124,614,994
1192 Cct Breakers <115Kv		45		45		165,568,109
1193 Cct Breakers Install		45		45		255,894,446
1194 Encld Swgr (All Compnt)		45		45		85,635,341
Station equipment		45		45		998,108,991
Total USoA 1715	45 S2	42	48 R2.5	46.48		10,331,573,044
1720 Towers and Fixtures						
1230 Steel Twr, Sup & Ftng		90		90		1,621,295,029
1240 Poles Incl Xarm, Guy, Anchr		50		50		845,894,804
1245 Steel Poles		90		90		116,630,691
1249 Composite Poles		80		80		8,147,241
Tower and Fixtures		75		75		191,322,074
Total USoA 1720	75 S2	73	75 R3	5.39		2,783,289,839
1730 Overhead Conductors and Devices						
1220 Insulators		60		60		371,337,956
1232 Grounding System		50		50		163,470,457
1235 Opt Grnd Wire		50		50		67,493,185
1250 Overhd Conductor All		70		70		1,128,086,876
1252 Switches&Devce		60		60		48,899,023
1254 Retension Costs		60		60		40,718,896
Overhead Conductors and Devices		65		65		199,107,914
Total USoA 1730	65 S3	64	70 R4	63.26		2,019,114,308
1735 Underground Conduit						
1220 Insulators		55		60		140,166
1261 Ugrd Conduit		55		60		310,198,810
Total USoA 1735	55 S2	55	60 R2	60		310,338,976
1740 Underground Conductors and Devices						
1262 Ugrd Conductor		55		55		150,502,197
Underground Conductors and Devices		55		55		3,200,168
Total USoA 1740	55 S2	55	55 R2	55		153,702,365
1745 Roads and Trails						
1122 Perm Rds & Surfc Area		25		25		62,298,819
1174 Railway Track		30		30		8,007,705
1215 Clrng & Overbldng		70		70		162,494,424
1271 Roads & Trails		70		70		48,821,877
Roads and Trails		50		50		26,833,435
Total USoA 1745	50 S2	49	60 R4	21.26		308,456,260
GENERAL PLANT						
Depreciable						
1905D Land - Depreciable						
1828 Genrl -Comm -Site Improvement		100				
Total USoA 1905D	100 S6	100				

Hydro One 2019 Tx BU 210
Summary of Project Lives

Description	Current P-Life		Recommended P-Life		Plant	
	UsoA	Category	UsoA	Category	UsoA	Category
1908 Buildings and Fixtures						
1612 Genrl -Adm & Serv-Landscaping		50		50		23,920
1621 Genrl -Adm & Serv_Bld Frame & Mtl		50		50		33,080,432
1622 Genrl -Adm & Serv-Rds & Surfaces		25		25		4,049,783
1623 Genrl -Adm & Serv-Bld Frame		50		50		15,167,793
1628 Genrl -Adm & Serv-Fence		30		30		4,126,610
1650 Genrl - Adm & Serv-Distn Sys		50		50		14,510,214
1663 Genrl -Adm & Serv_Aux Eq Bld		50		50		13,235,290
1813 Genrl -Comm-Landscaping		50		50		62,867
1820 Genrl -Comm-Buildings		50		50		13,855,943
1853 Genrl -Comm-Str & Footings-Poles		50		50		33,313,180
Buildings and Fixtures		45		45		20,189,072
Total USoA 1908	45 S4	47	50 S4	31.53		151,615,103
1910 Leasehold Improvements						
1624 Genrl -Adm & Serv-Bldgs-Leased		10		10		100,228
Total USoA 1910	10 S6	10	10 S6	10		100,228
1922 Computer Hardware - Major						
1653 Genrl -Adm & Serv-Lan Elect Dev		10		10		12,746,679
1655 Genrl -Adm & Serv-Lan Cable		10		10		672,183
1656 Genrl -Adm & Serv-Lan Fib Opt		10		10		987,842
1657 Genrl - Adm & Serv-Sys Software		10		10		
Computer Hardware - Major		10		10		761,207
Total USoA 1922	10 S6	10	10 S6	10		15,167,911
1955 Communication Equipment						
1654 Genrl - Adm & Serv-Telcm Wire		7		7		2,594,458
1658 Genrl - Adm & Serv-Telcm Equip		7		7		2,246,461
1659 Genrl - Adm & Serv-Telcom Sw		7		7		717,041
1850 Genrl - Comm-Radio Equipment		10		10		56,562,632
1854 Genrl - Comm-Admin Telcom Equp		7		7		23,021,767
1863 Genrl - Comm Optical Wire		25		25		96,198,429
1864 Fenrl - Comm-Opt Wire Termtn		20		20		159,723,166
1865 Genrl - Comm-Opgw W Fib Cable		25		25		69,939,422
1870 Genrl - Comm-Power Supply Equp		15		15		20,776,985
Communication Equipment		20		20		67,572,178
Total USoA 1955	20 L2	17	20 R2.5	16.80		499,352,541
1980 System Supervisory Equipment						
1840 Genrl - Comm-Pwr Line Equip		15		15		172,434,836
1844 Genrl - Comm-Sys Cntrl Comp Eq		6		6		149,272,583
1846 Genrl - Comm-Dacs Appl S/Ware		6		6		2,678,368
1847 Genrl - Comm-Dacs Sys S/Ware		6		6		98,568,831
1860 Genrl - Comm-Pole		25		25		28,776,785
1864 Genrl - Comm-Opt Wire Termtn		20		20		16,209
System Supervisory Equipment		10		10		417,992
Total USoA 1980	10 L2	8	10 R4	4.93		452,165,605
Amortizable						
1925 Computer Software - Major						
1657 Genrl - Adm & Serv-Sys Software		6		6		8,931,156
Total USoA 1925	6 SQ	6	6 SQ	6		8,931,156

HYDRO ONE
BU 220 DISTRIBUTION PLANT
DEPRECIATION STUDY AS OF DECEMBER 31, 2019
SUMMARY OF P-LIFE ANALYSIS

	Current P-Life		Recommended P-Life		Plant
INTANGIBLE PLANT					
1609 Capital Contributions					
Computer software - Capital Contribution		10		10	3,452,431
2000		10		10	45,190,181
Total USoA 1609	10 SQ		10 SQ	10.00	48,642,612
1610 Computer Software					
Computer Software		10		10	39,939,973
1656		10		10	2,672,767
1657 Genrl - Adm & Serv-Sys Software		10		10	212,932,238
Total USoA 1610	10 SQ	10	10 SQ	10.00	255,544,978
DISTRIBUTION PLANT					
1806 Land Rights					
1806 Land Rights					
Land Rights					7,373,121
1111 Rights & Easmnts <Landscaping>		100		100	1,150,944
1212 Easmnts & Rights, Purch & Acqui		100		100	6,447,629
1215 Clrng & Overbldg		100		100	45,004,178
1311 Rural Intl Clring & Ovrbldg		100		100	177,843,246
1313 Rural Easements-Land Rights		100		100	2,589,204
1314 Rural Perm Rd & Surf Areas		25		25	14,095
Total USoA 1806	100 S6	100	100 R4	96.93	240,422,418
1808 Buildings & Fixtures					
1112 Landscaping		50		50	1,567,559
1120 Stn Buildings Components		50		50	22,527,848
1270 Serv Structures		50		50	2,250,042
1312 Rural Landscaping		50		50	698,243
Total USoA 1808	50 S4	50	50 R4	50.00	27,043,692
1815 Transformer Station Equipment > 50 kV					
Misc. Transformer Station Equipment > 50 kV		50		60	11,434,653
1113 Site Imprv - Excl Fence, Rd, Easmt		50		50	10,322,751
1122 Perm Rds & Surfc Area		25		60	3,414,614
1123 Cost Equip Foundations, Excav		50		65	12,241,338
1127 Steel/Pipe Struc for Switch Eq		50		65	13,835,009
1128 Fences, Gates, Bldg		30		30	7,709,810
1150 Rot Elec Eqp (No Wind'G)		65		20	129,369
1152 Capacitors		35		35	762,947
1155 Regulators Incl Instal Cost		40		40	2,057,108
1160 Misc Stn Eqp - Trsf/Volt Trsf		40		40	12,692,406
1161 Serv Swg - Ac/Dc-Light Trsf		50		55	2,397,858
1162 Control Cable & Conduit		50		60	3,577,327
1163 Grounding Systems		50		60	8,478,408
1164 Metering Units		15		15	7,866,112
1166 Switchboards		25		40	1,272,929
1167 Sup Cntrl - Prim H/Ware & Sys		20		20	1,253,618
1168 Sup Cntrl - Prim Appl S/Ware		20		20	646,032
1170 Service Systems		50		50	80,312
1175 Transf <=50Kv or <5Mva		50		50	6,586,096
1176 Transf <=115Kv or >5Mva		50		50	54,522,329
1177 Transf <=230Kv		50		50	7,473,860
1179 Transf Instal Cost		50		50	13,317,741
1181 Switching >=34.5Kv		40		40	8,663,807
1182 Switching >=115Kv		40		40	3,433,869
1184 Sf6 Switchgear		40		40	284,934
1185 Reclosures		40		40	22,982,798
1186 Misc Switching		40		45	3,336,473
1187 Bus (Rigid & Strain)		40		45	4,749,941
1188 Cable		40		45	4,488,552
1190 Cct Breakers >=230Kv		40		45	2,997
1191 Cct Breakers >=115Kv		40		45	706,868
1192 Cct Breakers <115Kv		40		45	540,039
1193 Cct Breakers Install		40		45	130,016
1194 Encld Swgr (All Compnt)		40		40	103,627
Total USoA 1815	40 R2.5	42	48 R2.5	48.21	231,496,548

HYDRO ONE
BU 220 DISTRIBUTION PLANT
DEPRECIATION STUDY AS OF DECEMBER 31, 2019
SUMMARY OF P-LIFE ANALYSIS

	Current P-Life		Recommended P-Life		Plant
1820 Distribution Station Equipment < 50 kV					
Misc Distribution Statnio Equipment < 50 kV		60		60	78,148,136
1113 Site Imprv - Excl Fence, Rd, Easmt		50		50	21,573,130
1122 Perm Rds & Surfc Area		60		60	8,513,238
1123 Cost Equip Foundations, Excav		60		65	41,089,729
1127 Steel/Pipe Struc for Switch Eq		50		65	37,312,713
1128 Fences, Gates, Bldg		50		30	34,379,700
1150 Rot Elec Eqp (No Wind'G)		65		20	1,150,165
1151 Rot Elec Eqp (Wind'Gs)		65		20	275,616
1152 Capacitors		35		35	426,170
1155 Regulators Incl Instal Cost		40		40	19,403,769
1159 Mobile Sub-Stations		30		30	27,415,878
1160 Misc Stn Eqp - Trsf/Volt Trsf		30		40	54,074,568
1161 Serv Swg - Ac/Dc-Light Trsf		50		55	4,802,480
1162 Control Cable & Conduit		50		60	7,095,245
1163 Grounding Systems		50		60	29,812,811
1164 Metering Units		12		15	96,245,560
1166 Switchboards		25		40	2,129,164
1167 Sup Cntrl - Prim H/Ware & Sys		15		20	8,697,192
1168 Sup Cntrl - Prim Appl S/Ware		15		20	590,086
1170 Service Systems		50		50	309,678
1173 Transf <=50Kv & >5Mva		50		50	102,309,358
1175 Transf <=50Kv or <5Mva		50		50	78,816,922
1179 Transf Instal Cost		50		50	37,550,132
1181 Switching >=34.5Kv		50		40	22,436,640
1184 Sf6 Switchgear		35		40	2,246,947
1185 Reclosures		40		40	50,779,371
1186 Misc Switching		50		45	8,070,419
1187 Bus (Rigid & Strain)		50		45	7,425,668
1188 Cable		50		45	12,678,060
1192 Cct Breakers <115Kv		40		45	521,791
1193 Cct Breakers Install		40		45	197,475
1194 Encld Swgr (All Compnt)		40		40	3,300,027
Total USoA 1820	30 R2.5	29	48 R2.5	44.77	799,777,839
1830 Poles, Towers and Fixtures					
Unidentfied		47		47	449,301,552
1230 Steel Twr, Sup & Ftng		75		75	1,195,861
1240 Poles Incl Xarm, Guy, Anchr		60		55	681,720,392
1245 Steel Poles		75		75	5,152,248
1249 Composite Poles		80		80	18,217,500
1340 Rural supports-Wood,Concret		55		55	2,486,502,196
1349 Steel Poles Support		75		75	5,740,747
Total UsoA 1830	55 S2	55	55 R2	54.21	3,647,830,496
1835 Overhead Conductors and Devices					
Unidentfied		45		45	4,946,546
1220 Insulators		45		45	76,890,368
1232 Grounding System		45		45	2,367,028
1235 Opt Grnd Wire		50		50	2,906
1250 Overhd Conductor All		60		65	369,773,551
1252 Switches & Devce		40		40	78,209,959
1320 Rural Switches/Load Interptr		40		40	311,945,015
1321 Rural Oil Sectnizer & Reclsr Sw		40		40	34,825,892
1322 Rural Instasectnlr & Rclsr Sw		45		45	26,614,903
1330 Rural Conductor Prim & Sec Overh		60		65	1,107,649,273
1376 Rural Voltage Regulators		40		40	26,729,892
1377 Rural Instl Vltge Regulators		40		40	13,455,780
1378 Rural Capacitors		40		40	10,234,930
1379 Rural install Capacitors		40		40	4,721,593
Total USoA 1835	55 S2	55	58 R2	58.13	2,068,367,636
1261 Ugrd Conduit		50		60	24,297,741
Total USoA 1840	50 S2	50	60 R1	60.00	24,297,741

HYDRO ONE
BU 220 DISTRIBUTION PLANT
DEPRECIATION STUDY AS OF DECEMBER 31, 2019
SUMMARY OF P-LIFE ANALYSIS

	Current P-Life		Recommended P-Life		Plant
1845 Underground Conductors and Devices					
Unidentfied		30		30	8,229,246
1231 Condctr Submarine Cbl		30		20	1,890,788
1262 Ugrd Conductor		30		30	21,885,607
1293 Ugrd Conductor Primary		30		30	1,797,750
1331 Rural Condctr Submarine Cbl		30		20	157,977,649
1393 Rural U/grd Conductor-Prime		30		30	207,203,542
1394 Rural U/Grd Condr Sec Serv		30		40	472,699,275
1395 Rural U/Grd Fuse Housing		30		30	54,545,991
Total USoA 1845	30 S3	30	33 R3	33.38	926,229,848
1850 Line Transformers					
Unidentfied		40		40	11,222,216
1255 Dx - Subtx Transformers		40		40	5,712,331
1256 Dx - Subtx Trnsfmrs Install		40		40	3,926,853
1295 U/GRD Fuse Housing		40		40	2,610,798
1341 Rural OH Trfmrs <=25 Kva		40		40	365,409,280
1342 Rural OH Trfmrs >25 & <=50 Kva		40		40	127,096,133
1343 Rural OH Trfmrs >50 & <=75 Kva		40		40	42,841,302
1344 Rural OH Trfmr >75 & <=100 Kva		40		40	35,865,777
1345 Pole Top Trfs >100 & <=200 Kva		40		40	19,418,760
1346 Pole Top Trfs >200 & <=300 Kva		40		40	9,456,497
1347 Dx - Ptop Trfmrs >300 & <=500 Kva		40		40	1,021,577
1348 Dx - Pole Top Trfmrs >500 Kva		40		40	931,265
1351 Rural Trsf Instal		40		40	870,698,262
1385 Rural U/Grd Trsf 0-50Kva		40		40	106,294,602
1386 Rural U/Grd Trsf 51-75 Kva		40		40	48,055,309
1387 Rural U/Grd Trsf 76-100 Kva		40		40	42,964,537
1388 Rural U/Grd Trsf 101-200Kva		40		40	19,374,797
1389 Rural U/Grd Trsf 201-300Kva		40		40	19,578,896
1390 Rural U/Grd Trsf 301-500Kva		40		40	35,557,176
1391 Rural U/Grd Trsf 501-750Kva		40		40	13,020,666
1392 Rural U/Grd Trsf >750Kva		40		40	10,627,242
1396 Rural U/Grd Trfmrs Instal		40		40	290,288,232
Total USoA 1850	40 R2	40	40 R2	40.00	2,081,972,509
1860 Meters					
All conventional meters are now 1 category		20		20	127,522,542
1356 Meters - Watthour, Single Ph		20		18	4,652,940
1358 Metering Polyphase		20		18	2,126,317
1360 PRIM M UNIT >=75 (MAT ONLY)		20		18	42,879
1361 Install - W/Hr & Dmd M S Ph		20		18	12,734,926
1362 Install - Meters Polyphase		20		18	1,985,716
1363 PRIM M UNIT<'75(MAT&INST)		20		18	8,881
1365 - Smart meters. See below		15		18	115,899,211
Total USoA 1860 excluding 1365	20 R5	20	18 R3	18.96	264,973,413
UsoA 1860 1365	15 R5	15			
*All assets being depreciated at 1860 1365 Rate					
1555 Smart Meters (No additions since 2016)					
1365 Smart Mtr - Incl Cost & Inst		15		15	330,328,119
Total USoA 1555	15 R5	15	18 R3	15.00	330,328,119
GENERAL PLANT					
Depreciable					
1908 Buildings and Fixtures					
Unidentfied		50		50	10,326,439
1612 Genrl - Adm & Serv-Landscaping		50		50	88,004
1621 Genrl - Adm & Serv Bld Frame & Mtl		50		50	51,623,437
1622 Genrl - Adm & Serv-Rds & Surfaces		50		50	16,190,102
1623 Genrl - Adm & Serv-Bld Frame		50		50	51,163,817
1628 Genrl - Adm - & Serv-Fence, Gate		30		30	1,924,207
1650 Genrl - Adm & Serv-Distn Sys		50		50	1,890,885
1663 Genrl - Adm & Serv Aux Eq Bld		50		50	14,331,390
1853 Communication building		50		50	134,622
Total USoA 1908	50 S4	49	50 S4	49.74	147,672,903

HYDRO ONE
BU 220 DISTRIBUTION PLANT
DEPRECIATION STUDY AS OF DECEMBER 31, 2019
SUMMARY OF P-LIFE ANALYSIS

	Current P-Life		Recommended P-Life		Plant
1910 Leasehold Improvements					
Unidentfied		10		10	183,579
1624 Genrl - Adm & Serv-Bldgs-Leased		10		10	7,965,651
Total USoA 1910	10 S6	10	10 S6	10.00	8,149,230
1922 Computer Hardware - Major					
1653 Genrl - Adm & Serv-Lan Elect Dev		10		10	2,035,010
1655 Genrl - Adm & Serv-Lan Cable		10		10	2,290,724
1656 Genrl - Adm & Serv-Lan Fib Opt		10		10	161,333
1657 Genrl - Adm & Serv-Sys Software		10		10	246,063
Total USoA 1922	10 S6	10	10 S6	10.00	4,733,131
1955 Communication Equipment					
Communication equipment		10		10	1,288,297
1654 Genrl - Adm & Serv-Telcm Wire		7		7	7,108,308
1656 Genrl - Adm & Serv-Lan Fib Opt		10		10	117,949
1658 Genrl - Adm & Serv-Telcm Equip		7		7	11,610,451
1659 Genrl - Adm & Serv-Telcom Sw		7		7	186,059
1850 Genrl - Comm Radio Equipment		10		10	7,670,314
1854 Genrl - Admin Telcom Equip		7		7	668,746
1863 Genrl - Comm Optical Wire		25		25	222,029
1864 Genrl - Comm Optical Wire Terrntn		7		7	211,852
1870 Genrl - Comm Power Supply Equp		15		15	2,972
Total USoA 1955	7 S6	7	7 S6	8.07	29,086,977
1980 System Supervisory Equipment					
1840 Genrl - Comm Pwr Line Equip		15		15	138,912
1844 Genrl - Comm Sys Cntrl Comp Eq		6		6	6,387,414
1847 Genrl - Comm Dacs Sys S/Ware		6		6	126,720,243
1860 Genrl - Comm Pole Comm Cab Bths		25		25	66,364
Total USoA 1980	6 L2	6	6 L2	6.02	133,312,933
1985 Sentinel Lightning Rental Units					
Genrl - Dist Sentnal Lite Units		30		30	1,000
1374 Genrl - Dist Sentnal Lite Units		30		30	15,299,030
Total USoA 1985	30 R1.5	30	27 R3	30.00	15,300,030
Amortizable					
1925 Computer Software - Major					
1657 Genrl - Adm & Serv-Sys Software		6		6	41,261,340
Total USoA 1925	6 SQ	6	6 SQ	6.00	41,261,340

HYDRO ONE
BU 300 COMMON PLANT
DEPRECIATION STUDY AS OF DECEMBER 31, 2019
SUMMARY OF P-LIFE ANALYSIS

Description	Current P-Life		Recommended P-Life		Plant	
	UsoA	Category	UsoA	Category	UsoA	Category
INTANGIBLE PLANT						
1610 Computer Software						
1656 Genrl- Adm & Serv- Lan Fib Opt		10			10	30,330,585
1657 Genrl - Adm & Serv-Sys Software		10			12	486,755,349
Computer Software		10			12	119,206,953
Total USoA 1610	10 SQ	10		12 SQ	11.90	636,292,886
GENERAL PLANT						
Depreciable						
1610 Buildings and Fixtures						
1621 Genrl - Adm & Serv-Bld Frame&Mtl		50			50	43,375,143
1622 Genrl - Adm & Serv-Rds&Surfaces		25			25	6,375,550
1623 Genrl - Adm & Serv-Bld Frame		50			50	43,732,509
1628 Genrl - Adm & Serv-Fence,Gate		30			30	1,445,483
1650 Genrl - Adm & Serv-Distn Sys		50			50	987,634
1663 Genrl - Adm & Serv-Aux Eq Bld		50			50	14,292,836
1812 Genrl- Comm-Road and Surface Areas		50			50	2,408
Buildings and Fixtures		50			10	20,556,584
Total USoA 1908	50 S4	47		50 S4	42.27	130,768,147
1910 Leasehold Improvements						
1624 Genrl - Adm & Serv-Bldgs-Leased		10			10	45,291,202
Leasehold Improvemetns		10			10	375,120
Total USoA 1910	10 S6	10		10 S6	10.00	45,666,322
1922 Computer Equipment - Hardware						
Unidentifed		10			10	3,558,618
1653 Genrl - Adm & Serv-Lan Elect Dev		10			10	11,836,023
1655 Genrl - Adm & Serv-Lan Cable		10			10	505,356
Total USoA 1922	10 S6	10		10 S6	10.00	15,899,996
1955 Communication Equipment						
1654 Genrl - Adm & Serv-Telcm Wire		7			7	2,396,026
1658 Genrl - Adm & Serv-Telcm Equip		7			7	15,285,793
1850 Genrl - Comm-Radio Equipment		10			10	11,318
1854 Genrl - Comm-Admin Telcom Equp		7			7	4,433,155
1870		?			7	313,718
Total USoA 1955	7 S6	7		7 S6	7.00	22,440,009
1980 System Supervisory Equipment						
1840 Genrl - Comm-Pwr Line Equip		15			15	389,017
1844 - Genrl - Comm-Sys Cntrl Comp Eq		6			6	3,705,164
1847 Genrl- Comm-DASC Sys S/Ware		6			6	3,240,918
System Supervisory Equipment		7			7	12,346,456
Total USoA 1980	7 S6	6		7 S6	6.81	19,681,555
Amortizable						
1915 Office Furniture and Equipment						
S007 Mfa - 7 Yr Sl		7			7	10,563,024
Total USoA 1915	7 SQ	7		7 SQ	7.00	10,563,024
1920 Computer Hardware - Minor						
S005 Computers - 40% Db (Default)		5			5	67,662,865
Total USoA 1920	5 SQ	5		5 SQ	5.00	67,662,865
1925 Computer Software - Major						
1657 Genrl - Adm & Serv-Sys Software		6			6	129,894,394
Computer Hardware - Major		6			6	327,722
Total USoA 1925	6 SQ	6		6 SQ	6.00	130,222,116

HYDRO ONE
BU 300 COMMON PLANT
DEPRECIATION STUDY AS OF DECEMBER 31, 2019
SUMMARY OF P-LIFE ANALYSIS

Description	Current P-Life		Recommended P-Life		Plant	
	UsoA	Category	UsoA	Category	UsoA	Category
1935 Stores Equipment						
S008 Mfa - 8Yr Sl(Def)		8			8	415,591
Total USoA 1935	8 SQ	8		8 SQ	8.00	415,591
1940 Tools, Shop and Garage Equipment						
S006 Mfa - 6Yr Sl(Def)		8			8	16,760,402
Total USoA 1940	8 SQ	8		8 SQ	8.00	16,760,402
1945 Measurement and Testing Equipment						
S005 Mfa - 5Yr Sl(Def)		5			5	12,092,835
Total USoA 1945	5 SQ	5		5 SQ	5.00	12,092,835
1960 Miscellaneous Equipment						
S005 Mfa - 5Yr Sl(Def)		5			5	3,417,518
Total USoA 1960	5 SQ	5		5 SQ	5.00	3,417,518
Total BU 300						1,111,883,265

APPENDIX F

Alliance Consulting Group –

Background and Qualifications

COMPANY PROFILE

Alliance Consulting Group is an international consulting firm formed in 2004 by Dane Watson. In addition to the partner, Alliance also has three full-time Senior Consultants, Dr. Karen Ponder, Ms. Rhonda Watts and Ms. Rebecca Richards as well as other support staff. Alliance is dedicated to providing quality consulting and expert services to the utility industry. Our professionals have more than 120 years of combined experience around the utility industry, and we have been employed in the industry as utility employees and consultants.

The Alliance Consulting Group has performed over 275 depreciation studies for electric, gas, steam, water, wastewater, cable and communications utilities across the country and Canada since its founding by Mr. Watson in 2004. These utilities encompass regulated, non-regulated, municipal and federal agencies. The studies were provided in a timely manner with thorough analysis.

PERSONNEL

PEOPLE

DANE WATSON, PROJECT MANAGER

The project manager will be Dane Watson of Alliance. He was previously employed as a Property Accounting Services Manager for TXU and has twenty years of experience at a Fortune 100 utility in property accounting, depreciation and valuation. He has managed fixed asset accounting for regulated entities and non-regulated entities. He has an industry-wide reputation with significant experience as an expert witness in depreciation, valuation and rate base areas and has provided testimony and support in many state regulatory commission dockets. Mr. Watson has conducted depreciation studies for a variety of assets for both regulated and non-regulated companies. He has held a number of national industry roles related to depreciation and property accounting including twice chairing the Plant Accounting and Valuation Committee of the Edison Electric Institute. He has attended all the classes offered by the Depreciation Programs, Inc. (DPI) and continues to re-fresh his training by teaching various depreciation related seminars across the country. He developed the training materials for the Intermediate and Advanced Training sessions of the Society for Depreciation Professionals and teaches a number of courses. He twice served as general editor of the industry publication "Introduction to Depreciation and Net Salvage of Public Utility Plant and Plant of Other Industries", is contributing editor of other industry publications and is a frequent speaker at conferences on depreciation related issues. Mr. Watson led the industry adoption of SFAS 143 and was industry panelist before FERC (FERC Docket 02-0700) testifying on their implementation of SFAS 143. He also served as project lead (functional) in the development of both automated regulated group depreciation and fixed asset systems and item based fixed asset and depreciation systems while at TXU. Mr. Watson is a Licensed Professional Engineer in the State of Texas (PE) and a Certified Depreciation Professional (CDP).

KAREN PONDER, SENIOR CONSULTANT

Dr. Karen Ponder is a Senior Consultant at Alliance with over forty years of experience in utility financial matters. Dr. Ponder has a doctorate degree in engineering valuation from Iowa State University where her dissertation was entitled, "Some Aspects of Statistically Modeling the Simulated Plant Record Method." She is considered a subject matter expert in depreciation and capital recovery in the utility industry and has performed studies for regulated and non-regulated entities involving property of various types. Dr. Ponder has conducted statistical analysis of life and net salvage components and incorporated knowledge of equipment failure, new technological trends, and company practices to develop life and net salvage estimates. She has provided support during rate case litigation including study write-up, testimony, and responses to interrogatories. She was an instructor for many years at Depreciation Programs, Inc. in Kalamazoo, Michigan and serves as a faculty member for the Society of Depreciation Professional's Annual Training courses. Dr, Ponder is a Certified Depreciation Professional. (CDP).

RHONDA WATTS, SENIOR CONSULTANT

Rhonda Watts is a Senior Consultant at Alliance who participates in the various activities related to the completion of the depreciation study and provides Expert Witness testimony if needed. Rhonda has over thirty years of experience in utility accounting, depreciation and regulatory matters. She is considered a subject matter expert in depreciation and capital recovery in the utility industry and has performed studies for regulated entities involving property of electric, gas, water and wastewater and communication utilities. She has conducted statistical analysis of life and net salvage components and incorporated knowledge of equipment failure, new technological trends, and company practices to develop life and net salvage estimates. She has provided support during rate case litigation including study write-up, testimony, and responses to interrogatories. Rhonda has also testified before three state regulatory bodies.

REBECCA RICHARDS, SENIOR CONSULTANT

Rebecca Richards is a Senior Consultant at Alliance and a Certified Depreciation Professional (CDP). She was previously employed as a Team Lead of Property Accounting at We Energies and has nine years of experience at a Fortune 500 company in utility property accounting, depreciation and areas of corporate finance. She has a vast working knowledge of fixed asset and finance systems including SAP, UI, and PowerPlan. Rebecca has managed fixed asset accounting for both regulated and non-regulated entities. She has coordinated depreciation studies for all types of utilities including electric, gas, water, and steam heating.

Dane A. Watson, PE, MBA, CDP

Managing Partner, Alliance Consulting Group

Profile

- 36 years of experience in utility depreciation, valuation and property accounting.
- Industry wide reputation with significant experience as Expert Witness, in depreciation, valuation, and rate base areas.
- Proven experience in effectively managing property systems and reengineering processes/ systems to achieve significant cost savings.
- Goal-Oriented, "outside the box" thinker with demonstrated strong leadership and communication capabilities.

Relevant Experience and Accomplishments

- Depreciation and Asset Accounting
  - Conducted over 275 depreciation studies for electric (generation, transmission, and distribution), gas (transmission, distribution, LNG and storage), water/wastewater, telecom and mining companies (regulated and non-regulated) and supported over 35 state regulatory bodies and FERC.
  - Ongoing teaching of depreciation (basic and advanced) in many industry venues (EEI/AGA, SDP, Michigan State, State Commissions).
  - Lead or served in numerous national industry roles related to depreciation and property accounting including twice chairing the Plant Accounting and Valuation Committee of the Edison Electric Institute and twice chairing the Society of Depreciation Professionals.
  - Served as gas and electric industry Project Manager for the implementation of SFAS 143.
  - Served as general editor for "Introduction to Depreciation and Net Salvage".
  - Managed fixed asset accounting, depreciation accounting and analysis, lease accounting, inventory accounting, transportation accounting and records management for one of the largest electric and gas utilities in the US.
- System/Process Reengineering
  - Reengineered fixed asset process and managed redesign of a Fixed Asset system to create a $1.5-$2.0 million savings per year.
  - Designed and implemented a new leased asset tracking and payment system that enabled reduction of errors in lease payments by $3-$4 million per year.
  - Designed and implemented an internal shared asset tracking and allocation system to meet stringent affiliate transaction rules.
  - Championed, designed and implemented imaging system to replace paper and microfilm document storage system saving over $1 million per year.

Employment History:

- 2004-present
  - Partner Alliance Consulting Group, Plano, TX
- 1996-2004

- o Manager of Property Accounting Services TXU Business Services, Dallas, TX
  Testified in 15 rate or restructuring proceedings before various Commissions including the Texas Railroad Commission, the Texas Public Utilities Commission and the FERC. Lead Sarbanes-Oxley implementation for property processes. During tenure, increased scope to managing all fixed asset and construction accounting, inventory accounting, transportation accounting, and fixed asset accounting systems. Lead efforts to convert 14 companies to a new fixed asset system. Restructured valuation system to provide a 90% faster response time. Implemented new construction/fixed asset systems that facilitated a 12 FTE reduction in staff. Built state-of-the-art lease accounting system to handle reporting and payment of all TXU leases. Built highly automated imaging system to replace microfilm and paper document storage and retrieval system reducing costs and shortening response time.

- 1992-1996
  - o Technical Support Manager Texas Utilities Generating Company, Dallas, TX
    Managed group responsible for depreciation and valuation analysis for TXU as well as special projects. Responsible for teaching and running engineering economics analysis for large capital projects. Managed nuclear plant decommissioning studies and electrical line loss allocation studies, as well as depreciation studies.

- 1985-1992
  - o Associate Engineer to Senior Engineer Texas Utilities Generating Company, Dallas, TX
    Given increasing responsibility related to depreciation and valuation program creation, valuation analysis, depreciation analysis, training TXU employees in engineering economics, report preparation, writing and supporting depreciation testimony before the Texas Public Utilities Commission.

Education:

- M.B.A., General Business, Amberton University, Garland, TX
- B.S., Electrical Engineering, University of Arkansas

Honors and Awards

- Professional Engineer (TX)
- Certified Depreciation Professional (“CDP”)
- Senior Member of the Institute of Electronics and Electrical Engineers (“IEEE”)
- IEEE 3rd Millennium Medal
- IEEE Region 5 Treasurer, Audit Committee Chair, IEEE-USA Secretary Treasurer, IEEE MGA Treasurer, IEEE Finance Committee Member
- American Association of Engineering Societies (AESS) Treasurer
- Twice Chair of the Edison Electric Institute (“EEI”) Property Accounting and Valuation Committee
- Former Board member and twice President of the Society of Depreciation Professionals

Karen Hallaman Ponder, Ph.D., CDP

Senior Consultant, Alliance Consulting Group

Profile

- Recognized expert in the field, particularly with regard to historical analyses of life and net salvage.
- More than 40 years of experience in utility property accounting, depreciation, and valuation.
- Involved in dozens of depreciation studies through all facets of the process including regulatory support through information discovery and rate proceedings.
- Prepared depreciation studies for all types of utilities including electric, gas water and wastewater.
- Taught courses on depreciation models and theory, actuarial analysis, and simulated plant record analysis more than 35 years in nationally recognized training venues.
- Certified Depreciation Professional as recognized by the Society of Depreciation Professionals

Professional Experience:

- 2004-present
    - Senior Consultant - Alliance Consulting Group, Plano, TX

      Involved in all aspects of conducting depreciation studies from data gathering to analysis and supporting recommendations through testimony. Participated in more than 250 depreciation studies. Subject matter expert on depreciation theory. Performed depreciation studies for various entities ranging from electric, gas, mining, water and wastewater.
- 1993-2004
    - Capital Recovery Specialist - Texas Utilities, Dallas, TX.

      Responsible for studies and analysis of asset data in a variety of assignments ranging from the engineering department to property accounting.
- 1985-1997
    - Faculty Member - Depreciation Programs of Kalamazoo, Michigan

      Taught classes on Depreciation Models, Simulated Plant Record Method Analysis, and Actuarial Analysis. Participants included company representatives, staff of various state commissions and consultants from the United States and Canada.
- 1978-1984
    - Senior Engineer - Texas Utilities, Dallas, TX.

      Held positions of increasing responsibility in various utility departments including general office engineering, economic research and budgets. Responsibilities included preparing depreciation studies and rate case support.

Education

- Ph.D., Industrial Engineering with specialty in Engineering Valuation, Iowa State University
- M.S., Statistics, Iowa State University
- B.S., Mathematical Statistics *summa cum laude*, McNeese State University, Lake Charles, LA

Memberships

- Society of Depreciation Professionals
- Society of Depreciation Professionals, Training Faculty, 2007 to present
- Society of Depreciation Professionals, Secretary, 2014 to 2015
- Society of Depreciation Professionals, Training Deputy Chair, 2018 to present

RHONDA WATTS

SENIOR CONSULTANT, ALLIANCE CONSULTING GROUP

Profile

- 31 years of experience in utility accounting, property accounting, depreciation, and regulatory processes. Participated in over 200 depreciation studies.
- Industry reputation with experience as Expert Witness in depreciation.
- Performed numerous depreciation studies through all facets of the process including regulatory support and testimony. Experienced focus on historical analyses of life and net salvage.
- Prepares depreciation studies for all types of utilities including electric, gas, telecommunication, water and wastewater.

Professional Experience

- 2009-present
    - Senior Consultant - Alliance Consulting Group, Plano, TX

      Senior Consultant involved in all aspects of depreciation studies. Performs depreciation studies for electric, gas, communication, water and wastewater utility clients. Provides study support during rate case litigation including drafting study narratives and testimony and responding to interrogatories. Provided testimony before state regulatory bodies.
- 1996-2009
    - Senior Manager - Deloitte & Touche LLP

      Senior Manager in the Energy and Resources Group with concentration in the areas of depreciation and fixed asset accounting systems. Areas of expertise include the principles and procedures of capital recovery, utility organization, accounting and information systems and regulatory practices.
- 1990-1996
    - Accountant - Nevada Power Company

      Accountant and Analyst positions of increasing responsibility. Areas of responsibility include plant and receivables accounting, depreciation study updating, rate case schedule preparation and support, regulatory compliance reporting, financial report preparation, and budget variance analysis.
- 1986-1990
    - Primary Accountant - UNLV Foundation

      Primary Accountant responsible for the proper processing and accounting of donations to the UNLV Foundation in support of academic excellence. Also compiled financial reports for the Board of Directors and Trustees.

Major Projects

- Conducted numerous depreciation studies and assisted in regulatory support through testimony, information discovery and rate proceedings for various electric, gas, water and wastewater utility companies.
- Assisted various audit teams in the review of client's implementation of FASB 143 and Interpretation No. 47 (Asset Retirement Obligations). The review encompasses the Company's processes, assessments, calculations and supporting documentation.
- Managed teams in the conduct of Sarbanes Oxley Section 404 readiness testing for international advertising, marketing and communication services companies in 2004 and 2005.

Education

- Bachelor of Science in Business Administration, Accounting and Finance emphasis, University of Nevada, Las Vegas

Certifications and Memberships

- Member of EEI/AGA Property Accounting and Valuation Committee and Society of Depreciation Professionals
- Past President and other leadership positions for the Society of Depreciation Professionals

Other Professional Activities

- Review and content contributor for Hahne-Aliff "Accounting for Public Utilities", Chapter 6 Public Utility Depreciation during tenure at Deloitte
- Former Board member as well as Treasurer, Secretary, Vice President and President of the Society of Depreciation Professionals
- Presenter at AGA/EEI Accounting Committee Meetings
- Taught client requested Depreciation Basics

Rebecca Richards, CDP

Senior Consultant, Alliance Consulting Group

Profile

- 15 years of experience in utility property accounting, depreciation, and corporate finance.
- Coordinated several depreciation studies for all types of utilities including electric, gas, water, and steam heating
- Certified Depreciation Professional as recognized by the Society of Depreciation Professionals

Professional Experience

- 2015-present
    - Senior Consultant - Alliance Consulting Group, Plano, TX

      Senior Consultant involved in all aspects of depreciation studies. Perform depreciation studies for electric, gas, communication, water and wastewater utility clients. Provide support during rate case litigation including drafting study narratives and responding to interrogatories.
- 2006-2015
    - Team Lead Property Accounting - We Energies, Milwaukee, WI

      Managed all fixed asset internal and external reporting and property accounting functions in compliance with state and federal regulatory requirements. Established and maintained the Company's capitalization and depreciation policies. Initiated and oversaw all process improvement initiatives related to fixed asset finance systems and processes. Coordinated depreciation studies and supported rate case and regulatory proceedings. Vast working knowledge of fixed asset and finance systems including SAP, UI, and PowerPlant.
- 1995-2006
    - Operations Manager - Courtyard by Marriott, Brookfield, WI

      Hired, trained, and developed all front desk associates and maintained Marriott's high quality customer service standards.

Education

- Bachelor of Science in Accounting, Marquette University, Milwaukee, WI
- Associates Degree in Accounting, Milwaukee Area Technical College, Milwaukee, WI

Memberships

- EEI/AGA Property Accounting and Valuation Committee
- Society of Depreciation Professionals

TESTIMONY APPEARANCES

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study
Texas	Texas Public Utility Commission	51802	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study
Yukon Territory Canada	Yukon Energy Board	2021 General Rate Application	Yukon Energy	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51611	Sharyland Utilities	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study
Texas	Texas Public Utility Commission	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study
Tennessee	Tennessee Public Utility Commission	20-00086	Piedmont Natural Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study

Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable**	**Company**	**Year**	**Description**
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study

Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates

Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study

Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study

Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study

Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study

Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General

Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study

Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study

Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study

Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service Company of Colorado	2009	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study

Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Asset Location	**Commission**	**Docket (If Applicable)**	**Company**	**Year**	**Description**
Texas, New Mexico	Public Utility Commission of Texas	32766	Southwestern Public Service Company	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint

Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciation Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

HYDRO ONE NETWORKS INC.
TRANSMISSION
Depreciation & Amortization Expenses
Historical Years (2018, 2019, 2020 and 2021-Forecast)
Year Ending December 31
($M)

		2018		2019		2020		2021	
Line No.	**Particulars**	**Deprn Rate**	**Provision ($M)**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision**	**Deprn Rate**	**Provision ($M)**
		(a)	(b)	(e)	(f)	(g)	(h)	(a)	(b)
	Depreciation Expenses								
1	Major Fixed Assets	2.06%	362.3	2.07%	382.0	2.01%	386.7	2.02%	409.3
2	Minor Fixed Assets	11.32%	25.0	7.43%	24.6	7.90%	24.2	7.84%	30.9
3	Depreciation on Fixed Assets		387.3		406.6		410.9		440.2
4	Less Capitalized Depreciation		(13.0)		(13.1)		(14.4)		(14.5)
5	Asset Removal Costs		37.7		45.9		39.6		63.1
6	Losses/(Gains) on Asset Disposition		(0.5)		(0.5)		(2.4)		0.0
7	Total Depreciation Expenses		411.5		438.9		433.7		488.8
	Amortization Expenses								
8	Environmental Costs		6.7		5.5		7.7		15.5
9	Other Regulatory Amortization		0.0		0.0		0.0		-
10	Other Amortization		0.0		0.0		0.0		-
11	Total Amortization Expenses		6.7		5.5		7.7		15.5
12	Total Depreciation & Amortization Expenses		418.2		444.4		441.4		504.3
13	Exclude Other Reg Amort		0.0		-		-		-
14	Depreciation & Amortization for recovery		418.2		444.4		441.4		504.3

HYDRO ONE NETWORKS INC.
TRANSMISSION
Depreciation & Amortization Expenses
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

Line No.	Particulars	2022 Deprn Rate	2022 Provision ($M)	2023 Deprn Rate	2023 Provision ($M)	2024 Deprn Rate	2024 Provision ($M)	2025 Deprn Rate	2025 Provision ($M)	2026 Deprn Rate	2026 Provision ($M)	2027 Deprn Rate	2027 Provision ($M)
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(i)	(j)	(i)	(j)
	Depreciation Expenses												
1	Major Fixed Assets	2.02%	432.0	2.01%	452.9	2.02%	479.2	2.02%	508.4	2.01%	536.3	2.00%	560.1
2	Minor Fixed Assets	7.33%	29.2	7.09%	28.9	7.12%	30.1	6.86%	29.9	6.69%	30.3	6.72%	32.1
3	Depreciation on Fixed Assets		461.2		481.8		509.3		538.3		566.6		592.2
4	Less Capitalized Depreciation		(14.5)		(14.8)		(14.9)		(15.1)		(15.2)		(15.3)
5	Asset Removal Costs		56.4		61.2		63.3		70.7		73.8		70.5
6	Total Depreciation Expenses		503.1		528.2		557.6		593.8		625.1		647.3
	Amortization Expenses												
7	Environmental Costs		16.3		7.6		7.5		6.6		0.0		0.0
8	Other Regulatory Amortization												
9	Other Amortization												
10	Total Amortization Expenses		16.3		7.6		7.5		6.6		0.0		0.0
11	Total Depreciation & Amortization Expenses		519.4		535.8		565.1		600.4		625.1		647.3
12	Exclude Other Reg Amort												
13	Depreciation & Amortization for recovery		519.4		535.8		565.1		600.4		625.1		647.3

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Depreciation & Amortization Expenses
Historical Years (2018, 2019, 2020 and 2021-Forecast)
Year Ending December 31
($M)

Line No.	Particulars	2018 Deprn Rate	2018 Provision ($M)	2019 Deprn Rate	2019 Provision	2020 Deprn Rate	2020 Provision	2021 Deprn Rate	2021 Provision ($M)
		(a)	(b)	(e)	(f)	(g)	(h)	(a)	(b)
	Depreciation Expenses								
1	Major Fixed Assets	2.80%	303.5	2.76%	312.1	2.68%	316.6	2.59%	335.6
2	Minor Fixed Assets	7.17%	41.4	7.43%	39.6	7.90%	38.8	7.29%	34.5
3	Depreciation on Fixed Assets		344.9		351.7		355.4		370.1
4	Less Capitalized Depreciation		(18.0)		(18.3)		(17.7)		(17.9)
5	Asset Removal Costs		50.6		53.8		59.3		54.8
6	Losses/(Gains) on Asset Disposition		(1.3)		(1.2)		(0.5)		
7	Total Depreciation Expenses		376.2		386.0		396.5		407.0
	Amortization Expenses								
8	Environmental Costs		14.4		15.5		14.3		13.4
9	Other Regulatory Amortization		0.0		0.0		0.0		0.0
10	Other Amortization		0.0		0.0		0.0		
11	Total Amortization Expenses		14.4		15.5		14.3		13.4
12	Total Depreciation & Amortization Expenses		390.6		401.5		410.8		420.4
13	Exclude Other Reg Amort		3.9		4.3		4.4		4.1
14	Depreciation & Amortization for recovery		386.7		397.2		406.4		416.3

2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock). 2023-2027 figures are presented on a combined basis including Acquired Utilities.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Depreciation & Amortization Expenses
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

Line No.	Particulars	2022 Deprn Rate	2022 Provision ($M)	2023 Deprn Rate	2023 Provision ($M)	2024 Deprn Rate	2024 Provision ($M)	2025 Deprn Rate	2025 Provision ($M)	2026 Deprn Rate	2026 Provision ($M)	2027 Deprn Rate	2027 Provision ($M)
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(i)	(j)	(i)	(j)
	Depreciation Expenses												
1	Major Fixed Assets	2.59%	350.6	2.55%	365.9	2.53%	382.8	2.58%	414.7	2.64%	447.1	2.67%	475.2
2	Minor Fixed Assets	7.09%	34.3	7.25%	36.9	7.72%	42.2	7.85%	45.9	7.90%	49.6	7.89%	53.4
3	Depreciation on Fixed Assets		384.9		402.9		425.0		460.6		496.6		528.7
4	Less Capitalized Depreciation		(17.9)		(18.2)		(18.3)		(18.5)		(18.7)		(18.9)
5	Asset Removal Costs		56.4		79.2		78.5		83.9		83.4		86.6
6	Total Depreciation Expenses		423.4		463.9		485.2		526.0		561.3		596.4
	Amortization Expenses												
7	Environmental Costs		12.9		5.5		5.4		1.0		0.0		0.0
8	Other Regulatory Amortization												
9	Other Amortization												
10	Total Amortization Expenses		12.9		5.5		5.4		1.0		0.0		0.0
11	Total Depreciation & Amortization Expenses		436.3		469.4		490.6		527.0		561.3		596.4
12	Exclude Other Reg Amort		4.3		3.8		3.9		4.0		4.0		4.1
13	Depreciation & Amortization for recovery		432.0		465.6		486.7		523.0		557.3		592.3

2018-2022 figures refer only to Hydro One Distribution excluding Acquired Utilities (Norfolk, Haldimand and Woodstock). 2023-2027 figures are presented on a combined basis including Acquired Utilities.

CORPORATE INCOME TAXES

1.0 INTRODUCTION

This Exhibit explains how Hydro One calculates its income tax expenses for the purposes of rate recovery (Regulatory Taxes) and is organized as follows:

- Section 2.0 briefly describes Hydro One's 2015 departure from the payments-in-lieu of income taxes (PILs) regime and the related tax impact;
- Section 3.0 provides a general overview of Regulatory Taxes as a component of revenue requirement;
- Section 4.0 details the applicable income tax rates used in determining Regulatory Taxes;
- Section 5.0 explains the different bases for computation of accounting and taxable income;
- Section 6.0 addresses the general adjustments made in computing taxable income and categorizes the types of adjustments commonly observed;
- Section 7.0 discusses the tax treatment of regulatory assets and regulatory liabilities;
- Section 8.0 reconciles regulatory net income and taxable income; and
- Section 9.0 summarizes steps taken by Hydro One to ensure data integrity.

Hydro One also provides detailed calculations of its income tax expenses for the historical, bridge and test years, along with supporting schedules and reconciliations, tax credit calculations, and other supporting schedules in Exhibit E-09-02, as well as a copy of its most recent tax return in Exhibit E-09-03.

The information provided in these schedules is responsive to Section 2.4.5.1 of the Distribution Filing Requirements and Section 2.8.11 of the Transmission Filing Requirements.

2.0 DEPARTURE FROM PILS REGIME

Prior to its initial public offering (IPO), Hydro One was a wholly-owned provincial Crown corporation that was exempt from paying corporate income taxes under Section 149(1) of the *Income Tax Act (Canada)* (ITA) and the *Corporations Taxation Act, 2007* (Ontario) (OCTA). Under the *Electricity Act, 1998* (Ontario), an entity that would otherwise be required to pay corporate income taxes but for its tax-exempt status is obligated to pay PILs to the Ontario Electricity Financial Corporation. The amount of PILs required to be paid by an entity under that regime is equal to the amount of tax that the entity would be liable to pay under the ITA if it were a corporation to which the tax exemption did not apply. While under the PILs regime, Hydro One was subject to audit by the Ontario Ministry of Finance (MoF).

Effective October 31, 2015, upon the IPO of its shares, Hydro One ceased to be tax exempt under the ITA and was therefore required to exit the PILs regime. Under the ITA, as a result of the IPO, Hydro One was deemed to have disposed of its assets at fair market value at that time and to have immediately re-acquired them at the same value. Hydro One was also obligated to pay a one-time PILs departure tax on the deemed disposition of its assets upon exiting the PILS regime and concurrently recognized a deferred tax benefit associated with the deemed reacquisition of its assets upon entering the federal income tax regime. Since entering the federal income tax regime, Hydro One is no longer subject to PILs audit by the MoF but, instead, is subject to audit by the Canada Revenue Agency (CRA).[1]

In the Transmission Decision and Order in proceeding EB-2016-0160 (the Original Decision), the Board concluded that the net deferred tax benefit resulting from Hydro One's departure from the PILs regime (the Future Tax Savings) should not accrue entirely to Hydro One's shareholder and that a portion of the deferred tax benefit should instead be given to ratepayers. Hydro One

[1] Under the federal income tax regime, Hydro One is subject to tax under both the ITA and the OCTA but the CRA administers the Ontario corporation income tax and Ontario corporate minimum tax on behalf of the Province of Ontario.

filed a Motion to Review and Vary the Original Decision on October 18, 2017. The OEB issued a Decision and Order on the Motion to Review and Vary (EB-2018-0269), dated March 7, 2019 (the Rehearing Decision), dismissing the motion and upholding the Original Decision.[2] On April 5, 2019, Hydro One filed an appeal with Ontario's Divisional Court with respect to the Rehearing Decision and the matter (File No. 200/19) was heard on November 21, 2019.[3] The Ontario Divisional Court, which issued its decision on July 16, 2020 (the ODC Decision), determined that no portion of the Future Tax Savings should be allocated to ratepayers and ordered that the matter be remitted back to the Ontario Energy Board.

Subsequently, the OEB issued a decision (the DTA Recovery Decision) on April 8, 2021, which approved Hydro One's recovery of the Future Tax Savings previously allocated to ratepayers over a two year period from July 1, 2021 to June 30, 2023. In the DTA Recovery Decision, the OEB acknowledges the finding in the ODC Decision that no portion of the Future Tax Savings should be allocated to ratepayers and confirmed that the 2022 rates for Transmission and Distribution be adjusted to remove any Future Tax Savings allocated to ratepayers. In accordance with the ODC Decision and the DTA Recovery Decision, the Regulatory Taxes included in Hydro One's proposed Transmission and Distribution revenue requirements for the 2023 to 2027 period exclude any further allocation of Future Tax Savings to customers.

3.0 REGULATORY TAXES – A COMPONENT OF REVENUE REQUIREMENT

Regulatory Taxes recoverable from ratepayers form part of the revenue requirement and are computed based on enacted tax legislation. Regulatory Taxes in a particular year represent the estimated current tax liability associated with regulatory net income before tax (NIBT) based on

[2] On the same day, the OEB issued its decision for Hydro One 2018-2022 distribution rate application (EB-2017-0049) dated March 7, 2019 directing Hydro One to "apply the OEB's findings from the Tax Savings Motion decision" (page 16).
[3] Hydro One, as directed by the OEB, also applied the Original Decision to allocate a portion of the Future Tax Savings to ratepayers in its Custom Incentive Rate application for 2020-2022 transmission rates which was approved by the OEB on July 16, 2020 (EB-2019-0082).

the applicable statutory tax rates for the year. Regulatory Taxes exclude future taxes arising from timing differences between when an amount is deductible or taxable for financial accounting and income tax purposes. Since Regulatory Taxes are recovered as part of revenue requirement, in years where Regulatory Taxes are higher or lower, revenue requirement is expected to trend similarly all else being equal.

The income tax expenses for which Hydro One seeks recovery in this proceeding exclude tax impacts in respect of items for which the OEB has explicitly prohibited recovery (i.e. donation credits), as well as in respect of items that do not relate to Hydro One's regulated Transmission and Distribution businesses, consistent with the stand-alone principle.[4]

4.0 REGULATORY TAXES – APPLICABLE INCOME TAX RATES (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the test years 2023 to 2027, as set out in Table 1 below, based on a federal rate of 15%[5] and a provincial rate of 11.5%.[6] Any variance between actual taxes payable and forecast taxes, as a result of changes in tax policy, tax legislation, income tax rates or capital cost allowance rates will be captured in a variance account for tax rate changes, Account 1592 – PILs and Taxes Variances, in accordance with Section 7.1 of the Electricity Distribution Rate (EDR) Handbook, as described further in Exhibit G-01-01.

[4] Section 2.4.5 of the Chapter 2 Distribution Filing Requirements dated June 24, 2021
[5] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/corporation-tax-rates.html
[6] https://www.fin.gov.on.ca/en/tax/cit/index.html

Table 1 - Combined Income Tax Rates

	Historical				Bridge	Test				
	2018	**2019**	**2020**	**2021-Forecast**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Federal Tax Rate (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Provincial Rate (%)	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50
Total Statutory Tax Rate (%)	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**

5.0 CALCULATING TAXABLE INCOME

Regulatory Taxes are determined by applying the combined statutory tax rate to taxable income, which is derived from Hydro One's Transmission and Distribution regulated NIBT as shown on the utility's income statements for the year as provided in Exhibit A-06-02. Hydro One's NIBT is prepared in accordance with U.S. Generally Accepted Accounting Principles (US GAAP), but taxable income is computed based on the applicable tax legislation (i.e., the ITA and OCTA), interpretations and CRA assessment practices. As such, adjustments are typically made to NIBT to arrive at taxable income.

Generally, to arrive at taxable income, NIBT is increased by amounts that are temporarily or permanently not deductible for tax purposes, and reduced by amounts that are deductible for tax purposes, but which have not been deducted in computing NIBT.

6.0 TIMING/TEMPORARY DIFFERENCES

There are a number of adjustments made to NIBT to arrive at taxable income and most of these adjustments are made to account for timing differences. Adjustments for timing differences are temporary in nature and are necessary in circumstances where the treatment for financial accounting purposes differs from the treatment for tax purposes, but ultimately both treatments lead to the same result over time. The need for adjustments to NIBT due to timing differences can arise when:

1. Expenditures are both capitalized and depreciated over time under both financial accounting and tax requirements, but the depreciation rates and depreciation methodology differ;
2. accrued costs are expensed for financial accounting purposes but tax deductions are allowed only when cash payments are made (i.e., Other Post-Employment Benefits (OPEB) and contingent liabilities); or
3. Costs are expensed for financial accounting purposes but are capitalized for tax purposes, or vice versa (i.e., capitalized overheads).

Common items that increase NIBT (i.e., they are added back to NIBT for tax purposes) include accounting depreciation, contingent liabilities, accounting losses, accrued expenditures related to OPEB and revenue that has been received but not recognized for accounting purposes.[7]

Common items that reduce NIBT (i.e., they are deducted from NIBT for tax purposes) include capital cost allowance, the deductible portion of capitalized overhead costs, accounting gains, OPEB payments, and expenses incurred for which a deferral and variance account has been set up on the balance sheet, rather than shown as deductions through the income statement.

Sections 6.1 to 6.4 below provide more detailed descriptions of the key timing differences and how they have historically impacted and will continue to impact Hydro One's Regulatory Tax for the test years. Of particular note is that, in Section 6.4 below, Hydro One describes a change in its income tax filing position, relative to its historical practice. Specifically, Hydro One has increased the deduction of capitalized overhead costs for tax purposes, as further discussed under Section 6.3 below. This change is expected to result in material reductions to Hydro One's taxable income, and therefore has enabled a material reduction to the Regulatory Taxes that Hydro One seeks to recover through its Transmission and Distribution revenue requirements.

[7] For example, income received with respect to a deferral account that has been set-up on the balance sheet rather than shown as additional income on the income statement.

6.1 ACCOUNTING DEPRECIATION VS. TAX CAPIAL COST ALLOWANCE (CCA)

Accounting depreciation is based upon US GAAP while tax depreciation is based upon tax legislation resulting in differences in the calculation methods, asset classifications and the applicable depreciation rates used. Accounting depreciation is generally computed on a straight line basis while tax depreciation, also known as capital cost allowance (CCA), is generally determined on a declining balance basis. Over the life of a particular asset, the tax CCA deductions will be higher in the earlier years and decline over time while the accounting depreciation will remain constant. This difference gives rise to one of the most significant timing differences, which must be reflected through adjustments to NIBT. Regulatory Taxes will generally be lower in years where CCA tax deductions are greater than accounting depreciation but higher in years where CCA tax deductions are lower than accounting depreciation.

On June 21, 2019, Bill C-97 received Royal Assent and was enacted into federal legislation as the *Budget Implementation Act, 2019, No. 1* (BIA). The BIA temporarily enhanced CCA tax deductions pursuant to the Accelerated Investment Incentive (Accelerated CCA) and provided that certain capital property that was subject to the general CCA rules would be eligible for an enhanced first-year allowance. Property would be eligible if it was acquired after November 20, 2018, and became available for use before 2028. The enhancements provided a total of three times the normal tax CCA deductions for assets in-serviced up to December 31, 2023, and a total of two times the normal tax CCA deductions for assets in-serviced after December 31, 2023 through to December 31, 2027.

By providing additional CCA tax deductions in the first year of the eligible assets being in service, the BIA has further accentuated the inverse relationship between CCA tax deductions and Regulatory Taxes, whereby in years where CCA tax deductions are higher, Regulatory Taxes are lower. Even though the total tax deductions from an eligible capital asset remain unchanged, Regulatory Taxes would appear lower in the initial years when the Accelerated CCA deductions are first introduced (i.e., in the historical and bridge years of this proceeding) as higher CCA deductions are allowed on eligible capital assets in-serviced. Subsequently, Regulatory Taxes trend upward because the Accelerated CCA deductions lower the available undepreciated capital cost (UCC) pool carry forward, which is used to determine maximum allowable CCA deductions in subsequent years.

In the context of Hydro One's current Application, even if the level of eligible capital assets in-serviced remains constant, Regulatory Taxes would be expected to trend upward due to a combination of a lower UCC pool and the lower enhanced CCA deductions. The enhanced CCA deductions are lower because they are based on a total of two times the normal CCA deductions for the period commencing January 1, 2024 to December 31, 2027 rather than the total of three times the normal CCA deductions for the period from November 20, 2018 to December 31, 2023.

6.2 ACCRUAL VS CASH DISBURSEMENT

Net income determined under US GAAP generally allows a deduction for expenditures that have been incurred but not necessarily paid (i.e. on an accrual basis). For tax purposes, certain expenditures can be similarly deducted on an accrual basis, but some expenditures are explicitly limited to situations where there is an associated cash payment. Two examples that highlight this different treatment are OPEB costs and contingent liability accruals, which are discussed in Sections 6.2.1 and 6.2.2 below.

6.2.1 OTHER POST EMPLOYMENT BENEFITS

Annual OPEB costs accrued for financial accounting purposes are comprised of amounts that are capitalized into fixed assets as well as amounts that are expensed as operations, maintenance and administration (OM&A) costs. However, for tax purposes, only the portion of annual OPEB costs that is actually paid for in the year can be deducted. OPEB payments are generally paid many years after they are accrued and, as a result, can give rise to significant timing differences between when the OPEB costs are accrued for financial accounting purposes and when the OPEB costs may be deducted for tax purposes.

Regulatory Taxes will generally be higher in years where OPEB expenditures are accrued without offsetting cash disbursements. Conversely, Regulatory Taxes will generally be lower in years where OPEB related cash disbursements are in excess of those accrued. The total available OPEB tax deduction over time does not change based on whether OPEB charges are recognized as OM&A costs or capitalized into fixed assets. However, revenue requirement is directly impacted by the method through which OPEB costs are recognized and recovered.

If OPEB amounts are capitalized into fixed assets, their recovery occurs over the life of the capital assets, as part of annual accounting depreciation. If OPEB amounts are expensed as OM&A costs, their recovery is immediate. Regulatory Taxes will be higher when OPEB amounts are expensed (as the immediate recovery of OMA is higher) as compared to when capitalized. Even though the total tax deductions from annual OPEB costs remains unchanged, irrespective of the 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, all other things being equal.

6.2.2 CONTINGENT LIABILITIES

Contingent liabilities (costs), which are recognized on Hydro One’s financial statements, represent liabilities that may be incurred depending on the outcome of uncertain events, and are also known as accounting reserves. Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future, the accrued expenditure will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed and may be adjusted by the utility to reflect new information available at that time. The balance may be adjusted upward or downward, with NIBT either decreasing or increasing, respectively, as a result.

For tax purposes, the costs and deductions associated with a contingent liability or accounting reserve is not reflected until the obligation is settled. Therefore, to the extent that NIBT has been increased (or decreased) by the contingent liability or accounting reserve accrual, the NIBT impact must be reversed in computing taxable income.

6.3 CAPITALIZED OVERHEAD COSTS FOR ACCOUNTING VS. FOR TAX

Annually, for financial accounting purposes and in accordance with US GAAP, Hydro One capitalizes a certain portion of overhead costs to fixed assets. That ability to capitalize overhead costs for financial accounting purposes is distinct from the ability to capitalize overhead costs for tax purposes. For the purposes of determining taxable income, capitalized overhead costs can be deducted immediately on the basis that they are not directly related to the acquisition or construction of capital assets and are considered to be recurring costs incurred as part of the day-to-day expenses of operating the business (Tax Deductible Capitalized Overheads). Tax Deductible Capitalized Overheads are based on tax legislation, jurisprudence, interpretation and principles accepted by the CRA and are <u>not</u> dependent on accounting treatments established under applicable accounting standards (US GAAP or IFRS).

In light of this contrasting treatment, overhead costs being capitalized under US GAAP, but expensed for tax purposes, are another significant source of deductible timing differences, which have the effect of reducing Hydro One's taxable income, the related Regulatory Taxes, and ultimately its revenue requirement.

6.4 DEDUCTING ADDITIONAL TAX DEDUCTIBLE CAPITALIZED OVERHEADS

6.4.1 BACKGROUND

In 1998, the CRA provided its interpretation in relation to the tax treatment of capitalized expenses in a regulated industry setting pursuant to CRA Views Document #9812566 – Capitalized Expenses in Regulated Industry (the Views Document).[8] Specifically, the Views Document addressed the deductibility of capitalized expenses in the regulated natural gas

[8] CRA Views Document #9812566 – Capitalized Expenses in Regulated Industry dated September 24, 1998

transmission and distribution industry following the issuance of three relevant decisions by the Supreme Court of Canada.

As described in Section 2.0, above, Hydro One was under the PILs regime and subject to audit by the MoF prior to its 2015 IPO. In 2004, Hydro One requested that the MoF provide guidance on how the principles interpreted by the CRA in the Views Document should be applied to Hydro One's regulated electricity transmission and distribution businesses in determining the Company's PILs requirements.

In response to Hydro One's request, the MoF issued a technical interpretation of the Views Document (the MoF Ruling). In the MoF Ruling, which was made effective back to the 1999 taxation year, the MoF opined that the position taken by the CRA in the Views Document:

> *"…is applicable to [allow the current deduction of] general administrative overhead expenses that Hydro One capitalized for book purposes but are not directly related to the improvement or construction of assets."*

Hydro One adopted the position set out in the MoF Ruling effective from the 1999 taxation year and has maintained the same position with respect to Tax Deductible Capitalized Overheads, which has been confirmed by the MoF for subsequent years through an audit.

Since the IPO in late 2015, Hydro One is no longer subject to audit by the MoF, but instead is subject to audit by the CRA. While the CRA Views Document continues to be relevant to Hydro One despite the transition from the PILs regime to the federal income tax regime, the MoF Ruling no longer applies.

6.4.2 TAX REVIEW FINDINGS - THE MOF RULING REFLECTED A NARROWER INTERPRETATION

Hydro One regularly reviews its tax filing positions to ensure that they continue to be supportable, that they reflect the tax landscape Hydro One operates in, that current tax deductions are optimized[9], and that Regulatory Taxes to be recovered from ratepayers are minimized (Tax Review). In connection with a recent Tax Review, and in recognition of the OEB's direction for Hydro One to review its approach to overhead capitalization[10], Hydro One revisited the tax treatment of capitalized overheads and concluded that there is potential for Hydro One to increase its deductions of Tax Deductible Capitalized Overheads on its income tax returns as compared to what it had been deducting, based on the MoF Ruling, on its income tax returns since 2016 (the first full year Hydro One was subject to federal income tax).

Increasing the Tax Deductible Capitalized Overheads deduction (the Updated Approach) would enable Hydro One to reduce its Regulatory Taxes in the near term (relative to the current treatment) and consequently to pass that reduction on to ratepayers. While the MoF Ruling was consistent with the CRA's interpretation, the MoF applied a narrower interpretation, as compared to the CRA interpretation, by specifically excluding certain types of capitalized overheads that would otherwise have been deductible in the year the costs were incurred on the principle that those costs were not directly related to or attributable to the improvement or creation of assets.

Hydro One's Tax Review identified that the Company is no longer compelled to follow the MoF Ruling after exiting the PILS regime and that there is a supportable basis to increase the Tax Deductible Capitalized Overheads deduction as compared to that which had been deducted by Hydro One since 1999 based on the MoF Ruling.

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[9] As mandated by the OEB; See 2006 EDR Handbook and 2016 Transmission Rate Filing Requirements, which require utilities to claim maximum annual allowable tax deductions.

[10] In EB-2019-0082, the OEB ordered that a detailed review of Hydro One's methodology regarding overhead capitalization be filed in its next rebasing application. See Decision and Order dated April 23, 2020, p. 183.

The Updated Approach accelerates the timing of deduction for tax purposes. The total tax deduction of an overhead expenditure amount remains unchanged whether the overhead is capitalized or is reflected as a current expense. The only difference is in the timing of when the tax deduction occurs, being either immediately when an overhead expenditure is expensed or over a multi-year period when an overhead expenditure is capitalized. When capitalized, the deduction takes the form of an annual CCA deduction, which is computed based on a prescribed rate on a declining balance basis.

6.4.3 UNCERTAINTY WITH THE UPDATED APPROACH

While the additional deduction is supportable and confirmed with external tax advisors, there is no definitive test for what constitutes a current expense as opposed to a capital expenditure for tax purposes. Ultimately, the Updated Approach to deduct additional Tax Deductible Capitalized Overheads will require CRA concurrence.

Until a taxation year is statute-barred, Hydro One is subject to the risk of a CRA audit. Not all tax years are audited and CRA auditors are not bound by the positions accepted in prior CRA audits, which could result in inconsistency from year to year. Should the CRA disagree with Hydro One’s additional deductions for Tax Deductible Capitalized Overheads in a particular tax year, CRA may deny those deductions through its audit and reassessment process. Pragmatically, absent any changes in the CRA’s view and/or jurisprudence, this audit risk is expected to be lessened over time if Hydro One continues to follow an approach previously audited by the CRA.

6.4.4 THE UPDATED APPROACH – REFLECTED IN THE TAX RETURNS

Based on the statute-barred dates of the historically filed income tax returns, Hydro One is permitted to amend its historical tax returns back five years to 2016 (the first full taxation year under the federal income tax regime) to reflect the Updated Approach of immediately deducting additional Tax Deductible Capitalized Overheads.

Hydro One identified an opportunity to submit requests to the CRA to amend its prior tax filings to reflect the Updated Approach for those prior tax years. If the CRA ultimately concurs with the additional deductions, Hydro One would be eligible for additional deductions which can be used to reduce taxable income and Regulatory Taxes in that year. If the CRA rejects the amendment, there would be no change to Hydro One's Regulatory Taxes for the year.

Hydro One has therefore filed with the CRA an amendment request to its 2016 tax return to reflect the additional deductions. Beyond 2016, for the 2017-2019 tax years, Hydro One intends to amend the tax filings pending CRA's assessment of the 2016 amendment. For the 2020-2022 tax years, Hydro One has reflected or intends to reflect the Updated Approach in its income tax return filings, also subject to the CRA concurring with the Updated Approach in the 2016 amendment. Hydro One has had discussions with the CRA about amending its 2017-2019 returns to reflect the additional deductions if and when the CRA concurs with the requested 2016 amendment. The amendment for 2016 is expected to be completed before the end of 2021.

In the event the CRA disagrees with the Updated Approach, Hydro One intends to revert back to the original filing method in its future tax returns. If timing permits, Hydro One will then update its current evidence to remove the Updated Approach currently reflected in the 2023-2027 test years. However, if timing does not permit an update to the evidence, Hydro One intends to reflect the impact related to the 2023-2027 test years in a variance account as discussed in Section 6.4.6 below.

6.4.5 THE UPDATED APPROACH – REFLECTED IN THE EVIDENCE

To reiterate, Hydro One's forecast Regulatory Taxes for Transmission and Distribution for 2023-2027 have been calculated on the basis of the Updated Approach, with additional deductions for Tax Deductible Capitalized Overheads, thereby reducing Hydro One's tax expense and revenue requirement over the test period from 2023 to 2027 by approximately $73M as compared to the prior filing position confirmed by the MoF.

6.4.6 KEEPING RATEPAYERS AND HYDRO ONE WHOLE PENDING A CRA DECISION ON THE UPDATED APPROACH – REQUESTING A NEW VARIANCE ACCOUNT

In light of (i) Hydro One's approach with the amended filings for 2016-2019,[11] (ii) the filings for 2020-2022, (iii) the manner in which Hydro One has reflected the impact of the Updated Approach in this Application, (iv) the uncertainty associated with the deductions of additional Tax Deductible Capitalized Overheads for income tax purposes,[12] and (v) the materiality of the amounts at issue, Hydro One is requesting new variance accounts for each of the Transmission and Distribution businesses.

As described in greater detail in Exhibit G-01-02, the purpose for the accounts is to record differences between Hydro One's OEB-approved Regulatory Taxes in rates and its actual Regulatory Taxes as impacted by any CRA reassessment or final audit for a tax year during the 2016-2027 period, strictly insofar as the difference is related to Tax Deductible Capitalized Overheads for income tax purposes. It would, therefore, be used to capture any reductions in Hydro One's actual Regulatory Taxes to be refunded to ratepayers relative to what it has been approved to recover in rates for the 2016 to 2022 years, to the extent the Updated Approach on Tax Deductible Capitalized Overheads is accepted by CRA for each of those years. Similarly, the proposed variance accounts would be used to capture any increases in Hydro One's actual Regulatory Taxes to be recovered from ratepayers relative to what the OEB approves on a forecast basis for recovery in rates over the 2023-2027 rate period, to the extent the Updated Approach is rejected for any or all of these years by future CRA actions. Hydro One would propose to dispose of the net balances, along with applicable carrying costs, at its next rebasing application.

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[11] 2016 already amended and subject to CRA concurrence, 2017-2019 to be amended pending CRA concurrence for 2016

[12] Both for the historical years and for the 2023-2027 rate period

7.0 TAX TREATMENT OF REGULATORY ASSETS AND LIABILITIES

Regulatory Assets and Regulatory Liabilities are typically recognized on utilities' balance sheets for foregone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of Regulatory Account balances is determined by the OEB.

Regulatory Assets and Regulatory Liabilities have not been included in computing Regulatory Taxes for purposes of calculating revenue requirement in accordance with Section 2.8.11 of the Transmission Filing Requirements issued February 11, 2016 and Section 2.4.5.1 the Distribution Filing Requirements issued June 24, 2021.

8.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between Hydro One's regulatory NIBT and taxable income for the test years 2023 to 2027 is provided in Exhibit E-09-02, Attachment 1. This Schedule contains the income tax computation. It also shows how taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and CCA. The calculation of CCA is provided in Exhibit E-09-02, Attachment 2. Reconciliation between accounting fixed asset additions and net tax additions is provided in Exhibit E-09-02, Attachment 2A. Reconciliation between Hydro One's accounting NIBT and taxable income for the historical years 2019 and 2020 is provided in Exhibit E-09-02, Attachment 3. The calculation of CCA for the historical years is provided in Exhibit E-09-02, Attachment 4.

In order to make it easier to follow these reconciliations, Hydro One has placed these adjustments into the following five categories:

1. Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, accounting depreciation versus CCA);
2. Deferral accounts not included in the revenue requirement;

3. Reversal of accounting adjustments not included in the revenue requirement;
4. Recurring items not in the revenue requirement; and
5. Items whose impact is immaterial in total, and as such, have not been included in Hydro One's business plan.

9.0 INTEGRITY CHECKS

Hydro One has performed the integrity checks described in Section 2.4.5.1 of the Distribution Filing Requirements and Section 2.8.11 of the Transmission Filing Requirements Material exceptions are described below.

- The capital additions in the undepreciated capital cost (UCC) schedule do not agree with the rate base in the historical, bridge and test years in Exhibit E-09-02, Attachment 2. This is primarily due to capitalized costs that are deductible (and not capitalized) for tax. Please see reconciliation provided in Exhibit E-09-02, Attachment 2A.
- 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.

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CALCULATION OF UTILITY INCOME TAXES

Attachment 1:	Calculation of Utility Income Taxes – Bridge and Test Years
Attachment 2:	Calculation of Capital Cost Allowance – Bridge and Test Years
Attachment 2A:	Reconciliation of Accounting to Tax Additions – Bridge and Test Years
Attachment 3:	Calculation of Utility Income Taxes - Historical Years
Attachment 4:	Calculation of Capital Cost Allowance - Historical Years
Attachment 5:	Calculation of Tax Credits – Bridge and Test Years
Attachment 6:	Calculation of Tax Credits – Historical Years

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HYDRO ONE NETWORKS INC.
TRANSMISSION & DISTRIBUTION
Calculation of Utility Income Taxes
Historical Actual (2021-Forecast), Bridge (2022) & Test Years (2023 - 2027)
Year Ending December 31
($M)

Line No.	Particulars	2021*		2022*		2023		2024		2025		2026		2027	
	Determination of Taxable Income	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION
1	Regulatory Net Income (before tax)	$ 491.4	360.8	$ 542.6	401.4	$ 527.3	349.8	$ 586.3	386.9	$ 610.2	397.4	$ 663.3	436.2	$ 693.4	465.0
2	Book to Tax Adjustments:														
3	Other Post Employment Benefits expense	30.6	27.4	32.9	29.2	31.2	44.7	32.1	45.7	33.1	47.4	34.0	49.4	35.6	50.5
4	Other Post Employment Benefits payments	(27.1)	(32.3)	(28.2)	(33.5)	(29.1)	(34.5)	(29.9)	(35.5)	(30.9)	(36.6)	(31.8)	(37.5)	(32.6)	(38.5)
5	Depreciation and amortization	500.2	442.3	524.5	455.4	528.2	460.1	557.6	481.3	593.8	522.0	625.1	557.3	647.3	592.3
7	Capital Cost Allowance	(682.4)	(522.5)	(736.7)	(502.5)	(788.0)	(567.6)	(759.3)	(558.6)	(855.9)	(657.8)	(864.1)	(669.4)	(909.4)	(695.8)
8	Removal costs	(3.7)	(4.0)	(3.7)	(4.0)	(3.7)	(4.0)	(3.7)	(4.0)	(3.7)	(4.0)	(3.7)	(4.0)	(3.7)	(4.0)
9	Environmental costs	(15.5)	(13.4)	(16.2)	(12.9)	(7.6)	(5.5)	(7.5)	(5.4)	(6.6)	(1.0)	0.0	0.0	0.0	0.0
10	Hedge loss - amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Non-deductible meals & entertainment	3.0	2.1	3.0	2.1	3.0	2.1	3.0	2.1	3.0	2.1	3.0	2.1	3.0	2.1
13	Research & Development ITC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Federal apprenticeship & education credits	0.3	0.4	0.4	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3	0.4
15	Capitalized overhead costs	(45.2)	(34.7)	(47.1)	(35.5)	(72.6)	(63.3)	(73.6)	(63.8)	(74.4)	(66.9)	(74.7)	(65.9)	(75.3)	(66.8)
16	Capitalized pension costs	(22.9)	(22.8)	(35.3)	(31.9)	(34.5)	(40.9)	(36.2)	(42.2)	(35.9)	(42.4)	(36.6)	(43.9)	(39.1)	(44.8)
17	Debt Issuance costs - amortization	2.5	1.5	2.5	1.5	2.6	1.5	2.7	1.7	3.0	1.9	3.3	2.1	3.6	2.3
18	Debt Issuance costs - 21(e) deduction	(3.3)	(1.7)	(3.9)	(2.1)	(3.7)	(2.3)	(3.7)	(2.3)	(3.6)	(2.3)	(4.1)	(2.8)	(4.1)	(2.9)
19	Premium/Discount - amortization	(0.4)	(0.5)	(0.2)	(0.3)	(0.2)	(0.3)	(0.2)	(0.4)	(0.2)	(0.4)	(0.2)	(0.4)	(0.3)	(0.5)
23	Other	1.2	2.2	1.1	2.1	0.9	1.6	0.9	1.6	0.9	1.5	0.8	1.4	0.8	1.4
		$ (262.7)	(155.9)	$ (306.9)	(131.9)	$ (373.2)	(207.9)	$ (317.5)	(179.3)	$ (377.1)	(235.8)	$ (348.7)	(211.2)	$ (373.8)	(204.1)
24	Regulatory Taxable Income	$ 228.8	204.8	$ 235.7	269.5	$ 154.1	141.9	$ 268.8	207.6	$ 233.0	161.6	$ 314.7	225.0	$ 319.5	260.9
25	Corporate Income Tax Rate	% 26.5	26.5	% 26.5	26.5	% 26.5	26.5	% 26.5	26.5	% 26.5	26.5	% 26.5	26.5	% 26.5	26.5
26	Subtotal	$ 60.6	54.3	$ 62.5	71.4	$ 40.8	37.6	$ 71.2	55.0	$ 61.8	42.8	$ 83.4	59.6	$ 84.7	69.1
27	Less: Deferred Tax Sharing	$ (22.4)	(16.6)	$ 0.0	0.0	$ 0.0	0.0	$ 0.0	0.0	$ 0.0	0.0	$ 0.0	0.0	$ 0.0	0.0
28	Less: R&D ITC / Ontario education credits	$ (0.3)	(0.4)	$ (0.4)	(0.4)	$ (0.3)	(0.4)	$ (0.3)	(0.4)	$ (0.3)	(0.4)	$ (0.3)	(0.4)	$ (0.3)	(0.4)
29	Regulatory Income Tax	37.9	37.2	62.1	71.0	40.5	37.2	70.9	54.6	61.4	42.4	83.1	59.2	84.3	68.7
	Tax Rates														
30	Federal Tax	% 15.00	15.00	% 15.00	15.00	% 15.00	15.00	% 15.00	15.00	% 15.00	15.00	% 15.00	15.00	% 15.00	15.00
31	Provincial Tax	% 11.50	11.50	% 11.50	11.50	% 11.50	11.50	% 11.50	11.50	% 11.50	11.50	% 11.50	11.50	% 11.50	11.50
32	Total Tax Rate	% 26.50	26.50	% 26.50	26.50	% 26.50	26.50	% 26.50	26.50	% 26.50	26.50	% 26.50	26.50	% 26.50	26.50

* 2021 and 2022 is Distribution only - the Acquired Utilities are included in 2023 and subsequent years

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost allowance (CCA)
Historical Actual (2021-Forecast), Bridge (2022) & Test Years (2023 - 2027)
Year Ending December 31
($M)

2021 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,850.0	29.3	1,879.3	(14.7)	27.0	1,891.6	4%	75.7	1,803.6
2	393.1	-	393.1	-	-	393.1	6%	23.6	369.5
3	195.9	-	195.9	-	-	195.9	5%	9.8	186.1
6	53.1	-	53.1	-	-	53.1	10%	5.3	47.8
7	1.6	-	1.6	-	-	1.6	15%	0.2	1.4
8	140.7	106.8	247.6	(53.4)	98.3	292.4	20%	58.5	189.1
9	1.6	-	1.6	-	-	1.6	25%	0.4	1.2
10	24.8	9.9	34.7	(4.9)	9.1	38.8	30%	11.6	23.0
12	2.4	24.8	27.2	(12.4)	11.4	26.2	100%	26.2	1.0
13	6.7	-	6.7	-	-	6.7	N/A	1.3	5.4
14.1 (ECE)	27.7	-	27.7	-	-	27.7	7%	1.9	25.7
14.1 (Post-2017)	15.2	8.3	23.5	(4.2)	7.6	27.0	5%	1.3	22.1
17	108.3	1.9	110.2	(1.0)	1.8	111.0	8%	8.9	101.4
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	50.4	-	50.4	-	-	50.4	12%	6.0	44.3
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	8.0	-	8.0	-	-	8.0	30%	2.4	5.6
47	4,441.0	720.9	5,161.8	(360.4)	663.2	5,464.6	8%	437.2	4,724.7
50	25.1	8.9	34.0	(4.5)	8.2	37.8	55%	20.8	13.3
Total CCA	**7,345.8**	**910.8**	**8,256.6**	**(455.4)**	**826.6**	**8,627.7**		**691.2**	**7,565.3**
						Less CCA not in rates		(8.9)	
						Total CCA for RR		**682.4**	

2022 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,803.6	24.5	1,828.1	(12.2)	24.5	1,840.4	4%	73.6	1,754.5
2	369.5	-	369.5	-	-	369.5	6%	22.2	347.4
3	186.1	-	186.1	-	-	186.1	5%	9.3	176.8
6	47.8	-	47.8	-	-	47.8	10%	4.8	43.0
8	189.1	46.3	235.3	(23.1)	46.3	258.4	20%	51.7	183.6
9	1.2	-	1.2	-	-	1.2	25%	0.3	0.9
10	23.0	8.1	31.1	(4.0)	8.1	35.2	30%	10.5	20.6
12	1.0	24.1	25.1	(12.1)	12.1	25.1	100%	25.1	-
13	5.4	-	5.4	-	-	5.4	N/A	1.3	4.1
14.1 (ECE)	25.7	-	25.7	-	-	25.7	7%	1.8	23.9
14.1 (Post-2017)	22.1	14.3	36.5	(7.2)	14.3	43.6	5%	2.2	34.3
17	101.4	4.4	105.8	(2.2)	4.4	108.0	8%	8.6	97.2
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	44.3	-	44.3	-	-	44.3	12%	5.3	39.0
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	5.6	-	5.6	-	-	5.6	30%	1.7	3.9
47	4,724.7	1,134.1	5,858.8	(567.0)	1,134.1	6,425.8	8%	514.1	5,344.7
50	13.3	5.8	19.0	(2.9)	5.8	21.9	55%	12.1	7.0
Total CCA	**7,565.3**	**1,261.6**	**8,826.9**	**(630.8)**	**1,249.5**	**9,445.7**		**744.8**	**8,082.1**
						not in rates		(8.1)	
						Total CCA		**736.7**	

2023 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
	A	**B**	**C = A + B**	**D**	**E**	**F= C-D+E**			
1	1,754.5	21.9	1,776.4	(10.9)	21.9	1,787.4	4%	71.5	1,704.9
2	347.4	-	347.4	-	-	347.4	6%	20.8	326.5
3	176.8	-	176.8	-	-	176.8	5%	8.8	167.9
6	43.0	-	43.0	-	-	43.0	10%	4.3	38.7
8	183.6	111.7	295.3	(55.8)	111.7	351.1	20%	70.2	225.1
9	0.9	-	0.9	-	-	0.9	25%	0.2	0.7
10	20.6	17.1	37.6	(8.5)	17.1	46.1	30%	13.8	23.8
12	-	24.2	24.2	(12.1)	12.1	24.2	100%	24.2	-
13	4.1	-	4.1	-	-	4.1	N/A	1.3	2.8
14.1 (ECE)	23.9	-	23.9	-	-	23.9	7%	1.7	22.3
14.1 (Post-2017)	34.3	6.0	40.2	(3.0)	6.0	43.2	5%	2.2	38.1
17	97.2	2.7	99.8	(1.3)	2.7	101.2	8%	8.1	91.7
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	39.0	-	39.0	-	-	39.0	12%	4.7	34.3
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	3.9	-	3.9	-	-	3.9	30%	1.2	2.8
47	5,344.7	1,048.6	6,393.3	(524.3)	1,048.6	6,917.6	8%	553.4	5,839.9
50	7.0	6.0	12.9	(3.0)	6.0	15.9	55%	8.8	4.2
Total CCA	**8,082.1**	**1,238.0**	**9,320.2**	**(619.0)**	**1,225.9**	**9,927.1**		**795.5**	**8,524.7**
						not in rates		(7.4)	
						for RR		**788.0**	

2024 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,704.9	44.9	1,749.8	(22.4)	22.4	1,749.8	4%	70.0	1,679.8
2	326.5	-	326.5	-	-	326.5	6%	19.6	306.9
3	167.9	-	167.9	-	-	167.9	5%	8.4	159.5
6	38.7	-	38.7	-	-	38.7	10%	3.9	34.9
8	225.1	90.3	315.3	(45.1)	45.1	315.3	20%	63.1	252.3
9	0.7	-	0.7	-	-	0.7	25%	0.2	0.5
10	23.8	17.2	41.0	(8.6)	8.6	41.0	30%	12.3	28.7
12	-	18.6	18.6	(9.3)	9.3	18.6	100%	18.6	-
13	2.8	-	2.8	-	-	2.8	N/A	1.3	1.5
14.1 (ECE)	22.3	-	22.3	-	-	22.3	7%	1.6	20.7
14.1 (Post-2017)	38.1	7.8	45.9	(3.9)	3.9	45.9	5%	2.3	43.6
17	91.7	0.9	92.7	(0.5)	0.5	92.7	8%	7.4	85.2
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.1
42	34.3	-	34.3	-	-	34.3	12%	4.1	30.2
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	2.8	-	2.8	-	-	2.8	30%	0.8	1.9
47	5,839.9	1,013.2	6,853.1	(506.6)	506.6	6,853.1	8%	548.2	6,304.8
50	4.2	3.5	7.7	(1.8)	1.8	7.7	55%	4.2	3.5
Total CCA	**8,524.7**	**1,196.4**	**9,721.1**	**(598.2)**	**598.2**	**9,721.1**		**766.1**	**8,955.0**
								(6.8)	
						for RR		**759.3**	

2025 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,679.8	26.2	1,706.0	(13.1)	13.1	1,706.0	4%	68.2	1,637.7
2	306.9	-	306.9	-	-	306.9	6%	18.4	288.5
3	159.5	-	159.5	-	-	159.5	5%	8.0	151.6
6	34.9	-	34.9	-	-	34.9	10%	3.5	31.4
8	252.3	97.4	349.6	(48.7)	48.7	349.6	20%	69.9	279.7
9	0.5	-	0.5	-	-	0.5	25%	0.1	0.4
10	28.7	18.0	46.7	(9.0)	9.0	46.7	30%	14.0	32.7
12	-	44.5	44.5	(22.3)	22.3	44.5	100%	44.5	-
13	1.5	-	1.5	-	-	1.5	N/A	1.5	(0.0)
14.1 (ECE)	20.7	-	20.7	-	-	20.7	7%	1.4	19.2
14.1 (Post-2017)	43.6	10.1	53.7	(5.0)	5.0	53.7	5%	2.7	51.0
17	85.2	3.2	88.4	(1.6)	1.6	88.4	8%	7.1	81.4
35	0.1	-	0.1	-	-	0.1	7%	0.0	0.0
42	30.2	-	30.2	-	-	30.2	12%	3.6	26.6
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.9	-	1.9	-	-	1.9	30%	0.6	1.3
47	6,304.8	1,375.6	7,680.4	(687.8)	687.8	7,680.4	8%	614.4	7,066.0
50	3.5	3.7	7.1	(1.8)	1.8	7.1	55%	3.9	3.2
Total CCA	**8,955.0**	**1,578.7**	**10,533.6**	**(789.3)**	**789.3**	**10,533.6**		**862.1**	**9,671.5**
						not in rates		(6.2)	
						for RR		**855.9**	

2026 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,637.7	28.4	1,666.2	(14.2)	14.2	1,666.2	4%	66.6	1,599.5
2	288.5	-	288.5	-	-	288.5	6%	17.3	271.2
3	151.6	-	151.6	-	-	151.6	5%	7.6	144.0
6	31.4	-	31.4	-	-	31.4	10%	3.1	28.2
8	279.7	96.4	376.1	(48.2)	48.2	376.1	20%	75.2	300.9
9	0.4	-	0.4	-	-	0.4	25%	0.1	0.3
10	32.7	17.7	50.4	(8.8)	8.8	50.4	30%	15.1	35.2
12	-	22.5	22.5	(11.3)	11.3	22.5	100%	22.5	-
13	(0.0)	-	(0.0)	-	-	(0.0)	N/A	0.1	(0.1)
14.1 (ECE)	19.2	-	19.2	-	-	19.2	7%	1.3	17.9
14.1 (Post-2017)	51.0	9.5	60.5	(4.8)	4.8	60.5	5%	3.0	57.5
17	81.4	1.8	83.2	(0.9)	0.9	83.2	8%	6.7	76.5
35	0.0	-	0.0	-	-	0.0	7%	0.0	0.0
42	26.6	-	26.6	-	-	26.6	12%	3.2	23.4
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.3	-	1.3	-	-	1.3	30%	0.4	0.9
47	7,066.0	973.6	8,039.6	(486.8)	486.8	8,039.6	8%	643.2	7,396.5
50	3.2	4.4	7.6	(2.2)	2.2	7.6	55%	4.2	3.4
Total CCA	**9,671.5**	**1,154.4**	**10,825.9**	**(577.2)**	**577.2**	**10,825.9**		**869.8**	**9,956.1**
						not in rates		(5.7)	
						for RR		**864.1**	

2027 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,599.5	24.7	1,624.2	(12.4)	12.4	1,624.2	4%	65.0	1,559.3
2	271.2	-	271.2	-	-	271.2	6%	16.3	254.9
3	144.0	-	144.0	-	-	144.0	5%	7.2	136.8
6	28.2	-	28.2	-	-	28.2	10%	2.8	25.4
8	300.9	52.4	353.3	(26.2)	26.2	353.3	20%	70.7	282.6
9	0.3	-	0.3	-	-	0.3	25%	0.1	0.2
10	35.2	18.7	53.9	(9.3)	9.3	53.9	30%	16.2	37.7
12	-	19.1	19.1	(9.5)	9.5	19.1	100%	19.1	-
13	(0.1)	-	(0.1)	-	-	(0.1)	N/A	1.0	(1.1)
14.1 (ECE)	17.9	-	17.9	-	-	17.9	5%	0.9	17.0
14.1 (Post-2017)	57.5	11.8	69.4	(5.9)	5.9	69.4	5%	3.5	65.9
17	76.5	1.5	78.0	(0.7)	0.7	78.0	8%	6.2	71.8
35	0.0	-	0.0	-	-	0.0	7%	0.0	0.0
42	23.4	-	23.4	-	-	23.4	12%	2.8	20.6
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	0.9	-	0.9	-	-	0.9	30%	0.3	0.7
47	7,396.5	1,327.4	8,723.9	(663.7)	663.7	8,723.9	8%	697.9	8,025.9
50	3.4	5.3	8.7	(2.6)	2.6	8.7	55%	4.8	3.9
Total CCA	**9,956.1**	**1,460.8**	**11,416.9**	**(730.4)**	**730.4**	**11,416.9**		**914.7**	**10,502.2**
						not in rates		(5.3)	
						for RR		**909.4**	

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
Historical Actual (2021-Forecast), Bridge (2022) & Test Years (2023 - 2027)
Year Ending December 31
($M)

2021 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,326.6	32.5	1,359.1	(16.2)	32.1	1,375.0	4%	55.0	1,304.1
2	177.4	-	177.4	-	-	177.4	6%	10.6	166.7
3	10.2	-	10.2	-	-	10.2	5%	0.5	9.7
6	17.5	-	17.5	-	-	17.5	10%	1.7	15.7
7	1.8	-	1.8	-	-	1.8	15%	0.3	1.5
8	82.8	75.9	158.6	(37.9)	75.1	195.8	20%	39.2	119.5
9	1.8	-	1.8	-	-	1.8	25%	0.4	1.3
10	57.8	21.0	78.8	(10.5)	20.8	89.2	30%	26.7	52.1
12	1.3	55.1	56.4	(27.5)	27.3	56.1	100%	56.1	0.3
13	15.9	2.9	18.8	(1.4)	-	17.4	N/A	2.2	16.6
14	1.4	-	1.4	-	-	1.4	N/A	0.1	1.3
14.1 (ECE)	17.0	0.2	17.2	(0.1)	0.2	17.2	7%	1.2	15.9
14.1 (Post-2017)	0.3	3.2	3.5	(1.6)	3.2	5.1	5%	0.3	3.3
17	32.0	-	32.0	-	-	32.0	8%	2.6	29.4
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	7.0	-	7.0	-	-	7.0	30%	2.1	4.9
47	3,521.5	467.0	3,988.5	(233.5)	462.5	4,217.5	8%	337.4	3,651.1
50	2.7	2.4	5.1	(1.2)	2.4	6.3	55%	3.5	1.6
Total CCA	**5,275.0**	**660.2**	**5,935.2**	**(330.1)**	**623.7**	**6,228.7**		**539.9**	**5,395.3**
							Less CCA not in rates	(6.4)	
							Less CCA (acquired LDC)	(11.0)	
							Total CCA for RR	**522.5**	

2022 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,304.0	24.7	1,328.7	(12.3)	24.7	1,341.0	4%	53.6	1,275.0
2	166.7	-	166.7	-	-	166.7	6%	10.0	156.7
3	9.7	-	9.7	-	-	9.7	5%	0.5	9.2
6	15.7	-	15.7	-	-	15.7	10%	1.6	14.2
7	1.5	-	1.5	-	-	1.5	15%	0.2	1.3
8	119.5	20.9	140.4	(10.5)	20.9	150.9	20%	30.2	110.2
9	1.3	-	1.3	-	-	1.3	25%	0.3	1.0
10	52.1	16.9	69.0	(8.5)	16.9	77.5	30%	23.2	45.8
12	0.3	38.1	38.3	(19.0)	19.0	38.3	100%	38.3	-
13	16.6	5.8	22.5	(2.9)	-	19.6	N/A	2.7	19.7
14	1.3	-	1.3	-	-	1.3	N/A	0.1	1.2
14.1 (ECE)	16.4	0.1	16.5	(0.0)	0.1	16.5	7%	1.2	15.3
14.1 (Post-2017)	3.3	4.3	7.6	(2.2)	4.3	9.7	5%	0.5	7.1
17	29.4	-	29.4	-	-	29.4	8%	2.4	27.1
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	4.9	-	4.9	-	-	4.9	30%	1.5	3.4
47	3,651.1	491.5	4,142.7	(245.8)	491.5	4,388.4	8%	351.1	3,791.6
50	1.6	1.7	3.4	(0.9)	1.7	4.3	55%	2.3	1.0
Total CCA	**5,395.8**	**604.1**	**5,999.8**	**(302.0)**	**579.2**	**6,277.0**		**519.8**	**5,480.1**
							Less CCA not in rates	(6.2)	
							Less CCA (acquired LDC)	(11.1)	
							Total CCA for RR	**502.5**	

2023 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,275.0	27.6	1,302.6	(13.8)	27.6	1,316.4	4%	52.7	1,249.9
1b	0.0	-	0.0	-	-	0.0	6%	0.0	0.0
2	156.7	-	156.7	-	-	156.7	6%	9.4	147.3
3	9.2	-	9.2	-	-	9.2	5%	0.5	8.7
6	14.2	-	14.2	-	-	14.2	10%	1.4	12.8
7	1.3	-	1.3	-	-	1.3	15%	0.2	1.1
8	110.2	56.6	166.8	(28.3)	56.6	195.1	20%	39.0	127.8
9	1.0	-	1.0	-	-	1.0	25%	0.3	0.8
10	45.8	34.9	80.7	(17.4)	34.9	98.1	30%	29.4	51.2
12	-	42.0	42.0	(21.0)	21.0	42.0	100%	42.0	-
13	19.7	6.2	25.9	(3.1)	-	22.8	N/A	3.3	22.6
14	1.2	-	1.2	-	-	1.2	N/A	0.1	1.1
14.1 (ECE)	15.3	0.1	15.4	(0.0)	0.1	15.4	7%	1.1	14.3
14.1 (Post-2017)	7.1	5.7	12.8	(2.9)	5.7	15.7	5%	0.8	12.0
17	27.1	-	27.1	-	-	27.1	8%	2.2	24.9
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	3.4	-	3.4	-	-	3.4	30%	1.0	2.4
47	3,791.6	706.1	4,497.7	(353.0)	706.1	4,850.7	8%	388.1	4,109.6
50	1.0	1.7	2.8	(0.9)	1.7	3.6	55%	2.0	0.8
Total CCA	**5,480.1**	**880.8**	**6,360.9**	**(440.4)**	**853.6**	**6,774.1**		**573.4**	**5,787.5**
							Less CCA not in rates	(5.8)	
							Total CCA for RR	**567.6**	

2024 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,249.9	63.4	1,313.3	(31.7)	31.7	1,313.3	4%	52.5	1,260.8
2	147.3	-	147.3	-	-	147.3	6%	8.8	138.5
3	8.7	-	8.7	-	-	8.7	5%	0.4	8.3
6	12.8	-	12.8	-	-	12.8	10%	1.3	11.5
7	1.1	-	1.1	-	-	1.1	15%	0.2	0.9
8	127.8	75.6	203.4	(37.8)	37.8	203.4	20%	40.7	162.7
9	0.8	-	0.8	-	-	0.8	25%	0.2	0.6
10	51.2	35.6	86.9	(17.8)	17.8	86.9	30%	26.1	60.8
12	-	38.6	38.6	(19.3)	19.3	38.6	100%	38.6	-
13	22.6	16.7	39.3	(8.3)	-	30.9	N/A	5.0	34.3
14	1.1	-	1.1	-	-	1.1	N/A	0.1	1.0
14.1 (ECE)	14.3	0.1	14.4	(0.0)	0.0	14.4	7%	1.0	13.4
14.1 (Post-2017)	12.0	9.8	21.8	(4.9)	4.9	21.8	5%	1.1	20.7
17	24.9	-	24.9	-	-	24.9	8%	2.0	22.9
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	2.4	-	2.4	-	-	2.4	30%	0.7	1.7
47	4,109.6	691.2	4,800.8	(345.6)	345.6	4,800.8	8%	384.1	4,416.7
50	0.8	1.5	2.3	(0.8)	0.8	2.3	55%	1.3	1.0
Total CCA	**5,787.5**	**932.5**	**6,720.0**	**(466.2)**	**457.9**	**6,711.6**		**564.1**	**6,155.9**
							Less CCA not in rates	(5.5)	
							Total CCA for RR	**558.6**	

2025 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,260.8	45.1	1,305.8	(22.5)	22.5	1,305.8	4%	52.2	1,253.6
2	138.5	-	138.5	-	-	138.5	6%	8.3	130.2
3	8.3	-	8.3	-	-	8.3	5%	0.4	7.9
6	11.5	-	11.5	-	-	11.5	10%	1.1	10.3
7	0.9	-	0.9	-	-	0.9	15%	0.1	0.8
8	162.7	95.7	258.4	(47.8)	47.8	258.4	20%	51.7	206.7
9	0.6	-	0.6	-	-	0.6	25%	0.1	0.4
10	60.8	36.6	97.4	(18.3)	18.3	97.4	30%	29.2	68.2
12	-	86.3	86.3	(43.2)	43.2	86.3	100%	86.3	-
13	34.3	12.1	46.4	(6.0)	-	40.3	N/A	6.4	39.9
14	1.0	-	1.0	-	-	1.0	N/A	0.1	0.8
14.1 (ECE)	13.4	0.1	13.5	(0.0)	0.0	13.5	7%	0.9	12.5
14.1 (Post-2017)	20.7	8.3	29.0	(4.2)	4.2	29.0	5%	1.5	27.6
17	22.9	-	22.9	-	-	22.9	8%	1.8	21.1
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.7	-	1.7	-	-	1.7	30%	0.5	1.2
47	4,416.7	822.9	5,239.7	(411.5)	411.5	5,239.7	8%	419.2	4,820.5
50	1.0	4.2	5.2	(2.1)	2.1	5.2	55%	2.9	2.4
Total CCA	**6,155.9**	**1,111.3**	**7,267.2**	**(555.6)**	**549.6**	**7,261.2**		**663.0**	**6,604.3**
							Less CCA not in rates	(5.2)	
							Total CCA for RR	**657.8**	

2026 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,253.6	28.0	1,281.6	(14.0)	14.0	1,281.6	4%	51.3	1,230.3
2	130.2	-	130.2	-	-	130.2	6%	7.8	122.4
3	7.9	-	7.9	-	-	7.9	5%	0.4	7.5
6	10.3	-	10.3	-	-	10.3	10%	1.0	9.3
7	0.8	-	0.8	-	-	0.8	15%	0.1	0.7
8	206.7	86.3	293.1	(43.2)	43.2	293.1	20%	58.6	234.5
9	0.4	-	0.4	-	-	0.4	25%	0.1	0.3
10	68.2	36.7	104.9	(18.4)	18.4	104.9	30%	31.5	73.4
12	-	65.8	65.8	(32.9)	32.9	65.8	100%	65.8	-
13	39.9	6.0	45.9	(3.0)	-	42.9	N/A	5.4	40.5
14	0.8	-	0.8	-	-	0.8	N/A	0.1	0.7
14.1 (ECE)	12.5	0.1	12.6	(0.0)	0.0	12.6	7%	0.9	11.7
14.1 (Post-2017)	27.6	5.7	33.3	(2.8)	2.8	33.3	5%	1.7	31.6
17	21.1	-	21.1	-	-	21.1	8%	1.7	19.4
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	1.2	-	1.2	-	-	1.2	30%	0.4	0.8
47	4,820.5	736.1	5,556.6	(368.1)	368.1	5,556.6	8%	444.5	5,112.1
50	2.4	3.2	5.5	(1.6)	1.6	5.5	55%	3.0	2.5
Total CCA	**6,604.3**	**967.8**	**7,572.1**	**(483.9)**	**480.9**	**7,569.1**		**674.3**	**6,897.8**
							Less CCA not in rates	(4.9)	
							Total CCA for RR	**669.4**	

2027 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	Bonus Depreciation	UCC for CCA	CCA Rate (%)	Regular CCA	Closing UCC
1	1,230.3	50.8	1,281.1	(25.4)	25.4	1,281.1	4%	51.2	1,229.8
2	122.4	-	122.4	-	-	122.4	6%	7.3	115.0
3	7.5	-	7.5	-	-	7.5	5%	0.4	7.1
6	9.3	-	9.3	-	-	9.3	10%	0.9	8.4
7	0.7	-	0.7	-	-	0.7	15%	0.1	0.6
8	234.5	83.0	317.4	(41.5)	41.5	317.4	20%	63.5	253.9
9	0.3	-	0.3	-	-	0.3	25%	0.1	0.2
10	73.4	38.2	111.6	(19.1)	19.1	111.6	30%	33.5	78.1
12	-	59.4	59.4	(29.7)	29.7	59.4	100%	59.4	-
13	40.5	13.1	53.6	(6.5)	-	47.1	N/A	6.6	47.0
14	0.7	-	0.7	-	-	0.7	N/A	0.1	0.6
14.1 (ECE)	11.7	0.1	11.8	(0.0)	0.0	11.8	5%	0.6	11.2
14.1 (Post-2017)	31.6	8.8	40.4	(4.4)	4.4	40.4	5%	2.0	38.4
17	19.4	-	19.4	-	-	19.4	8%	1.6	17.9
35	-	-	-	-	-	-	7%	-	-
42	0.1	-	0.1	-	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	-	0.0	45%	0.0	0.0
46	0.8	-	0.8	-	-	0.8	30%	0.2	0.6
47	5,112.1	759.0	5,871.1	(379.5)	379.5	5,871.1	8%	469.7	5,401.4
50	2.5	2.9	5.4	(1.5)	1.5	5.4	55%	3.0	2.4
Total CCA	**6,897.8**	**1,015.3**	**7,913.1**	**(507.7)**	**501.1**	**7,906.6**		**700.3**	**7,212.8**
							Less CCA not in rates	(4.6)	
							Total CCA for RR	**695.8**	

HYDRO ONE NETWORKS INC.
TRANSMISSION & DISTRIBUTION
Reconciliation of Accounting to Tax Additions
Historical Actual (2021-Forecast), Bridge (2022) & Test Years (2023 - 2027)
Year Ending December 31
($ Millions)

	2021		2022		2023		2024		2025		2026		2027	
	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION
Fixed asset additions	1,006.0	716.2 *	1,381.6	669.3 *	1,368.1	970.9	1,332.4	1,027.3	1,710.3	1,203.4	1,280.3	1,061.2	1,599.8	1,107.8
Adjustments:														
Asset Removal	59.4	50.8	52.7	52.5	57.5	73.5	59.5	72.4	67.0	78.5	70.0	77.7	66.7	80.6
Land	(4.1)	(0.3)	(7.8)	(0.5)	(1.7)	(0.9)	(0.8)	(0.6)	(3.6)	(1.0)	(1.9)	(0.8)	(2.2)	(0.7)
Share Compensation	(3.0)	(3.0)	(3.0)	(2.7)	(2.8)	(3.3)	(2.8)	(3.3)	(2.6)	(3.1)	(2.5)	(3.0)	(2.6)	(2.9)
Interest Capitalized	(43.3)	(6.8)	(40.2)	(6.9)	(36.4)	(7.6)	(40.9)	(8.2)	(39.6)	(6.5)	(37.0)	(5.3)	(41.4)	(4.6)
Overhead capitalized	(45.2)	(34.7)	(47.1)	(35.5)	(72.6)	(63.3)	(73.6)	(63.8)	(74.4)	(66.9)	(74.7)	(65.9)	(75.3)	(66.8)
Depreciation capitalized	(14.5)	(17.9)	(14.5)	(17.9)	(14.8)	(18.2)	(14.9)	(18.3)	(15.1)	(18.5)	(15.2)	(18.7)	(15.3)	(18.9)
OPEB capitalized	(21.5)	(21.4)	(24.8)	(22.4)	(24.9)	(29.5)	(26.4)	(30.8)	(27.3)	(32.2)	(28.1)	(33.6)	(29.8)	(34.2)
Pension capitalized	(22.9)	(22.8)	(35.3)	(31.9)	(34.5)	(40.9)	(36.2)	(42.2)	(35.9)	(42.4)	(36.6)	(43.9)	(39.1)	(44.8)
Net Tax Additions to UCC	910.8	660.2	1,261.6	604.1	1,238.0	880.8	1,196.4	932.5	1,578.7	1,111.3	1,154.4	967.8	1,460.8	1,015.3

* The accounting additions for DX includes the LDC as illustrated below.

	2021	2022
DX	700.1	656.4
Acquired Utilities (Norfolk, Woodstock, Haldimand)	16.1	12.9
	716.2	669.3

HYDRO ONE NETWORKS INC.
TRANSMISSION & DISTRIBUTION
Calculation of Utility Income Taxes
Historical Years (2018 - 2020)
Year Ending December 31
($M)

Line No.	Particulars		2018		2019		2020*	
1	Net Income Before Tax (NIBT)	$	545.2	336.4	512.7	453.1	562.5	414.4
	Required Adjustments to accounting NIBT							
	Recurring items included in Revenue Requirement (RR):							
2	Other Post Employment Benefit expense greater than payments**		(5.7)	5.9	(5.5)	4.9	17.9	8.9
3	Depreciation and amortization		419.4	392.0	445.0	408.2	443.7	417.3
4	Capital Cost Allowance		(581.3)	(469.8)	(679.5)	(539.3)	(676.1)	(534.6)
5	Removal costs		(1.2)	(2.9)	(7.4)	(2.7)	(10.2)	(1.7)
6	Environmental costs paid		(6.7)	(14.6)	(5.5)	(15.6)	(7.7)	(14.3)
7	Non-deductible items (50% Meals & entertainment / interest)		3.0	2.2	2.5	1.8	1.9	1.3
8	R & D Fed ITC/ Apprenticeship (prior yr addback)		0.4	0.7	0.3	0.5	0.4	0.9
9	Capitalized overhead costs deducted		(45.0)	(28.3)	(44.8)	(32.1)	(46.7)	(33.3)
10	Capital items expensed for accounting		1.5	2.2	1.1	1.4	0.0	0.0
11	Capitalized Pension cost deductions		(24.5)	(18.0)	(24.3)	(18.6)	(24.4)	(18.7)
12	Capitalized SRED Expenditures deductible for tax		0.0	0.0	0.0	0.0	0.0	0.0
13	Net Underwriting/Finance costs		(0.7)	(0.7)	(0.7)	(0.8)	(1.7)	(1.1)
14	Capital contributions		6.8	0.0	0.0	0.0	2.1	0.0
15	Non-deductible Share based compensation		4.6	3.9	2.1	2.4	3.3	4.1
16		$	(229.4)	(127.4)	(316.8)	(189.8)	(297.5)	(171.2)
	Deferral accounts not part of RR:							
17	Deferral accounts		(21.2)	54.6	(9.2)	(33.1)	(44.9)	122.9
		$	(21.2)	54.6	(9.2)	(33.1)	(44.9)	122.9
	Reversal of accounting adjustments not part of RR:							
18	Contingent liability movement		0.4	0.7	(0.6)	(0.7)	(1.3)	(1.5)
19	Capitalized interest deductible for tax		(45.5)	(7.6)	(40.9)	(6.7)	(40.5)	(8.0)
		$	(45.0)	(6.9)	(41.5)	(7.4)	(41.8)	(9.5)
	Recurring items not part of RR:							
20	Project Cancellation Costs		11.6	3.6	1.5	5.9	0.5	(0.3)
21	CCRA true ups		0.0	0.0	2.7	0.0	0.0	0.0
22	CCA not included in rates (CCRA True up, OPA directed Costs)		(11.3)	(3.0)	(11.1)	(3.4)	(10.2)	(3.2)
		$	0.3	0.6	(6.8)	2.4	(9.7)	(3.5)
	Items not in business plan detail:							
23	Reverse Insurance proceeds included in NIBT		(3.5)	(0.3)	(14.1)	0.0	(4.8)	0.0
24	Tenant Inducement		(1.2)	(1.6)	0.6	0.8	(0.5)	(0.6)
25	Cash received on OPEB transfer		0.0	0.0	0.0	0.0	0.0	23.5
26	Other		(4.3)	(2.6)	1.4	1.2	(0.9)	5.5
			(9.0)	(4.5)	(12.1)	2.0	(6.2)	28.4
27	NET Adjustments to Accounting NIBT	$	(304.4)	(83.5)	(386.4)	(225.9)	(400.2)	(32.9)
28	Taxable Income	$	240.9	252.9	126.3	227.2	162.3	381.5
29	Corporate Income Tax Rate		26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
30	Subtotal		63.8	67.0	33.5	60.2	43.0	101.1
31	Less: Tax Credits		(0.4)	(0.6)	(0.4)	(0.9)	(0.3)	(0.5)
32	Less: Deferred Tax Asset Sharing ***		(25.8)	(14.2)	(26.0)	(19.3)	(24.1)	(17.8)
33	Income Tax	$	37.6	52.3	7.1	40.0	18.6	82.8
	Tax Rates							
34	Federal Tax		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
35	Provincial Tax		11.5%	11.5%	11.5%	11.5%	11.5%	11.5%
36	Total Tax Rate		26.5%	26.5%	26.5%	26.5%	26.5%	26.5%

Notes:

* Based on tax estimates for 2020, as the 2020 Income Tax Returns will not be filed until June 2021.

** 2020 Transmission net add back of $17.9M for Other Post Employment Benefit expense greater than payments reflects the OEB's finding that the non-service component of 2020 OPEB costs shall be recognized as OM&A pursuant to EB-2019-0082 revenue requirement and charge determinant order dated July 16, 2020.

*** The amounts in this line are net of tax gross-up, as the tax gross-up is included in the line 30 - Subtotal above. As such, the total Deferred Tax Asset Sharing amounts deducted from Regulatory Income Tax is as follows:

	2018		2019		2020	
	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION	TRANSMISSION	DISTRIBUTION
Deferred Tax Asset Sharing in line 32	(25.8)	(14.2)	(26.0)	(19.3)	(24.1)	(17.8)
Tax gross-up included in line 30	(9.3)	(5.1)	(9.4)	(7.0)	(8.7)	(6.4)
Total Deferred Tax Asset Sharing included in Income Tax expense ****	(35.1)	(19.3)	(35.4)	(26.3)	(32.8)	(24.2)

**** These amounts agree to EB-2020-0194, Exhibit A-1-1, Table 1, page 7 of 20 filed October 28, 2020

HYDRO ONE NETWORKS INC.
TRANSMISSION & DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
2018 Networks Tax Return Allocation to Transmission & Distribution
Year Ending December 31
($M)

2018 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate (%)	CCA	Closing UCC
1	1,925.2	59.0	1,984.2	29.5	1,954.7	4%	78.2	1,906.0
2	473.3	-	473.3	-	473.3	6%	28.4	444.9
3	228.1	0.3	228.3	0.1	228.2	5%	11.4	216.9
6	62.4	5.2	67.6	2.6	65.0	10%	6.5	61.1
7	0.0	-	0.0	-	0.0	15%	0.0	0.0
8	116.9	42.5	159.4	21.3	138.2	20%	27.6	131.8
9	0.5	-	0.5	-	0.5	25%	0.1	0.4
10	41.9	5.3	47.2	2.6	44.6	30%	13.4	33.8
10.1	0.8	0.0	0.8	0.0	0.8	30%	0.2	0.6
12	17.4	27.0	44.4	13.5	30.9	100%	30.9	13.5
13	11.4	0.2	11.6	0.1	11.5	N/A	1.7	9.9
14.1 (ECE)*	41.9	-	41.9	-	41.9	7%	2.9	39.0
14.1 (Post-2017)	6.4	3.5	9.9	1.8	8.1	5%	0.4	9.5
17	92.2	28.7	121.0	14.4	106.6	8%	8.5	112.4
35	0.1	-	0.1	-	0.1	7%	0.0	0.1
42	72.2	1.5	73.7	0.7	73.0	12%	8.8	64.9
45	0.0	-	0.0	-	0.0	45%	0.0	0.0
46	7.7	5.4	13.1	2.7	10.4	30%	3.1	10.0
47	3,459.5	756.9	4,216.3	378.4	3,837.9	8%	307.0	3,909.3
50	56.9	116.3	173.2	58.2	115.1	55%	63.3	109.9
Total CCA	**6,614.9**	**1,051.8**	**7,666.7**	**525.9**	**7,140.8**		**592.5**	**7,074.2**
					Less CCA not in rates		(11.2)	
					Total		**581.3**	

2018 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate (%)	CCA	Closing UCC
1	1,452.5	7.6	1,460.0	3.8	1,456.2	4%	58.2	1,401.8
2	213.5	-	213.5	-	213.5	6%	12.8	200.7
3	11.9	-	11.9	-	11.9	5%	0.6	11.3
6	19.2	1.7	20.9	0.8	20.0	10%	2.0	18.9
8	138.8	34.5	173.3	17.3	156.0	20%	31.2	142.1
9	1.1	-	1.1	-	1.1	25%	0.3	0.9
10	100.7	13.4	114.1	6.7	107.4	30%	32.2	81.8
10.1	1.7	0.0	1.8	0.0	1.7	30%	0.5	1.2
12	30.7	60.3	91.0	30.1	60.9	100%	60.9	30.1
13	14.3	0.2	14.5	0.1	14.4	N/A	1.7	12.7
14.1 (ECE)*	21.1	-	21.1	-	21.1	7%	1.5	19.6
14.1 (Post-2017)	(0.1)	0.4	0.4	0.2	0.2	5%	0.0	0.4
17	21.5	4.0	25.4	2.0	23.5	8%	1.9	23.6
42	0.2	-	0.2	-	0.2	12%	0.0	0.2
45	0.0	-	0.0	-	0.0	45%	0.0	0.0
46	4.6	5.9	10.6	3.0	7.6	30%	2.3	8.3
47	3,012.0	457.4	3,469.3	228.7	3,240.7	8%	259.3	3,210.1
50	10.3	5.5	15.8	2.7	13.1	55%	7.2	8.6
Total CCA	**5,055.8**	**590.8**	**5,646.7**	**295.4**	**5,351.2**		**472.7**	**5,174.0**
					Less CCA not in rates		(2.9)	
					Total CCA for RR		**469.8**	

Note:
* The Eligible Capital Expenditures (ECE) was transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027.

HYDRO ONE NETWORKS INC.
TRANSMISSION & DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
2019 Networks Tax Return Allocation to Transmission & Distribution
Year Ending December 31
($M)

2019 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate (%)	CCA	Accelerated CCA on Eligible Net Additions	Closing UCC
1	1,906.0	48.2	1,954.2	24.1	1,930.1	4%	77.2	1.0	1,876.0
2	444.9	-	444.9	-	444.9	6%	26.7	-	418.2
3	216.9	0.1	217.0	0.0	217.0	5%	10.8	0.0	206.2
6	61.1	3.4	64.5	1.7	62.8	10%	6.3	0.2	58.0
7	0.0	-	0.0	-	0.0	15%	0.0	-	0.0
8	131.8	47.8	179.6	23.9	155.7	20%	31.1	4.9	143.5
9	0.4	2.2	2.6	1.1	1.5	25%	0.4	0.3	2.0
10	33.8	8.3	42.1	4.1	38.0	30%	11.4	1.4	29.3
10.1	0.6	0.6	1.2	0.3	0.9	30%	0.3	0.1	0.8
12	13.5	57.3	70.8	28.6	42.2	100%	42.2	14.6	14.0
13	9.9	0.1	10.0	0.1	10.0	N/A	1.7	-	8.3
14.1 (ECE)*	39.0	-	39.0	-	39.0	7%	2.7	-	36.3
14.1 (Post-2017)	9.5	6.5	16.0	3.3	12.8	5%	0.6	0.2	15.2
17	112.4	6.6	119.1	3.3	115.8	8%	9.3	0.3	109.5
35	0.1	-	0.1	-	0.1	7%	0.0	-	0.1
42	64.9	0.0	65.0	0.0	65.0	12%	7.8	0.0	57.2
45	0.0	-	0.0	-	0.0	45%	0.0	-	0.0
46	10.0	4.9	14.9	2.4	12.4	30%	3.7	0.8	10.4
47	3,909.3	647.9	4,557.2	324.0	4,233.3	8%	338.7	31.6	4,187.0
50	109.9	7.0	117.0	3.5	113.5	55%	62.4	2.0	52.6
Total CCA	**7,074.2**	**841.0**	**7,915.2**	**420.5**	**7,494.7**		**633.3**	**57.3**	**7,224.6**
						Total CCA	690.6		
						Less CCA not in rates	(11.1)		
						Total CCA for RR	**679.5**		

2019 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate (%)	CCA	Accelerated CCA on Eligible Net Additions	Closing UCC
1	1,401.8	8.1	1,409.9	4.0	1,405.8	4%	56.2	0.3	1,353.3
2	200.7	-	200.7	-	200.7	6%	12.0	-	188.7
3	11.3	0.0	11.3	0.0	11.3	5%	0.6	0.0	10.7
6	18.9	1.5	20.4	0.8	19.6	10%	2.0	0.1	18.3
8	142.1	(21.7)	120.4	(10.9)	131.2	20%	26.2	(4.0)	98.1
9	0.9	2.4	3.3	1.2	2.1	25%	0.5	0.6	2.2
10	81.8	20.3	102.1	10.1	92.0	30%	27.6	6.0	68.5
10.1	1.2	1.2	2.4	0.6	1.8	30%	0.6	0.3	1.6
12	30.1	56.7	86.8	28.3	58.5	100%	58.5	25.8	2.5
13	12.7	0.3	13.0	0.2	12.9	N/A	1.8	-	11.3
14	1.7	-	1.7	-	1.7	N/A	0.1	-	1.5
14.1 (ECE)*	19.6	-	19.6	-	19.6	7%	1.4	-	18.2
14.1 (Post-2017)	0.4	0.0	0.4	0.0	0.4	5%	0.0	0.0	0.4
17	23.6	6.2	29.7	3.1	26.7	8%	2.1	0.5	27.2
42	0.2	-	0.2	-	0.2	12%	0.0	-	0.2
45	0.0	-	0.0	-	0.0	45%	0.0	-	0.0
46	8.3	5.2	13.5	2.6	10.9	30%	3.3	1.4	8.8
47	3,210.1	473.2	3,683.3	236.6	3,446.7	8%	275.7	34.5	3,373.1
50	8.6	4.8	13.5	2.4	11.0	55%	6.1	2.4	4.9
Total CCA	**5,174.0**	**558.3**	**5,732.3**	**279.1**	**5,453.1**		**474.7**	**68.0**	**5,189.5**
						Total CCA	542.7		
						Less CCA not in rates	(3.4)		
						Total CCA for RR	**539.3**		

Note:
* The Eligible Capital Expenditures (ECE) was transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027.

HYDRO ONE NETWORKS INC.
TRANSMISSION & DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
2020* Networks Tax Return Allocation to Transmission & Distribution
Year Ending December 31
($ Millions)

2020 TRANSMISSION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate (%)	CCA	Accelerated CCA on Eligible Net Additions	Closing UCC
1	1,876.0	52.0	1,928.0	26.0	1,902.0	4%	76.1	1.9	1,850.0
2	418.2	-	418.2	-	418.2	6%	25.1	-	393.1
3	206.2	0.0	206.2	0.0	206.2	5%	10.3	0.0	195.9
6	58.0	1.1	59.1	0.5	58.6	10%	5.9	0.1	53.1
7	0.0	2.0	2.0	1.0	1.0	15%	0.2	0.3	1.6
8	143.5	35.8	179.3	17.9	161.4	20%	32.3	6.3	140.7
9	2.0	0.2	2.2	0.1	2.1	25%	0.5	0.0	1.6
10	29.3	6.8	36.1	3.4	32.7	30%	9.8	2.0	24.2
10.1	0.8	-	0.8	-	0.8	30%	0.2	-	0.6
12	14.0	37.2	51.2	18.6	32.6	100%	32.6	16.2	2.4
13	8.3	0.1	8.4	0.0	8.4	N/A	1.6		6.7
14.1 (ECE)**	36.3	(6.8)	29.5	(3.4)	32.9	7%	2.3	(0.5)	27.7
14.1 (Post-2017)	15.2	0.8	16.0	0.4	15.6	5%	0.8	0.0	15.2
17	109.5	8.5	118.0	4.2	113.8	8%	9.1	0.6	108.3
35	0.1	-	0.1	-	0.1	7%	0.0	-	0.1
42	57.2	0.1	57.3	0.0	57.2	12%	6.9	0.0	50.4
45	0.0	-	0.0	-	0.0	45%	0.0	-	0.0
46	10.4	1.3	11.7	0.6	11.0	30%	3.3	0.3	8.0
47	4,187.0	662.4	4,849.3	331.2	4,518.2	8%	361.5	46.9	4,441.0
50	52.6	6.2	58.8	3.1	55.7	55%	30.6	3.0	25.1
Total CCA	**7,224.6**	**807.5**	**8,032.1**	**403.8**	**7,628.3**		**609.1**	**77.3**	**7,345.8**
						Total CCA	686.3		
						Less CCA not in rates	(10.3)		
						Total CCA for RR	**676.1**		

2020 DISTRIBUTION

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate (%)	CCA	Accelerated CCA on Eligible Net Additions	Closing UCC
1	1,353.3	29.1	1,382.4	14.6	1,367.9	4%	54.7	1.1	1,326.6
2	188.7	-	188.7	-	188.7	6%	11.3	-	177.4
3	10.7	-	10.7	-	10.7	5%	0.5	-	10.2
6	18.3	1.2	19.5	0.6	18.9	10%	1.9	0.1	17.5
7	-	2.3	2.3	1.1	1.1	15%	0.2	0.3	1.8
8	98.1	6.2	104.3	3.1	101.2	20%	20.2	1.3	82.8
9	2.2	0.2	2.4	0.1	2.3	25%	0.6	0.1	1.8
10	68.5	16.2	84.7	8.1	76.6	30%	23.0	5.0	56.7
10.1	1.6	-	1.6	-	1.6	30%	0.5	-	1.1
12	2.5	73.6	76.1	36.8	39.3	100%	39.3	35.5	1.3
13	11.3	7.0	18.3	3.5	14.8	N/A	2.3		15.9
14	1.5	-	1.5	-	1.5	N/A	-	0.1	1.4
14.1 (ECE)**	18.2	-	18.2	-	18.2	7%	1.3	-	17.0
14.1 (Post-2017)	0.4	(0.1)	0.3	(0.0)	0.3	5%	0.0	(0.0)	0.3
17	27.2	7.9	35.1	4.0	31.1	8%	2.5	0.6	32.0
42	0.2	-	0.2	-	0.2	12%	0.0	-	0.1
46	8.8	1.5	10.3	0.7	9.5	30%	2.9	0.4	7.0
47	3,373.1	474.0	3,847.1	237.0	3,610.1	8%	288.8	36.8	3,521.5
50	4.9	4.2	9.2	2.1	7.1	55%	3.9	2.6	2.7
Total CCA	**5,189.5**	**623.3**	**5,812.8**	**311.6**	**5,501.2**		**453.9**	**83.9**	**5,275.0**
						Total CCA	537.8		
						Less CCA not in rates	(3.2)		
						Total CCA for RR	**534.6**		

Note:
* The 2020 Capital Cost Allowance is estimates only, as the tax return has not been filed.

** The Eligible Capital Expenditures (ECE) was transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027.

HYDRO ONE NETWORKS INC.
Transmission & Distribution
Calculation of Apprenticeship, Co-op, and SR&ED Tax Credit
Historical Actual (2021-Forecast), Bridge (2022) & Test Years (2023 - 2027)
Year Ending December 31
($ Thousands)

Particulars	2021		2022		2023		2024		2025		2026		2027	
	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution
Ontario Coop Education Credit	$ 333	$ 787	$ 333	$ 787	$ 333	$ 787	$ 333	$ 787	$ 333	$ 787	$ 333	$ 787	$ 333	$ 787
Eligible Positions	111	263	111	263	111	263	111	263	111	263	111	263	111	263
Ontario Apprenticeship Credit (2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eligible Positions (2)														
Ontario Business Research Credit	$ 9	$ 21	$ 9	$ 21	$ 9	$ 21	$ 9	$ 21	$ 9	$ 21	$ 9	$ 21	$ 9	$ 21
Federal Apprenticeship Credit	$ 343	$ 427	$ 356	$ 414	$ 331	$ 439	$ 334	$ 436	$ 332	$ 438	$ 329	$ 441	$ 336	$ 434
Eligible Positions	181	225	187	218	174	231	176	230	175	231	173	232	177	229
SR&ED (3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL TAX CREDITS	**$ 685**	**$ 1,235**	**$ 697**	**$ 1,223**	**$ 673**	**$ 1,247**	**$ 675**	**$ 1,245**	**$ 674**	**$ 1,246**	**$ 671**	**$ 1,249**	**$ 677**	**$ 1,243**
Tax Credit included in OM&A (1)	$ 342	$ 808	$ 342	$ 808	$ 342	$ 808	$ 342	$ 808	$ 342	$ 808	$ 342	$ 808	$ 342	$ 808
Tax Credit included in tax expense (1)	$ 343	$ 427	$ 356	$ 414	$ 331	$ 439	$ 334	$ 436	$ 332	$ 438	$ 329	$ 441	$ 336	$ 434
	$ 685	**$ 1,235**	**$ 697**	**$ 1,223**	**$ 673**	**$ 1,247**	**$ 675**	**$ 1,245**	**$ 674**	**$ 1,246**	**$ 671**	**$ 1,249**	**$ 677**	**$ 1,243**

(1) In accordance with US GAAP, refundable tax credits included are recorded in OM&A and non-refundable tax credits are recorded as a reduction to tax expense. Consequently, the tax credits relating Ontario Co-op, Ontario Apprenticeship, and Ontario Business Research are recorded in OM&A.

(2) The Ontario government replaced the Ontario Apprenticeship Credit with the new Graduated Apprenticeship Grant for Employers (GAGE) for eligible apprentices hired after November 14, 2017. The GAGE is no longer administered through the tax return. Fiscal year 2020 is the last year the Ontario Apprenticeship Credit is claimed.

(3) No estimate for the SR&ED tax credit has been made due to uncertainty on which Hydro One's projects (if any) will meet the Canada Revenue Agency's SR&ED eligibility requirements. Hydro One will continue to review its annual claim eligibility, and to file a SR&ED claim where possible.

HYDRO ONE NETWORKS INC.
Transmission & Distribution
Calculation of Apprenticeship, Co-op, and SR&ED Tax Credit
Tax Credit Historical Years (2018 to 2020)
Year Ending December 31
($ Thousands)

Particulars	2018		2019		2020	
	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution
Ontario Coop Education Credit	$ 372	$ 580	$ 257	$ 609	$ 147	$ 243
Eligible Positions	125	194	86	203	49	81
Ontario Apprenticeship Credit [2]	$ 1,007	$ 1,570	$ 374	$ 884	$ 157	$ 258
Eligible Positions [2]	221	345	113	267	63	103
Ontario Business Research Credit	$ -	$ -	$ 6	$ 14	$ 34	$ 56
Federal Apprenticeship Credit	$ 349	$ 545	$ 244	$ 578	$ 309	$ 510
Eligible Positions	185	288	124	295	158	260
SR&ED	$ 98	$ 68	$ 143	$ 338	$ -	$ -
TOTAL TAX CREDITS	**$ 1,826**	**$ 2,762**	**$ 1,024**	**$ 2,423**	**$ 647**	**$ 1,068**
Tax Credit included in OM&A [1]	$ 1,379	$ 2,150	$ 637	$ 1,507	$ 338	$ 557
Tax Credit included in tax expense [1]	$ 447	$ 612	$ 387	$ 916	$ 309	$ 510
	$ 1,826	**$ 2,762**	**$ 1,024**	**$ 2,423**	**$ 647**	**$ 1,068**

(1) In accordance with US GAAP, refundable tax credits included are recorded in OM&A and non-refundable tax credits are recorded as a reduction to tax expense. Consequently, the tax credits relating Ontario Co-op, Ontario Apprenticeship, and Ontario Business Research are recorded in OM&A.

(2) The Ontario government replaced the Ontario Apprenticeship Credit with the new Graduated Apprenticeship Grant for Employers (GAGE) for eligible apprentices hired after November 14, 2017. The GAGE is no longer administered through the tax return. Apprentices hired prior to November 15, 2017 continue to be eligible for the Ontario Apprenticeship Credit for the first 36 months of their apprenticeship programs. Fiscal year 2020 will be the last year the Ontario Apprenticeship Credit is claimed.

The tax credits are based on historical amounts updated for the budget change which reduced Ontario Apprenticeship Tax Credits from 10K to 5K. This has not incorporated the new GAGE program effective November 15, 2017 as no information is available.

(3) 2020 tax credits are based on estimates of actual tax credits.

HYDRO ONE NETWORKS INC. INCOME TAX RETURN

Attachment 1: Hydro One Networks Inc. 2020 Income Tax Return

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Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) **001**

Corporation's name

002 HYDRO ONE NETWORKS INC.

Address of head office

Has this address changed since the last time we were notified? . . . . **010** Yes [ ] No [X]

If **yes**, complete lines 011 to 018.

011 483 BAY STREET, 8TH FLOOR

012 SOUTH TOWER

City **015** TORONTO — Province, territory, or state **016** ON

Country (other than Canada) **017** CA — Postal or ZIP code **018** M5G 2P5

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . **020** Yes [ ] No [X]

If **yes**, complete lines 021 to 028.

021 c/o TAX DEPARTMENT

022 483 BAY STREET, 7TH FLOOR

023 SOUTH TOWER

City **025** TORONTO — Province, territory, or state **026** ON

Country (other than Canada) **027** — Postal or ZIP code **028** M5G 2P5

Location of books and records (if different from head office address)

Has this address changed since the last time we were notified? . . . . **030** Yes [ ] No [X]

If **yes**, complete lines 031 to 038.

031 483 BAY STREET, 7TH FLOOR

032 SOUTH TOWER

City **035** TORONTO — Province, territory, or state **036** ON

Country (other than Canada) **037** — Postal or ZIP code **038** M5G 2P5

040 **Type of corporation at the end of the tax year** (tick one)

- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [X] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** Year Month Day

To which tax year does this return apply?

Tax year start **060** Year Month Day 2020-01-01 — Tax year-end **061** Year Month Day 2020-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . **063** Yes [ ] No [X]

If **yes**, provide the date control was acquired . . . . **065** Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . **066** Yes [ ] No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** Yes [ ] No [X]

Is this the first year of filing after:

Incorporation? . . . . **070** Yes [ ] No [X]

Amalgamation? . . . . **071** Yes [ ] No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** Yes [X] No [ ]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** Yes [ ] No [X]

Is this the final return up to dissolution? . . . . **078** Yes [ ] No [X]

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada? **080** Yes [X] No [ ]

If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** Yes [ ] No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area

095 **096** **898**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	X	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170	X	29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272		58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

[redacted]

Attachments (continued)

	Line	Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	X	54

Additional information

	Line	Yes	No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product or service	Line	%
284	Electricity	285	100.000 %
286		287	%
288		289	%

	Line	Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 Yes No

Taxable income

	Line	Amount		
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		33,288,191	A
Deduct:				
Charitable donations from Schedule 2	311	2,030,654		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331	30,767,995		
Net capital losses of previous tax years from Schedule 4	332	489,542		
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities under an employee stock options agreement		a		
Subtotal		33,288,191 ▶	33,288,191	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360			
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7 . . . . . **400** ________ A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** ________ B

Business limit (see notes 1 and 2 below) . . . . . **410** ________ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C ________ x **415** *** ________ / 11,250 D = ... ________ E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** . **417** ________ – 50,000 = . . ________ F

Amount C ________ / 100,000 x Amount F ________ = ... ________ G

The greater of amount E and amount G **422** ________ H

Reduced business limit (amount C **minus** amount H) (if negative, enter "0") . . . . . **426** ________ I

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . ________ J

Reduced business limit after assignment (amount I **minus** amount J) . . . . . **428** ________ K

Small business deduction – Amount A, B, C, or K, whichever is the least . . . . ________ x 19 % = **430** ________

Enter amount from line 430 at amount J on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount **490**	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] **500**	N Business limit assigned to corporation identified in column L [4] **505**
1.				
			Total **510** ________	Total **515** ________

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if

   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and

   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to

   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or

   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.

4. Theamount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B		
Amount 13K from Part 13 of Schedule 27		C		
Personal services business income	432	D		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least		E		
Aggregate investment income from line 440 on page 6*		F		
Subtotal (**add** amounts B to F)		►		G
Amount A **minus** amount G (if negative, enter "0")				H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %				I

Enter amount I on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3				J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		K		
Amount 13K from Part 13 of Schedule 27		L		
Personal services business income	434	M		
Subtotal (**add** amounts K to M)		►		N
Amount J **minus** amount N (if negative, enter "0")				O
General tax reduction – Amount O **multiplied** by 13 %				P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 30 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 8 . . . . ________ B

Foreign investment income from Schedule 7 . . . . **445** ________ x 8 % = ________ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") ________ ► ________ D

Amount A **minus** amount D (if negative, enter "0") . . . . ________ E

Taxable income from line 360 on page 3 . . . . ________ F

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least . . . . ________ G

Foreign non-business income tax credit from line 632 on page 8 . . . . ________ x 75 / 29 = ________ H

Foreign business income tax credit from line 636 on page 8 . . ________ x 4 = ________ I

Subtotal (**add** amounts G to I) ________ ► ________ J

Subtotal (amount F **minus** amount J) ________ K x 30 2 / 3 % = ________ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . ________ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ________ N

Refundable dividend tax on hand

Refundable dividend tax on hand (RDTOH) at the end of the previous tax year	460			
Dividend refund for the previous tax year	465			
Net RDTOH transferred on an amalgamation or the wind-up of a subsidiary	480			
Subtotal (line 460 **minus** line 465 **plus** line 480)				A
General rate income pool (GRIP) at the end of the previous tax year (from line 100 of Schedule 53)				B
Total eligible dividends paid in the previous tax year (from line 300 of Schedule 53)			C	
Total excessive eligible dividend designation in the previous tax year (from line 310 of Schedule 53)			D	
Subtotal (amount C **minus** amount D) (if negative, enter "0")			▶	E
Net GRIP at the end of the previous tax year (amount B **minus** amount E) (if negative, enter "0")			F	
GRIP transferred on an amalgamation or the wind-up of a subsidiary (total of lines 230 and 240 of Schedule 53)			G	
Subtotal (amount F **plus** amount G)			▶	H
Amount H **multiplied** by 38 1 / 3 %				I
Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A or I, whichever is less, otherwise, use line 530 of the preceding tax year)	520			J
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A **minus** amount I, otherwise, use line 545 of the preceding tax year) (if negative, enter "0")	535			K
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)			L	
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)			M	
Subtotal (amount L **plus** amount M)			▶	N
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525			O
ERDTOH dividend refund for the previous tax year	570			P
Refundable portion of Part I tax (from line 450 on page 6)				Q
Part IV tax before deductions (amount 2A from Schedule 3)			R	
Part IV tax allocated to ERDTOH (amount N)			S	
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)			T	
Subtotal (amount R **minus** total of amounts S and T)			▶	U
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540			V
NERDTOH dividend refund for the previous tax year	575			W
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)				X
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount U **minus** amount X) (if negative enter "0")				Y
NERDTOH at the end of the tax year (total of amounts K, Q, V, and Y **minus** amount W) (if negative, enter "0")	545			
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount N **minus** the amount, if any, by which amount X exceeds amount U) (if negative, enter "0")				Z
ERDTOH at the end of the tax year (total of amounts J, O, and Z **minus** amount P) (if negative, enter "0")	530			

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)	383,333	AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)		DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")		GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 % . . . . 550 ______ A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business . . . . 555 ______ x 5 % = 560 ______ B

Recapture of investment tax credit from Schedule 31 . . . . 602 ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . ______ D

Taxable income from line 360 on page 3 . . . . ______ E

Deduct:

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least . . . . ______ F

Net amount (amount E **minus** amount F) ______ ► ______ G

Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G . . . . 604 ______ H

Subtotal (**add** amounts A, B, C, and H) ______ I

Deduct:

Small business deduction from line 430 on page 4 . . . . ______ J

Federal tax abatement . . . . 608 ______

Manufacturing and processing profits deduction from Schedule 27 . . . . 616 ______

Investment corporation deduction . . . . 620 ______

Taxed capital gains 624 ______

Federal foreign non-business income tax credit from Schedule 21 . . . . 632 ______

Federal foreign business income tax credit from Schedule 21 . . . . 636 ______

General tax reduction for CCPCs from amount I on page 5 . . . . 638 ______

General tax reduction from amount P on page 5 . . . . 639 ______

Federal logging tax credit from Schedule 21 . . . . 640 ______

Eligible Canadian bank deduction under section 125.21 . . . . 641 ______

Federal qualifying environmental trust tax credit . . . . 648 ______

Investment tax credit from Schedule 31 . . . . 652 ______

Subtotal ______ ► ______ K

Part I tax payable – Amount I **minus** amount K . . . . ______ L

Enter amount L on line 700 on page 9.

Privacy statement

Personal information (including the SIN) is collected for the purposes of the administration or enforcement of the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties, or other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	24,780,410
Total tax payable	770	24,780,410 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount JJ on page 7	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit (Form T1131)	796	
Film or video production services tax credit (Form T1177)	797	
Canadian journalism labour tax credit from Schedule 58	798	
Tax withheld at source	800	
Total payments on which tax has been withheld 801		
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	29,873,988
Total credits	890	29,873,988 ▶ 29,873,988 B

Balance (amount A **minus** amount B) -5,093,578

If the result is negative, you have a **refund**.
If the result is positive, you have a **balance owing**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Refund code 894 2 Refund 5,093,578

Balance owing

For information on how to make your payment, go to **canada.ca/payments**.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920

Certification

I, 950 Tran (Last name) 951 Nancy (First name) 954 VP, Corporate Tax (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2021-06-28 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☒ No ☐

958 Name of other authorized person 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Schedule of Instalment Remittances

Name of corporation contact: Nancy Tran
Telephone number: (416) 345-6778

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	29,873,988
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	29,873,988 A
	Total instalments credited to the taxation year per T9	29,873,988 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2020-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	1,256,000,000	1,250,000,000
	Total tangible capital assets	2008	+	33,394,000,000	31,795,000,000
	Total accumulated amortization of tangible capital assets	2009	–	11,811,000,000	11,255,000,000
	Total intangible capital assets	2178	+	1,264,000,000	1,137,000,000
	Total accumulated amortization of intangible capital assets	2179	–	585,000,000	515,000,000
	Total long-term assets	2589	+	3,309,000,000	2,538,000,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	26,827,000,000	24,950,000,000
	Liabilities				
	Total current liabilities	3139	+	2,082,000,000	2,701,000,000
	Total long-term liabilities	3450	+	14,021,000,000	12,708,545,241
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	16,103,000,000	15,409,545,241
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	10,724,000,000	9,538,746,937
	Total liabilities and shareholder equity	3640	=	26,827,000,000	24,948,292,178
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	7,799,000,000	6,000,746,937

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2020-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	7,065,317,802	6,323,249,824
	Cost of sales	8518	–	3,796,000,000	3,111,000,000
	Gross profit/loss	8519	=	3,269,317,802	3,212,249,824
	Cost of sales	8518	+	3,796,000,000	3,111,000,000
	Total operating expenses	9367	+	2,298,473,643	2,244,401,075
	Total expenses (mandatory field)	9368	=	6,094,473,643	5,355,401,075
	Total revenue (mandatory field)	8299	+	7,100,858,397	6,336,643,312
	Total expenses (mandatory field)	9368	–	6,094,473,643	5,355,401,075
	Net non-farming income	9369	=	1,006,384,754	981,242,237
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	1,006,384,754	981,242,237
	Total – other comprehensive income	9998	=	-6,572,258	242,458
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	29,395,032	26,200,712
	Future (deferred) income tax provision	9995	–	-814,263,341	21,488,775
	Total – Other comprehensive income	9998	+	-6,572,258	242,458
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,784,680,805	933,795,208

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
HYDRO ONE NETWORKS INC.		2020-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI) and T4012, T2 Corporation – Income Tax Guide.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** Yes [X] No [ ]

Is the accountant connected* with the corporation? . . . **097** Yes [X] No [ ]

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . 1 [ ]

Completed a review engagement report . . . 2 [ ]

Conducted a compilation engagement . . . 3 [ ]

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** Yes [ ] No [ ]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . **101** Yes [X] No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . **104** Yes [X] No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . **105** Yes [X] No [ ]

Is contingent liability information mentioned in the notes? . . . **106** Yes [X] No [ ]

Is information regarding commitments mentioned in the notes? . . . **107** Yes [X] No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** Yes [X] No [ ]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . **200** Yes [X] No [ ]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	-257,597
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . **250** Yes [ ] No [X]

Did the corporation apply hedge accounting during the tax year? . . . . **255** Yes [X] No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . **260** Yes [ ] No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . **265** Yes [ ] No [X]

If **yes**, you have to maintain a separate reconciliation.

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13(7.4) ELECTION:
The Taxpayer is electing under subsection 13(7.4) of the Income Tax Act with respect to amounts that would normally be included in income under paragraph 12(1)(x). The amount elected to reduce the cost of depreciable property instead of being included in income is $201,482,846.
1. DESCRIPTION OF THE BUSINESS
Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the Business Corporations Act (Ontario) and is a wholly-owned subsidiary of Hydro One Inc. (Hydro One). The Company owns and operates regulated transmission and distribution businesses. The regulated transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).Rate Setting
Transmission
On March 7, 2019, the OEB issued its reconsideration decision (DTA Decision) with respect to Hydro One's rate-setting treatment of the benefits of the deferred tax asset resulting from the transition from the payments in lieu of tax regime to tax payments under the federal and provincial tax regimes. On July 16, 2020, the Ontario Divisional Court rendered its decision on the Company's appeal of the OEB's DTA Decision. See Note 11 - Regulatory Assets and Liabilities.
On April 23, 2020, the OEB rendered its decision on Hydro One Networks' 2020-2022 transmission rate application (2020-2022 Transmission Decision). On July 16, 2020, the OEB issued its final rate order for the 2020-2022 transmission rates approving a revenue requirement of $1,630 million, $1,701 million and $1,772 million for 2020, 2021 and 2022, respectively. On July 30, 2020, the OEB issued its decision for Uniform Transmission Rates (UTRs). The 2020 UTRs that were put in place on an interim basis on January 1, 2020 continued for the remainder of 2020 in light of the COVID-19 pandemic. On December 17, 2020, the OEB issued its decision and order setting the final 2021 UTRs effective January 1, 2021, which included the approval of a two-year disposition period for Hydro One Networks' 2020 foregone revenue including interest, beginning on January 1, 2021.Distribution
In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. On March 7, 2019, the OEB rendered its decision on the distribution rates application. In accordance with the OEB decision, the Company filed its draft rate order reflecting updated revenue requirements of $1,459 million for 2018, $1,498 million for 2019, $1,532 for 2020, $1,578 million for 2021, and $1,624 million for 2022. On June 11, 2019, the OEB approved the rate order confirming these updated revenue requirements.
2. SIGNIFICANT ACCOUNTING POLICIES
Basis of Accounting
These unconsolidated financial statements (Financial Statements) are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP), with the exception that business combinations of entities under common control have been accounted for as of the date of the transfer, such that (1) the Financial Statements were not prepared as though the transfer of entities under common control had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted.

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Notes to the financial statements

The Financial Statements have been prepared solely for the purpose of filing the Company's income tax return. Since these Financial Statements have not been prepared for general purposes, some users may require additional information. Consolidated financial statements of Hydro One for the year ended December 31, 2020 have been prepared and are publicly available.
Hydro One Networks performed an evaluation of subsequent events through to April 29, 2021, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 31 - Subsequent Events
Use of Management Estimates
The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, contingencies, and unbilled revenues. Actual results may differ significantly from these estimates.
As the COVID-19 pandemic (COVID-19 or the pandemic) has resulted in incremental operating costs and lost revenues, the Company has also analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2020 and has determined that there was no
material impact. Additional details regarding the impact of the pandemic on the Financial Statements are available in Note 7 - Accounts Receivable and Note 11 - Regulatory Assets and Liabilities.
As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Company's financial results and operations.
Regulatory Accounting
The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.
Cash and Cash Equivalents
Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.Revenue Recognition
Transmission revenues predominantly consist of transmission tariffs, which

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are collected through OEB-approved UTRs which are applied against the monthly peak demand for electricity across Hydro One's high-voltage network.
OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are recognized as electricity is transmitted and delivered to customers.
Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.
Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.
Accounts Receivable and Allowance for Doubtful Accounts
Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates.
The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses (CECL) for all accounts receivable balances. The Company estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions. Income Taxes
Income taxes are accounted for using the asset and liability method. Current tax assets and liabilities are recognized based on the taxes payable or refundable on the current and prior year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more likely than not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement.
Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.
Deferred Income Taxes
Deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more likely than not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are

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measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date.
Deferred income taxes associated with its regulated operations which are considered to be more-likely-than-not to be recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory assets and liabilities with an offset to deferred income tax expense.
Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.
Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more likely than not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that the tax benefit will be realized.Inter-company Demand Facility
Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Networks. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled bank accounts.
Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%. Materials and Supplies
Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.Property, Plant and Equipment
Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.
The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program.
Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology (IT). Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.
Property, plant and equipment in service consists of transmission, distribution, administration and service, and other communication assets as well as land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.
Transmission
Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.Distribution
Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems. Administration and Service

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Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.Other Other assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings. Other assets also include easements which include statutory rights of use for transmission corridors and abutting lands granted under the Reliable Energy and Consumer Protection Act, 2002, and other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service. Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2020 for Hydro One Networks' distribution and transmission businesses, respectively. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

assets is included below:

Average Rate

Service Life Range Average

Property, plant and equipment:

Transmission 54 years 1% - 2% 2%

Distribution 46 years 1% - 7% 2%

Communication 16 years 1% - 15% 5%

Administration and service 22 years 1% - 20% 4%

Intangible assets 10 years 10% 10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

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The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base. At December 31, 2020 and 2019, the entire goodwill balance was attributable to the Distribution Business.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more likely than not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more likely than not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more likely than not that the fair value of the applicable reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed. The quantitative assessment compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on the assessment performed as at September 30, 2020 and with no significant events since, the Company has concluded that goodwill was not impaired at December 31, 2020.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One Networks' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally

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developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a
change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the
cash flows related to these long-lived assets. As at December 31, 2020 and 2019, no asset impairment had been recorded for
assets within the Company's regulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro
One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance
sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the
amortization is included within financing charges in the statements of operations and comprehensive income. Transaction costs
for items classified as held-for-trading are expensed immediately.

Comprehensive Income / Loss

Comprehensive income/loss is comprised of net income/loss and other comprehensive income (OCI) or other comprehensive
loss (OCL). The Company presents net income/loss and OCI/OCL in a single continuous statement of operations andcomprehensive income/loss.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables;
held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured
at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts
due from related parties, which are measured at its net realizable value. Accounts receivable and amounts due from related
parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and
amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these
instruments. The Company estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the
allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible.

All financial instrument transactions are recorded at trade date.

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company
designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk
management policy disclosed in Note 17 - Fair Value of Financial Instruments and Risk Management.Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses
various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are
designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges
(hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative
instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's

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transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.
The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the balance sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its balance sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.
For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI). Amounts in AOCI are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the statements of operations and comprehensive income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the statements of operations and comprehensive income. The changes in fair value of the undesignated derivative instruments are reflected inresults of operations.
Embedded derivative instruments are separated from their host contracts and are carried at fair value on the balance sheets when (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract, (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period, and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation atDecember 31, 2020 or 2019.
Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.
Employee Future Benefits
Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are

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recorded over the periods during which employeesrender service.
Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and postemployment
plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of
each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded
when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the
consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability,
long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the
benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the
PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit
plans are unfunded because there are no related plan assets.
Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion
being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation,
maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.Defined Benefit Pension
Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries,
including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual
subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group.
Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no
pension benefit asset or liability is recorded.
Post-retirement and Post-employment Benefits
Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its
subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans
are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the
post-retirement and post-employment benefit obligations are reflective of earnings allocations of relevant employees to theCompany.
Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by
independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect
management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the
expected average remaining service period.
For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated
above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life
of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan.
The post-retirement benefit obligation is remeasured to its fair value at

each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.
For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.
All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approvedrates.
Stock-Based Compensation
Share Grant Plans
The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as theyoccur.
Deferred Share Unit (DSU) Plans
The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Hydro One Limited common share closing price at the end of each reporting period.Long-term Incentive Plan (LTIP)
The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis.
Forfeitures are recognized as they occur.
Loss Contingencies
Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.
Management regularly reviews current information available to determine

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whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators.
Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.
Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees areexpensed as incurred.
Environmental Liabilities
Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Networks records 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, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.
Asset Retirement Obligations
Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.
When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to

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the carrying amount of the associated asset and the
resulting asset retirement cost is depreciated over the estimated useful life
of the asset. The present value is determined with a
discount rate that equates to the Company's credit-adjusted risk-free rate.
Where an asset is no longer in service when an asset
retirement obligation is recorded, the asset retirement cost is recorded in
results of operations.
Some of the Company's transmission and distribution assets, particularly
those located on unowned easements and rights-ofway,
may have asset retirement obligations, conditional or otherwise. The majority
of the Company's easements and rights-ofway
are either of perpetual duration or are automatically renewed annually. Land
rights with finite terms are generally subject to
extension or renewal. As the Company expects to use the majority of its
facilities in perpetuity, no asset retirement obligations
have been recorded for these assets. If, at some future date, a particular
facility is shown not to meet the perpetuity assumption,
it will be reviewed to determine whether an estimable asset retirement
obligation exists. In such a case, an asset retirement
obligation would be recorded at that time.
The Company's asset retirement obligations recorded to date relate to
estimated future expenditures associated with the removal
and disposal of asbestos-containing materials installed in some of its
facilities.Leases
At the commencement date of a lease, the minimum lease payments are
discounted and recognized as a lease obligation.
Discount rates used correspond to the Company's incremental borrowing rates.
Renewal options are assessed for their likelihood
of being exercised and are included in the measurement of the lease
obligation when it is reasonably certain they will be
exercised. The Company does not recognize leases with a term of less than 12
months. A corresponding Right-of-Use (ROU)
asset is recognized at the commencement date of a lease. The ROU asset is
measured as the lease obligation adjusted for any
lease payments made and/or any lease incentives and initial direct costs
incurred. ROU assets are included in other long-term
assets, and corresponding lease obligations are included in other current
liabilities and other long-term liabilities on the balancesheets.
Subsequent to the commencement date, the lease expense recognized at each
reporting period is the total remaining lease
payments over the remaining lease term. Lease obligations are measured as the
present value of the remaining unpaid lease
payments using the discount rate established at commencement date. The
amortization of the ROU assets is calculated as the
difference between the lease expense and the accretion of interest, which is
calculated using the effective interest method.
Lease modifications and impairments are assessed at each reporting period to
assess the need for a re-measurement of thelease obligations or ROU assets.
3. NEW ACCOUNTING PRONOUNCEMENTS
The following tables present Accounting Standard Updates (ASUs) issued by the
Financial Accounting Standards Board that areapplicable to Hydro One Networks:
Recently Adopted Accounting Guidance
Guidance Date issued Description Effective date Impact on Hydro One Networks
ASU
2017-04
January 2017 The amendment removes the second step of the

previous two-step goodwill impairment test to simplify
the process of testing goodwill.
January 1, 2020 No impact upon adoption
ASU
2018-13
August 2018 Disclosure requirements on fair value measurements
in Accounting Standard Codification (ASC) 820 are
modified to improve the effectiveness of disclosures in
financial statement notes.
January 1, 2020 No impact upon adoption
ASU
2019-01
March 2019 This amendment carries forward the exemption
previously provided under ASC 840 relating to the
determination of the fair value of underlying assets by
lessors that are not manufacturers or dealers. It also
provides for clarification on cash-flow presentation of
sales-type and financing leases and clarifies that
transition disclosures under Topic 250 are applicable
in the adoption of ASC 842.
January 1, 2020 No impact upon adoption
Recently Issued Accounting Guidance Not Yet Adopted
Guidance Date issued Description Effective date Anticipated Impact on Hydro
One NetworksASU
2018-14
August 2018 Disclosure requirements related to single-employer
defined benefit pension or other post-retirement
benefit plans are added, removed or clarified to
improve the effectiveness of disclosures in financial
statement notes.
January 1, 2021 No impact upon adoption
ASU
2019-12
December
2019
The amendments simplify the accounting for income
taxes by removing certain exceptions to the general
principles and improving consistent application of
Topic 740 by clarifying and amending existing
guidance.
January 1, 2021 No impact upon adoption
ASU
2020-01
January 2020 The amendments clarify the interaction of the
accounting for equity securities under Topic 321,
investments under the equity method of accounting in
Topic 323 and the accounting for certain forward
contracts and purchased options accounted for under
Topic 815.
January 1, 2021 No impact upon adoption
ASU
2020-06
August 2020 The update addresses the complexity associated with
applying GAAP for certain financial instruments with
characteristics of liabilities and equity. The amendments
reduce the number of accounting models for convertible

debt instruments and convertible preferred stock.
January 1, 2022 Under assessment
ASU
2020-10
October 2020 The amendments are intended to improve the Codification by ensuring the guidance required for an entity to disclose information in the notes of financial statements are codified in the disclosure sections to reduce the likelihood of disclosure requirements being missed.
January 1, 2021 No impact upon adoption

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS
Year ended December 31 (millions of dollars) 2020 2019
Depreciation of property, plant and equipment 662 644
Amortization of intangible assets 69 81
Amortization of regulatory assets 22 21
Depreciation and amortization 753 746
Asset removal costs 100 101
853 847

5. FINANCING CHARGES
Year ended December 31 (millions of dollars) 2020 2019
Interest on long-term debt (Note 26) 485 470
Interest on inter-company demand facility (Note 26) 7 19
Other 14 19
Less: Interest capitalized on construction and development in progress (49)
(48)457 460

6. INCOME TAXES
As a rate regulated utility company, the Company recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated business. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Company's tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Company's income tax expense or recovery differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate.The reconciliation between the statutory and the effective tax rates is provided as follows:Year ended December 31 (millions of dollars) 2020 2019
Income before income tax expense 1,006 982
Income tax expense at statutory rate of 26.5% (2019 - 26.5%) 267 260
Increase (decrease) resulting from:
Net temporary differences recoverable in future rates charged to customers:
Capital cost allowance in excess of depreciation and amortization1 (97) (100)
Impact of tax deductions from deferred tax asset sharing2 (41) (60)
Overheads capitalized for accounting but deducted for tax purposes (21) (20)
Interest capitalized for accounting but deducted for tax purposes (13) (13)
Environmental expenditures (6) (6)
Pension and post-retirement benefit contributions in excess of pension expense (4) (12)Other 1 (3)
Net temporary differences attributable to regulated business (181) (214)

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Net permanent differences (4) 2
Recognition of deferred income tax regulatory asset (Note 11) (867) -
Total income tax expense (recovery) (785) 48
Effective income tax rate (78.0) % 4.9 %
1 Includes accelerated tax depreciation of up to three times the first-year rate for certain eligible capital investments acquired after November 20, 2018 and placed inservice
before January 1, 2028, as introduced in the 2019 federal and Ontario budgets and enacted in the second quarter of 2019.
2 Prior to the ODC Decision, the impact represents tax deductions from deferred asset tax sharing given to ratepayers as previously mandated by the OEB.Subsequent to the ODC Decision, the impact represents the recovery of deferred tax asset sharing currently allocated to rate-payers. See Note 11 - RegulatoryAssets and Liabilities
The major components of income tax expense are as follows:
Year ended December 31 (millions of dollars) 2020 2019
Current income tax expense 29 26
Deferred income tax expense (recovery) (814) 22
Total income tax expense (recovery) (785) 48
Deferred Income Tax Assets and Liabilities
Deferred income tax assets and liabilities reflect the future tax consequences attributable to temporary differences between the
tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax
losses and tax credits. Deferred income tax assets and liabilities attributable to the Company's regulated business are
recognized with a corresponding offset in deferred income tax regulatory assets and liabilities to reflect the anticipated recovery
or repayment of these balances in the future electricity rates. At December 31, 2020 and 2019, deferred income tax assets and
liabilities consisted of the following:
As at December 31 (millions of dollars) 2020 2019
Deferred income tax assets
Post-retirement and post-employment benefits expense in excess of cash payments 672 626Non-capital losses 271 286
Non-depreciable capital property 130 130
Tax credit carryforwards 118 90
Investment in subsidiaries 100 23
Environmental expenditures 32 39
Other - 4
1,323 1,198
Less: valuation allowance (233) (156)
Total deferred income tax assets 1,090 1,042
Deferred income tax liabilities
Capital cost allowance in excess of depreciation and amortization (1,022) (314)Regulatory assets and liabilities (99) (69)
Goodwill (11) (10)
Other (14) (17)
Total deferred income tax liabilities (1,146) (410)
Net deferred income tax assets (liabilities)1 (56) 632
1 The net deferred income tax assets (liabilities) are presented on the balance sheets as long-term.7. ACCOUNTS RECEIVABLE
As at December 31 (millions of dollars) 2020 2019
Accounts receivable - billed 327 327
Accounts receivable - unbilled 389 388
Accounts receivable, gross 716 715

Corporation's name	Business number	Tax year end Year Month Day
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Allowance for doubtful accounts (45) (22)
Accounts receivable, net 671 693
The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2020 and2019:
Year ended December 31 (millions of dollars) 2020 2019
Allowance for doubtful accounts - beginning (22) (21)
Write-offs 11 18
Additions to allowance for doubtful accounts1 (34) (19)
Allowance for doubtful accounts - ending (45) (22)
1 Additions to allowance for doubtful accounts for the year ended December 31, 2020 include incremental $14 million related to the COVID-19 pandemic which wererecognized in OM&A in 2020 (2019 - $nil).
8. OTHER CURRENT ASSETS
As at December 31 (millions of dollars) 2020 2019
Regulatory assets (Note 11) 89 100
Prepaid expenses and other assets 47 32
Materials and supplies 18 17
Derivative assets (Note 17) 3 -
157 149
9. PROPERTY, PLANT AND EQUIPMENT
As at December 31, 2020 (millions of dollars)
Property, Plant
and Equipment1 Accumulated
Depreciation
Construction
in Progress Total
Transmission 17,434 5,922 873 12,385
Distribution 11,387 3,921 95 7,561
Administration and service 1,712 953 113 872
Other 1,741 1,015 39 765
32,274 11,811 1,120 21,583
1 Includes future use assets totalling $164 million.
As at December 31, 2019 (millions of dollars)
Property, Plant
and Equipment1 Accumulated
Depreciation
Construction
in Progress Total
Transmission 16,678 5,661 709 11,726
Distribution 10,931 3,723 82 7,290
Administration and service 1,602 927 53 728
Other 1,702 944 38 796
30,913 11,255 882 20,540
1 Includes future use assets totalling $151 million.
On September 18, 2019, transmission assets related to a new 230 kV transmission line (Niagara Line) in the Niagara region totalling $119 million were transferred from Hydro One Networks to Niagara Reinforcement LP (NRLP), a subsidiary of Hydro One. See Note 12 - Investments in Subsidiaries.
Financing charges capitalized on property, plant and equipment under construction were $46 million in 2020 (2019 - $44 million).
10. INTANGIBLE ASSETS
As at December 31, 2020 (millions of dollars)
Intangible
Assets
Accumulated

Corporation's name	Business number	Tax year end Year Month Day
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Amortization
Development
in Progress Total
Computer applications software 1,032 580 58 510
Other 6 5 - 1
1,038 585 58 511
As at December 31, 2019 (millions of dollars)
Intangible
Assets
Accumulated
Amortization
Development
in Progress Total
Computer applications software 910 511 55 454
Other 4 4 - -
914 515 55 454
Financing charges capitalized to intangible assets under development were $3 million in 2020 (2019 - $4 million). The estimated annual amortization expense for intangible assets is as follows: 2021 - $73 million; 2022 - $70 million; 2023 - $59 million; 2024 - $49 million; and 2025 - $48 million.
11. REGULATORY ASSETS AND LIABILITIES
Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Networks has recorded the following regulatory assets and liabilities:
As at December 31 (millions of dollars) 2020 2019
Regulatory assets:
Deferred income tax regulatory asset 2,343 1,106
Deferred tax asset sharing 204 -
Post-retirement and post-employment benefits non-service cost 113 96
Environmental 90 107
Post-retirement and post-employment benefits 59 104
Foregone revenue deferral 55 62
Stock-based compensation 40 42
Conservation and Demand Management (CDM) variance 16 -
Other 20 20
Total regulatory assets 2,940 1,537
Less: current portion (89) (100)
2,851 1,437
Regulatory liabilities:
Retail settlement variance account 92 23
Tax rule changes variance 69 44
Earnings sharing mechanism deferral 37 21
Pension cost differential 31 31
Green energy expenditure variance 22 31
Asset removal costs cumulative variance 19 -
External revenue variance 7 6
Distribution rate riders 1 42
Deferred income tax regulatory liability - 57
Other 11 9
Total regulatory liabilities 289 264
Less: current portion (66) (102)
223 162
Deferred Income Tax Regulatory Asset and Liability
Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the

Corporation's name	Business number	Tax year end Year Month Day
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financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2020 income tax expense would have been higher by approximately $181 million (2019 - higher by $217 million), of which $140 million is included in Deferred Income Tax Regulatory Asset and Liability with the remaining $41 million included in Deferred TaxAsset Sharing.
On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the Electricity Act, 1998 (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One Limited shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a decision and order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would have resulted in an impairment of a portion of both Hydro One Networks' transmission and distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal). In both cases, the Company's position was that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Original Decision relating to the deferred tax asset to an OEB panel for reconsideration.
On March 7, 2019, the OEB issued its DTA Decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result, as at December 31, 2018, the Company recorded impairment charges relating to Hydro One Networks' distribution and transmission deferred income tax regulatory asset. Notwithstanding the recognition of the effects of the DTA Decision in the 2018 financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's DTA Decision. The appeal washeard on November 21, 2019.
On July 16, 2020, the Ontario Divisional Court rendered its decision (ODC Decision) on the Company's appeal of the OEB's DTADecision.
In connection with the ODC Decision, the Company recorded a reversal of the previously recognized impairment charge of Hydro One Networks' distribution and transmission deferred income tax regulatory asset in its financial statements for the year ended December 31, 2020. The reversal of the previously recognized impaired charge included the regulatory asset relating to the cumulative deferred tax asset amounts shared with ratepayers (deferred tax

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asset sharing) up to and including June 30, 2020 by
Hydro One Networks' distribution and transmission segments of $58 million and
$118 million, respectively. Hydro One recognized
deferred income tax regulatory assets of $504 million and $673 million for
Hydro One Networks distribution and transmission
segments, respectively, and associated deferred income tax liability of $310
million. The Company also recorded an increase in
net income of $867 million as deferred income tax recovery during the year
ended December 31, 2020.Deferred Tax Asset Sharing
On October 2, 2020, the OEB issued a procedural order to implement the
direction of the Ontario Divisional Court and required
Hydro One to submit its proposal for the recovery of the deferred tax asset
amounts allocated to ratepayers for the 2017 to 2022
period. As at December 31, 2020, Hydro One recorded a regulatory asset of
$204 million for the cumulative deferred tax asset
amounts shared with ratepayers since 2017 to date, consisting of $70 million
and $134 million for Hydro One Networks'
distributions and transmission segments, respectively. As a result of the
OEB's procedural order, the $204 million regulatory
asset relating to the cumulative deferred tax asset amounts allocated to
ratepayers since 2017 has been separately presented
from the deferred income tax regulatory asset. Additional amounts shared with
ratepayers up to December 31, 2021 will continue
to increase this regulatory asset. On April 8, 2021, the OEB rendered its
decision and order regarding the recovery of the
deferred tax asset amounts allocated to ratepayers for the 2017 to 2022
period (Implementation Decision). In its decision, the
OEB approved recovery of the deferred tax asset amounts allocated to
ratepayers for the 2017 to 2021 period including the
$70 million and $134 million at December 31, 2020 for Hydro One Networks'
distributions and transmission segments,
respectively. See Note 31 - Subsequent Events for additional information.
Post-Retirement and Post-Employment Benefits - Non-Service Cost
Hydro One Networks has recorded a regulatory asset relating to the future
recovery of its post-retirement and post-employment
benefits other than service costs. The regulatory asset includes the
applicable tax impact to reflect taxes payable. Prior to
adoption of ASU 2017-07 in 2018, these amounts were capitalized to property,
plant and equipment and intangible assets. As
part of Hydro One Networks' 2020-2022 Transmission Decision, the OEB
concluded that the non-service cost component of
Hydro One's other post-employment benefits (OPEB) costs shall be recognized
as OM&A for both its transmission and
distribution businesses. Hydro One Networks distribution continues to record
the non-service cost component of OPEBs in this
account until its next rebasing application. The OEB approved the disposition
of Hydro One Networks transmission's account
balance as at December 31, 2018, including accrued interest, which is being
collected from ratepayers over a three-year periodending December 31, 2022.
Environmental
The Company records a liability for the estimated future expenditures
required to remediate environmental contamination. A
regulatory asset is recognized because management considers it to be probable
environmental expenditures will be recovered in
the future through the rate-setting process. In 2020, the environmental
regulatory asset increased by $2 million (2019 -

decreased by $6 million) to reflect related changes in the Company's PCB and LAR environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One Networks' actual environmental expenditures. In the absence of rate-regulated accounting, 2020 OM&A expenses would have been higher by $2 million (2019 - lower by $6 million). In addition, 2020 amortization expense would have been lower by $22 million (2019 - $21 million), and 2020 financing charges would have been higher by $3 million (2019 - $4 million).

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the balance sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2020 OCL would have been lower by $45 million (2019 - higher by $233 million

Foregone Revenue Deferral

As at December 31, 2020, the foregone revenue deferral account is primarily made up of the difference between revenue earned by Hydro One Networks under the approved UTRs based on OEB-approved 2020 rates revenue requirement and load forecast and the revenues earned under interim 2020 UTRs. Hydro One Networks transmission's foregone revenue, including accrued interest, is being collected from ratepayers over a two-year period ending December 31, 2022. As at December 31, 2019, the foregone revenue deferral account was primarily made up of the difference between revenue earned based on distribution rates approved by the OEB in Hydro One Networks' 2018-2022 distribution rates application, effective May 1, 2018, and revenue earned under the interim rates until the approved 2018 and 2019 rates were implemented on July 1, 2019. This amount was recovered from ratepayers over an eighteen-month period ending December 31, 2020.Stock-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, there would be no material impact to OM&A expenses (2019 - $nil). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.CDM Variance

The CDM variance account tracks the impact of actual CDM and demand response programs on the actual load forecast compared to the estimated load forecast included in revenue requirement. As

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per the OEB's decision on Hydro One Networks'
2017 and 2018 transmission rates, and 2019 transmission rates, this account
was maintained to record any variances for 2017,
2018, and 2019. A CDM variance amount for 2017 was calculated and proposed
for disposition in Hydro One Networks'
2020-2022 transmission rate application. In April 2020, the amount as at
December 31, 2018, including accrued interest, was
approved for disposition by the OEB and was recognized as a regulatory asset.
The amount was approved to be recovered from
ratepayers over a three-year period ending December 31, 2022.
Retail Settlement Variance Account (RSVA)
Hydro One has deferred certain retail settlement variance amounts under the
provisions of Article 490 of the OEB's Accounting
Procedures Handbook. The RSVA account tracks the difference between the cost
of power purchased from the Independent
Electricity System Operator (IESO) and the cost of power recovered from
ratepayers. The balance as at December 31, 2014,
including accrued interest, was approved for disposition by the OEB in March
2019, and was transferred to the 2019-2020 Rate
Rider. The balance as at December 31, 2019, including accrued interest, was
approved for disposition over a one year period
ending December 31, 2021 by the OEB as part of Hydro One Networks
distribution 2021 annual update rate application.Tax Rule Changes Variance
The 2019 federal and Ontario budgets (Budgets) provided certain time-limited
investment incentives permitting Hydro One
Networks to deduct accelerated capital cost allowance of up to three times
the first-year rate for capital investments acquired
after November 20, 2018 and placed in-service before January 1, 2028
(Accelerated Depreciation). Following the enactment of
the Budget measures in the second quarter of 2019, the OEB directed all
Ontario regulated utilities including Hydro One to track
the full revenue impact of the tax benefits related to the Accelerated
Depreciation rules to ratepayers. The tax benefit to be
returned to ratepayers in the future gave rise to a regulatory liability and
resulted in a decrease in revenues as current rates do
not include the benefit of the Accelerated Depreciation; therefore, the
revenue subject to refund cannot be recognized.
Earnings Sharing Mechanism Deferral
In March 2019, the OEB approved the establishment of an earnings sharing
mechanism deferral account for Hydro One
Networks' distribution business to record over-earnings including tax
impacts, if any, realized for any year from 2018 to 2022.
Under this mechanism, Hydro One Networks shares 50% of regulated earnings
that exceed the OEB-approved regulatory returnon-
equity by more than 100 basis points with distribution ratepayers. This
account is asymmetrical to the benefit of ratepayers.
The balance as at December 31, 2019, including accrued interest, was approved
for disposition on an interim basis over a one
year period ending December 31, 2021 by the OEB as part of Hydro One Networks
distribution 2021 annual update rateapplication.
Pension Cost Differential
Variances between the pension cost recognized and the cost embedded in rates
as part of the rate-setting process for Hydro
One Networks' transmission and distribution businesses are recognized as a
regulatory asset or regulatory liability, as the case
may be. Variances into the account were not recognized for the distribution

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business in 2019 in accordance with the OEB's
decision on the motion to review and vary the OEB's decision as it relates to
rates revenue requirement recovery of employer
pension costs. In March 2019, the OEB approved the disposition of the
distribution business portion of the balance as at
December 31, 2016, including accrued interest, and the balance was
transferred to the 2019-2020 Rate Rider. In April 2020, the
OEB approved the disposition of the transmission business portion of the
balance as at December 31, 2018, including accrued
interest, which is being returned to ratepayers over a three-year period
ending December 31, 2022. In the absence of rateregulated
accounting, 2020 revenue would have been higher by $1 million (2019 - $5
million).
Green Energy Expenditure Variance
In April 2010, the OEB requested the establishment of deferral accounts which
capture the difference between the revenue
recorded on the basis of Green Energy Plan expenditures incurred and the
actual recoveries received. The smart grid variance
account balance as at December 31, 2016, including accrued interest, was
approved for disposition by the OEB in March 2019,
and was transferred to the 2019-2020 Rate Rider.
Asset Removal Costs Cumulative Variance
In April 2020, the OEB approved the establishment of an asset removal costs
cumulative variance account for Hydro One
Networks transmission to record the difference between the revenue
requirement associated with forecast asset removal costs
included in depreciation expense and actual asset removal costs incurred from
2020 to 2022. This account is asymmetrical to the
benefit of ratepayers on a cumulative basis over the 2020-2022 rate period.
External Revenue Variance
The external revenue variance account balance reflects the difference between
Hydro One Networks transmission's actual
export service revenue and external revenues from secondary land use, and the
OEB-approved amounts. The account also
records the difference between actual net external station maintenance,
engineering and construction services revenue, and
other external revenue, and the OEB-approved amounts. In April 2020, the OEB
approved the disposition of the external revenue
variance account as at December 31, 2018, including accrued interest, which
is being returned to ratepayers over a three-year
period ending December 31, 2022.
Distribution Rate Riders
In March 2019, as part of its decision on Hydro One Networks' distribution
rates application for 2018-2022, the OEB approved
the disposition of certain deferral and variance accounts which were
accumulated in a 2019-2020 Rate Rider. The Distribution
Rate Riders balance includes the 2019-2020 Rate Rider, where amounts were
returned to ratepayers over an 18-months period
ending December 31, 2020. There is a balance in the 2019-2020 Rate Rider that
remains which represents amounts that shall
be collected from ratepayers in a future rate application. This amount is
largely offset by the 2015-2017 Rate Rider balance,
which was approved for disposition over a one year period ending December 31,
2021 by the OEB as part of Hydro One
Networks distribution 2021 annual update rate application.
COVID-19 Emergency Deferral

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The COVID-19 emergency deferral account comprises of five sub-accounts established to track incremental costs and lost revenues related to the COVID-19 pandemic: (i) Billing and System Changes as a Result of the Emergency Order Regarding Time-of-Use Pricing, (ii) Lost Revenues Arising from the COVID-19 Emergency, (iii) Other Incremental Costs, (iv) Foregone Revenues from Postponing Rate Implementation, and (v) Bad Debt.

On December 16, 2020, the OEB Staff released their proposal on the COVID-19 deferral accounts which introduces certain criteria to that may need to be satisfied for amounts to be eligible for recovery. Based on Hydro One Networks' interpretation of the OEB Staff's proposal, the Company has assessed that these amounts are not probable for future recovery in rates and no amounts related to the COVID-19 pandemic have been recognized as regulatory asset. Hydro One continues to track certain incremental costs and lost revenues that have arisen due to the COVID-19 pandemic.12. INVESTMENTS IN SUBSIDIARIES

As at December 31 (millions of dollars) 2020 2019
Investment in HOSSM 225 225
Investment in B2M LP 138 -
Investment in NRLP 27 36
Investment in HOIP GP - 135
390 396

Investment in HOSSM

On December 10, 2018, the common shares of 1937672 Ontario Inc., the parent company of Hydro One Sault Ste. Marie (HOSSM) entities, were transferred to Hydro One Networks by Hydro One. The transfer was accounted as a non-monetary transfer, based on 1937672 Ontario Inc.'s carrying values at December 10, 2018. This resulted in a transfer of the $225 million investment in 1937672 Ontario Inc. to Hydro One Networks, thereby increasing Hydro One's investment in Hydro One Networksby $225 million.

Investment in B2M LP and HOIP GP

On November 28, 2019, the common shares of Hydro One Indigenous Partnership GP Inc. (HOIP GP) were transferred to Hydro One Networks by Hydro One. The transfer was accounted as a non-monetary transfer, based on HOIP GP carrying values at November 28, 2019. This resulted in a transfer of the $135 million investment in HOIP GP to Hydro One Networks, thereby increasing Hydro One's investment in Hydro One Networks by $135 million. On January 1, 2020, HOIP GP started dissolution proceedings and, as a result, its net assets were transferred to Hydro One Networks, including its $138 million investment in B2M Limited Partnership (B2M LP).

Investment in NRLP

On September 18, 2019, assets related to the Niagara Line totalling $119 million were transferred from Hydro One Networks to NRLP in return for cash consideration of $71 million and NRLP partnership units totalling $48 million issued to Hydro One Networks. Subsequently, on the same date, Hydro One Networks sold to the Six Nations of the Grand River Development Corporation (Six Nations) and to the Mississaugas of the Credit First Nation (Mississaugas FN), through a trust, a 25.0% and 0.1%, respectively, equity interest in NRLP partnership units for total consideration of $12 million, representing the fair value of the equity interest acquired.

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On January 31, 2020, the Mississaugas FN exercised an option to purchase an additional 19.9% equity interest in NRLP partnership units from Hydro One Networks for total cash consideration of $9 million. Following this transaction, Hydro One Networks' interest in the equity portion of NRLP partnership units was reduced to 55%, with the Six Nations of the Grand River Development Corporation and the Mississaugas FN owning 25% and 20%, respectively, of the equity interest in NRLPpartnership units.

13. OTHER LONG-TERM ASSETS

As at December 31 (millions of dollars) 2020 2019
Right-of-Use assets (Note 22) 68 71
Derivative assets (Note 17) - 1
Other long-term assets - 1
68 73

14. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 (millions of dollars) 2020 2019
Accrued liabilities 514 573
Accounts payable 224 176
Accrued interest (Note 26) 114 107
Regulatory liabilities (Note 11) 66 102
Environmental liabilities (Note 20) 30 27
Lease obligations (Note 22) 10 8
958 993

15. OTHER LONG-TERM LIABILITIES

As at December 31 (millions of dollars) 2020 2019
Post-retirement and post-employment benefit liability (Note 19) 1,757 1,685
Environmental liabilities (Note 20) 60 80
Lease obligations (Note 22) 63 66
Long-term inter-company payable (Note 26) 31 35
Long-term accounts payable and other liabilities 16 14
Asset retirement obligations (Note 21) 13 10
1,940 1,890

16. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt. In addition, long-term debt includes $229 million payable to Hydro One transferred to Hydro One Networks from Hydro One in 2018. The following table presents long-term debt outstanding at December 31, 2020 and 2019:

As at December 31 (millions of dollars) 2020 2019
Long-term debt 12,641 11,018
Add: Net unamortized debt premiums 10 11
Add: Unrealized mark-to-market loss1 3 1
Less: Deferred debt issuance costs (49) (42)
Less: Long-term debt payable within one year (803) (330)
Long-term debt 11,802 10,658

1 The unrealized mark-to-market net loss of $3 million (2019 - $1 million) relates to $300 million notes due 2021. The unrealized mark-to-market net loss is offset by a $3 million unrealized mark-to-market net gain (2019 - $1 million) on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair valuehedges.

In 2020, Hydro One issued $2,300 million long-term debt under its MTN Program (2019 - $1,500 million), of which $1,953 million was mirrored down to Hydro One Networks.

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In 2020, Hydro One repaid $650 million (2019 - $728 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $330 million (2019 - $728 million) to Hydro One.Principal and Interest Payments
At December 31, 2020, future principal repayments, interest payments, and related weighted-average interest rates were asfollows:
Long-Term Debt
Principal Repayments Interest Payments
Weighted-Average
Interest Rate
(millions of dollars) (millions of dollars) (%)
Year 1 800 484 2.4
Year 2 580 469 3.2
Year 3 829 454 1.3
Year 4 700 439 2.8
Year 5 624 420 2.7
3,533 2,266 2.5
Years 6-10 1,714 1,948 4.0
Thereafter 7,394 4,091 4.6
12,641 8,305 3.9
17. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT
Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.
The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:
Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.
Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability.
Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.
Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.
Non-Derivative Financial Assets and Liabilities
At December 31, 2020 and 2019, the carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value due to the

short-term nature of these instruments.
Fair Value Measurements of Long-Term Debt
The fair values and carrying values of the Company's long-term debt at December 31, 2020 and 2019 are as follows:2020 2020 2019 2019
As at December 31 (millions of dollars) Carrying Value Fair Value Carrying Value Fair ValueLong-term debt measured at fair value:
$30 million notes due 2020 - - 30 30
$300 million notes due 2021 303 303 301 301
Other notes and debentures 12,302 14,948 10,657 10,571
Long-term debt, including current portion 12,605 15,251 10,988 10,902
Fair Value Measurements of Derivative Instruments
Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interestrate swap agreements are mirrored down to Hydro One Networks.
At December 31, 2020, Hydro One Networks had interest-rate swaps with a total notional amount of $300 million (2019 - $330 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was approximately 2% (2019 - 3%) of its total long-term debt. At December 31, 2020,
Hydro One Networks had the following interest-rate swap designated as a fair value hedge:
. a $300 million fixed-to-floating interest-rate swap agreement to convert the $300 million notes maturing June 25, 2021 into three-month variable rate debt.
At December 31, 2020 and 2019, the Company had no derivative instruments classified as undesignated contracts.Fair Value Hierarchy
The fair value hierarchy of financial assets and liabilities at December 31, 2020 and 2019 is as follows:As at December 31, 2020 (millions of dollars)
Carrying
Value
Fair
Value Level 1 Level 2 Level 3
Assets:
Derivative instruments - fair value hedges (Note 8) 3 3 - 3 -
3 3 - 3 -
Liabilities:
Long-term debt, including current portion 12,605 15,251 - 15,251 -
12,605 15,251 - 15,251 -
As at December 31, 2019 (millions of dollars)
Carrying
Value
Fair
Value Level 1 Level 2 Level 3
Assets:
Derivative instruments - fair value hedges (Note 13) 1 1 - 1 -
1 1 - 1 -
Liabilities:
Long-term debt, including current portion 10,988 10,902 - 10,902 -
10,988 10,902 - 10,902 -
The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

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There were no transfers between any of the fair value levels during the years ended December 31, 2020 or 2019
Risk Management
Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.Market Risk
Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates.
The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach
that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or
material foreign exchange risk.
Hydro One Networks uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One
Networks also uses derivative financial instruments to manage interest-rate risk. Hydro One's derivative instruments, or portions
thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution
businesses. Hydro One Networks may utilize interest-rate swaps designated as fair value hedges, as a means to manage its
interest rate exposure to achieve a lower cost of debt, and may also utilize interest-rate derivative instruments to lock in interestrate
levels on forecasted financing.
A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a
significant decrease in the Company's net income for the years ended December 31, 2020 and 2019.
For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as
well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the statements of
operations and comprehensive income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for
the years ended December 31, 2020 and 2019 were not material.
Credit Risk
Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31,
2020 and 2019, there were no significant concentrations of credit risk with respect to any class of financial assets. The
Company's revenue is earned from a broad base of customers. As a result, Hydro One Networks did not earn a material amount
of revenue from any single customer. At December 31, 2020 and 2019, there was no material accounts receivable balance duefrom any single customer.
At December 31, 2020, the Company's allowance for doubtful accounts was $45 million (2019 - $22 million). The allowance for
doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue
balances, customer payments and write-offs. At December 31, 2020, approximately 4% (2019 - 5%) of the Company's net
accounts receivable were outstanding for more than 60 days. Please see Note 7 - Accounts Receivable for additions to
allowance for doubtful accounts related to the impact of the COVID-19 pandemic.
Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly
rated counterparties, (ii) limiting total exposure levels with individual

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counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Company's credit risk for accounts receivable is limited to the carrying amounts on the balance sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2020 and 2019, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material.

At December 31, 2020, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, was with four financial institutions with investment grade credit ratings as counterparties.Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term operating liquidity requirements through the inter-company demand facility with Hydro One and funds from operations.

The short-term liquidity available to the Company is expected to be sufficient to fund the Company's operating requirements. The Company's currently available liquidity is also expected to be sufficient to address any reasonably foreseeable impacts that the COVID-19 pandemic may have on the Company's cash requirements.

18. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. At December 31, 2020 and 2019, the Company's capital structurewas as follows:

As at December 31 (millions of dollars)	2020	2019
Long-term debt payable within one year	803	330
Inter-company demand facility	(109)	1,076
	694	1,406
Long-term debt	11,802	10,658
Common shares	2,934	3,541
Retained earnings	7,799	6,001
Contributed surplus	5	5
Total capital	23,234	21,611

19. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and postemploymentbenefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the Income Tax Act (Canada) in the form of credits to a notional account. Hydro One Networks contributions

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to the DC Plan for the year ended December 31,
2020 were $2 million (2019 - $1 million).
Pension Plan and Supplemental Plan
The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its
subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management
employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-
represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After
retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were
not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible tojoin the DC Plan.
Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least
every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was
performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later
than effective December 31, 2021. The Company's annual cash Pension Plan employer contributions for 2020 were $55 million
(2019 - $59 million). The Estimated annual Pension Plan employer contributions for the years 2021, 2022, 2023, 2024, 2025,
2026 and 2027 are approximately $56 million, $90 million, $104 million, $106 million, $107 million, $109 million and $113 millionrespectively.
The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under
the Pension Plan beyond the limitations imposed by the Income Tax Act (Canada). The Supplemental Plan obligation is included
with other post-retirement and post-employment benefit obligations on the balance sheets.
At December 31, 2020, the present value of Hydro One's projected pension benefit obligation was estimated to be $9,763 million
(2019 - $8,973 million). The fair value of pension plan assets available for these benefits was $8,103 million (2019 - $7,848million).
Post-Retirement and Post-Employment Plans
During the year ended December 31, 2020, the Company charged $62 million (2019 - $47 million) of post-retirement and postemployment
benefit costs to operation, maintenance and administration expenses, and capitalized $107 million (2019 - $69
million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2020 were $45 million (2019 -
$47 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $45
million (2019 - increased by $233 million).
The Company presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:
As at December 31 (millions of dollars) 2020 2019
Accrued liabilities 60 59
Post-retirement and post-employment benefit liability 1,757 1,685
Net unfunded status 1,817 1,744
Transfers from Other Plans
Effective March 1, 2018, certain employees who provided customer service operations for Hydro One through Inergi LP were

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transferred to Hydro One Networks (Transferred Employees), and began accruing pension and OPEB in the Pension Plan and post-retirement and post-employment benefit plans, respectively. Pursuant to the arrangement, Inergi LP, Vertex Customer Management (Canada) Ltd. (Vertex) and Hydro One Networks agreed to transfer the defined benefit assets and related pension obligations (for current and former members) of the Inergi LP Customer Service Operations Pension Plan and the Vertex Customer Management (Canada) Limited Pension Plan to the Pension Plan. In addition, Inergi LP, Vertex and Hydro One Networks agreed to transfer the OPEB liability related to the Transferred Employees to Hydro One's post-retirement and postemployment benefit plans. Regulatory approval for the pension transfer was received on November 27, 2019.

The transfer of the OPEB liability of $33 million was completed on April 1, 2020. The liability was recorded as a post-retirement and post-employment benefit liability with an offset to OCL. In addition, as a part of the transfers, cash totaling $24 million was transferred to Hydro One Networks and recorded as an asset with an offset to OCI. Both, the OCI resulting from the transfer of the cash asset and the OCL resulting from the transfer of the other post-retirement benefit liability are being recognized in net income over the expected average remaining service lifetime (EARSL) of the Transferred Employees.20. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31, 2020 (millions of dollars) PCB LAR Total
Environmental liabilities - beginning 90 17 107
Interest accretion 3 - 3
Expenditures (17) (5) (22)
Revaluation adjustment - 2 2
Environmental liabilities - ending 76 14 90
Less: current portion (25) (5) (30)
51 9 60
Year ended December 31, 2019 (millions of dollars) PCB LAR Total
Environmental liabilities - beginning 108 22 130
Interest accretion 4 - 4
Expenditures (17) (4) (21)
Revaluation adjustment (5) (1) (6)
Environmental liabilities - ending 90 17 107
Less: current portion (19) (8) (27)
71 9 80

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the balance sheets after factoring in the discount rate:

As at December 31, 2020 (millions of dollars) PCB LAR Total
Undiscounted environmental liabilities 80 14 94
Less: discounting environmental liabilities to present value (4) - (4)
Discounted environmental liabilities 76 14 90
As at December 31, 2019 (millions of dollars) PCB LAR Total
Undiscounted environmental liabilities 97 18 115
Less: discounting environmental liabilities to present value (7) (1) (8)
Discounted environmental liabilities 90 17 107

At December 31, 2020, the estimated future environmental expenditures were as follows:(millions of dollars)
2021 30

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2022 30
2023 13
2024 12
2025 8
Thereafter 1
94
The Company records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCBcontaminated
mineral oil removed from electrical equipment when it is determined that future environmental remediation
expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonablyestimated.
There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation
or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities,
the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures
will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately
2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been
discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when
expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent
management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is
reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and
the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with
respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and
the ability to take maintenance outages in critical facilities may influence the timing of expenditures.PCBs
The Environment Canada regulations, enacted under the Canadian Environmental Protection Act, 1999, govern the
management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCBcontamination
thresholds. Under current regulations, the Company's PCBs have to be disposed of by the end of 2025, with the
exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by
removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than2 ppm.
At December 31, 2020, the Company's best estimate of the total estimated future expenditures to comply with current PCB
regulations was $80 million (2019 - $97 million). These expenditures are expected to be incurred over the period from 2021 to
2025. As a result of its annual review of environmental liabilities, no revaluation adjustment to the PCB environmental liability was
recorded in 2020 (2019 - revaluation adjustment was recorded to decrease the PCB environmental liability by $5 million).LAR
At December 31, 2020, the Company's best estimate of the total estimated future expenditures to complete its LAR program was

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$14 million (2019 - $18 million). These expenditures are expected to be incurred over the period from 2021 to 2027. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2020 to increase the LAR environmental liability by $2 million (2019 - decrease by $1 million).

21. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 4.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, the Company recorded a revaluation adjustment in 2020 to increase the assets retirement liability by $3 million (2019 - $nil).

At December 31, 2020, Hydro One Networks had recorded asset retirement obligations of $13 million (2019 - $10 million), primarily consisting of the estimated future expenditures associated with the

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removal and disposal of asbestos-containing
materials installed in some of its facilities. The amount of interest
recorded is nominal.22. LEASES
Hydro One has operating lease contracts for buildings used in administrative
and service-related functions. These leases have
terms between three and seven years with renewal options of additional three-
to five-year terms at prevailing market rates at the
time of extension. All leases include a clause to enable upward revision of
the rental charge on an annual basis or on renewal
according to prevailing market conditions or pre-established rents. There are
no restrictions placed upon Hydro One by entering
into these leases. Renewal options are included in the lease term when their
exercise is reasonably certain. Other information
related to the Company's operating leases was as follows:
Year ended December 31 (millions of dollars) 2020 2019
Lease expense 12 9
Lease payments made 11 6
As at December 31 2020 2019
Weighted-average remaining lease term1 (years) 7 8
Weighted-average discount rate 2.6 % 2.7 %
1 Includes renewal options that are reasonably certain to be exercised.
At December 31, 2020, future minimum operating lease payments were as follows:
(millions of dollars)
2021 12
2022 11
2023 10
2024 10
2025 10
Thereafter 27
Total undiscounted minimum lease payments 80
Less: discounting minimum lease payments to present value (8)
Total discounted minimum lease payments 72
At December 31, 2019, future minimum operating lease payments were as follows:
(millions of dollars)
2020 10
2021 11
2022 10
2023 9
2024 9
Thereafter 33
Total undiscounted minimum lease payments1 82
Less: discounting minimum lease payments to present value (9)
Total discounted minimum lease payments 73
1 Excludes committed amounts of $6 million for leases that have not yet
commenced.
Hydro One presents its ROU assets and lease obligations on the balance sheets
as follows:As at December 31 (millions of dollars) 2020 2019
Other long-term assets (Note 13) 68 71
Accounts payable and other current liabilities (Note 14) 10 8
Other long-term liabilities (Note 15) 63 66
23. SHARE CAPITAL
Common Shares
Hydro One Networks is authorized to issue an unlimited number of common and
preferred shares. At December 31, 2020 and
2019, Hydro One Networks had 209,401,290 common shares issued and outstanding
and no preferred shares issued andoutstanding.

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During 2020, Hydro One Networks declared common share dividends in the amount of $1 million (2019 - $1 million) and made a
return of stated capital of $607 million (2019 - $738 million) to Hydro One.
24. EARNINGS PER COMMON SHARE
Basic and diluted earnings per common share is calculated by dividing net income attributable to common shareholder of Hydro
One Networks by the weighted-average number of common shares outstanding. At December 31, 2020 and 2019, the weightedaverage
number of common shares outstanding was 209,401,290. There were no dilutive securities during 2020 or 2019.25. STOCK-BASED COMPENSATION
The following compensation plans were established by Hydro One Limited, however they represent components of
compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.Share Grant Plans
Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers'
Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan).
Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for
the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for
the value of shares granted to the Company's eligible employees relating to these plans.
The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible
members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an
eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a
member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have
under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date
the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be
equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of
Hydro One Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable
under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,913,671 Hydro One Limited common
shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by Hydro OneNetworks.
The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible
members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an
eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a
member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to
have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1,
2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's

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salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,352,503 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by Hydro One Networks.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks was $108 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2020, 429,173 common shares of Hydro One Limited were issued under the Share Grant Plans (2019 - 450,622) to eligible employees of Hydro One Networks. Total stock-based compensation recognized by Hydro One Networks during 2020 was $7 million (2019 - $8 million) and was recorded as a regulatory asset.

A summary of Hydro One Networks' share grant activity under the Share Grant Plans during the years ended December 31,2020 and 2019 is presented below:

Year ended December 31, 2020

	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	3,572,712	$20.50
Vested and issued1	(429,173)	-
Transfers2	(2,865)	$20.50
Forfeited	(76,329)	$20.50
Share grants outstanding - ending	3,064,345	$20.50

1 In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

2 Transfers relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2020. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

Year ended December 31, 2019

	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	4,115,838	$20.50
Vested and issued1	(450,622)	-
Forfeited	(92,504)	$20.50
Share grants outstanding - ending	3,572,712	$20.50

1 In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2020 and 2019, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks were asfollows:

Year ended December 31 (number of DSUs)	2020	2019
DSUs outstanding - beginning	63,767	60,182
Granted	13,610	18,124
Settled	(37,881)	(14,539)
DSUs outstanding - ending	39,496	63,767

For the year ended December 31, 2020, an expense recognized in earnings with respect to the Directors' DSU Plan was less than $1 million (2019 - $1 million). At December 31, 2020, a liability of $1 million (2019 - $1 million) related to Directors' DSUs has been recorded at the closing price of Hydro One Limited common shares of $28.65. This liability is included in other longterm liabilities on the balance sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual shortterm incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2020 and 2019, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks wereas follows:

Year ended December 31 (number of DSUs)	2020	2019
DSUs outstanding - beginning	31,500	75,072
Granted	5,415	12,458
Paid	(12,208)	-
Other1	-	(56,030)
DSUs outstanding - ending	24,707	31,500

1 In 2018, the Province of Ontario issued the Hydro One Accountability Act (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the Ontario Energy Board Act (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the year ended December 31, 2020 and 2019, no executive-related stock-based compensation was allocated to theregulated businesses of Hydro One Networks.

For the year ended December 31, 2020, an expense recognized in earnings with respect to the Management DSU Plan was $nil (2019 - $nil). At December 31, 2020, a liability of $1 million (2019 - $1

million) related to Management DSUs has been recorded
at the closing price of Hydro One Limited common shares of $28.65. This
liability is included in other long-term liabilities on thebalance sheets.
Employee Share Ownership Plan
In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP)
for certain eligible management and nonrepresented
employees (Management ESOP) and for certain eligible Society-represented
staff (Society ESOP). Under the
Management ESOP, the eligible management and non-represented employees may
contribute between 1% and 6% of their base
salary towards purchasing common shares of Hydro One Limited. The Company
matches 50% of their contributions, up to a
maximum Company contribution of $25,000 per calendar year. Under the Society
ESOP, the eligible Society-represented staff
may contribute between 1% and 4% of their base salary towards purchasing
common shares of Hydro One Limited. The
Company matches 25% of their contributions, with no maximum Company
contribution per calendar year. In 2020, Company
contributions made under the ESOP were $2 million (2019 - $2 million).
LTIP
Effective August 31, 2015, the Board of Directors of Hydro One Limited
adopted an LTIP. Under the LTIP, long-term incentives
are granted to certain executive and management employees of Hydro One
Limited and its subsidiaries, and all equity-based
awards will be settled in newly issued shares of Hydro One Limited from
treasury, consistent with the provisions of the plan which
also permit the participants to surrender a portion of their awards to
satisfy related withholding taxes requirements. The
aggregate number of shares issuable under the LTIP shall not exceed
11,900,000 shares of Hydro One Limited.
The LTIP provides flexibility to award a range of vehicles, including
Performance Share Units (PSUs), Restricted Share Units
(RSUs), stock options, share appreciation rights, restricted shares, DSUs,
and other stock-based awards. The mix of vehicles is
intended to vary by role to recognize the level of executive accountability
for overall business performance.
PSUs and RSUs
During 2020 and 2019, LTIP awards granted by Hydro One Limited that related
to Hydro One Networks were as follows:PSUs RSUs
Year ended December 31 (number of units) 2020 2019 2020 2019
Units outstanding - beginning 128,750 465,980 126,029 317,244
Vested and issued1 (34,032) (56,803) (3,692) (54,114)
Forfeited (5,568) (128,071) (5,347) (67,530)
Settled - (76,839) (17,690) (14,108)
Other2 - (75,517) - (55,463)
Units outstanding - ending 89,150 128,750 99,300 126,029
1 In 2020 and 2019, Hydro One Limited issued from treasury common shares to
eligible Hydro One Networks employees in accordance with provisions of the
LTIP. In
accordance with the inter-company agreement between Hydro One and Hydro One
Limited, Hydro One Networks made payments to Hydro One for the common
shares issued.
2 In 2018, the Province of Ontario issued the Accountability Act that
directed compensation related changes for Hydro One Limited as well as
amended the OEB Act to
restrict the recovery of any executive compensation in the rate approvals of

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any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act
and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the year ended
December 31, 2020 and 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.
No awards were granted in 2020 or 2019. The compensation expense related to the PSU and RSU awards recognized by the
Company during 2020 was $2 million (2019 - $2 million). At December 31, 2020, $3 million (2019 - $4 million) payable relating to
PSU and RSU awards was included in due to related parties on the balance sheets.Stock Options
Hydro One Limited is authorized to grant stock options under its LTIP to certain eligible employees. No stock options were
granted in 2020 or 2019. The stock options previously granted are exercisable for a period not to exceed seven years from the
date of grant. The original three-year vesting period for 706,070 stock options was modified in 2019 due to agreements reached
with five option-holders, resulting in applicable stock options being fully vested in 2019. The incremental compensation cost
resulting from the modification was not significant. There was no modification of stock options in 2020.
The fair value-based method is used to measure compensation expense related to stock options and the expense was
recognized over the vesting period on a straight-line basis. The fair value of the stock option awards granted was estimated on
the date of grant using a Black-Scholes valuation model. Updates related to stock options subject to modification were notsignificant.
A summary of stock options activity related to Hydro One Networks during the years ended December 31, 2020 and 2019 ispresented below:
Number of
Stock Options
Weightedaverage
exercise price
Stock options outstanding - January 1, 2019 559,901 $ 20.70
Exercised1 (129,780) $ 20.66
Forfeited2 (243,840) $ 20.75
Other3 (118,521)
Stock options outstanding - December 31, 20194 67,760 $ 20.66
Exercised1 (67,760) $ 20.66
Stock options outstanding - December 31, 2020 - $ -
1 Stock options exercised in 2020 had an aggregate intrinsic value of $1 million (2019 - $nil).
2 Stock options forfeited in 2019 had a fair value of $1.65 per option.
3 In 2018, the Province of Ontario issued the Accountability Act that directed compensation related changes for Hydro One Limited as well as amended the OEB Act to
restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act
and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the year ended
December 31, 2020 and 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

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4 During 2019, 197,540 stock options vested with a modified fair value of $1.03 per option, of which 129,870 were exercised. At December 31, 2019, all stock optionsoutstanding were vested and exercisable.
No compensation expense related to stock options was recognized by the Company during 2020 (2019 - $1 million). At December 31, 2020 and 2019, no amounts were payable to Hydro One Limited relating to stock options awards.
26. RELATED PARTY TRANSACTIONS
The Company is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.3% ownership at December 31, 2020. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy. B2M LP is a subsidiary of Hydro One Networks, HOSSM is a subsidiary of Hydro One, and Hydro One Telecom Inc. (Hydro One Telecom) is a subsidiary of Hydro One Limited. The following is a summary of the Company's related party transactions during the years ended December 31, 2020 and 2019:Year ended December 31 (millions of dollars)
Related Party Transaction 2020 2019
IESO Power purchased 2,454 1,808
Revenues for transmission services1 1,633 1,562
Amounts related to electricity rebates 1,581 689
Distribution revenues related to rural rate protection 242 240
Funding received related to CDM programs 24 42
OPG Power purchased 6 8
Revenues related to provision of services and supply of electricity 7 7
Capital contribution received from OPG 3 -
Costs related to the purchase of services 3 1
OEFC Power purchased from power contracts administered by the OEFC 1 2
OEB OEB fees 9 9
Hydro One Services received - costs expensed 3 3
Interest expense on long-term debt 485 470
Interest expense on inter-company demand facility 7 19
Return of stated capital 607 738
Dividends paid 1 1
Stock-based compensation costs 9 10
B2M LP Revenues for services provided 5 1
HOSSM Revenues for services provided 15 13
Hydro One Telecom Services received - costs expensed 21 21
Revenues for services provided 3 3
Hydro One Limited and its other
subsidiaries2 Revenues for services provided 8 3
Services received - costs recovered 4 3
1 Consistent with the Company's revenue recognition policy, the Company recognized revenues of $1,619 million in 2020 (2019 - $1,547 million).
2 On November 28, 2019, the common shares of HOIP GP were transferred to Hydro One Networks by Hydro One. On January 1, 2020, HOIP GP was wound up into Hydro One Networks, and its investment in B2M LP was transferred to the Company. See Note 12 - Investments in Subsidiaries.
Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code.
Outstanding balances at period end are interest-free and settled in cash.
Invoices are issued monthly, and amounts are due andpaid on a monthly basis.
The amounts due to and from related parties at December 31, 2020 and 2019 are

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as follows:As at December 31 (millions of dollars) 2020 2019
Inter-company demand facility 109 (1,076)
Due from related parties 319 408
Due to related parties (321) (302)
Accrued interest (114) (107)
Long-term inter-company payable (31) (35)
Long-term debt, including current portion (12,605) (10,988)
27. STATEMENTS OF CASH FLOWS
The changes in non-cash balances related to operations consist of the
following:Year ended December 31 (millions of dollars) 2020 2019
Accounts receivable 24 (79)
Due from related parties 89 (160)
Materials and supplies (1) -
Other assets (13) -
Accounts payable 46 10
Accrued liabilities (58) 55
Due to related parties 17 226
Accrued interest 7 12
Long-term accounts payable and other liabilities 2 2
Post-retirement and post-employment benefit liability 69 31
182 97
Capital Expenditures
The following tables reconcile investments in property, plant and equipment
and intangible assets and the amounts presented in
the statements of cash flows for the years ended December 31, 2020 and 2019.
The reconciling items include net change in
accruals and capitalized depreciation.
Year ended December 31, 2020 (millions of dollars)
Property,
Plant and
Equipment
Intangible
Assets Total
Capital investments (1,731) (127) (1,858)
Reconciling items 33 1 34
Cash outflow for capital expenditures (1,698) (126) (1,824)
Year ended December 31, 2019 (millions of dollars)
Property,
Plant and
Equipment
Intangible
Assets Total
Capital investments (1,536) (117) (1,653)
Reconciling items 33 1 34
Cash outflow for capital expenditures (1,503) (116) (1,619)
Capital Contributions
Hydro One Networks enters into contracts governed by the OEB Transmission
System Code when a transmission customer
requests a new or upgraded transmission connection. The customer is required
to make a capital contribution to Hydro One
Networks based on the shortfall between the present value of the costs of the
connection facility and the present value of
revenues. The present value of revenues is based on an estimate of load
forecast for the period of the contract with Hydro One
Networks. Once the connection facility is commissioned, in accordance with
the OEB Transmission System Code, Hydro One

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Networks will periodically reassess the estimated load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to property, plant and equipment in service. In 2020, there were no capital contributions from these assessments (2019 - $3 million). In 2019, this represented the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 (millions of dollars) 2020 2019
Net interest paid 478 458
Income taxes paid 31 17

28. CONTINGENCIES

Legal Proceedings

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the Indian Act (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2020, the Company paid approximately $2 million (2019 - $2 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.29. COMMITMENTS

The following table presents a summary of Hydro One Networks' commitments under outsourcing and other agreements due in the next five years and thereafter:

Outsourcing and other agreements 99 8 4 6 2 15
Long-term software/meter agreement 8 2 1 2 - -
As at December 31, 2020 (millions of dollars) Year 1 Year 2 Year 3 Year 4 Year 5 ThereafterOutsourcing and Other Agreements

Hydro One Networks has an agreement with Inergi LP for the provision of back-office and IT outsourcing services, including supply chain, pay operations, IT, and finance and accounting services. The agreement expired on February 28, 2021 for IT services and expires on October 31, 2021 for supply chain services. The agreement for pay operations, and for finance and accounting services was extended in October 2020 and now expires on December 31, 2021. In February 2021, Hydro One entered into an agreement for information technology services with Capgemini

Canada Inc., which expires on February 29, 2024,
and includes an option to extend for two additional one-year terms at Hydro One's discretion. Effective January 1, 2022, Ceridian
Canada Ltd. will replace Inergi LP as the new provider of pay operations for a five-year term.
BGIS Global Integrated Solutions Canada LP (BGIS) provides services to Hydro One Networks, including facilities management
and execution of certain capital projects as deemed required by the Company. The agreement with BGIS for these services
expires in December 2024, with an option for the Company to renew the agreement for an additional term of three years.
Long-term Software/Meter Agreement
Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One Networks for the
supply, maintenance and support services for smart meters and related hardware and software, including additional software
licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, with
an option for the Company to renew the agreement for an additional term of five years.Other Commitments
Prudential Support
Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based
on their expected activity in the market. As at December 31, 2020, Hydro One provided prudential support to the IESO on behalf
of Hydro One Networks using parental guarantees of $484 million (2019 - $325 million). In addition, as at December 31, 2020,
Hydro One provided letters of credit in the amount of $22 million (2019 - $9 million) to the IESO on behalf of Hydro One
Networks. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required
by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amountof the parental guarantees.
Retirement Compensation Arrangements
Bank letters of credit have been issued to provide security for Hydro One's liability under the terms of a trust fund established
pursuant to the supplementary pension plan for eligible employees of Hydro One, including Hydro One Networks. The
supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations
under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as
well as letters of credit sufficient to secure Hydro One's liability under the plan, to pay benefits payable under the plan and to pay
the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2020, Hydro
One had letters of credit of $164 million (2019 - $171 million) outstanding relating to retirement compensation arrangements.
30. SEGMENTED REPORTING
Hydro One Networks has three reportable segments:
. The Transmission Segment, which comprises the transmission of high voltage electricity across the province,
interconnecting local distribution companies and certain large directly connected industrial customers throughout theOntario electricity grid;
. The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipalelectricity distributors; and

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. Other Segment, which includes certain corporate activities. The Other Segment includes a portion of the deferred tax asset
which arose from the revaluation of the tax bases of Hydro One's assets to fair market value when the Company
transitioned from the provincial payments in lieu of tax regime to the federal tax regime at the time of Hydro One's initial
public offering in 2015. This deferred tax asset is not required to be shared with ratepayers, the Company considers it to
not be part of the regulated transmission and distribution segment assets, and it is included in the other segment.
The designation of segments has been based on a combination of regulatory status and the nature of the services provided.
Operating segments of the Company are determined based on information used by the chief operating decision-maker in
deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment
performance based on income before financing charges and income tax expense from continuing operations (excluding certain
allocated corporate governance costs).
Year ended December 31, 2020 (millions of dollars) Transmission Distribution
Other UnconsolidatedRevenues 1,715 5,383 - 7,098
Purchased power - 3,796 - 3,796
Operation, maintenance and administration 415 570 1 986
Depreciation, amortization and asset removal costs 441 412 - 853
Income (loss) before financing charges and income tax expense 859 605 (1)
1,463Capital investments 1,151 707 - 1,858
Year ended December 31, 2019 (millions of dollars) Transmission Distribution
Other UnconsolidatedRevenues 1,606 4,727 2 6,335
Purchased power - 3,111 - 3,111
Operation, maintenance and administration 370 567 (2) 935
Depreciation, amortization and asset removal costs 445 402 - 847
Income before financing charges and income tax expense 791 647 4 1,442
Capital investments 1,033 620 - 1,653
Total Assets by Segment:
As at December 31 (millions of dollars) 2020 2019
Transmission 16,245 13,769
Distribution 10,391 9,486
Other 191 1,695
Total assets 26,827 24,950
All revenues, assets and costs, as the case may be, are earned, held or incurred in Canada.31. SUBSEQUENT EVENTS
Dividends
On February 23, 2021, Hydro One Networks declared a dividend of $149 million.
Deferred Tax Asset Sharing
On April 8, 2021, the OEB rendered the Implementation Decision. In its decision, the OEB approved recovery of the deferred tax
asset amounts allocated to ratepayers for the 2017 to 2021 period plus carrying charges over a two-year period commencing on
July 1, 2021. In addition, Hydro One shall adjust the transmission revenue requirement and the base distribution rates beginning
January 1, 2022 to eliminate any further amounts of future tax savings flowing to customers. The impact of the Implementation
Decision will be reflected prospectively in the Company's financial statements.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

Assets – lines 1000 to 2599

1060	716,000,000	1061	-45,000,000	1120	18,000,000
1400	319,000,000	1401	109,000,000	1480	139,000,000
1599	1,256,000,000	1900	32,274,000,000	1901	-11,811,000,000
1920	1,120,000,000	2008	33,394,000,000	2009	-11,811,000,000
2010	1,096,000,000	2011	-585,000,000	2012	168,000,000
2178	1,264,000,000	2179	-585,000,000	2240	390,000,000
2420	2,919,000,000	2589	3,309,000,000	2599	26,827,000,000

Liabilities – lines 2600 to 3499

2620	958,000,000	2700	803,000,000	2860	321,000,000
3139	2,082,000,000	3140	11,802,000,000	3240	56,000,000
3320	2,163,000,000	3450	14,021,000,000	3499	16,103,000,000

Shareholder equity – lines 3500 to 3640

3500	2,934,000,000	3541	5,000,000	3580	-14,000,000
3600	7,799,000,000	3620	10,724,000,000	3640	26,827,000,000

Retained earnings – lines 3660 to 3849

3660	6,000,746,937	3680	1,791,253,063	3701	-1,000,000
3740	8,000,000	3849	7,799,000,000		

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7008	257,597	**7010**	-2,180,075	**7020**	-9,009,930

Revenue – lines 8000 to 8299

8000	7,065,317,802	**8089**	7,065,317,802	**8210**	2,858,397
8235	32,682,198	**8299**	7,100,858,397		

Cost of sales – lines 8300 to 8519

8320	3,796,000,000	**8518**	3,796,000,000	**8519**	3,269,317,802

Operating expenses – lines 8520 to 9369

8523	5,578,326	**8570**	68,813,947	**8623**	11,614,322
8670	697,182,267	**8710**	457,000,000	**9270**	90,114,323
9284	968,170,458	**9367**	2,298,473,643	**9368**	6,094,473,643
9369	1,006,384,754				

Extraordinary items and taxes – lines 9970 to 9999

9970	1,006,384,754	**9990**	29,395,032	**9995**	-814,263,341
9998	-6,572,258	**9999**	1,784,680,805		

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,784,680,805	A
Add:				
Provision for income taxes – current	101	29,395,032		
Provision for income taxes – deferred	102	-814,263,341		
Interest and penalties on taxes	103	3,643		
Amortization of tangible assets	104	697,182,267		
Amortization of intangible assets	106	68,813,947		
Charitable donations and gifts from Schedule 2	112	1,064,654		
Taxable capital gains from Schedule 6	113	4,182,414		
Scientific research expenditures deducted per financial statements	118	920,174		
Non-deductible meals and entertainment expenses	121	2,789,163		
Other reserves on lines 270 and 275 from Schedule 13	125	39,804,769		
Reserves from financial statements – balance at the end of the year	126	1,931,214,681		
Income or loss for tax purposes – partnerships	129	11,976,828		
Subtotal of additions		1,973,084,231 ▶	1,973,084,231	
Other additions:				
Capital items expensed	206	215,723		
Financing fees deducted in books	216	4,563,640		
Non-deductible legal and accounting fees	228	39,939		
Taxable/non-deductible other comprehensive income items	239	7,620,199		

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	CCRA true up	2,134,700
2	LTIP expense	1,550,225
3	Union share grant expenses	5,808,871
4	Asset removal costs	100,314,403
5	Loss on housing guarantee	87,015
6	Prior year Ontario ITC underaccrual	143,014
7	OPEB reg offset tax gross up	25,361,093
8	Current year Coop underaccrual	194,160
	Total of column 2	135,593,481

Total of column 2 ▶	296	135,593,481		
Subtotal of other additions	199	148,032,982 ▶	148,032,982	D
Total additions	500	2,121,117,213 ▶	2,121,117,213	
Amount A **plus** line 500			3,905,798,018	B
Deduct:				
Gain on disposal of assets per financial statements	401	2,858,397		
Capital cost allowance from Schedule 8	403	1,684,918,664		
Other reserves on line 280 from Schedule 13	413	40,544,685		
Reserves from financial statements – balance at the beginning of the year	414	1,760,545,044		
Contributions to deferred income plans from Schedule 15	417	43,118,981		

Subtotal of deductions	3,531,985,771 ▶	3,531,985,771

Other deductions:

Book income of partnership 349 32,682,198

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Deduction under 20(1)(e) ITA	7,225,031
2	Capitalized interest expenses	48,515,819
3	Capitalized overhead (OM&A)	146,715,080
4	Capitalized OPEB expenses	43,417,729
5	Capitalized removal costs	11,881,017
6	OPEB CSO liability booked to OCI	9,800,275
7	Non-deductible interest adjustment	10,636
8	Capitalized depreciation	32,120,115
9	S. 18(9.1) ded - debt prepay penalty amort	135,474
10	Landscaping adjustment	36,394
11	Insurance proceeds (cr to OMA but cap for tax)	4,140,415
12	2020 ARO Valuation Adjustment	2,598,726
13	Unrealized mark to market loss on interest rate swaps	88,744
14	Current year OBRI overaccrual	90,000
15	Current year Ontario Apprenticeship overaccrual	106,575
16	Bond premium amortization (2015 & prior)	959,578
17	Assistance included in line 431 of T661	250
	Total of column 2	307,841,858

Total of column 2	307,841,858 ▶ 396	307,841,858	
Subtotal of other deductions	499	340,524,056 ▶	340,524,056 E
Total deductions	510	3,872,509,827 ▶	3,872,509,827

Net income (loss) for income tax purposes (amount B **minus** line 510) . . . . 33,288,191 C

Enter amount C on line 300 of the T2 return.

Attached Schedule with Total

Line 206 – Capital items expensed

Title Line 206 – Capital items expensed

Description	Operator (Note)	Amount
Project Cancellation Costs (GL 670000)		215,723 00
	+	
	+	
	+	
	+	
	Total	215,723 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 216 – Financing fees deducted in books

Title Line 216 – Financing fees deducted in books

Description	Operator (Note)	Amount
Amortization of Underwriting fee (GL #761780)		3,428,484 00
Amortization of Prospectus fee (GL #761790)	+	277,884 00
Amortization of Upfront Loan fee (GL #761735)	+	857,272 00
	+	
	Total	4,563,640 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 129 – Income or loss for tax purposes – partnerships

Title Line 129 – Income or loss for tax purposes – partnerships

Explanatory note

Partnership Name: Hydro One Sault Ste Marie Holdings II LP ("HOSSMH II LP")
Partnership Business Number: [redacted]

Partnership Name: Niagara Reinforcement Limited Partnership ("NRP LP")
Partnership Business Number: [redacted]

Partnership Name: B2M Limited Partnership ("B2M LP")
Partnership Business Number: [redacted]

Description	Operator (Note)	Amount	
HOSSMH II LP Taxable Income - Box 104		11,313,999	72
NRP LP Taxable Income - Box 104	+	-1,427,536	00
B2M Limited Partnership - Box 104	+	2,090,364	00
	+		
	Total	11,976,827	72

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 239 – Taxable/non-deductible other comprehensive income items

Title Line 239 – Taxable/non-deductible other comprehensive income items

Description	Operator (Note)	Amount	
Total OCI Expense added back for tax		6,572,257	00
Add Hedge Amortization	+	257,597	00
Add OPEB Expense	+	790,345	00
	+		
	Total	7,620,199	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Deduction summary as per paragraph 20(1)(e) of the ITA

Federal

Deduction summary as per paragraph 20(1)(e) of the ITA

	Description	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	E Annual deduction (This amount is posted to one of the lines 395 of Schedule 1)	F Balance at the end of the year
1.	2016 Underwriting Fees ($500M/5YRS 0.35% + $500M/20YRS 0.3	2016-02-24	5,460,000	4,370,992	1,089,008	
2.	2016 Underwriting Fees ($500M/3YRS 0.25% + $450M/31YRS 0.5	2016-11-18	3,500,000	2,801,918	698,082	
3.	2016 Prospectus Fees ($1,350M of new debt)	2016-02-24	207,156	165,838	41,318	
4.	2016 Prospectus Fees ($950M of new debt)	2016-11-18	149,199	119,442	29,757	
5.	2016 Upfront Loan Fees ($2.3B of new debt)	2016-08-15	1,438,109	1,151,276	286,833	
6.	2015 Legal Fees	2015-11-05	63,475	52,956	10,519	
7.	2016 Legal Fees	2016-01-01	211,970	169,692	42,278	
8.	2017 Upfront Fees	2017-06-01	920,000	552,000	184,504	183,496
9.	2018 Prospectus Additions ($300M/3 years + $350M/7 years + $7	2018-06-21	202,252	80,900	40,561	80,791
10.	2018 Underwriting Additions ($300M/3 years + $350M/7 years +	2018-06-21	5,795,000	2,318,000	1,162,175	2,314,825
11.	2019 Underwriting Fees	2019-04-05	5,900,000	1,180,000	1,183,233	3,536,767
12.	2019 Prospectus Fees	2019-04-05	240,312	48,062	48,194	144,056
13.	2019 Upfront Fees	2019-06-01	1,610,000	322,000	322,882	965,118
14.	2020 Prospectus Fees	2020-06-30	459,271		92,106	367,165
15.	2020 Underwriting Fees	2020-06-30	9,940,668		1,993,581	7,947,087
		Totals	36,097,412	13,333,076	7,225,031	15,539,305

Deduction as per paragraph 20(1)(e) of the ITA

This workchart allows you to determine the tax deduction as per paragraph 20(1)(e) of the Income Tax Act (ITA). It relates to the expenses of issuing or selling shares, units or interests and expenses of borrowing money.

Ensure that any of these expenses deducted in the financial statements have been added back on line 216, "Financing fees deducted in books," and/or on line 235, "Share issue expense" to Schedule 1, if applicable.

* If the check box was selected, the annual deduction will be equal to the amount in column C.

1 Description: 2016 Underwriting Fees ($500M/5YRS 0.35% + $500M/20YRS 0.392% + $350M/30YRS 0.5%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-02-24	5,460,000	4,370,992	1,089,008	1,094,992	1,089,008	

2 Description: 2016 Underwriting Fees ($500M/3YRS 0.25% + $450M/31YRS 0.5%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-11-18	3,500,000	2,801,918	698,082	701,918	698,082	

3 Description: 2016 Prospectus Fees ($1,350M of new debt)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-02-24	207,156	165,838	41,318	41,545	41,318	

4 Description: 2016 Prospectus Fees ($950M of new debt)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-11-18	149,199	119,442	29,757	29,922	29,757	

5 Description: 2016 Upfront Loan Fees ($2.3B of new debt)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-08-15	1,438,109	1,151,276	286,833	288,410	286,833	

6 Description: 2015 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-11-05	63,475	52,956	10,519	12,730	10,519	

7 Description: 2016 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-01-01	211,970	169,692	42,278	42,510	42,278	

8 Description: 2017 Upfront Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2017-06-01	920,000	552,000	368,000	184,504	184,504	183,496

9 Description: 2018 Prospectus Additions ($300M/3 years + $350M/7 years + $750M/3 years)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2018-06-21	202,252	80,900	121,352	40,561	40,561	80,791

10 Description: 2018 Underwriting Additions ($300M/3 years + $350M/7 years + $750M/3 years)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2018-06-21	5,795,000	2,318,000	3,477,000	1,162,175	1,162,175	2,314,825

11 Description: 2019 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2019-04-05	5,900,000	1,180,000	4,720,000	1,183,233	1,183,233	3,536,767

12 Description: 2019 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2019-04-05	240,312	48,062	192,250	48,194	48,194	144,056

13 Description: 2019 Upfront Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2019-06-01	1,610,000	322,000	1,288,000	322,882	322,882	965,118

14 Description: 2020 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2020-06-30	459,271		459,271	92,106	92,106	367,165

15 Description: 2020 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2020-06-30	9,940,668		9,940,668	1,993,581	1,993,581	7,947,087

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- For use by corporations to claim any of the following:
  – the eligible amount of charitable donations to qualified donees
  – the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
  – the eligible amount of gifts of certified cultural property
  – the eligible amount of gifts of certified ecologically sensitive land or
  – the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  – Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  – If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Black Health Alliance	50,000
YES Shelter for Youth and Families	25,000
Outside Looking In	25,000
TIRF	2,000
Camp Ooch	25,000
Advanced Coronary Treatment Foundation of Canada	150,000
Advanced Coronary Treatment Foundation of Canada	150,000
Advanced Coronary Treatment Foundation of Canada	44,154
Feed Ontario	100,000
INDSPIRE	112,000
Frontier College	50,000
Scouts Canada	219,000
Scouts Canada	50,000
Shaw Woods Outdoor Education Centre Inc.	5,000
City of Dryden - Red Lake Evacuation	7,500
Frontier College	50,000
Subtotal	1,064,654
Add: Total donations of less than $100 each	
Total donations in current tax year	1,064,654

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		966,000	1A	966,000	966,000
Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year (amount 1A **minus** line 239)	240	966,000		966,000	966,000
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1, Net Income (Loss) for Income Tax Purposes)	210	1,064,654		1,064,654	1,064,654
Subtotal (line 250 **plus** line 210)		1,064,654	1B	1,064,654	1,064,654
Subtotal (line 240 **plus** amount 1B)		2,030,654	1C	2,030,654	2,030,654
Adjustment for an acquisition of control	255				
Total charitable donations available (amount 1C **minus** line 255)		2,030,654	1D	2,030,654	2,030,654
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2) (enter this amount on line 311 of the T2 return)	260	2,030,654		2,030,654	2,030,654
Charitable donations closing balance (amount 1D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . . **262** ____________

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . . ____________ 1

Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . . **263** ____________

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . . ____________ 2

Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016, and before January 1, 2024) . . . . **265** ____________

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . . ____________ 3

Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31	966,000	966,000	966,000
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2015-11-04			
7th prior year	2015-10-31			
8th prior year	2014-12-31			
9th prior year	2013-12-31			
10th prior year	2012-12-31			
11th prior year	2011-12-31			
12th prior year	2010-12-31			
13th prior year	2009-12-31			
14th prior year	2008-12-31			
15th prior year	2007-12-31			
16th prior year	2006-12-31			
17th prior year	2005-12-31			
18th prior year	2004-12-31			
19th prior year	2003-12-31			
20th prior year	2002-12-31			
21st prior year*	2001-12-31			
Total (to line A)		966,000	966,000	966,000

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes Note 1 **multiplied** by 75 %			24,966,143	2A
Taxable capital gains arising in respect of gifts of capital property included in Part 1 Note 2	225			
Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01)	227			
The amount of the recapture of capital cost allowance in respect of charitable donations	230			
Proceeds of disposition, **less** outlays and expenses Note 2	2B			
Capital cost Note 2	2C			
Amount 2B or 2C, whichever is less	235			
Amount on line 230 or 235, whichever is less		2D		
Subtotal (**add** lines 225, 227, and amount 2D)		2E		
Amount 2E **multiplied** by 25 %				2F
Subtotal (amount 2A **plus** amount 2F)			24,966,143	2G
Maximum allowable deduction for charitable donations (enter amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is the least)			2,030,654	2H

Note 1: For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

Note 2: This amount must be prorated by the following calculation, eligible amount of the gift **divided** by the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			3A		
Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year (amount 3A **minus** line 439)	440				
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			3B		
Subtotal (line 440 **plus** amount 3B)			3C		
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			3D		
Gifts of certified cultural property closing balance (amount 3C **minus** amount 3D)	480				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31			
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2015-11-04			
7th prior year	2015-10-31			
8th prior year	2014-12-31			
9th prior year	2013-12-31			
10th prior year	2012-12-31			
11th prior year	2011-12-31			
12th prior year	2010-12-31			
13th prior year	2009-12-31			
14th prior year	2008-12-31			
15th prior year	2007-12-31			
16th prior year	2006-12-31			
17th prior year	2005-12-31			
18th prior year	2004-12-31			
19th prior year	2003-12-31			
20th prior year	2002-12-31			
21st prior year*	2001-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 4 – Gifts of certified ecologically sensitive land

	Line	Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			4A		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A **minus** line 539)	540				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land (include this amount on line 112 of Schedule 1)	520				
Subtotal (line 550 **plus** line 520)			4B		
Subtotal (line 540 **plus** amount 4B)			4C		
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			4D		
Gifts of certified ecologically sensitive land closing balance (amount 4C **minus** amount 4D)	580				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . . ____

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31			
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2015-11-04			
7th prior year	2015-10-31			
8th prior year	2014-12-31			
9th prior year	2013-12-31			
10th prior year	2012-12-31			
11th prior year*	2011-12-31			
12th prior year	2010-12-31			
13th prior year	2009-12-31			
14th prior year	2008-12-31			
15th prior year	2007-12-31			
16th prior year	2006-12-31			
17th prior year	2005-12-31			
18th prior year	2004-12-31			
19th prior year	2003-12-31			
20th prior year	2002-12-31			
21st prior year*	2001-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 5 – Additional deduction for gifts of medicine

	Line	Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			5A		
Additional deduction for gifts of medicine expired after five tax years*	[redacted]				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A **minus** line 639)	[redacted]				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	[redacted]				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	[redacted]				
Cost of gifts of medicine made before March 22, 2017	[redacted]				
Subtotal (line 602 **minus** line 601)			5B		
Amount 5B **multiplied** by 50 %			5C		
Eligible amount of gifts	[redacted]				

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . ______

where:

a is the **lesser** of line 601 and amount 5C

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

	Line	Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			5D		
Subtotal (line 640 **plus** amount 5D)			5E		
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			5F		
Additional deduction for gifts of medicine closing balance (amount 5E **minus** amount 5F)	680				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31			
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2015-11-04			
7th prior year	2015-10-31			
8th prior year	2014-12-31			
9th prior year	2013-12-31			
10th prior year	2012-12-31			
11th prior year	2011-12-31			
12th prior year	2010-12-31			
13th prior year	2009-12-31			
14th prior year	2008-12-31			
15th prior year	2007-12-31			
16th prior year	2006-12-31			
17th prior year	2005-12-31			
18th prior year	2004-12-31			
19th prior year	2003-12-31			
20th prior year	2002-12-31			
21st prior year*	2001-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2019-12-31	
2nd prior year	2018-12-31	
3rd prior year	2017-12-31	
4th prior year	2016-12-31	
5th prior year	2015-12-31	
6th prior year*	2015-11-04	
7th prior year	2015-10-31	
8th prior year	2014-12-31	
9th prior year	2013-12-31	
10th prior year	2012-12-31	
11th prior year	2011-12-31	
12th prior year	2010-12-31	
13th prior year	2009-12-31	
14th prior year	2008-12-31	
15th prior year	2007-12-31	
16th prior year	2006-12-31	
17th prior year	2005-12-31	
18th prior year	2004-12-31	
19th prior year	2003-12-31	
20th prior year	2002-12-31	
21st prior year*	2001-12-31	
Total		

* These gifts expired in the current year.

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Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations.
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
  Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, I, I.1 and L **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1			2			
					Total of column E (enter amount on line 402 of Schedule 1)	

Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] **240**	F1	G Eligible dividends included in column F **242**	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) **250**
1				

	I Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2] **260**	I.1 Dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (for tax year in column D) [notes 2 and 5]	J Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3%[note 3] **265**	K Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3%[note 4] **275**	L Part IV tax before deductions on taxable dividends received from **connected** corporations [notes 2 and 5] **280**
1					

Total of column L (enter amount on line 2E in Part 2) ______

Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) . . . . ______ 1A

Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) . . . . ______ 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) ______ 1C

Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) . . . . ______ 1D

Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) . . . . ______ 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) . . . . ______ 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) . . . . ______ 1G

Subtotal (amount 1F **plus** amount 1G) ______ ▶ ______ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) . . . . ______ 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) . . . . ______ 1J

Subtotal (amount 1I **plus** amount 1J) ______ ▶ ______ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) . . . . ______ 1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column J or column K whichever one applies. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable. For column L, you only have to estimate the payer's dividend refund from its eligible refundable dividend tax on hand (ERDTOH) (column I.1).

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column F.

5 For taxable dividends received from **connected** corporations (with a tax year starting **after 2018**), Part IV tax on dividends is equal to: column I.1 (total of amounts CC and II of the connected payer corporation (on page 7 of the T2 return)) **divided** by column H **multiplied** by column F. If there is no dividend refund to the connected payer corporation from its ERDTOH for paying the taxable dividends, line 280 is nil.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1)			2A	
Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43)	320			
Subtotal (amount 2A **minus** line 320)				2B
Current-year non-capital loss claimed to reduce Part IV tax	330			
Non-capital losses from previous years claimed to reduce Part IV tax	335			
Current-year farm loss claimed to reduce Part IV tax	340			
Farm losses from previous years claimed to reduce Part IV tax	345			
Total losses applied against Part IV tax (total of lines 330 to 345)			2C	
Amount 2C **multiplied** by 38 1 / 3 %				2D
Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") (enter amount on line 712 of the T2 return)	360			

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1)		2E
Amount 4A from Schedule 43		2F
Part IV tax payable on taxable dividends received from connected corporations (amount 2E **minus** amount 2F, if negative enter "0") (enter at amount L on page 7 of the T2 return)		2G

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1)		2H
Amount 4C from Schedule 43		2I
Part IV tax payable on eligible dividends received from non-connected corporations (amount 2H **minus** amount 2I, if negative enter "0") (enter at amount M on page 7 of the T2 return)		2J

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	L Name of connected recipient corporation 400	M Business Number 410	N Tax year-end of connected recipient corporation in which the dividends in column O were received YYYYMMDD 420	O Taxable dividends paid to connected corporations 430	P Eligible dividends included in column O 440
1	Hydro One Inc.	[redacted]	2020-12-31	1,000,000	1,000,000
				1,000,000 (Total of column O)	1,000,000 (Total of column P)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations			450	
Eligible dividends included in line 450	455			
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column O **plus** line 450)			460	1,000,000
Total eligible dividends paid in the tax year (total of column P **plus** line 455)			465	1,000,000
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)			470	

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)	383,333	3A
Line 470 **multiplied** by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)		3B

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)				1,000,000	
Other dividends paid in the tax year (total of 510 to 540)					
Total dividends paid in the tax year			500	1,000,000	
Dividends paid out of capital dividend account	510				
Capital gains dividends	520				
Dividends paid on shares described in subsection 129(1.2)	530				
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540				
Subtotal (total of lines 510 to 540)			►		4A
Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount 4A)				1,000,000	4B

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the Income Tax Act, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the T2 Corporation – Income Tax Guide.
- File this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the Income Tax Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			33,288,191	1A
Net capital losses deducted in the year (enter as a positive amount)	489,542	1B		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)		1C		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)		1D		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		1E		
Employer deduction in respect of non-qualified securities – Paragraph 110(1)(e)		1F		
Subtotal (total of amounts 1B to 1F)	489,542 ►		489,542	1G
Subtotal (amount 1A **minus** amount 1G; if positive, enter "0"				1H
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions				1I
Subtotal (amount 1H **minus** amount 1I)				1J
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)				1K
Current-year non-capital loss (amount 1J **plus** amount 1K; if positive, enter "0") If amount 1L is negative, enter it on line 110 as a positive.				1L

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		1,072,065,502	1M	
Non-capital loss expired **(note 1)**	100			
Non-capital losses at the beginning of the tax year (amount 1M **minus** line 100)	102	1,072,065,502 ►		1,072,065,502
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary **(note 2)** corporation	105			
Current-year non-capital loss (from amount 1L)	110			
Subtotal (line 105 **plus** line 110)		►		1N
Subtotal (line 102 **plus** amount 1N)				1,072,065,502 1O

Note 1: A non-capital loss expires after **20** tax years and an allowable business investment loss becomes a net capital loss after **10** tax years.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Other adjustments (includes adjustments for an acquisition of control)	[redacted]			
Section 80 – Adjustments for forgiven amounts				
Subsection 111(10) – Adjustments for fuel tax rebate				
Non-capital losses of previous tax years applied in the current tax year Enter line 130 on line 331 of the T2 Return.	[redacted]	30,767,995		
Current and previous years non-capital losses applied against current-year taxable dividends subject to Part IV tax **(note 3)**	135			
Subtotal (total of lines 150, 140, 130 and 135)		30,767,995 ▶	30,767,995	1P
Non-capital losses before any request for a carryback (amount 1O **minus** amount 1P)			1,041,297,507	1Q

Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901			
Second previous tax year to reduce taxable income	902			
Third previous tax year to reduce taxable income	903			
First previous tax year to reduce taxable dividends subject to Part IV tax	911			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913			
Total of requests to carry back non-capital losses to previous tax years (total of lines 901 to 913)		▶		1R
Closing balance of non-capital losses to be carried forward to future tax years (amount 1Q **minus** amount 1R)	180		1,041,297,507	

Note 3: Line 135 is the total of lines 330 and 335 from Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	979,083		
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205			
Subtotal (line 200 **plus** line 205)		979,083 ▶	979,083	2A
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Subtotal (line 250 **plus** line 240)		▶		2B
Subtotal (amount 2A **minus** amount 2B)			979,083	2C
Current-year capital loss (from the calculation on Schedule 6, Summary of Dispositions of Capital Property)	210			
Unused non-capital losses from the 11th previous tax year **(note 4)**			2D	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year **(note 5)**			2E	
Enter amount 2D or 2E, whichever is less	215			
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220			
Subtotal (amount 2C **plus** line 210 **plus** line 220)			979,083	2F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220.

Note 4: Determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not deducted in the previous 11 years.

Note 5: Enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on amount 2E.

Part 2 – Capital losses (continued)

Capital losses from previous tax years applied against the current-year net capital gain **(note 6)**		225	979,083
Capital losses before any request for a carryback (amount 2F **minus** line 225)			2G

Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)		
First previous tax year		951			
Second previous tax year		952			
Third previous tax year		953			
Subtotal (total of lines 951 to 953)				▶	2H
Closing balance of capital losses to be carried forward to future tax years (amount 2G **minus** amount 2H) **(note 8)**				280	

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current tax year, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **divide** this amount by 2. The result represents the 50% inclusion rate.

Note 8: Capital losses can be carried forward indefinitely.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			3A	
Farm loss expired **(note 9)**	300			
Farm losses at the beginning of the tax year (amount 3A **minus** line 300)	302		▶	
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305			
Current-year farm loss (amount 1K in Part 1)	310			
Subtotal (line 305 **plus** line 310)			▶	3B
Subtotal (line 302 **plus** amount 3B)				3C
Other adjustments (includes adjustments for an acquisition of control)	350			
Section 80 – Adjustments for forgiven amounts	340			
Farm losses of previous tax years applied in the current tax year Enter line 330 on line 334 of the T2 Return.	330			
Current and previous years farm losses applied against current-year taxable dividends subject to Part IV tax **(note 10)**	335			
Subtotal (total of lines 350, 340, 330 and 335)			▶	3D
Farm losses before any request for a carryback (amount 3C **minus** amount 3D)				3E

Request to carry back farm loss to:

First previous tax year to reduce taxable income	921			
Second previous tax year to reduce taxable income	922			
Third previous tax year to reduce taxable income	923			
First previous tax year to reduce taxable dividends subject to Part IV tax	931			
Second previous tax year to reduce taxable dividends subject to Part IV tax	932			
Third previous tax year to reduce taxable dividends subject to Part IV tax	933			
Subtotal (total of lines 921 to 933)			▶	3F
Closing balance of farm losses to be carried forward to future tax years (amount 3E **minus** amount 3F)			380	

Note 9: A farm loss expires after **20** tax years.

Note 10: Line 335 is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			**485**		
(line 485 ____ – $2,500) **divided** by 2		4A			
Amount 4A or $ 15,000 , whichever is less		▶		4B	
			2,500	4C	
Subtotal (amount 4B **plus** amount 4C)			2,500 ▶	2,500	4D
Current-year restricted farm loss (line 485 **minus** amount 4D)					4E

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			4F		
Restricted farm loss expired **(note 11)**	**400**				
Restricted farm losses at the beginning of the tax year (amount 4F **minus** line 400)	**402**		▶		
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	**405**				
Current-year restricted farm loss (from amount 4E) Enter line 410 on line 233 of Schedule 1, Net Income (Loss) for Income Tax Purposes.	**410**				
Subtotal (line 405 **plus** line 410)			▶		4G
Subtotal (line 402 **plus** amount 4G)					4H
Restricted farm losses from previous tax years applied against current farming income Enter line 430 on line 333 of the T2 return.	**430**				
Section 80 – Adjustments for forgiven amounts	**440**				
Other adjustments	**450**				
Subtotal (total of lines 430 to 450)			▶		4I
Restricted farm losses before any request for a carryback (amount 4H **minus** amount 4I)					4J

Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	**941**				
Second previous tax year to reduce farming income	**942**				
Third previous tax year to reduce farming income	**943**				
Subtotal (total of lines 941 to 943)			▶		4K
Closing balance of restricted farm losses to be carried forward to future tax years (amount 4J **minus** amount 4K)			**480**		

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 11: A restricted farm loss expires after **20** tax years.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year				5A
Listed personal property loss expired **(note 12)**	500			
Listed personal property losses at the beginning of the tax year (amount 5A **minus** line 500)	502		►	
Current-year listed personal property loss (from Schedule 6)			510	
Subtotal (line 502 **plus** line 510)				5B
Listed personal property losses from previous tax years applied against listed personal property gains Enter line 530 on line 655 of Schedule 6.	530			
Other adjustments	550			
Subtotal (line 530 **plus** line 550)			►	5C
Listed personal property losses remaining before any request for a carryback (amount 5B **minus** amount 5C)				5D

Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
Subtotal (total of lines 961 to 963)			►	5E
Closing balance of listed personal property losses to be carried forward to future tax years (amount 5D **minus** amount 5E)			580	

Note 12: A listed personal property loss expires after **7** tax years.

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number 600	Tax year ending yyyy/mm/dd 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6) 620
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number 630	Tax year ending yyyy/mm/dd 632	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary 664	Current-year limited partnership losses (from line 620) 670	Limited partnership losses applied in the current year (must be equal to or less than line 650)	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) 680
1.						

Total (enter this amount on line 335 of the T2 return)

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . 190 Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent.

Attached Schedule with Total

Adjusted taxable income – Second previous tax year

Title Adjusted taxable income – Second previous tax year

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A				N/A		
1st preceding taxation year 2019-12-31	180,287,846	N/A		N/A			180,287,846
2nd preceding taxation year 2018-12-31	434,525	N/A		N/A			434,525
3rd preceding taxation year 2017-12-31	120,276,804	N/A		N/A			120,276,804
4th preceding taxation year 2016-12-31	549,209,136	N/A		N/A			549,209,136
5th preceding taxation year 2015-12-31	219,765,360	N/A		N/A	28,676,164		191,089,196
6th preceding taxation year 2015-11-04	2,091,831	N/A		N/A	2,091,831		
7th preceding taxation year 2015-10-31		N/A		N/A			
8th preceding taxation year 2014-12-31		N/A		N/A			
9th preceding taxation year 2013-12-31		N/A		N/A			
10th preceding taxation year 2012-12-31		N/A		N/A			
11th preceding taxation year 2011-12-31		N/A		N/A			
12th preceding taxation year 2010-12-31		N/A		N/A			
13th preceding taxation year 2009-12-31		N/A		N/A			
14th preceding taxation year 2008-12-31		N/A		N/A			
15th preceding taxation year 2007-12-31		N/A		N/A			
16th preceding taxation year 2006-12-31		N/A		N/A			
17th preceding taxation year 2005-12-31		N/A		N/A			
18th preceding taxation year 2004-12-31		N/A		N/A			
19th preceding taxation year 2003-12-31		N/A		N/A			
20th preceding taxation year 2002-12-31		N/A		N/A			*
Total	1,072,065,502				30,767,995		1,041,297,507

* **This balance expires this year and will not be available next year.**

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Tax Calculation Supplementary – Corporations

Schedule 5

Corporation's name	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this schedule if, during the tax year, your corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B, and D in Part 1)
  - is claiming provincial or territorial tax credits or rebates (see Part 2), or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references are to the Income Tax Regulations.
- For more information, see the T2 Corporation – Income Tax Guide.
- For the regulation number to be entered in field 100 of Part 1, see the chart below.

Part 1 – Allocation of taxable income

100 ______ Enter the regulation that applies (402 to 413)

A Jurisdiction. Tick yes if your corporation had a permanent establishment in the jurisdiction during the tax year *		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue attributable to jurisdiction	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 Yes ☐	104		144		
Prince Edward Island	005 Yes ☐	105		145		
Nova Scotia	007 Yes ☐	107		147		
Nova Scotia Offshore	008 Yes ☐	108		148		
New Brunswick	009 Yes ☐	109		149		
Quebec	011 Yes ☐	111		151		
Ontario	013 Yes ☐	113		153		
Manitoba	015 Yes ☐	115		155		
Saskatchewan	017 Yes ☐	117		157		
Alberta	019 Yes ☐	119		159		
British Columbia	021 Yes ☐	121		161		
Yukon	023 Yes ☐	123		163		
Northwest Territories	025 Yes ☐	125		165		
Nunavut	026 Yes ☐	126		166		
Outside Canada	027 Yes ☐	127		167		
Total		129 G		169 H		

* **Permanent establishment** is defined in subsection 400(2)

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, complete Part 2.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

	Line			Amount	
Ontario basic income tax (from Schedule 500)	270				
Ontario small business deduction (from Schedule 500)	402				
Subtotal (line 270 **minus** line 402)			►		5A
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal (line 276 **plus** line 277)			►		5B
Gross Ontario tax (amount 5A **plus** amount 5B)					5C
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Ontario non-refundable tax credits (total of lines 404 to 415)			►		5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")					5E
Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")					5F
Ontario corporate minimum tax credit (from Schedule 510)			418		
Ontario community food program donation tax credit for farmers (from Schedule 2)			420		
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative, enter "0")					5G
Ontario corporate minimum tax (from Schedule 510)	278	25,672,781			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal (line 278 **plus** line 280)		25,672,781	►	25,672,781	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)				25,672,781	5I
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	583,946			
Ontario apprenticeship training tax credit (from Schedule 552)	454	308,425			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Ontario regional opportunities investment tax credit (from Schedule 570)	472				
Ontario refundable tax credits (total of lines 450 to 472)		892,371	►	892,371	5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets) Include this amount on line 255.			290	24,780,410	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits . . . 255 24,780,410

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- All legislative references are to the federal Income Tax Act.
- Also use this schedule to make a designation under paragraph 111(4)(e) if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the T2 Corporation Income Tax Guide.
- If you need more space, attach additional schedules.

Designation under paragraph 111(4)(e)

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . . **050** Yes [ ] No [X]

If **yes**, attach a statement specifying which properties such a designation applies to.

In the various sections of this form:

- The abbreviation **FS** (for foreign source) is used to indicate the capital gain or loss arising from foreign property;
- The abbreviation **PA** (for passive asset) is used to indicate the capital gain or loss arising from the disposition of an asset other than an active asset of the corporation.

Part 1 – Shares

1 Number of shares 100	2 Name of corporation in which the shares are held 105	3 Class of shares 106	4 Date of acquisition YYYYMMDD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	A FS	A PA
19150837	Hydro One Indigenous Pa	Common		246,245,772	246,245,772				
			Totals	246,245,772	246,245,772				

Total adjustment under subsection 112(3) to all losses identified in Part 1 . . . . [redacted] ______

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . ______ A

Part 2 – Real estate (Do not include losses on depreciable property)

1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of acquisition YYYYMMDD [redacted]	3 Proceeds of disposition [redacted]	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	A FS	A PA
035302 Sideroad 21-22 E Luther	2014-04-30	1,325,000	265,333	50,098	1,009,569		
East Luther Grand Valley							
ON CA L9W 0E9							
045511 Southgate Rd 4	2014-08-01	975,000	180,859	40,012	754,129		
Southgate							
ON CA N0G 2L0							
322139 Concession 6-7	2009-10-09	950,000	97,124	28,925	823,951		
East Luther Grand Valley							
ON CA L9W 0X1							
104665 Southgate Rd 10	2011-10-31	600,000	93,741	47,661	458,598		
Southgate							
ON CA N0G 2L0							

Part 2 – Real estate (Do not include losses on depreciable property)

1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of acquisition YYYYMMDD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	A FS	A PA
441023 Concession Rd 12-13	2011-12-07	1,250,100	89,994	38,446	1,121,660		
East Luther Grand Valley							
ON CA L9W 0Z9							
033496 Grey Rd 28	2014-07-31	652,000	88,204	31,405	532,391		
Hanover							
ON CA N4N 3B9							
441038 Concession Rd 12-13	2010-04-01	165,000	87,445	6,760	70,795		
East Luther Grand Valley							
ON CA L9W 0Z9							
362129 Concession Rd 8-9	2010-04-28	590,000	84,747	17,515	487,738		
Luther							
East Luther Grand Valley							
ON CA L9W 0Y1							
243017 Southgate Rd 24	2009-10-06	165,000	84,484	13,157	67,359		
Southgate							
ON CA N0G 1R0							
13635 Bruce Road 10	2011-04-14	170,000	80,949	8,518	80,533		
West Grey							
ON CA N4N 3B9							
302165 Concession Rd 2	2010-03-01	420,354	52,967	19,662	347,725		
West Grey							
ON CA N4N 3B8							
302127 Concession Rd 2	2010-11-01	295,000	49,969	12,363	232,668		
West Grey							
ON CA N4N 3B8							
133272 Allan Park Rd	2011-09-29	47,000	31,260	2,244	13,496		
West Grey							
ON CA N4N 3B8							
302131 Concession 2 Sdr	2010-01-29	181,000	17,545	11,055	152,400		
West Grey							
ON CA N4N 3B8							
1560 Main St East	1979-07-05	1,826,278	2,539,976		-713,698		
Milton							
ON CA L9T 6H7							
305 Lakeview Blvd	2019-07-22	600,000	615,500	34,227	-49,727		
Keswick							
ON CA L4P 2Y6							

Part 2 – Real estate (Do not include losses on depreciable property)

1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of acquisition YYYYMMDD [redacted]	3 Proceeds of disposition [redacted]	4 Adjusted cost base [redacted]	5 Outlays and expenses from disposition [redacted]	6 Gain (or loss) (column 3 **minus** columns 4 and 5) [redacted]	A FS	 PA
370 Domanski Road	2020-01-16	390,000	405,000	22,288	-37,288		
Fort Frances							
ON CA P9A 3M2							
	Totals	10,601,732	4,865,097	384,336	5,352,299	B	

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYYMMDD 305	3 Name of bond issuer 307	4 Date of acquisition YYYYMMDD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	A FS	 PA
			Totals					C	

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property [redacted]	2 Date of acquisition YYYYMMDD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	A FS	 PA
NRLP Shares -Gain	2019-09-18	9,433,093	7,926,829		1,506,264		
NRLP Shares -Gain adjust to 100%	2019-09-18	1,506,264			1,506,264		
	Totals	10,939,357	7,926,829		3,012,528	D	

Note
Other property includes capital debts, debts in respect of the disposition of a personal-use property per subsection 50(2), and amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of acquisition YYYYMMDD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	A FS	 PA
	Totals					E	

Note
You **cannot** deduct losses on dispositions of personal-use property (other than listed personal property or a debt that is a personal-use property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of acquisition YYYYMMDD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss)* (column 3 **minus** columns 4 and 5) 650	A FS	PA
	Totals						

Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, Corporation Loss Continuity and Application) . . . . . 655 ______

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . . ______ F

Note

Net listed personal property losses can only be applied against listed personal property gains.

* Do **not** include gains arising on the disposition of certain certified cultural property to a designated cultural institution. See subparagraph 39(1)(a)(i.1) for more information.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter **1**; debt, enter **2** 905	3 Date of acquisition YYYYMMDD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 **minus** columns 5 and 6) 950	A FS	PA
		Totals						

Allowable business investment losses (ABILs) . . . . . Total of Column 7 ______ x 50.0000 % = ______ G

Enter amount G on line 406 of Schedule 1, Net Income (Loss) for Income Tax Purposes.

Note

Properties listed in Part 7 should **not** be included in any other parts of this schedule.

Part 8 – Capital gains or losses

			FS	PA
Total of amounts A to F (do **not** include amount F if it is a loss)		8,364,827	H	
Capital gains dividend received in the year	875			
Capital gains reserve opening balance (from Part 1 of Schedule 13, Continuity of Reserves)	880			
Subtotal (amount H **plus** total of lines 875 and 880)		8,364,827	I	
Capital gains reserve closing balance (from Part 1 of Schedule 13, Continuity of Reserves)	885			
Capital gains or losses, excluding ABILs (amount I **minus** line 885)	890	8,364,827		

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) . . . . . 8,364,827 J

Deduct the following amounts included in amount J, that are subject to the zero inclusion rate:

Note
When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 for more information.

Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under paragraphs 38(a.1)(i) and (iii) **895** ______ FS PA

Gain on the donation to a qualified donee of ecologically sensitive land under subsection 38(a.2)* . . . . . **896** ______ FS PA

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(a.3) . . . . . ______ a FS PA

Subtotal (line 895 **plus** line 896 **plus** line a) ______ ▶ ______ K

Subtotal (amount J **minus** amount K) 8,364,827 L

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12):

Exemption threshold at time of disposition . . . . . **897** ______

The total of all capital gains from the disposition of the actual property . . . . . **898** ______

Line 897 or line 898, whichever is less ______ M FS PA

Taxable capital gains under section 34.2 (line 275 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships) . . . . . ______ x 2 = **899** ______

Subtotal (total of amounts L and M **plus** line 899) 8,364,827 N

Allowable capital losses under section 34.2 (line 285 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships) . . . . . ______ x 2 = **901** ______

Total capital gains or losses (amount N **minus** line 901) 8,364,827 O

Taxable capital gains or total capital losses

Total capital losses (amount O, if amount O is negative; if amount O is positive, enter "0") . . . . . ______ P

Enter amount P on line 210 of Schedule 4.

Taxable capital gains (if amount O is positive, enter amount O 8,364,827 multiplied by 50.0000 %;
if amount O is negative, enter "0") . . . . . 4,182,414 Q

Enter amount Q on line 113 of Schedule 1.

* Do **not** include gains on donations of ecologically sensitive land to a private foundation.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes [ ] No [X]

	1 Class number * See note 1 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) See note 2 203	4 Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP) or zero-emission vehicle (ZEV) See note 3 225	5 Adjustments and transfers See note 4 205	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 5 221	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 6 222	8 Proceeds of dispositions See note 7 207	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8
1.	1		4,712,378,442	77,570,916	66,968,647				0	4,789,949,358
2.	1b		34,325						0	34,325
3.	2		2,517,251,162						0	2,517,251,162
4.	3		265,832,887	23,370	18,817				0	265,856,257
5.	6		76,409,868	2,165,192	1,931,510				0	78,575,060
6.	7			4,079,988	3,634,967				0	4,079,988
7.	8		228,933,029	41,043,122	34,143,431				67,952	269,908,199
8.	9		8,666,782	407,315	362,887				0	9,074,097
9.	10	Class 10.1	2,385,949	2,067,900	1,886,835				0	4,453,849
10.	10		144,536,864	22,801,998	20,990,176	-990,900			1,811,822	164,536,140
11.	12		16,555,019	107,448,672	97,776,838				0	124,003,691
12.	13	2017 "Get Local" Office Upgrade (WBS 7	31						0	31
13.	13	255 Matheson Mississauga (WBS 300043	123,469						0	123,469
14.	13	483 Bay Street (WBS 300040950)	260,192						0	260,192
15.	13	483 Bay Street (WBS 300042991C/70000	11,904,515						0	11,904,515
16.	13	Arnprior Forestry Work Centre (WBS 700	80,951						0	80,951
17.	13	Atrium on Bay (WBS 300040666)	7,492						0	7,492
18.	13	Lionhead (WBS 700015140)	3,628						0	3,628
19.	13	Newmarket Garage (WBS 300040668)	12,472						0	12,472
20.	13	Newmarket SC (WBS 700016578)	2,026						0	2,026
21.	13	Nipigon (WBS 700011829)	14,545						0	14,545
22.	13	Orillia Forestry Work Centre (WBS 70001	98,280						0	98,280
23.	13	Orleans OC (WBS 700010809)	250,702						0	250,702
24.	13	PCB Light Replacement		18,789	18,122				0	18,789

	1 Class number * See note 1 (200)	Description	2 Undepreciated capital cost (UCC) at the beginning of the year (201)	3 Cost of acquisitions during the year (new property must be available for use) See note 2 (203)	4 Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP) or zero-emission vehicle (ZEV) See note 3 (225)	5 Adjustments and transfers See note 4 (205)	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 5 (221)	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 6 (222)	8 Proceeds of dispositions See note 7 (207)	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8
25.	13	Post-2016	1,819,132						0	1,819,132
26.	13	Smart Meter Facility - 255 Matheson Blvd	128,505	1,815,099	1,750,712				0	1,943,604
27.	13	Sudbury (WBS 700010356)	98,928						0	98,928
28.	13	Sudbury 500 Barrydowne (WBS 7000253	339,508						0	339,508
29.	13	Switch to LED fixtures/light bulbs		91,865	88,606				0	91,865
30.	13	Thunder Bay Fleet Garage (WBS 700002	29,632						0	29,632
31.	13	Thunder Bay Fleet Garage (WBS 700003	3,040,989						0	3,040,989
32.	13	Woodstock office 763 Athlone Dr WBS 7(		4,851,853	4,679,746				0	4,851,853
33.	14.1	Pre-2017 (formerly ECE)	2,999,944,318						0	2,999,944,318
34.	14.1		15,580,480	686,199	542,742				0	16,266,679
35.	17		150,205,049	15,695,191	13,835,191				0	165,900,240
36.	42		90,583,810	94,799	76,331				0	90,678,609
37.	43.2		1,981						0	1,981
38.	45		2,037,592						0	2,037,592
39.	46		18,550,716	2,612,137	2,327,221				0	21,162,853
40.	47		8,691,421,387	1,090,119,828	950,359,635				891,847	9,780,649,368
41.	50		64,919,489	11,129,054	9,803,667				0	76,048,543
		Totals	20,024,444,146	1,384,723,287	1,211,196,081	-990,900			2,771,621	21,405,404,912

	1 Class number * See note 1 (200)	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 (224)	14 CCA rate % See note 11 (212)	15 Recapture of CCA See note 12 (213)	16 Terminal loss See note 13 (215)	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 (217)	18 UCC at the end of the year (column 9 **minus** column 17) (220)
1.	1			66,968,647	33,484,324	5,301,135	4	0	0	192,349,314	4,597,600,044
2.	1b						6	0	0	2,060	32,265
3.	2						6	0	0	151,035,070	2,366,216,092
4.	3			18,817	9,409	2,277	5	0	0	13,265,958	252,590,299
5.	6			1,931,510	965,755	116,841	10	0	0	7,861,198	70,713,862

	1 Class number * See note 1 [redacted]	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 224	14 CCA rate % See note 11 [redacted]	15 Recapture of CCA See note 12 213	16 Terminal loss See note 13 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 [redacted]	18 UCC at the end of the year (column 9 **minus** column 17) 220
6.	7			3,634,967	1,817,484	222,511	15	0	0	851,244	3,228,744
7.	8			34,143,431	17,071,716	3,415,870	20	0	0	55,474,115	214,434,084
8.	9			362,887	181,444	22,214	25	0	0	2,269,814	6,804,283
9.	10	Class 10.1		1,886,835	943,418	90,533	30	0	0	1,592,020	2,861,829
10.	10			20,990,176	10,495,088		30	0	0	51,572,205	112,963,935
11.	12			97,776,838		4,835,917	100	0	0	118,541,690	5,462,001
12.	13	2017 "Get Local" Office Upgra					NA	0	0	6	25
13.	13	255 Matheson Mississauga (W					NA	0	0	123,469	
14.	13	483 Bay Street (WBS 3000409					NA	0	0	13,480	246,712
15.	13	483 Bay Street (WBS 3000429					NA	0	0	1,861,803	10,042,712
16.	13	Arnprior Forestry Work Centre					NA	0	0	28,561	52,390
17.	13	Atrium on Bay (WBS 3000406					NA	0	0	7,492	
18.	13	Lionhead (WBS 700015140)					NA	0	0	3,628	
19.	13	Newmarket Garage (WBS 3000					NA	0	0	12,472	
20.	13	Newmarket SC (WBS 7000165					NA	0	0	1,104	922
21.	13	Nipigon (WBS 700011829)					NA	0	0	14,545	
22.	13	Orillia Forestry Work Centre (W					NA	0	0	27,666	70,614
23.	13	Orleans OC (WBS 700010809)					NA	0	0	250,702	
24.	13	PCB Light Replacement		18,122		56	NA	0	0	4,586	14,203
25.	13	Post-2016					NA	0	0	74,023	1,745,109
26.	13	Smart Meter Facility - 255 Mat		1,750,712		3,577	NA	0	0	313,720	1,629,884
27.	13	Sudbury (WBS 700010356)					NA	0	0	16,961	81,967
28.	13	Sudbury 500 Barrydowne (WB					NA	0	0	68,617	270,891
29.	13	Switch to LED fixtures/light bul		88,606		272	NA	0	0	22,423	69,442
30.	13	Thunder Bay Fleet Garage (WB					NA	0	0	19,756	9,876
31.	13	Thunder Bay Fleet Garage (WB					NA	0	0	116,483	2,924,506
32.	13	Woodstock office 763 Athlone		4,679,746		5,737	NA	0	0	473,712	4,378,141
33.	14.1	Pre-2017 (formerly ECE)					5	0	0	209,996,102	2,789,948,216
34.	14.1			542,742	271,371	71,729	5	0	0	771,380	15,495,299
35.	17			13,835,191	6,917,596	930,000	8	0	0	13,479,511	152,420,729
36.	42			76,331	38,166	9,234	12	0	0	10,805,568	79,873,041
37.	43.2						50	0	0	991	990
38.	45						45	0	0	916,916	1,120,676

	1 Class number * See note 1 [redacted]	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 [redacted]	14 CCA rate % See note 11 [redacted]	15 Recapture of CCA See note 12 [redacted]	16 Terminal loss See note 13 [redacted]	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 [redacted]	18 UCC at the end of the year (column 9 **minus** column 17) [redacted]
39.	46			2,327,221	1,163,611	142,458	30	0	0	6,432,531	14,730,322
40.	47			950,359,635	475,179,818	69,434,173	8	0	0	801,225,592	8,979,423,776
41.	50			9,803,667	4,901,834	662,694	55	0	0	43,020,176	33,028,367
		Totals		1,211,196,081	553,441,034	85,267,228				1,684,918,664	19,720,486,248

Enter the total of column 15 on line 107 of Schedule 1.
Enter the total of column 16 on line 404 of Schedule 1.
Enter the total of column 17 on line 403 of Schedule 1.

Note 1. If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101. Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 2. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule.

Note 3. An AIIP is a property (other than ZEV) that you acquired after November 20, 2018 and became available for use before 2028. ZEV is, subject to certain exceptions, a new motor vehicle included in Class 54 or 55 that you acquired after March 18, 2019 and became available for use before 2028. The Government proposes to create Class 56 for zero-emission automotive equipment and vehicles that currently do not benefit from the accelerated rate provided by Classes 54 and 55. Class 56 would apply to eligible zero-emission automotive equipment and vehicles that are acquired after March 1, 2020, and became available for use before 2028. Columns 4, 10, 11, 12 and 13 also apply for additions of class 56 property. See the T2 Corporation Income Tax Guide for more information.

Note 4. Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost (column 9). Items that increase the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the undepreciated capital cost (show amounts that reduce the undepreciated capital cost in brackets) include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.
Also include the UCC of each property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property continuously owned by the transferor for at least 364 days before the end of your tax year.

Note 5. Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 6. Include all amounts you have repaid during the year with respect to any legally required repayment, made after the disposition of a corresponding property, of:
- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Also include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year.

Note 7. For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
The proceeds of disposition of a ZEV that has been included in Class 54 and that is subject to the $55,000 (plus sales taxes) capital cost limit will be adjusted based on a factor equal to the capital cost limit of $55,000 (plus sales taxes) as a proportion of the actual cost of the vehicle.

Note 8. If the amount in column 5 reduces the undepreciated capital cost (i.e. it is shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 9. The relevant factors for property of a class in Schedule II, that is AIIP or included in Classes 54 to 56, available for use before 2024 are:
- 2 1/3 for property in Classes 43.1, 54 and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 14 for additional information) and
- 0.5 for all other property that is AIIP

Note 10. The UCC adjustment for property acquired during the year other than AIIP and ZEV (formerly known as the half-year rule or 50% rule) does not apply to certain property (including AIIP). For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 11. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 17.

Note 12. If the amount in column 9 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 9 in column 15 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1.

Note 13. If no property is left in the class at the end of the tax year and there is still a positive amount in the column 9, you have a terminal loss. If applicable, enter the positive amount from column 9 in column 16. The terminal loss rules do not apply to:
- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates or
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply

Note 14. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year allowance you can claim is determined as follows:
- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraph 1100(1)(y.2)(for single mine properties) and 1100(1)(ya.2)(for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		1,377,945,681	
Additions for tax purposes – Schedule 8 leasehold improvements	+	6,777,606	
Operating leases capitalized for book purposes	+		
Capital gain deferred	+		
Recapture deferred	+		
Deductible expenses capitalized for book purposes – Schedule 1	+	332,223,131	
Other (specify):			
CCRA true up credited to fixed assets	+	-2,134,700	
Land adjustments	+	3,305,300	
Project cancellation costs expensed for book purposes	+	-215,723	
Disallowed Class 10.1 Additions	+	702,514	
Insurance proceeds capitalized for tax	+	4,140,415	
Removal costs (cap for tax but deduct for accounting)	+	-100,314,403	
UCC adjustment (on Sch 8 adj column)	+		
Total additions per books	=	1,622,429,821 ►	1,622,429,821
Proceeds up to original cost – Schedule 8 regular classes		2,771,621	
Proceeds up to original cost – Schedule 8 leasehold improvements	+		
Proceeds in excess of original cost – capital gain	+		
Recapture deferred – as above	+		
Capital gain deferred – as above	+		
Pre V-day appreciation	+		
Other (specify):			
Decrease in CIP ending (excluded from Sch 8 adds)	+	-241,000,000	
Future use assets movement	+	-13,580,917	
Proceeds of disposition on land	+	9,283,909	
Rounding to FS (FS prepared in millions)	+	1,817,391	
Total proceeds per books	=	-240,707,996 ►	– -240,707,996
Depreciation and amortization per accounts – Schedule 1		–	765,996,214
Loss on disposal of fixed assets per accounts		–	
Gain on disposal of fixed assets per accounts		+	2,858,397
Net change per tax return		=	1,100,000,000

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		22,262,000,000
Opening net book value	–	21,162,000,000
Net change per financial statements	=	1,100,000,000

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Tax return – Deductible expenses capitalized for book purposes – Schedule 1

Title Tax return – Deductible expenses capitalized for book purposes – Schedule

Explanatory note

Refer to T2 - Fixed Asset Roll and 8.4 Accting to Tax Adds for details.

Description	Operator (Note)	Amount	
Pension Expenses		43,118,981	00
Capitalized Interest Expenses	+	48,515,819	00
OMA Expenses Capitalized Overhead	+	146,715,080	00
Capitalized OPEB	+	43,417,729	00
LTIP Expenses	+	828,790	00
Landscaping	+	36,394	00
Removal Costs	+	11,881,017	00
Union share grant expenses	+	2,990,480	00
Capitalized depreciation	+	32,120,115	00
ARO	+	2,598,726	00
	+		
	Total	332,223,131	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Explanatory note

Refer to tab T2- Fixed Asset Roll

Description	Operator (Note)	Amount	
CIP Opening - Fixed assets		882,000,000	00
CIP Ending - Fixed assets	-	1,120,000,000	00
CIP Opening - Intangibles	+	55,000,000	00
CIP Ending - Intangibles	-	58,000,000	00
	+		
	Total	-241,000,000	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1)	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Hydro One Limited	CA	[redacted]	3					
2.	Hydro One Inc.	CA		1					
3.	2486267 Ontario Inc.	CA		3					
4.	2486268 Ontario Inc.	CA		3					
5.	Hydro One Remote Communites Inc	CA		3					
6.	Hydro One Telecom Inc.	CA		3					
7.	Hydro One Telecom Link Limited	CA		3					
8.	Municipal Billing Services Inc.	CA		3					
9.	Hydro One Lake Erie Link Manageme	CA		3					
10.	1938454 Ontario Inc.	CA		3					
11.	1943404 Ontario Inc.	CA		3					
12.	Hydro One Indigenous Partnerships	CA		3					
13.	Norfolk Energy Inc.	CA		3					
14.	Norfolk Power Distribution Inc.	CA		3					
15.	Haldimand County Energy Inc.	CA		3					
16.	Haldimand County Hydro Inc.	CA		3					
17.	Woodstock Hydro Services Inc.	CA		3					
18.	Hydro One Sault Ste. Marie Holdings	CA		3					
19.	Hydro One Sault Ste. Marie Inc.	CA		3					
20.	Hydro One Sault Ste. Marie Holding	CA		3					
21.	1228185 Ontario Inc.	CA		3					
22.	Hydro One East-West Tie Inc.	CA		3					
23.	1937680 Ontario Inc.	CA		3					
24.	1937681 Ontario Inc.	CA		3					
25.	2587264 Ontario Inc.	CA		3					
26.	Hydro One Holdings Limited	CA		3					
27.	2587265 Ontario Inc.	CA		3					
28.	Hydro One Investment Holdings Inc	CA		3					
29.	Orillia Power Distribution Corporatio	CA		3					
30.	Aux Energy Inc.	CA		3					
31.	Olympus Holding Corp.	CA		3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description		Balance at the beginning of the year $	Transfer on an amalgamation or the wind-up of a subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts	☐	110	115			120
Reserve for undelivered goods and services not rendered	X	130 39,804,769	135	739,916		140 40,544,685
Reserve for prepaid rent	☐	150	155			160
Reserve for refundable containers	☐	190	195			200
Reserve for unpaid amounts	☐	210	215			220
Other tax reserves	☐	230	235			240
Totals		270 39,804,769	275	739,916		280 40,544,685

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability LT	1,743,700,950		74,509,077		1,818,210,027
2	Environmental liability LT	107,064,513			17,021,228	90,043,285
3	Reg offset - Environmental liab	-107,064,513		17,021,228		-90,043,285
4	Net Regulatory Liabilities	123,417,219		71,767,994		195,185,213
5	Tenant Inducement	2,805,060			1,126,665	1,678,395
6	Asset Retirement Obligations	10,685,944		2,668,975		13,354,919
7	Insurance proceeds reserve	2,893,169				2,893,169
8	Bonus payable	1,745,558			1,569,025	176,533
9	Contingent Liabilities	11,081,546			2,792,899	8,288,647
10	Director Share Units (DSU)	1,143,211			89,409	1,053,802
11	Lease Adjustment	2,669,227		2,338,815		5,008,042
12	Reg offset - OPEB Liability Valu	-103,565,589		44,424,167		-59,141,422
13	Allowance for Doubtful Account			14,300,000		14,300,000
14	Reg offset - OPEB Cost Deferra	-75,836,020		-34,501,309		-110,337,329
15						
	Reserves from Part 2 of Schedule 13	39,804,769		739,916		40,544,685
	Totals	1,760,545,044		193,268,863	22,599,226	1,931,214,681

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Inc	483 Bay Street Toronto ON M5G 2P5			4,228,368		
2	Hydro One Limited	483 Bay Street Toronto ON M5G 2P5			603,830		

T2 SCH 14 (99)

Canadä

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	54,733,303	1059104			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	54,733,303	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	11,614,322	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")	43,118,981	C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

T2 SCH 15 (13)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 24

FIRST-TIME FILER AFTER INCORPORATION, AMALGAMATION, OR WINDING-UP OF A SUBSIDIARY INTO A PARENT

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

This schedule must be filed by corporations for the first year of filing after incorporation, amalgamation, or by parent corporations filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act* during the current taxation year.

Part 1 – Type of operation

100 For those corporations filing for the first time after incorporation or amalgamation, please identify the type of operation that applies to your corporation:

Part 2 – First year of filing after amalgamation

For the first year of filing after an amalgamation, please provide the following information:

Name of predecessor corporation(s) **200**	Business Number (If a corporation is not registered, enter "NR") **300**

Part 3 – First year of filing after wind-up of subsidiary corporation(s)

For the parent corporation filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act*, please provide the following information:

	Name of subsidiary corporation(s) **400**	Business Number (If a corporation is not registered, enter "NR") **500**	Commencement date of wind-up (YYYY/MM/DD) **600**	Date of wind-up (YYYY/MM/DD) **700**
1	Hydro One Indigenous Partnerships Inc.	[redacted]	2020-01-01	2020-10-27

T2 SCH 24 (04) Canada

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 29

PAYMENTS TO NON-RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than $100, you do not have to complete the information for that payee.

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
1	Accruent LLC	PO Box 679881 Dallas TX US 75267	09	275,611
2	Ancile Solutions Inc	300- 6085 Marshalee Drive Elkridge MD US 21075	09	14,200
3	Arcos LLC	445 Hutchinson Ave Suite 600 Columbus OH US 43235	09	4,996
4	Catalyst Inc	120 Wall St 15th Fl New York NY US 10006	09	39,159
5	CGIT Systems Inc	PO Box 843771 Dallas TX US 75284	09	125,742
6	Clear Path Utility Solutions LLC	612 Lakeridge Drive Auburn CA US 95603	09	197,517
7	Convergent Performance LLC	7150 Campus Drive Suite 275 Colorado Springs CO US 80920	09	11,673
8	Cyber-Ark Software Inc.	60 Wells Ave Suite 103 Newton Center MA US 02459	09	6,960
9	Daniel L Sun Inc	2150 North First Street Suite 550 San Jose CA US 95131	09	64,297
10	Electric Power Research Institute Inc. (EPRI)	PO Box 10412 Palo Alto CA US 94303	09	13,785
11	FIS AvantGard LLC	601 Riverside Ave Jacksonville FL US 32204	09	83

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
12	Geotherm USA LLC	21239 FM529 Rd Bldg F Cypress TX US 77433	09	25,863
13	[redacted]	[redacted]	09	5
14	Kates Kesler Organization Consulting	118 E 28th Street Suite 1014 New York NY US 10016	09	23,010
15	[redacted]	[redacted]	09	50
16	[redacted]	[redacted]	09	550
17	Power System Engineering Inc.	1532 W Broadway Madison WI US 53713	09	20,116
18	Southern States LLC	30 Georgia Ave PO Box 985 Hampton GA US 30228	09	90,178
19	Spatial Business Systems Inc.	7175 West Jefferson Ave Suite 4300 Lakewood CO US 80235	09	192,695
20	System Improvements Inc.	301-238 South Peters Rd Knoxville TN US 37923	09	41,418
21	[redacted]	[redacted]	09	11,250
22	SOS International LLC	10715 Sikes Place Suite 114 Charlotte NC US 28277	09	15,792
23	Utilities Aviation Specialists Inc.	PO Box 810 Crown Point IN US 46308	09	10,441
24	VRT Power Ltd	17 Haneviim St PO Box 1176 Ramat Hasharon IL 4727919	09	290,332

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
25	Bertling Logistics Inc	19054 Kenswick Drive Humble TX US 77338	09	191,623
26	TTX Company	101 North Wacker Dr Chicago IL US 606067391	09	56,393
27	DMC Power	623 E Artesia Blvd Carson CA US 90746	09	128,714
28	[redacted]	[redacted]	09	90
29	Doble Engineering Company	123 Felton Street Marlborough MA US 01752	09	336,000
30	Intellirent	604 Henrietta Creek Suite 400 Roanoke TX US 76262	09	47,140
31	[redacted]	[redacted]	09	2,839

Note 1: Enter the applicable payment code in column 300:

1 – Royalties
2 – Rents
3 – Management fees/commissions
4 – Technical assistance fees
5 – Research and development fees
6 – Interest
7 – Dividends
8 – Film payments: – motion picture film, or – a film or video tape for use in connection with television
9 – Other services

T2 SCH 29 (99) Canadä

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year
  - to claim a deduction against Part I tax payable
  - to claim a refund of credit earned during the current tax year
  - to claim a carryforward of credit from previous tax years
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1)
  - to request a credit carryback to one or more previous years
  - if you are subject to a recapture of ITC
  - if you are claiming:
    - the **Ontario Research and Development Tax Credit**
    - the **Ontario Innovation Tax Credit**
- Unless otherwise stated, all legislative references are to the Income Tax Act and the Income Tax Regulations.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that currently earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
  - pre-production mining expenditures (Part 18)
    - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you made the investment.
  - apprenticeship job creation expenditures (Parts 19 to 21)
  - child care spaces expenditures (Parts 22 to 26)
    - Expenditures related to child care spaces incurred after March 21, 2017 no longer qualify for the ITC. However, if you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 remain eligible for the credit.
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, T2 Corporation – Income Tax Guide and read Information Circular IC78-4, Investment Tax Credit Rates, and its related Special Release.
- For more information on SR&ED, see guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired.
- An ITC deducted in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures.
- Expenditures for apprenticeship or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms).
- For tax purposes**,** Canada includes the **exclusive economic zone of Canada** as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).

Detailed information (continued)

- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012, unless transitional measures were granted*. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15% rate.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada	15 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred expenditures after March 18, 2007, and before March 22, 2017 (or before 2020 if you entered into a written agreement before March 22, 2017) for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . 101 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

a) one or more persons exempt from Part I tax under section 149
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority
c) any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . 102 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . ________ x 80 % = 103 ________
Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number 105	Description of investment 110	Date available for use 115	Location used in Atlantic Canada (province) 120	Amount of investment 125
			Total of investments for qualified property and qualified resource property	A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year					B1
Credit deemed as a remittance of co-op corporations	210				
Credit expired	215				
Subtotal (line 210 **plus** line 215)			▶		C1
ITC at the beginning of the tax year (amount B1 **minus** amount C1)			220		
Credit transferred on an amalgamation or the wind-up of a subsidiary	230				
ITC from repayment of assistance	235				
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ______ x 10 % =	240				
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ______ x 5 % =	242				
Credit allocated from a partnership	250				
Subtotal (total of lines 230 to 250)			▶		D1
Total credit available (line 220 **plus** amount D1)					E1
Credit deducted from Part I tax	260				
Credit carried back to previous years (amount H1 in Part 6)			a		
Credit transferred to offset Part VII tax liability	280				
Subtotal (total of line 260, amount a, and line 280)			▶		F1
Credit balance before refund (amount E1 **minus** amount F1)					G1
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)			310		
ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310)			320		

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day				
1st previous tax year				Credit to be applied	901		
2nd previous tax year				Credit to be applied	902		
3rd previous tax year				Credit to be applied	903		
				Total of lines 901 to 903 Enter at amount a in Part 5.			H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5)		I1
Credit balance before refund (from amount G1 in Part 5)		J1
Refund (40 % of amount I1 or J1, whichever is less)		K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter on line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 559 on Form T661)		1,141,647		
Contributions to agricultural organizations for SR&ED				
Deduct:				
Government assistance, non-government assistance, or contract payment				
Subtotal				
x	80 %			
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)*		+		
Qualified SR&ED expenditures (line 559 on Form T661 **plus** line 103 in Part 3)*		1,141,647	350	1,141,647
Repayments made in the year (from line 560 on Form T661)			370	
Total qualified SR&ED expenditures (line 350 **plus** line 370)			380	1,141,647

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes ☐ 2 No ☐

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied)	390	
Enter your taxable capital employed in Canada for the previous tax year **minus** $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million	398	

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation			**$ 8,000,000**	
Taxable income for the previous tax year (line 390 in Part 9) or $500,000, whichever is more		x 10 =		A2
Excess ($8,000,000 **minus** amount A2; if negative, enter "0")				B2
$ 40,000,000 **minus** line 398 in Part 9		b		
Amount b **divided** by $ 40,000,000				C2
For tax years ending before March 19, 2019 Amount B2 **multiplied** by amount C2				D2
For tax years ending after March 18, 2019 **multiplied** by amount C2				E2
Expenditure limit for the stand-alone corporation (amount D2 or amount E2, whichever applies)*				F2
For an associated corporation: If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49*		400		G2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount F2 or G2 ______ x Number of days in the tax year / 365   366 = ______ H2

Your SR&ED expenditure limit for the year (enter amount F2, G2, or H2, whichever applies) 410 ______

* Amount F2 or G2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Qualified SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x	35 %	=		I2
Line 350 **minus** line 410 (if negative, enter "0")	430	1,141,647	x	15 %	=	171,247	J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . . ______

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC**	460		x	35 %	=		c
Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred before 2015	480		x	20 %	=		d
Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred after 2014	490		x	15 %	=		e
Subtotal (total of amounts c to e)						▶	K2

Current-year SR&ED ITC (total of amounts I2 to K2; enter on line 540 in Part 12) 171,247 L2

* For corporations that are not CCPCs, enter "0" for amount I2.

** If you were a Canadian-controlled private corporation (CCPC), this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year			388,865	M2
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)		▶		N2
ITC at the beginning of the tax year (amount M2 **minus** amount N2)		520	388,865	
Credit transferred on an amalgamation or the wind-up of a subsidiary	530			
Total current-year credit (from amount L2 in Part 11)	540	171,247		
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)		171,247 ▶	171,247	O2
Total credit available (line 520 **plus** amount O2)			560,112	P2
Credit deducted from Part I tax	560			
Credit carried back to previous years (amount S2 in Part 13)		f		
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount f, and line 580)		▶		Q2
Credit balance before refund (amount P2 **minus** amount Q2)			560,112	R2
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)		610		
ITC closing balance on SR&ED (amount R2 **minus** line 610)		620	560,112	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	

Total of lines 911 to 913 ______ S2
Enter at amount f in Part 12.

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . **650** 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) . . . . . ______ g

Refundable credits (amount g or amount R2 in Part 12, whichever is less)* . . . . . ______ T2

Amount T2 or amount I2 in Part 11, whichever is less . . . . . ______ U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") . . . . . ______ V2

Amount V2 **multiplied** by 40 % . . . . . ______ W2

Amount U2 . . . . . ______ X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) . . . . . ______ Y2
Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (amount R2 in Part 12) 560,112 Z2

Refund of ITC (amount Z2 or amount I2 in Part 11, whichever is less) . . . . . ______ AA2
Enter amount AA2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal
Enter at amount C3 in Part 17. ______ A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (total of column F)
Enter at amount D3 in Part 17. ______ B3

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** ______
Enter at amount E3 in Part 17.

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16		C3
Recaptured ITC from calculation 2, amount B3 in Part 16		D3
Recaptured ITC from calculation 3, line 760 in Part 16		E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3) Enter at amount A8 in Part 27.		F3

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year				A4
Credit deemed as a remittance of co-op corporations	841			
Credit expired	845			
Subtotal (line 841 **plus** line 845)			►	B4
ITC at the beginning of the tax year (amount A4 **minus** amount B4)		850		
Credit transferred on an amalgamation or the wind-up of a subsidiary		860		
Total credit available (line 850 **plus** line 860)				C4
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year		885		
ITC closing balance from pre-production mining expenditures (amount C4 **minus** line 885)		890		

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

A Contract number (SIN or name of apprentice)	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
[redacted]		57,405	5,741	2,000
[redacted]		103,192	10,319	2,000
[redacted]		92,153	9,215	2,000
[redacted]		92,072	9,207	2,000
[redacted]		88,265	8,827	2,000
[redacted]		87,149	8,715	2,000
[redacted]		85,525	8,553	2,000
[redacted]		84,621	8,462	2,000
[redacted]		84,585	8,459	2,000
[redacted]		78,822	7,882	2,000
[redacted]		78,301	7,830	2,000
[redacted]		77,403	7,740	2,000
[redacted]		73,055	7,306	2,000
[redacted]		69,248	6,925	2,000
[redacted]		65,832	6,583	2,000
[redacted]		60,798	6,080	2,000
[redacted]		55,500	5,550	2,000
[redacted]		56,813	5,681	2,000
[redacted]		73,377	7,338	2,000
[redacted]		35,696	3,570	2,000
[redacted]		70,227	7,023	2,000
[redacted]		103,525	10,353	2,000
[redacted]		89,268	8,927	2,000
[redacted]		87,148	8,715	2,000
[redacted]		84,744	8,474	2,000
[redacted]		84,291	8,429	2,000
[redacted]		82,710	8,271	2,000
[redacted]		82,218	8,222	2,000
[redacted]		80,193	8,019	2,000
[redacted]		79,829	7,983	2,000
[redacted]		79,652	7,965	2,000
[redacted]		78,476	7,848	2,000
[redacted]		78,322	7,832	2,000
[redacted]		76,931	7,693	2,000
[redacted]		75,313	7,531	2,000
[redacted]		70,061	7,006	2,000
[redacted]		34,678	3,468	2,000
[redacted]		37,998	3,800	2,000
[redacted]		87,979	8,798	2,000
[redacted]		68,981	6,898	2,000
[redacted]		45,039	4,504	2,000
[redacted]		48,903	4,890	2,000
[redacted]		59,979	5,998	2,000
[redacted]		94,767	9,477	2,000

A Contract number (SIN or name of apprentice)	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
[redacted]	[redacted]	92,034	9,203	2,000
[redacted]	[redacted]	91,316	9,132	2,000
[redacted]	[redacted]	88,681	8,868	2,000
[redacted]	[redacted]	82,676	8,268	2,000
[redacted]	[redacted]	80,062	8,006	2,000
[redacted]	[redacted]	77,169	7,717	2,000
[redacted]	[redacted]	76,321	7,632	2,000
[redacted]	[redacted]	71,054	7,105	2,000
[redacted]	[redacted]	62,516	6,252	2,000
[redacted]	[redacted]	50,144	5,014	2,000
[redacted]	[redacted]	98,261	9,826	2,000
[redacted]	[redacted]	90,295	9,030	2,000
[redacted]	[redacted]	87,607	8,761	2,000
[redacted]	[redacted]	87,394	8,739	2,000
[redacted]	[redacted]	85,434	8,543	2,000
[redacted]	[redacted]	83,275	8,328	2,000
[redacted]	[redacted]	78,244	7,824	2,000
[redacted]	[redacted]	73,185	7,319	2,000
[redacted]	[redacted]	72,141	7,214	2,000
[redacted]	[redacted]	69,736	6,974	2,000
[redacted]	[redacted]	68,991	6,899	2,000
[redacted]	[redacted]	63,153	6,315	2,000
[redacted]	[redacted]	84,658	8,466	2,000
[redacted]	[redacted]	83,633	8,363	2,000
[redacted]	[redacted]	58,886	5,889	2,000
[redacted]	[redacted]	58,501	5,850	2,000
[redacted]	[redacted]	115,132	11,513	2,000
[redacted]	[redacted]	93,080	9,308	2,000
[redacted]	[redacted]	91,461	9,146	2,000
[redacted]	[redacted]	89,344	8,934	2,000
[redacted]	[redacted]	86,641	8,664	2,000
[redacted]	[redacted]	84,042	8,404	2,000
[redacted]	[redacted]	83,234	8,323	2,000
[redacted]	[redacted]	83,102	8,310	2,000
[redacted]	[redacted]	82,654	8,265	2,000
[redacted]	[redacted]	81,696	8,170	2,000
[redacted]	[redacted]	76,886	7,689	2,000
[redacted]	[redacted]	75,787	7,579	2,000
[redacted]	[redacted]	75,184	7,518	2,000
[redacted]	[redacted]	70,620	7,062	2,000
[redacted]	[redacted]	67,698	6,770	2,000
[redacted]	[redacted]	62,376	6,238	2,000
[redacted]	[redacted]	60,662	6,066	2,000
[redacted]	[redacted]	56,320	5,632	2,000
[redacted]	[redacted]	53,921	5,392	2,000
[redacted]	[redacted]	42,919	4,292	2,000
[redacted]	[redacted]	3,034	303	303
[redacted]	[redacted]	98,323	9,832	2,000
[redacted]	[redacted]	91,577	9,158	2,000
[redacted]	[redacted]	89,602	8,960	2,000
[redacted]	[redacted]	88,936	8,894	2,000
[redacted]	[redacted]	88,773	8,877	2,000
[redacted]	[redacted]	86,852	8,685	2,000
[redacted]	[redacted]	86,451	8,645	2,000

A Contract number (SIN or name of apprentice)	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
[redacted]		77,765	7,777	2,000
[redacted]		75,983	7,598	2,000
[redacted]		74,917	7,492	2,000
[redacted]		73,566	7,357	2,000
[redacted]		73,505	7,351	2,000
[redacted]		73,280	7,328	2,000
[redacted]		71,074	7,107	2,000
[redacted]		64,785	6,479	2,000
[redacted]		63,307	6,331	2,000
[redacted]		60,067	6,007	2,000
[redacted]		46,074	4,607	2,000
[redacted]		45,940	4,594	2,000
[redacted]		45,568	4,557	2,000
[redacted]		54,625	5,463	2,000
[redacted]		62,564	6,256	2,000
[redacted]		46,149	4,615	2,000
[redacted]		58,762	5,876	2,000
[redacted]		74,467	7,447	2,000
[redacted]		62,528	6,253	2,000
[redacted]		64,534	6,453	2,000
[redacted]		76,777	7,678	2,000
[redacted]		58,143	5,814	2,000
[redacted]		42,448	4,245	2,000
[redacted]		52,632	5,263	2,000
[redacted]		89,290	8,929	2,000
[redacted]		67,893	6,789	2,000
[redacted]		72,524	7,252	2,000
[redacted]		64,447	6,445	2,000
[redacted]		73,635	7,364	2,000
[redacted]		68,290	6,829	2,000
[redacted]		76,564	7,656	2,000
[redacted]		16,065	1,607	1,607
[redacted]		51,493	5,149	2,000
[redacted]		43,079	4,308	2,000
[redacted]		25,086	2,509	2,000
[redacted]		56,056	5,606	2,000
[redacted]		84,793	8,479	2,000
[redacted]		53,752	5,375	2,000
[redacted]		66,227	6,623	2,000
[redacted]		61,458	6,146	2,000
[redacted]		80,424	8,042	2,000
[redacted]		76,137	7,614	2,000
[redacted]		29,867	2,987	2,000
[redacted]		59,460	5,946	2,000
[redacted]		88,778	8,878	2,000
[redacted]		100,661	10,066	2,000
[redacted]		47,650	4,765	2,000
[redacted]		53,323	5,332	2,000
[redacted]		38,943	3,894	2,000
[redacted]		71,788	7,179	2,000
[redacted]		86,463	8,646	2,000
[redacted]		19,697	1,970	1,970
[redacted]		32,331	3,233	2,000
[redacted]		43,535	4,354	2,000

A Contract number (SIN or name of apprentice)	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
[redacted]		42,943	4,294	2,000
[redacted]		32,188	3,219	2,000
[redacted]		18,773	1,877	1,877
[redacted]		69,857	6,986	2,000
[redacted]		18,452	1,845	1,845
[redacted]		15,776	1,578	1,578
[redacted]		18,832	1,883	1,883
[redacted]		47,380	4,738	2,000
[redacted]		23,481	2,348	2,000
[redacted]		15,740	1,574	1,574
[redacted]		69,041	6,904	2,000
[redacted]		127,229	12,723	2,000
[redacted]		89,286	8,929	2,000
[redacted]		87,108	8,711	2,000
[redacted]		86,021	8,602	2,000
[redacted]		84,130	8,413	2,000
[redacted]		80,617	8,062	2,000
[redacted]		77,034	7,703	2,000
[redacted]		70,218	7,022	2,000
[redacted]		69,192	6,919	2,000
[redacted]		68,348	6,835	2,000
[redacted]		57,633	5,763	2,000
[redacted]		64,952	6,495	2,000
[redacted]		61,198	6,120	2,000
[redacted]		55,681	5,568	2,000
[redacted]		110,305	11,031	2,000
[redacted]		63,529	6,353	2,000
[redacted]		52,541	5,254	2,000
[redacted]		28,394	2,839	2,000
[redacted]		39,636	3,964	2,000
[redacted]		87,694	8,769	2,000
[redacted]		86,708	8,671	2,000
[redacted]		82,220	8,222	2,000
[redacted]		78,040	7,804	2,000
[redacted]		77,215	7,722	2,000
[redacted]		76,000	7,600	2,000
[redacted]		75,985	7,599	2,000
[redacted]		75,336	7,534	2,000
[redacted]		74,508	7,451	2,000
[redacted]		74,000	7,400	2,000
[redacted]		73,705	7,371	2,000
[redacted]		73,636	7,364	2,000
[redacted]		73,465	7,347	2,000
[redacted]		71,441	7,144	2,000
[redacted]		71,408	7,141	2,000
[redacted]		71,362	7,136	2,000
[redacted]		70,205	7,021	2,000
[redacted]		68,947	6,895	2,000
[redacted]		68,921	6,892	2,000
[redacted]		64,818	6,482	2,000
[redacted]		40,185	4,019	2,000
[redacted]		2,154	215	215
[redacted]		64,575	6,458	2,000
[redacted]		52,006	5,201	2,000

A Contract number (SIN or name of apprentice)	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
[redacted]	[redacted]	42,730	4,273	2,000
[redacted]	[redacted]	93,431	9,343	2,000
[redacted]	[redacted]	82,847	8,285	2,000
[redacted]	[redacted]	82,462	8,246	2,000
[redacted]	[redacted]	78,801	7,880	2,000
[redacted]	[redacted]	72,317	7,232	2,000
[redacted]	[redacted]	69,175	6,918	2,000
[redacted]	[redacted]	68,573	6,857	2,000
[redacted]	[redacted]	66,755	6,676	2,000
[redacted]	[redacted]	63,431	6,343	2,000
[redacted]	[redacted]	58,828	5,883	2,000
[redacted]	[redacted]	55,260	5,526	2,000
[redacted]	[redacted]	53,384	5,338	2,000
[redacted]	[redacted]	11,672	1,167	1,167
[redacted]	[redacted]	32,671	3,267	2,000
[redacted]	[redacted]	24,100	2,410	2,000
[redacted]	[redacted]	57,197	5,720	2,000
[redacted]	[redacted]	47,892	4,789	2,000
[redacted]	[redacted]	41,532	4,153	2,000
[redacted]	[redacted]	45,924	4,592	2,000
[redacted]	[redacted]	84,213	8,421	2,000
[redacted]	[redacted]	16,642	1,664	1,664
[redacted]	[redacted]	61,098	6,110	2,000
[redacted]	[redacted]	57,332	5,733	2,000
[redacted]	[redacted]	50,051	5,005	2,000
[redacted]	[redacted]	82,793	8,279	2,000
[redacted]	[redacted]	71,056	7,106	2,000
[redacted]	[redacted]	60,013	6,001	2,000
[redacted]	[redacted]	80,262	8,026	2,000
[redacted]	[redacted]	66,291	6,629	2,000
[redacted]	[redacted]	61,931	6,193	2,000
[redacted]	[redacted]	85,800	8,580	2,000
[redacted]	[redacted]	90,492	9,049	2,000
[redacted]	[redacted]	58,880	5,888	2,000
[redacted]	[redacted]	5,967	597	597
[redacted]	[redacted]	103,231	10,323	2,000
[redacted]	[redacted]	57,830	5,783	2,000
[redacted]	[redacted]	61,079	6,108	2,000
[redacted]	[redacted]	38,206	3,821	2,000
[redacted]	[redacted]	46,655	4,666	2,000
[redacted]	[redacted]	45,264	4,526	2,000
[redacted]	[redacted]	76,434	7,643	2,000
[redacted]	[redacted]	69,387	6,939	2,000
[redacted]	[redacted]	46,326	4,633	2,000
[redacted]	[redacted]	66,176	6,618	2,000
[redacted]	[redacted]	64,493	6,449	2,000
[redacted]	[redacted]	64,269	6,427	2,000
[redacted]	[redacted]	63,733	6,373	2,000
[redacted]	[redacted]	62,217	6,222	2,000
[redacted]	[redacted]	62,048	6,205	2,000
[redacted]	[redacted]	59,998	6,000	2,000
[redacted]	[redacted]	59,708	5,971	2,000
[redacted]	[redacted]	58,388	5,839	2,000
[redacted]	[redacted]	55,546	5,555	2,000

A Contract number (SIN or name of apprentice)	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
[redacted]		55,179	5,518	2,000
[redacted]		51,293	5,129	2,000
[redacted]		34,888	3,489	2,000
[redacted]		28,447	2,845	2,000
[redacted]		24,001	2,400	2,000
[redacted]		69,628	6,963	2,000
[redacted]		11,783	1,178	1,178
[redacted]		82,382	8,238	2,000
[redacted]		67,007	6,701	2,000
[redacted]		49,336	4,934	2,000
[redacted]		57,948	5,795	2,000
[redacted]		48,115	4,812	2,000
[redacted]		33,797	3,380	2,000
[redacted]		21,252	2,125	2,000
[redacted]		38,105	3,811	2,000
[redacted]		67,028	6,703	2,000
[redacted]		58,613	5,861	2,000
[redacted]		58,516	5,852	2,000
[redacted]		54,870	5,487	2,000
[redacted]		53,893	5,389	2,000
[redacted]		53,538	5,354	2,000
[redacted]		52,765	5,277	2,000
[redacted]		51,600	5,160	2,000
[redacted]		50,479	5,048	2,000
[redacted]		49,942	4,994	2,000
[redacted]		49,805	4,981	2,000
[redacted]		46,804	4,680	2,000
[redacted]		46,640	4,664	2,000
[redacted]		21,648	2,165	2,000
[redacted]		65,514	6,551	2,000
[redacted]		43,860	4,386	2,000
[redacted]		43,366	4,337	2,000
[redacted]		42,052	4,205	2,000
[redacted]		46,397	4,640	2,000
[redacted]		44,213	4,421	2,000
[redacted]		45,651	4,565	2,000
[redacted]		36,924	3,692	2,000
[redacted]		47,341	4,734	2,000
[redacted]		96,663	9,666	2,000
[redacted]		23,294	2,329	2,000
[redacted]		15,969	1,597	1,597
[redacted]		50,775	5,078	2,000
[redacted]		13,935	1,394	1,394
[redacted]		16,064	1,606	1,606
[redacted]		19,648	1,965	1,965
[redacted]		24,803	2,480	2,000
[redacted]		23,573	2,357	2,000
[redacted]		23,290	2,329	2,000
[redacted]		22,813	2,281	2,000
[redacted]		22,759	2,276	2,000
[redacted]		21,471	2,147	2,000
[redacted]		20,911	2,091	2,000
[redacted]		19,384	1,938	1,938
[redacted]		19,361	1,936	1,936

A Contract number (SIN or name of apprentice)	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
[redacted]		12,218	1,222	1,222
[redacted]		11,306	1,131	1,131
[redacted]		10,916	1,092	1,092
[redacted]		10,558	1,056	1,056
[redacted]		10,512	1,051	1,051
[redacted]		10,366	1,037	1,037
[redacted]		10,257	1,026	1,026
[redacted]		9,474	947	947
[redacted]		25,890	2,589	2,000
[redacted]		21,690	2,169	2,000
[redacted]		10,338	1,034	1,034
[redacted]		15,026	1,503	1,503
[redacted]		79,878	7,988	2,000
[redacted]		23,045	2,305	2,000
[redacted]		5,226	523	523
[redacted]		5,226	523	523
[redacted]		5,226	523	523
[redacted]		5,102	510	510
[redacted]		5,102	510	510
[redacted]		5,084	508	508
[redacted]		5,071	507	507
[redacted]		4,424	442	442
[redacted]		4,894	489	489
[redacted]		76,412	7,641	2,000
[redacted]		5,226	523	523
[redacted]		5,107	511	511
[redacted]		4,756	476	476
[redacted]		4,585	459	459
[redacted]		4,563	456	456
[redacted]		4,563	456	456
[redacted]		4,858	486	486
[redacted]		5,226	523	523
[redacted]		29,186	2,919	2,000
[redacted]		28,600	2,860	2,000
[redacted]		25,800	2,580	2,000
[redacted]		25,890	2,589	2,000
[redacted]		23,396	2,340	2,000
[redacted]		33,639	3,364	2,000
[redacted]		27,408	2,741	2,000
[redacted]		22,456	2,246	2,000
[redacted]		29,560	2,956	2,000
[redacted]		25,883	2,588	2,000
[redacted]		82,553	8,255	2,000
			Total current-year credit (total of column E) Enter on line 640 in Part 20.	669,418 A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				822,584	B5
Credit deemed as a remittance of co-op corporations	612				
Credit expired after 20 tax years	615				
Subtotal (line 612 **plus** line 615)			▶		C5
ITC at the beginning of the tax year (amount B5 **minus** amount C5)			625	822,584	
Credit transferred on an amalgamation or the wind-up of a subsidiary	630				
ITC from repayment of assistance	635				
Total current-year credit (amount A5 in Part 19)	640	669,418			
Credit allocated from a partnership	655				
Subtotal (total of lines 630 to 655)		669,418	▶	669,418	D5
Total credit available (line 625 **plus** amount D5)				1,492,002	E5
Credit deducted from Part I tax	660				
Credit carried back to previous years (amount G5 in Part 21)			h		
Subtotal (line 660 **plus** amount h)			▶		F5
ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5)			690	1,492,002	

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

	Year Month Day				
1st previous tax year		Credit to be applied	931		
2nd previous tax year		Credit to be applied	932		
3rd previous tax year		Credit to be applied	933		
		Total of lines 931 to 933 Enter at amount h in Part 20.			G5

Child Care Spaces

Part 22 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred after March 18, 2007, and before March 22, 2017,* to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property)
- the specified child care start-up expenditures

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695) **715** ______

Specified child care start-up expenditures from the current tax year . . . . . **705** ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ A6

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . **725** ______

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . . ______ B6

Repayments by the corporation of government and non-government assistance . . . . . **735** ______

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) . . . . . **745** ______

* If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.

Part 23 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 22) . . . . . ______ x 25 % = ______ C6

Number of child care spaces . . . . . **755** ______ x $ 10,000 = ______ D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) . . . . . ______ E6

Part 24 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F6
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G6
ITC at the beginning of the tax year (amount F6 **minus** amount G6)			775	
Credit transferred on an amalgamation or the wind-up of a subsidiary	777			
Total current-year credit (amount E6 in Part 23)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H6
Total credit available (line 775 **plus** amount H6)				I6
Credit deducted from Part I tax	785			
Credit carried back to previous years (amount K6 in Part 25)		i		
Subtotal (line 785 **plus** amount i)			▶	J6
ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6)			790	

Part 25 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2019-12-31	Credit to be applied	941	
2nd previous tax year	2018-12-31	Credit to be applied	942	
3rd previous tax year	2017-12-31	Credit to be applied	943	
		Total of lines 941 to 943 Enter at amount i in Part 24.		K6

Recapture – Child Care Spaces

Part 26 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property, one of the following situations takes place:

- the new child care space is no longer available
- property that was an eligible expenditure for the child care space is
  - disposed of or leased to a lessee
  - converted to another use

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . **792** ______

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . . ______ A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 24. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ______

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) . . . . . ______ B7

Enter at amount B8 in Part 27.

Summary of Investment Tax Credits

Part 27 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount F3 in Part 17)		A8
Recaptured child care spaces ITC (amount B7 in Part 26)		B8
Total recapture of investment tax credit (amount A8 **plus** amount B8)		C8

Enter on line 602 of the T2 return.

Part 28 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5)		D8
ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12)		E8
ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18)		F8
ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20)		G8
ITC from child care space expenditures deducted from Part I tax (line 785 in Part 24)		H8
Total ITC deducted from Part I tax (total of amounts D8 to H8)		I8

Enter on line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
669,418				669,418

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2019-12-31	822,584			822,584
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				*
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				*
Total	822,584			822,584

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
171,247				171,247

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2019-12-31	388,865			388,865
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				*
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				*
Total	388,865			388,865

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

	Line	Amount		
Reserves that have not been deducted in calculating income for the year under Part I	101	1,890,669,990		
Capital stock (or members' contributions if incorporated without share capital)	103	2,934,000,000		
Retained earnings	104	7,799,000,000		
Contributed surplus	105	5,000,000		
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	12,651,874,723		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		25,280,544,713	25,280,544,713	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)		25,280,544,713	A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)	►		B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	25,280,544,713	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	4,252,000
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	4,252,000

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		25,280,544,713	C
Deduct: Investment allowance for the year (line 490)		4,252,000	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	25,276,292,713	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 25,276,292,713 x (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = **Taxable capital employed in Canada** **690** 25,276,292,713

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ► ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . ______ F

Deduct: . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ______ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . ______ I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Schedule 33/CT23 - Supplementary Schedule Line 402

Description	Operator (Note)	Amount	
Prepaid insurance (a/c 277180)		2,907,111	00
Deposit -Bnft Provider (a/c 277290)	+	1,344,889	00
	+		
	Total	4,252,000	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in calculating income for th

Description	Operator (Note)	Amount
Schedule 13 Reserves Ending		1,890,669,990 00
	+	
	Total	1,890,669,990 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount	
LT Debt Payable within a year (FS)		803,000,000	00
Primary Debt (FS)	+	11802000000	00
Banked Vacation (GL 362100)	+	6,330,038	00
Customer Deposits (GL 390000/391010/392000/392010)	+	40,544,685	00
	+		
	+		
	Total	12651874723	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 54

Low Rate Income Pool (LRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

On: 2020-12-31

- Use this schedule to calculate the balance of the low rate income pool (LRIP) at any time in the tax year if you are a corporation resident in Canada that is:
  - a corporation **other** than a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC)
  - a corporation that elected under subsection 89(11) not to be a CCPC
- When an eligible dividend was paid or there was a change in the LRIP balance in the tax year, file this schedule with your T2 Corporation Income Tax Return. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend, excessive eligible dividend designation, general rate income pool,** and **low rate income pool.**

Did the corporation elect not to be a CCPC under subsection 89(11) ITA for the current year or a prior year or did it revoke this election in the current year*? . . . . . ☐ Yes ☒ No

* If the corporation revoked its election in the current year when filing Form T2002, this election will still be valid for the current year, but will cease to apply as of the end of the year.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

Change in the type of corporation

1. Was the corporation a CCPC during its preceding taxation year? . . . . . ☐ Yes ☒ No
2. Corporations that ceased to be a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 2 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

3. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 3 is yes, answer questions 4 and 5. If the answer is no, go to question 6.
4. Was one or several of the predecessor corporations a CCPC or a DIC during the taxation year that ended immediately before the amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 4 is yes, complete Part 5.
5. Was one or several of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 5 is yes, complete Part 5 (line R).

Winding-up

6. Corporations that wound-up a subsidiary . . . . . ☒ Yes ☐ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to Part 1.
7. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☒ No
   If the answer to question 7 is yes, complete Part 6.
8. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☒ Yes ☐ No
   If the answer to question 8 is yes, complete Part 6 (line R).

Part 1 – Low rate income pool (LRIP)

LRIP at the end of the immediately previous tax year . . . . . **100** ______

Aggregate investment income of a corporation that has elected under subsection 89(11) not to be a CCPC (line 440 of the T2 return of the previous tax year) . . . . . **140** ______ x 80 % = **150** ______

Investment corporation deduction (line 620 of the T2 return of the previous tax year) . . . . . ______ x 4 = **160** ______

Subtotal (**add** lines 100, 150, and 160) **190** ______

Part 2 – LRIP and excessive eligible dividend designations during the tax year

Complete this part if you paid an eligible dividend in the tax year.

	200 Date[1] (yyyy/mm/dd)	210 Total dividends[2] receivable in the year before the date on line 200 that are deductible under section 112	220 Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC[3]	230 Subtotal (**add** lines 190, 210, and 220)	240 Total dividends[4] payable in the year before the date on line 200	250 Total of excessive eligible dividend designations made before the date on line 200
1.	2020-11-05					

	260 LRIP as of the date on line 200 (line 230 **minus** the total of line 240 and line 250)	270 Total eligible dividends paid on the date on line 200	280 Excessive eligible dividend designation (lesser of lines 260 and 270)
1.		1,000,000	

Total excessive eligible dividend designations in the tax year (total of all amounts in column 280) ______ A
Enter amount A at amount C of Schedule 55.

1 Enter on line 200 each date where:
- an eligible dividend was paid in the year
- an adjustment was made as a result of an amalgamation or the wind-up of a subsidiary or on ceasing to be a CCPC (by an election or otherwise)

2 Taxable dividends from a corporation resident in Canada (other than eligible dividends)

3 Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC. Add up the adjustments for this date and enter on line 220.

4 Includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1))

Part 3 – LRIP closing balance

Amount from line 190 in Part 1 . . . . B

Dividends[5] receivable in the tax year that are deductible under section 112 (Amount on line 210 in the last row (last date) of the chart in Part 2) . . . .

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends receivable in the year that are deductible under section 112 (hereinafter: "dividends other than eligible dividends receivable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends receivable other than eligible dividends receivable. . . . .

Total dividends[5] receivable in the tax year that are deductible under section 112 . . . . **510**

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC[6] (Amount on line 220 in the last row (last date) of the chart in Part 2) . . . .

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC[6] if no eligible dividend has been paid in the tax year . . . .

Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC[6] **520**

Subtotal (line 510 **plus** line 520) ► C

Subtotal (amount B **plus** amount C) D

Total dividends[7] payable in the tax year (Amount on line 240 in the last row (last date) of the chart in Part 2) . . .

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends payable in the year (hereinafter: "dividends other that eligible dividends payable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends paid other than eligible dividends paid. . . . .

Total dividends[7] payable in the tax year **540**

Total excessive eligible dividend designations in the tax year (amount A in Part 2) . . . . E

Subtotal (line 540 **plus** amount E) ► F

LRIP at the end of the tax year (amount D **minus** amount F) (if negative, enter "0") **590**

5 Taxable dividends from a corporation resident in Canada (other than eligible dividends)

6 Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC.

7 Includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1))

Part 4 – Worksheet for adjustment when a corporation ceases to be a CCPC or DIC

Adjustment date . . . . ______

- Complete this part if the corporation is neither a CCPC nor a DIC in this tax year but was a CCPC or a DIC in the previous tax year.
- This adjustment to the LRIP can be made at any time in the tax year.
- Keep a copy of this calculation for your records in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of the previous tax year . . . . . . ______ 1

The corporation's cash on hand immediately before the end of the previous tax year . . . . . . ______ 2

Total of subsection 111(1) losses that would have been deductible in computing the corporation's taxable income for the previous tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous tax year:

Non-capital losses . . . . . . ______ 3
Net capital losses . . . . . . ______ 4
Farm losses . . . . . . ______ 5
Restricted farm losses . . . . . . ______ 6
Limited partnership losses . . . . . . ______ 7
Subtotal (**add** amounts 3 to 7) ______ ► ______ 8

Total of all amounts deducted under subsection 111(1) in computing the corporation's taxable income for the previous tax year:

Non-capital losses . . . . . . ______ 9
Net capital losses . . . . . . ______ 10
Farm losses . . . . . . ______ 11
Restricted farm losses . . . . . . ______ 12
Limited partnership losses . . . . . . ______ 13
Subtotal (**add** amounts 9 to 13) ______ ► ______ 14

Unused and unexpired losses at the end of the corporation's previous tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . . . . ______ ► ______ 15

Subtotal (**add** amounts 1, 2, and 15) ______ 16

All of the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous tax year . . . . . . ______ 17

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous tax year . . . . . . ______ 18

All of the corporation's reserves deducted in its previous tax year . . . . . . ______ 19

Is the corporation a private corporation? . . . . . . ☐ Yes ☒ No

The corporation's capital dividend account immediately before the end of its previous tax year if the corporation is **not** a private corporation in the current tax year . . . . . . ______ 20

The corporation's general rate income pool (GRIP) at the end of its previous tax year . . . . . . ______ 21

Eligible dividends paid in the previous tax year . . . . . . ______ 22

Excessive eligible dividend designations made in the previous tax year . . . . . . ______ 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . . . . ______ ► ______ 24

Subtotal (amount 21 **minus** amount 24) ______ ► ______ 25

Subtotal (**add** amounts 17, 18, 19, 20, and 25) ______ ► ______ 26

Adjustment for a corporation that ceases to be a CCPC or DIC (amount 16 **minus** amount 26) (if negative, enter "0") . . . . . . ______ 27

Part 5 – Worksheet for adjustment when a corporation is formed as a result of an amalgamation

nb. 1

Adjustment date . . . . ____________

- Complete this part if the corporation was formed as a result of an amalgamation or merger of two or more corporations, one or more of which is a taxable Canadian corporation. Complete a separate worksheet for **each** predecessor.
- This adjustment to the LRIP can be made at any time in the tax year.
- The last tax year was its tax year that ended immediately before the amalgamation.
- Keep a copy of this calculation for your records, in case we ask to see it later.

For a predecessor corporation that was a CCPC or a DIC in its tax year that ended immediately before the amalgamation

Cost amount to the predecessor of all property immediately before the end of its last tax year . . . . ____________ 1

The predecessor's cash on hand immediately before the end of its last tax year . . . . ____________ 2

Total of subsection 111(1) losses that would have been deductible in computing the predecessor's taxable income for its last tax year if the predecessor had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for its last tax year:

Non-capital losses . . . . ____________ 3

Net capital losses . . . . ____________ 4

Farm losses . . . . ____________ 5

Restricted farm losses . . . . ____________ 6

Limited partnership losses . . . . ____________ 7

Subtotal (**add** amounts 3 to 7) ____________ ► ____________ 8

Total of all amounts deducted under subsection 111(1) in computing the predecessor's taxable income for its last tax year:

Non-capital losses . . . . ____________ 9

Net capital losses . . . . ____________ 10

Farm losses . . . . ____________ 11

Restricted farm losses . . . . ____________ 12

Limited partnership losses . . . . ____________ 13

Subtotal (**add** amounts 9 to 13) ____________ ► ____________ 14

Unused and unexpired losses at the end of the predecessor's last tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . . ____________ ► ____________ 15

Subtotal (**add** amounts 1, 2, and 15) ____________ 16

All of the predecessor's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . ____________ 17

Paid up capital of all the predecessor's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . ____________ 18

All of the predecessor's reserves deducted in its last tax year . . . . ____________ 19

The predecessor's capital dividend account immediately before the end of its last tax year if the corporation is **not** a private corporation in its first tax year . . . . ____________ 20

The predecessor's general rate income pool (GRIP) at the end of its last tax year . . . . ____________ 21

Eligible dividends paid in its last tax year . . . ____________ 22

Excessive eligible dividend designations made in its last tax year . . . . ____________ 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . . ____________ ► ____________ 24

Subtotal (amount 21 **minus** amount 24) ____________ ► ____________ 25

Subtotal (**add** amounts 17, 18, 19, 20, and 25) ____________ ► ____________ 26

Adjustment for a predecessor corporation that was a CCPC or a DIC in its last tax year (amount 16 **minus** amount 26) (if negative, enter "0") . . . . ____________ 27

For a predecessor corporation that was neither a CCPC nor a DIC in its tax year that ended immediately before the amalgamation

LRIP at the end of its last tax year . . . . ____________ 28

Adjustment for a predecessor corporation involved in an amalgamation (amount 27 **plus** amount 28) . . . . ____________ 29

Calculate amount 29 for **each** predecessor.

Part 6 – Worksheet for adjustment when a corporation has wound-up a subsidiary

nb. 1

Adjustment date 2020-01-01

- Complete this part if the corporation is the parent corporation (parent) that is neither a CCPC nor a DIC in a tax year and has, in the year, received all or substantially all of the assets on dissolution or wind-up of a subsidiary. Complete a separate worksheet for **each** subsidiary involved in the wind-up.
- This adjustment to the parent's LRIP can be made at any time in the tax year that is at or after the end of the subsidiary's last tax year.
- The last tax year for the subsidiary was its tax year during which its assets were distributed to the parent corporation on the wind-up.
- Keep a copy of this calculation for your records in case we ask to see it later.

For a subsidiary that was a CCPC or a DIC in its last tax year

Cost amount to the subsidiary of all property immediately before the end of its last tax year 1

The subsidiary's cash on hand immediately before the end of its last tax year 2

Total of subsection 111(1) losses that would have been deductible in computing the subsidiary's taxable income for its last tax year if the subsidiary had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for its last tax year:

Non-capital losses 3
Net capital losses 4
Farm losses 5
Restricted farm losses 6
Limited partnership losses 7
Subtotal (**add** amounts 3 to 7) ▶ 8

Total of all amounts deducted under subsection 111(1) in computing the subsidiary's taxable income for the last tax year:

Non-capital losses 9
Net capital losses 10
Farm losses 11
Restricted farm losses 12
Limited partnership losses 13
Subtotal (**add** amounts 9 to 13) ▶ 14

Unused and unexpired losses at the end of the subsidiary's last tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . . ▶ 15

Subtotal (**add** amounts 1, 2, and 15) 16

All of the subsidiary's debts and other obligations to pay that were outstanding immediately before the end of its last tax year 17

Paid up capital of all the subsidiary's issued and outstanding shares of capital stock immediately before the end of its last tax year 18

All of the subsidiary's reserves deducted in its last tax year 19

The subsidiary's capital dividend account immediately before the end of its last tax year if the parent is **not** a private corporation in the tax year 20

The subsidiary's general rate income pool (GRIP) at the end of its last tax year 21

Eligible dividends paid in its last tax year . . . 22

Excessive eligible dividend designations made in its last tax year 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . . ▶ 24

Subtotal (amount 21 **minus** amount 24) ▶ 25

Subtotal (**add** amounts, 17, 18, 19, 20, and 25) ▶ 26

Adjustment for a subsidiary that was a CCPC or a DIC in its last tax year (amount 16 **minus** amount 26) (if negative, enter "0") . . . 27

For a subsidiary that was neither a CCPC nor a DIC in its last tax year

LRIP at the end of its last tax year 28

Adjustment for a subsidiary involved in a wind-up (amount 27 **plus** amount 28**)** 29

Calculate amount 29 for **each** subsidiary.

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	100			
Total eligible dividends paid in the tax year			150	
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			180	
Subtotal (amount A **minus** line 180)				B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B **multiplied** by 20 %)			190	

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		1,000,000		
Total taxable dividends paid in the tax year	200	1,000,000		
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)				C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			280	
Subtotal (amount C **minus** line 280)				D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D **multiplied** by 20 %)			290	

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.

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Schedule 508

Ontario Research and Development Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC earned in the tax year to reduce Ontario corporate income tax payable in any of the three previous tax years;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - add an ORDTC transferred after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year. The ORDTC rate is:
  - 4.5% for tax years that end before June 1, 2016;
  - 3.5% for tax years that start after May 31, 2016; and
  - prorated for a tax year that ends on or after June 1, 2016, and includes May 31, 2016.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Complete and attach this schedule to the *T2 Corporation Income Tax Return* for the tax year.
- To claim this credit, you must also send in completed copies of the Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*, and the Schedule 31, *Investment Tax Credit - Corporations*, within 18 months of the tax year end.

Part 1 – Ontario SR&ED expenditure pool

	Line				
Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	1,020,622	A		
Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	388	B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		1,020,234	C		
Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		1,020,234	▶	1,020,234	E
Eligible expenditures the corporation transferred to another corporation	115				F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120			1,020,234	G

Part 2 – Eligible repayments

The repayment of the ORDTC is calculated using the ORDTC rate that you used to determine your tax credit at the time your eligible expenditures were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayments for tax years that end before June 1, 2016 . . . . 210 ________ x 4.5 % = 215 ________ H

Repayment for a tax year that ends on or after June 1, 2016 and includes May 31, 2016. Complete the proration calculation below.

	Line	Days		Rate		Result	
Number of days in the tax year before June 1, 2016	240	152	x	4.5 %	=	1.8689 %	1
Number of days in the tax year	241	366					
Number of days in the tax year after May 31, 2016	242	214	x	3.5 %	=	2.0464 %	2
Number of days in the tax year	243	366					

Subtotal (percentage 1 **plus** percentage 2) 3.9153 % 3

Repayments for a tax year that ends on or after June 1, 2016 and includes May 31, 2016 . . . . . . 211 ________ x percentage 3 3.9153 % = 216 ________ I

Part 2 – Eligible repayments (continued)

Repayments for tax years that start after May 31, 2016 . . . . **212** ________ x 3.5 % = **217** ________ J

Repayments made in the tax year of government or non-government assistance or contract payments that reduced eligible expenditures for first term or second term shared-use equipment acquired before 2014 . . . . **220** ________ x 1 / 4 = ________ x 4.5 % = **225** ________ K

Eligible repayments (total of amounts H to K) . . . . **229** ________ L

Part 3 – Calculation of the current part of the ORDTC

For tax years that end before June 1, 2016

Ontario SR&ED expenditure pool (amount G in Part 1) . . . . ________ x 4.5 % = **200** ________ M

ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year * . . . . **205** ________ N

Eligible repayments (amount L in Part 2) . . . . ________ O

Current part of the ORDTC for tax years that end before June 1, 2016 (total of amounts M to O) . . . . **230** ________ P

For a tax year that ends on or after June 1, 2016, and includes May 31, 2016

Number of days in the tax year before June 1, 2016 / Number of days in the tax year ________ x 4.5 % = ________ % 4

Number of days in the tax year after May 31, 2016 / Number of days in the tax year ________ x 3.5 % = ________ % 5

Subtotal (percentage 4 **plus** percentage 5) ________ % 6

Ontario SR&ED expenditure pool (amount G in Part 1) . . ________ x percentage 6 ________ % = **201** ________ Q

ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year * . . . . **206** ________ R

Eligible repayments (amount L in Part 2) . . . . ________ S

Part of the ORDTC for a tax year that ends on or after June 1, 2016, and includes May 31, 2016 (total of amounts Q to S) . . . . **231** ________ T

For tax years that start after May 31, 2016

Ontario SR&ED expenditure pool (amount G in Part 1) . . . . 1,020,234 x 3.5 % = **202** 35,708 U

ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year * . . . . **207** ________ V

Eligible repayments (amount L in Part 2) . . . . ________ W

The ORDTC for tax years that start after May 31, 2016 (total of amounts U to W) . . . . **232** 35,708 X

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Part 4 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year				91,328	Y
ORDTC expired after 20 tax years			300		Z
ORDTC at the beginning of the tax year (amount Y **minus** amount Z)			305	91,328	AA
ORDTC transferred to the corporation on amalgamation or windup			310		BB
Current part of ORDTC (amount P, T or X in Part 3 whichever applies)		35,708 CC			

Are you waiving all or part of the current part of the ORDTC? **315** Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Waiver of the current part of the ORDTC	320	DD				
Subtotal (amount CC **minus** amount DD)		35,708 ▶		35,708	EE	
ORDTC available for deduction (total of amounts AA, BB and EE)				127,036 ▶		127,036 FF
ORDTC claimed ** (Enter amount GG on line 416 on page 5 of Schedule 5, *Tax Calculation Supplementary – Corporations*)					GG	
ORDTC carried back to previous tax years (from Part 5)					HH	
Subtotal (amount GG **plus** amount HH)				▶		II
ORDTC balance at the end of the tax year (amount FF **minus** amount II)					325	127,036 JJ

** This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount FF); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 on page 5 of Schedule 5).

Part 5 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2019-12-31	Credit to be applied	901	
2nd previous tax year	2018-12-31	Credit to be applied	902	
3rd previous tax year	2017-12-31	Credit to be applied	903	

Total (total of amount 901 to 903)(enter at amount HH in Part 4)

Part 6 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from previous tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
2002-12-31	
2003-12-31	
2004-12-31	
2005-12-31	
2006-12-31	
2007-12-31	
2008-12-31	
2009-12-31	
2010-12-31	
2011-12-31	

	Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
	2012-12-31	
	2013-12-31	
	2014-12-31	
	2015-10-31	
	2015-11-04	
	2015-12-31	
	2016-12-31	
	2017-12-31	
	2018-12-31	
	2019-12-31	91,328
Current tax year	2020-12-31	35,708

Total (equals line 325 in Part 4) 127,036

The amount available from the 20th previous tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 7 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate *** of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

Complete the columns for each disposition for which a recapture applies, using the calculation formats below.

*** Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – Complete this part If you meet all of the above conditions

	KK Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	LL Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	MM Amount from column 700 or 710, whichever is less
1.			

Total of column MM (enter at amount WW in Part 8) ________ NN

Part 7 – Calculation of a recapture of ORDTC (continued)

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line SS.

	OO Rate percentage that the transferee used to determine its federal ITC for qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	PP Proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	QQ Amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	RR Amount determined by the formula (OO x PP) - QQ (using the columns above)	SS Federal ITC earned by the transferee for the qualified expenditure that was transferred 750	TT Amount from column RR or SS, whichever is less
1.			

Total of column TT (enter at amount XX in Part 8) ______ UU

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205, 206, or 207 in Part 3, whichever applies. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line VV.

Corporate partner's share of the excess of ORDTC (enter at amount ZZ in Part 8) . . . . 760 ______ VV

Part 8 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount NN from Part 7) . . . . ______ WW

Recaptured federal ITC for Calculation 2 (amount UU from Part 7) . . . . ______ XX

Amount WW **plus** amount XX . . . . ______ x 23.56 % = ______ YY

Corporate partner's share of the excess of ORDTC for Calculation 3 (amount VV from Part 7) . . . . ______ ZZ

Recapture of ORDTC (amount YY **plus** amount ZZ) (enter amount AAA on line 277 on page 5 of Schedule 5) . . . . ______ AAA

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Total expenditures for SR&ED		723,773	
Add			
• payment of prior years' unpaid expenses (other than salary or wages)	+		
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	306,826	
• other additions	+		
Subtotal	=	1,030,599	
Less			
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–		
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–		
• 20% of contract expenditures for SR&ED performed on your behalf	–	9,977	
• prescribed expenditures not allowed by regulations	–		
• other deductions	–		
• non-arm's length transactions			
– expenditures for non-arm's length SR&ED contracts	–		
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		
Total	=	1,020,622	I

Enter amount I on line 100 of Schedule 508.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	26,827,000,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		26,827,000,000
Total revenue of the corporation for the tax year **	142	7,100,858,397
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		7,100,858,397

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	1,784,680,805
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	29,395,032		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228	27,190,635		
Total patronage dividends received, not already included in net income/loss	232			
281 Add: Estimated depreciation on capitalized interest	282	5,127,370		
283	284			
Subtotal		61,713,037 ▶		61,713,037 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322	814,263,341		
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326	32,682,198		
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336	48,515,819		
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381 Unrealized mark to market	382	88,744		
383	384			
385	386			
387	388			
389	390			
Subtotal		895,550,102 ▶		895,550,102 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	950,843,740

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515	950,843,740	
Deduct:			
CMT loss available (amount R from Part 7)			
Minus: Adjustment for an acquisition of control *	518		
Adjusted CMT loss available	▶		C
Net income subject to CMT calculation (if negative, enter "0")	520	950,843,740	

Amount from line 520: 950,843,740 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 366) x 4 % = ______ 1

Amount from line 520: 950,843,740 x (Number of days in the tax year after June 30, 2010: 366 / Number of days in the tax year: 366) x 2.7 % = 25,672,781 2

Subtotal (amount 1 **plus** amount 2) 25,672,781 3

Gross CMT: amount on line 3 above x OAF **	540	25,672,781	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		25,672,781	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		25,672,781	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		90,232,726	G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)		90,232,726	▶ 620	90,232,726	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650	1,348,070	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				91,580,796	H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)				91,580,796	J
Add:					
Net CMT payable (amount E from Part 3)		25,672,781			
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal		25,672,781	▶	25,672,781	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	117,253,577	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				91,580,796	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)	25,672,781	2			
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)		3			
Gross SAT (line 460 from Part 6 of Schedule 512)		4			
The **greater** of amounts 3 and 4		5			
Deduct: line 2 or line 5, whichever applies:		25,672,781	6		
Subtotal (if negative, enter "0")			▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)					
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		892,371			
Subtotal (if negative, enter "0")			▶		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax-year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ______ Q

Deduct:

CMT loss expired * . . . . 700 ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ______ ► 720 ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . 750 ______

CMT loss available (line 720 **plus** line 750) . . . . ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . 760 ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Attached Schedule with Total

4th previous year – Transfers

Title 4th previous year – Transfers

Description	Operator (Note)	Amount
		19,491 00
HOIP GP	+	310,027 00
	+	
	Total	329,518 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1)	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Hydro One Limited	[redacted]	0	0
2	Hydro One Inc.		0	0
3	2486267 Ontario Inc.		0	0
4	2486268 Ontario Inc.		0	0
5	Hydro One Remote Communites Inc.		0	0
6	Hydro One Telecom Inc.		0	0
7	Hydro One Telecom Link Limited		0	0
8	Municipal Billing Services Inc.		0	0
9	Hydro One Lake Erie Link Management Inc.		0	0
10	1938454 Ontario Inc.		0	0
11	1943404 Ontario Inc.		0	0
12	Hydro One Indigenous Partnerships Inc.		0	0
13	Norfolk Energy Inc.		0	0
14	Norfolk Power Distribution Inc.		0	0
15	Haldimand County Energy Inc.		0	0
16	Haldimand County Hydro Inc.		0	0
17	Woodstock Hydro Services Inc.		0	0
18	Hydro One Sault Ste. Marie Holdings Inc.		0	0
19	Hydro One Sault Ste. Marie Inc.		0	0
20	Hydro One Sault Ste. Marie Holding Corp.		0	0
21	1228185 Ontario Inc.		0	0
22	Hydro One East-West Tie Inc.		0	0
23	1937680 Ontario Inc.		0	0
24	1937681 Ontario Inc.		0	0
25	2587264 Ontario Inc.		0	0
26	Hydro One Holdings Limited		0	0
27	2587265 Ontario Inc.		0	0
28	Hydro One Investment Holdings Inc.		0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	Orillia Power Distribution Corporation		0	0
30	Aux Energy Inc.		0	0
31	Olympus Holding Corp.	NR	0	0
		Total	450	550

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
Nancy Tran	(416) 345-6778

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 971,966,719

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	Georgian College	Engineering
2.	Conestoga College	Engineering
3.	Georgian College	Engineering
4.	Georgian College	Engineering
5.	McMaster University	Engineering
6.	McMaster University	Engineering
7.	Brock University	Business/Engineering
8.	Brock University	Business/Engineering
9.	Brock University	Business/Engineering
10.	McMaster University	Engineering
11.	McMaster University	Engineering
12.	McMaster University	Engineering
13.	McMaster University	Engineering
14.	Ryerson University	Business/Engineering
15.	Ryerson University	Business/Engineering
16.	Brock University	Business/Engineering
17.	Brock University	Business/Engineering
18.	Brock University	Business/Engineering
19.	Brock University	Business/Engineering
20.	McMaster University	Engineering
21.	McMaster University	Engineering
22.	McMaster University	Engineering
23.	McMaster University	Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	Georgian College	Engineering
25.	Georgian College	Engineering
26.	Georgian College	Engineering
27.	Georgian College	Engineering
28.	Brock University	Business/Engineering
29.	Brock University	Business/Engineering
30.	Brock University	Business/Engineering
31.	Georgian College	Engineering
32.	Georgian College	Engineering
33.	University of Windsor	Business/Engineering
34.	University of Windsor	Business/Engineering
35.	University of Guelph	Business/Engineering
36.	University of Guelph	Business/Engineering
37.	Western University	Engineering
38.	Western University	Engineering
39.	Western University	Engineering
40.	Western University	Engineering
41.	McMaster University	Engineering
42.	McMaster University	Engineering
43.	McMaster University	Engineering
44.	Brock University	Business/Engineering
45.	Brock University	Business/Engineering
46.	University of Toronto	Engineering
47.	University of Toronto	Engineering
48.	McMaster University	Engineering
49.	McMaster University	Business/Engineering
50.	Ryerson University	Engineering
51.	Ryerson University	Engineering
52.	McMaster University	Engineering/Business
53.	Queen's University	Engineering
54.	Queen's University	Engineering
55.	University of Toronto	Engineering
56.	University of Toronto	Engineering
57.	McMaster University	Engineering
58.	University of Toronto	Engineering/Business
59.	University of Toronto	Engineering/Business
60.	University of Toronto	Engineering
61.	University of Toronto	Engineering
62.	University of Toronto	Engineering
63.	University of Toronto	Engineering
64.	Ryerson University	Engineering
65.	Ryerson University	Engineering
66.	Ryerson University	Engineering/Business
67.	Ryerson University	Engineering/Business
68.	Brock University	Business/Engineering
69.	Brock University	Business/Engineering
70.	McMaster University	Engineering
71.	McMaster University	Engineering
72.	York University	Engineering
73.	York University	Engineering
74.	McMaster University	Engineering/Business
75.	McMaster University	Engineering/Business
76.	McMaster University	Engineering
77.	UOIT	Business
78.	McMaster University	Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
79.	Queen's University	Business/Engineering
80.	University of Toronto	Engineering
81.	McMaster University	Engineering
82.	McMaster University	Engineering
83.	University of Toronto	Business
84.	McMaster University	Engineering
85.	McMaster University	Engineering
86.	University of Toronto	Business
87.	Georgian College	Engineering/Business
88.	University of Toronto	Engineering
89.	University of Toronto	Business
90.	Ryerson University	Engineering
91.	Georgian College	Business
92.	Georgian College	Business
93.	Brock University	Business
94.	Brock University	Business
95.	Mohawk College	Business/Engineering
96.	Mohawk College	Business/Engineering
97.	Wilfrid Laurier University	Business
98.	University of Toronto	Engineering
99.	Wilfrid Laurier University	Business
100.	Ryerson University	Engineering
101.	Ryerson University	Engineering
102.	University of Toronto	Engineering
103.	McMaster University	Engineering
104.	Mohawk College	Engineering
105.	UOIT	Engineering
106.	Niagara College	Engineering
107.	McMaster University	Engineering/Business
108.	McMaster University	Engineering/Business
109.	University of Waterloo	Business/Engineering
110.	McMaster University	Engineering
111.	University of Ottawa	Engineering
112.	University of Ottawa	Engineering
113.	University of Ottawa	Engineering
114.	University of Toronto	Business
115.	University of Toronto	Business
116.	McMaster University	Engineering
117.	McMaster University	Engineering
118.	UOIT	Engineering
119.	UOIT	Engineering
120.	UOIT	Engineering
121.	UOIT	Engineering
122.	University of Toronto	Engineering
123.	University of Toronto	Engineering
124.	University of Toronto	Engineering
125.	University of Toronto	Engineering
126.	York University	Engineering
127.	York University	Engineering
128.	McMaster University	Engineering
129.	McMaster University	Engineering
130.	McMaster University	Engineering
131.	McMaster University	Engineering
132.	McMaster University	Engineering
133.	UOIT	Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
134.	UOIT	Engineering
135.	University of Toronto	Business
136.	University of Toronto	Business
137.	UOIT	Engineering
138.	UOIT	Engineering
139.	McMaster University	Engineering
140.	McMaster University	Engineering
141.	UOIT	Engineering
142.	UOIT	Engineering
143.	University of Toronto	Business
144.	University of Toronto	Engineering
145.	University of Toronto	Engineering
146.	University of Toronto	Business/Engineering
147.	York University	Engineering
148.	York University	Engineering
149.	Western University	Computer Science
150.	Western University	Computer Science
151.	University of Windsor	Engineering
152.	University of Windsor	Engineering
153.	McMaster University	Engineering
154.	McMaster University	Engineering
155.	Ryerson University	Engineering
156.	Ryerson University	Engineering
157.	UOIT	Engineering
158.	UOIT	Engineering
159.	University of Toronto	Business
160.	University of Toronto	Business
161.	Brock University	Business
162.	Brock University	Business
163.	Ryerson University	Engineering
164.	Ryerson University	Engineering
165.	McMaster University	Business
166.	McMaster University	Business
167.	University of Windsor	Engineering
168.	University of Windsor	Engineering
169.	Ryerson University	Engineering
170.	Ryerson University	Engineering
171.	University of Windsor	Engineering
172.	University of Windsor	Engineering
173.	University of Windsor	Engineering
174.	McMaster University	Business
175.	McMaster University	Business
176.	University of Toronto	Business
177.	McMaster University	Engineering
178.	University of Toronto	Engineering
179.	University of Toronto	Engineering
180.	University of Toronto	Engineering
181.	University of Toronto	Engineering
182.	University of Toronto	Business/Engineering
183.	University of Toronto	Business/Engineering
184.	University of Toronto	Business
185.	University of Toronto	Business
186.	UOIT	Engineering
187.	UOIT	Engineering
188.	University of Toronto	Business

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
189.	Brock University	Business
190.	Brock University	Business
191.	Brock University	Business
192.	Georgian College	Business/Engineering
193.	Georgian College	Engineering
194.	University of Waterloo	Engineering
195.	Western University	Engineering

C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
[redacted]	2020-01-06	2020-04-04
[redacted]	2020-01-06	2020-05-07
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[redacted]	2020-06-15	2020-08-31
[redacted]	2020-09-01	2020-12-31
[redacted]	2020-01-06	2020-04-30
[redacted]	2020-05-01	2020-08-31
[redacted]	2020-09-01	2020-11-22
[redacted]	2020-06-11	2020-08-31
[redacted]	2020-09-01	2020-12-31
[redacted]	2020-06-11	2020-08-31
[redacted]	2020-09-01	2020-12-31
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[redacted]	2020-06-11	2020-08-31

C Name of student	D Start date of WP (see note 1 below)	E End date of WP (see note 2 below)
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[redacted]	2020-06-18	2020-08-31
[redacted]	2020-09-01	2020-12-31
[redacted]	2020-01-01	2020-04-30
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[redacted]	2020-01-01	2020-04-30
[redacted]	2020-05-01	2020-09-01
[redacted]	2020-09-03	2020-12-31
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[redacted]	2020-09-03	2020-12-31
[redacted]	2020-09-03	2020-12-31
[redacted]	2020-08-17	2020-12-31
[redacted]	2020-09-10	2020-12-31
[redacted]	2020-09-03	2020-12-31
[redacted]	2020-09-08	2020-12-31
[redacted]	2020-09-03	2020-12-31
[redacted]	2020-08-24	2020-12-31
[redacted]	2020-06-22	2020-08-31

C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
[redacted]	2020-09-01	2020-12-20
[redacted]	2020-09-08	2020-12-19
[redacted]	2020-08-24	2020-12-31
[redacted]	2020-09-08	2020-12-19
[redacted]	2020-09-24	2020-12-31
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[redacted]	2020-01-06	2020-04-04
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[redacted]	2020-01-01	2020-05-16
[redacted]	2020-01-09	2020-04-30
[redacted]	2020-05-01	2020-08-31
[redacted]	2020-09-01	2020-12-31
[redacted]	2020-01-06	2020-04-30
[redacted]	2020-05-01	2020-08-29
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[redacted]	2020-05-01	2020-08-04
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[redacted]	2020-08-17	2020-12-31
[redacted]	2020-01-01	2020-04-30
[redacted]	2020-05-01	2020-09-03
[redacted]	2020-09-08	2020-12-31
[redacted]	2020-01-01	2020-04-30
[redacted]	2020-05-01	2020-08-29
[redacted]	2020-01-01	2020-04-30

C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
[redacted]	2020-05-01	2020-08-29
[redacted]	2020-01-01	2020-04-30
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[redacted]	2020-01-01	2020-04-30
[redacted]	2020-05-01	2020-09-16
[redacted]	2020-01-01	2020-04-30
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[redacted]	2020-06-11	2020-08-31
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[redacted]	2020-05-01	2020-08-31
[redacted]	2020-09-01	2020-12-24
[redacted]	2020-01-01	2020-04-25
[redacted]	2020-01-01	2020-05-16
[redacted]	2020-09-08	2020-12-31
[redacted]	2020-09-09	2020-12-31

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	13,298	25.000 %		13
2.		10.000 %	15,729	25.000 %		17
3.		10.000 %	11,972	25.000 %		13
4.		10.000 %	12,175	25.000 %		13
5.		10.000 %	13,767	25.000 %		11
6.		10.000 %	13,767	25.000 %		16
7.		10.000 %	22,434	25.000 %		16
8.		10.000 %	22,434	25.000 %		17
9.		10.000 %	22,434	25.000 %		11
10.		10.000 %	16,041	25.000 %		11
11.		10.000 %	16,041	25.000 %		16
12.		10.000 %	16,155	25.000 %		11
13.		10.000 %	16,155	25.000 %		16
14.		10.000 %	21,520	25.000 %		15
15.		10.000 %	21,520	25.000 %		17
16.		10.000 %	20,703	25.000 %		16
17.		10.000 %	20,703	25.000 %		17
18.		10.000 %	20,703	25.000 %		16
19.		10.000 %	24,850	25.000 %		15
20.		10.000 %	16,057	25.000 %		11
21.		10.000 %	16,057	25.000 %		16
22.		10.000 %	16,057	25.000 %		11
23.		10.000 %	16,057	25.000 %		16
24.		10.000 %	11,965	25.000 %		13
25.		10.000 %	11,776	25.000 %		13
26.		10.000 %	11,875	25.000 %		13
27.		10.000 %	11,792	25.000 %		13
28.		10.000 %	17,784	25.000 %		15
29.		10.000 %	17,784	25.000 %		17
30.		10.000 %	17,784	25.000 %		16
31.		10.000 %	11,789	25.000 %		13
32.		10.000 %	11,965	25.000 %		13
33.		10.000 %	19,894	25.000 %		16
34.		10.000 %	19,894	25.000 %		16
35.		10.000 %	20,146	25.000 %		16
36.		10.000 %	20,146	25.000 %		18
37.		10.000 %	15,987	25.000 %		11
38.		10.000 %	15,987	25.000 %		16
39.		10.000 %	16,057	25.000 %		11
40.		10.000 %	16,057	25.000 %		16
41.		10.000 %	16,057	25.000 %		11
42.		10.000 %	16,057	25.000 %		16
43.		10.000 %	14,159	25.000 %		15
44.		10.000 %	17,057	25.000 %		11
45.		10.000 %	17,057	25.000 %		16
46.		10.000 %	16,057	25.000 %		11
47.		10.000 %	16,057	25.000 %		16
48.		10.000 %	13,934	25.000 %		13
49.		10.000 %	17,709	25.000 %		15
50.		10.000 %	15,987	25.000 %		11
51.		10.000 %	15,987	25.000 %		16

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
52.		10.000 %	16,652	25.000 %		15
53.		10.000 %	16,057	25.000 %		11
54.		10.000 %	16,057	25.000 %		16
55.		10.000 %	16,606	25.000 %		12
56.		10.000 %	16,606	25.000 %		16
57.		10.000 %	26,668	25.000 %		16
58.		10.000 %	16,057	25.000 %		11
59.		10.000 %	16,057	25.000 %		16
60.		10.000 %	16,379	25.000 %		12
61.		10.000 %	16,379	25.000 %		16
62.		10.000 %	16,057	25.000 %		11
63.		10.000 %	16,057	25.000 %		16
64.		10.000 %	15,987	25.000 %		11
65.		10.000 %	15,987	25.000 %		16
66.		10.000 %	15,987	25.000 %		11
67.		10.000 %	15,987	25.000 %		16
68.		10.000 %	16,336	25.000 %		10
69.		10.000 %	16,336	25.000 %		16
70.		10.000 %	24,144	25.000 %		16
71.		10.000 %	24,144	25.000 %		17
72.		10.000 %	14,233	25.000 %		10
73.		10.000 %	14,233	25.000 %		16
74.		10.000 %	14,166	25.000 %		10
75.		10.000 %	14,166	25.000 %		16
76.		10.000 %	27,946	25.000 %		16
77.		10.000 %	18,516	25.000 %		19
78.		10.000 %	13,934	25.000 %		13
79.		10.000 %	21,938	25.000 %		19
80.		10.000 %	17,169	25.000 %		16
81.		10.000 %	25,005	25.000 %		16
82.		10.000 %	25,005	25.000 %		17
83.		10.000 %	17,169	25.000 %		16
84.		10.000 %	24,064	25.000 %		16
85.		10.000 %	24,064	25.000 %		15
86.		10.000 %	20,653	25.000 %		19
87.		10.000 %	11,300	25.000 %		16
88.		10.000 %	17,169	25.000 %		16
89.		10.000 %	20,653	25.000 %		19
90.		10.000 %	17,294	25.000 %		15
91.		10.000 %	13,940	25.000 %		16
92.		10.000 %	13,031	25.000 %		15
93.		10.000 %	15,342	25.000 %		16
94.		10.000 %	16,991	25.000 %		18
95.		10.000 %	12,266	25.000 %		10
96.		10.000 %	12,266	25.000 %		15
97.		10.000 %	16,672	25.000 %		14
98.		10.000 %	19,409	25.000 %		18
99.		10.000 %	16,672	25.000 %		14
100.		10.000 %	13,686	25.000 %		13
101.		10.000 %	16,672	25.000 %		15
102.		10.000 %	16,210	25.000 %		15
103.		10.000 %	16,210	25.000 %		15
104.		10.000 %	16,704	25.000 %		16

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
105.		10.000 %	16,174	25.000 %		15
106.		10.000 %	13,953	25.000 %		13
107.		10.000 %	21,409	25.000 %		16
108.		10.000 %	21,409	25.000 %		13
109.		10.000 %	25,316	25.000 %		17
110.		10.000 %	34,282	25.000 %		19
111.		10.000 %	17,967	25.000 %		15
112.		10.000 %	17,967	25.000 %		17
113.		10.000 %	17,967	25.000 %		16
114.		10.000 %	20,899	25.000 %		16
115.		10.000 %	20,899	25.000 %		17
116.		10.000 %	23,849	25.000 %		16
117.		10.000 %	23,849	25.000 %		15
118.		10.000 %	25,730	25.000 %		16
119.		10.000 %	25,730	25.000 %		17
120.		10.000 %	24,565	25.000 %		16
121.		10.000 %	24,565	25.000 %		16
122.		10.000 %	23,176	25.000 %		16
123.		10.000 %	23,176	25.000 %		17
124.		10.000 %	25,331	25.000 %		16
125.		10.000 %	25,331	25.000 %		17
126.		10.000 %	25,205	25.000 %		16
127.		10.000 %	25,205	25.000 %		17
128.		10.000 %	28,189	25.000 %		16
129.		10.000 %	25,760	25.000 %		16
130.		10.000 %	25,760	25.000 %		17
131.		10.000 %	25,138	25.000 %		16
132.		10.000 %	25,138	25.000 %		17
133.		10.000 %	23,713	25.000 %		16
134.		10.000 %	23,713	25.000 %		17
135.		10.000 %	22,872	25.000 %		16
136.		10.000 %	22,872	25.000 %		13
137.		10.000 %	25,526	25.000 %		16
138.		10.000 %	25,526	25.000 %		17
139.		10.000 %	24,889	25.000 %		16
140.		10.000 %	24,889	25.000 %		17
141.		10.000 %	25,138	25.000 %		16
142.		10.000 %	25,138	25.000 %		17
143.		10.000 %	21,938	25.000 %		19
144.		10.000 %	24,206	25.000 %		16
145.		10.000 %	24,206	25.000 %		17
146.		10.000 %	14,595	25.000 %		15
147.		10.000 %	25,079	25.000 %		16
148.		10.000 %	25,079	25.000 %		17
149.		10.000 %	25,274	25.000 %		16
150.		10.000 %	25,274	25.000 %		17
151.		10.000 %	25,143	25.000 %		16
152.		10.000 %	25,143	25.000 %		17
153.		10.000 %	26,180	25.000 %		16
154.		10.000 %	26,180	25.000 %		19
155.		10.000 %	25,843	25.000 %		16
156.		10.000 %	25,843	25.000 %		18
157.		10.000 %	25,174	25.000 %		16

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
158.		10.000 %	25,174	25.000 %		18
159.		10.000 %	10,675	25.000 %		11
160.		10.000 %	10,675	25.000 %		14
161.		10.000 %	22,356	25.000 %		16
162.		10.000 %	22,356	25.000 %		19
163.		10.000 %	24,820	25.000 %		16
164.		10.000 %	24,820	25.000 %		16
165.		10.000 %	24,835	25.000 %		16
166.		10.000 %	24,835	25.000 %		17
167.		10.000 %	23,925	25.000 %		16
168.		10.000 %	23,925	25.000 %		15
169.		10.000 %	25,451	25.000 %		16
170.		10.000 %	25,451	25.000 %		18
171.		10.000 %	22,403	25.000 %		16
172.		10.000 %	22,403	25.000 %		17
173.		10.000 %	22,403	25.000 %		16
174.		10.000 %	25,563	25.000 %		16
175.		10.000 %	25,563	25.000 %		17
176.		10.000 %	26,490	25.000 %		16
177.		10.000 %	27,487	25.000 %		17
178.		10.000 %	24,924	25.000 %		16
179.		10.000 %	24,924	25.000 %		17
180.		10.000 %	24,892	25.000 %		16
181.		10.000 %	24,892	25.000 %		17
182.		10.000 %	23,675	25.000 %		16
183.		10.000 %	23,675	25.000 %		17
184.		10.000 %	24,658	25.000 %		16
185.		10.000 %	24,658	25.000 %		17
186.		10.000 %	24,724	25.000 %		16
187.		10.000 %	24,724	25.000 %		17
188.		10.000 %	17,971	25.000 %		17
189.		10.000 %	20,856	25.000 %		16
190.		10.000 %	20,856	25.000 %		17
191.		10.000 %	20,856	25.000 %		15
192.		10.000 %	17,250	25.000 %		16
193.		10.000 %	18,402	25.000 %		19
194.		10.000 %	15,900	25.000 %		15
195.		10.000 %	16,920	25.000 %		15

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,325	3,000	3,000		3,000
2.	3,932	3,000	3,000		3,000
3.	2,993	3,000	2,993		2,993
4.	3,044	3,000	3,000		3,000
5.	3,442	3,000	3,000		3,000
6.	3,442	3,000	3,000		3,000
7.	5,609	3,000	3,000		3,000
8.	5,609	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
9.	5,609	3,000	3,000		3,000
10.	4,010	3,000	3,000		3,000
11.	4,010	3,000	3,000		3,000
12.	4,039	3,000	3,000		3,000
13.	4,039	3,000	3,000		3,000
14.	5,380	3,000	3,000		3,000
15.	5,380	3,000	3,000		3,000
16.	5,176	3,000	3,000		3,000
17.	5,176	3,000	3,000		3,000
18.	5,176	3,000	3,000		3,000
19.	6,213	3,000	3,000		3,000
20.	4,014	3,000	3,000		3,000
21.	4,014	3,000	3,000		3,000
22.	4,014	3,000	3,000		3,000
23.	4,014	3,000	3,000		3,000
24.	2,991	3,000	2,991		2,991
25.	2,944	3,000	2,944		2,944
26.	2,969	3,000	2,969		2,969
27.	2,948	3,000	2,948		2,948
28.	4,446	3,000	3,000		3,000
29.	4,446	3,000	3,000		3,000
30.	4,446	3,000	3,000		3,000
31.	2,947	3,000	2,947		2,947
32.	2,991	3,000	2,991		2,991
33.	4,974	3,000	3,000		3,000
34.	4,974	3,000	3,000		3,000
35.	5,037	3,000	3,000		3,000
36.	5,037	3,000	3,000		3,000
37.	3,997	3,000	3,000		3,000
38.	3,997	3,000	3,000		3,000
39.	4,014	3,000	3,000		3,000
40.	4,014	3,000	3,000		3,000
41.	4,014	3,000	3,000		3,000
42.	4,014	3,000	3,000		3,000
43.	3,540	3,000	3,000		3,000
44.	4,264	3,000	3,000		3,000
45.	4,264	3,000	3,000		3,000
46.	4,014	3,000	3,000		3,000
47.	4,014	3,000	3,000		3,000
48.	3,484	3,000	3,000		3,000
49.	4,427	3,000	3,000		3,000
50.	3,997	3,000	3,000		3,000
51.	3,997	3,000	3,000		3,000
52.	4,163	3,000	3,000		3,000
53.	4,014	3,000	3,000		3,000
54.	4,014	3,000	3,000		3,000
55.	4,152	3,000	3,000		3,000
56.	4,152	3,000	3,000		3,000
57.	6,667	3,000	3,000		3,000
58.	4,014	3,000	3,000		3,000
59.	4,014	3,000	3,000		3,000
60.	4,095	3,000	3,000		3,000
61.	4,095	3,000	3,000		3,000

[redacted]

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
62.	4,014	3,000	3,000		3,000
63.	4,014	3,000	3,000		3,000
64.	3,997	3,000	3,000		3,000
65.	3,997	3,000	3,000		3,000
66.	3,997	3,000	3,000		3,000
67.	3,997	3,000	3,000		3,000
68.	4,084	3,000	3,000		3,000
69.	4,084	3,000	3,000		3,000
70.	6,036	3,000	3,000		3,000
71.	6,036	3,000	3,000		3,000
72.	3,558	3,000	3,000		3,000
73.	3,558	3,000	3,000		3,000
74.	3,542	3,000	3,000		3,000
75.	3,542	3,000	3,000		3,000
76.	6,987	3,000	3,000		3,000
77.	4,629	3,000	3,000		3,000
78.	3,484	3,000	3,000		3,000
79.	5,485	3,000	3,000		3,000
80.	4,292	3,000	3,000		3,000
81.	6,251	3,000	3,000		3,000
82.	6,251	3,000	3,000		3,000
83.	4,292	3,000	3,000		3,000
84.	6,016	3,000	3,000		3,000
85.	6,016	3,000	3,000		3,000
86.	5,163	3,000	3,000		3,000
87.	2,825	3,000	2,825		2,825
88.	4,292	3,000	3,000		3,000
89.	5,163	3,000	3,000		3,000
90.	4,324	3,000	3,000		3,000
91.	3,485	3,000	3,000		3,000
92.	3,258	3,000	3,000		3,000
93.	3,836	3,000	3,000		3,000
94.	4,248	3,000	3,000		3,000
95.	3,067	3,000	3,000		3,000
96.	3,067	3,000	3,000		3,000
97.	4,168	3,000	3,000		3,000
98.	4,852	3,000	3,000		3,000
99.	4,168	3,000	3,000		3,000
100.	3,422	3,000	3,000		3,000
101.	4,168	3,000	3,000		3,000
102.	4,053	3,000	3,000		3,000
103.	4,053	3,000	3,000		3,000
104.	4,176	3,000	3,000		3,000
105.	4,044	3,000	3,000		3,000
106.	3,488	3,000	3,000		3,000
107.	5,352	3,000	3,000		3,000
108.	5,352	3,000	3,000		3,000
109.	6,329	3,000	3,000		3,000
110.	8,571	3,000	3,000		3,000
111.	4,492	3,000	3,000		3,000
112.	4,492	3,000	3,000		3,000
113.	4,492	3,000	3,000		3,000
114.	5,225	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
115.	5,225	3,000	3,000		3,000
116.	5,962	3,000	3,000		3,000
117.	5,962	3,000	3,000		3,000
118.	6,433	3,000	3,000		3,000
119.	6,433	3,000	3,000		3,000
120.	6,141	3,000	3,000		3,000
121.	6,141	3,000	3,000		3,000
122.	5,794	3,000	3,000		3,000
123.	5,794	3,000	3,000		3,000
124.	6,333	3,000	3,000		3,000
125.	6,333	3,000	3,000		3,000
126.	6,301	3,000	3,000		3,000
127.	6,301	3,000	3,000		3,000
128.	7,047	3,000	3,000		3,000
129.	6,440	3,000	3,000		3,000
130.	6,440	3,000	3,000		3,000
131.	6,285	3,000	3,000		3,000
132.	6,285	3,000	3,000		3,000
133.	5,928	3,000	3,000		3,000
134.	5,928	3,000	3,000		3,000
135.	5,718	3,000	3,000		3,000
136.	5,718	3,000	3,000		3,000
137.	6,382	3,000	3,000		3,000
138.	6,382	3,000	3,000		3,000
139.	6,222	3,000	3,000		3,000
140.	6,222	3,000	3,000		3,000
141.	6,285	3,000	3,000		3,000
142.	6,285	3,000	3,000		3,000
143.	5,485	3,000	3,000		3,000
144.	6,052	3,000	3,000		3,000
145.	6,052	3,000	3,000		3,000
146.	3,649	3,000	3,000		3,000
147.	6,270	3,000	3,000		3,000
148.	6,270	3,000	3,000		3,000
149.	6,319	3,000	3,000		3,000
150.	6,319	3,000	3,000		3,000
151.	6,286	3,000	3,000		3,000
152.	6,286	3,000	3,000		3,000
153.	6,545	3,000	3,000		3,000
154.	6,545	3,000	3,000		3,000
155.	6,461	3,000	3,000		3,000
156.	6,461	3,000	3,000		3,000
157.	6,294	3,000	3,000		3,000
158.	6,294	3,000	3,000		3,000
159.	2,669	3,000	2,669		2,669
160.	2,669	3,000	2,669		2,669
161.	5,589	3,000	3,000		3,000
162.	5,589	3,000	3,000		3,000
163.	6,205	3,000	3,000		3,000
164.	6,205	3,000	3,000		3,000
165.	6,209	3,000	3,000		3,000
166.	6,209	3,000	3,000		3,000
167.	5,981	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
168.	5,981	3,000	3,000		3,000
169.	6,363	3,000	3,000		3,000
170.	6,363	3,000	3,000		3,000
171.	5,601	3,000	3,000		3,000
172.	5,601	3,000	3,000		3,000
173.	5,601	3,000	3,000		3,000
174.	6,391	3,000	3,000		3,000
175.	6,391	3,000	3,000		3,000
176.	6,623	3,000	3,000		3,000
177.	6,872	3,000	3,000		3,000
178.	6,231	3,000	3,000		3,000
179.	6,231	3,000	3,000		3,000
180.	6,223	3,000	3,000		3,000
181.	6,223	3,000	3,000		3,000
182.	5,919	3,000	3,000		3,000
183.	5,919	3,000	3,000		3,000
184.	6,165	3,000	3,000		3,000
185.	6,165	3,000	3,000		3,000
186.	6,181	3,000	3,000		3,000
187.	6,181	3,000	3,000		3,000
188.	4,493	3,000	3,000		3,000
189.	5,214	3,000	3,000		3,000
190.	5,214	3,000	3,000		3,000
191.	5,214	3,000	3,000		3,000
192.	4,313	3,000	3,000		3,000
193.	4,601	3,000	3,000		3,000
194.	3,975	3,000	3,000		3,000
195.	4,230	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 583,946 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ____________ x percentage on line 170 in Part 1 ________ % = ... ________ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: Ifthe WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: Whenclaiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	[redacted]	2020-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number
Nancy Tran	(416) 345-6778

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 971,966,719

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \frac{(\text{amount on line 300} \ \textbf{minus} \ 400{,}000)}{200{,}000} \right]$$

Specified percentage . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \frac{(\text{amount on line 300} \ \textbf{minus} \ 400{,}000)}{200{,}000} \right]$$

Specified percentage . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

A Trade code	B Apprenticeship program/trade name	C Name of apprentice
[redacted]	[redacted]	[redacted]

[redacted]

A Trade code	B Apprenticeship program/trade name	C Name of apprentice
[redacted]		

A Trade code	B Apprenticeship program/trade name	C Name of apprentice
[redacted]		

A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
[redacted]		

D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-23	2020-01-01	2020-01-23
[redacted]	2017-01-24	2020-01-01	2020-01-24
[redacted]	2017-01-24	2020-01-01	2020-01-24
[redacted]	2017-01-24	2020-01-01	2020-01-24
[redacted]	2017-01-24	2020-01-01	2020-01-24
[redacted]	2017-01-24	2020-01-01	2020-01-24
[redacted]	2017-01-24	2020-01-01	2020-01-24

D Original contract or training agreement number	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1)	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2)	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3)
[redacted]0	425	430	435
[redacted]	2017-01-24	2020-01-01	2020-01-24
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-03	2020-01-01	2020-02-03
[redacted]	2017-02-16	2020-01-01	2020-02-16
[redacted]	2017-03-21	2020-01-01	2020-03-20
[redacted]	2017-03-21	2020-01-01	2020-03-20
[redacted]	2017-03-21	2020-01-01	2020-03-20
[redacted]	2017-03-23	2020-01-01	2020-03-22
[redacted]	2017-03-23	2020-01-01	2020-03-22
[redacted]	2017-03-23	2020-01-01	2020-03-22
[redacted]	2017-03-24	2020-01-01	2020-03-23
[redacted]	2017-03-25	2020-01-01	2020-03-24
[redacted]	2017-03-26	2020-01-01	2020-03-25
[redacted]	2017-03-27	2020-01-01	2020-03-26
[redacted]	2017-03-28	2020-01-01	2020-03-27
[redacted]	2017-03-29	2020-01-01	2020-03-28
[redacted]	2017-03-30	2020-01-01	2020-03-29
[redacted]	2017-03-31	2020-01-01	2020-03-30
[redacted]	2017-04-01	2020-01-01	2020-03-31
[redacted]	2017-04-02	2020-01-01	2020-04-01
[redacted]	2017-04-03	2020-01-01	2020-04-02
[redacted]	2017-04-04	2020-01-01	2020-04-03
[redacted]	2017-04-05	2020-01-01	2020-04-04
[redacted]	2017-04-06	2020-01-01	2020-04-05
[redacted]	2017-04-07	2020-01-01	2020-04-06
[redacted]	2017-04-27	2020-01-01	2020-04-26
[redacted]	2017-04-28	2020-01-01	2020-04-27
[redacted]	2017-04-29	2020-01-01	2020-04-28
[redacted]	2017-04-30	2020-01-01	2020-04-29
[redacted]	2017-05-02	2020-01-01	2020-05-01
[redacted]	2017-05-03	2020-01-01	2020-05-02
[redacted]	2017-05-04	2020-01-01	2020-05-03
[redacted]	2017-05-05	2020-01-01	2020-05-04
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05

D Original contract or training agreement number [redacted] 0	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-06	2020-01-01	2020-05-05
[redacted]	2017-05-07	2020-01-01	2020-05-06
[redacted]	2017-05-08	2020-01-01	2020-05-07
[redacted]	2017-05-09	2020-01-01	2020-05-08
[redacted]	2017-05-10	2020-01-01	2020-05-09
[redacted]	2017-05-11	2020-01-01	2020-05-10
[redacted]	2017-05-11	2020-01-01	2020-05-10
[redacted]	2017-05-17	2020-01-01	2020-05-16
[redacted]	2017-05-23	2020-01-01	2020-05-22
[redacted]	2017-05-25	2020-01-01	2020-05-24
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-08	2020-01-01	2020-06-07
[redacted]	2017-06-13	2020-01-01	2020-06-12
[redacted]	2017-06-13	2020-01-01	2020-06-12
[redacted]	2017-06-13	2020-01-01	2020-06-12
[redacted]	2017-06-13	2020-01-01	2020-06-12
[redacted]	2017-06-13	2020-01-01	2020-06-12
[redacted]	2017-06-20	2020-01-01	2020-02-26
[redacted]	2017-06-20	2020-01-01	2020-06-19
[redacted]	2017-06-22	2020-01-01	2020-02-27
[redacted]	2017-06-22	2020-01-01	2020-06-21
[redacted]	2017-07-15	2020-01-01	2020-03-06
[redacted]	2017-07-16	2020-01-01	2020-07-15
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04

D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-05	2020-01-01	2020-08-04
[redacted]	2017-08-14	2020-01-01	2020-08-13
[redacted]	2017-08-15	2020-01-01	2020-08-14
[redacted]	2017-08-17	2020-01-01	2020-08-16
[redacted]	2017-08-28	2020-01-01	2020-08-27
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-09-02	2020-01-01	2020-09-01
[redacted]	2017-10-01	2020-01-01	2020-09-30
[redacted]	2017-10-04	2020-01-01	2020-10-03
[redacted]	2017-10-05	2020-01-01	2020-10-04
[redacted]	2017-10-06	2020-01-01	2020-10-05
[redacted]	2017-10-06	2020-01-01	2020-10-05
[redacted]	2017-10-08	2020-01-01	2020-10-07
[redacted]	2017-10-11	2020-01-01	2020-10-10
[redacted]	2017-10-11	2020-01-01	2020-10-10
[redacted]	2017-10-17	2020-01-01	2020-10-16
[redacted]	2017-10-19	2020-01-01	2020-10-18
[redacted]	2017-10-19	2020-01-01	2020-10-18
[redacted]	2017-10-19	2020-01-01	2020-10-18
[redacted]	2017-10-19	2020-01-01	2020-10-18
[redacted]	2017-10-20	2020-01-01	2020-10-19

Note 1: Enter theoriginal registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: Whenthere are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
1.		22	301
2.		22	301
3.		22	301
4.		22	301
5.		22	301
6.		22	301
7.		22	301
8.		22	301
9.		22	301
10.		22	301
11.		22	301
12.		22	301
13.		22	301
14.		22	301
15.		23	314
16.		23	314
17.		23	314
18.		23	314
19.		23	314
20.		23	314
21.		23	314
22.		33	451
23.		33	451
24.		33	451
25.		33	451
26.		33	451
27.		33	451
28.		33	451
29.		33	451
30.		33	451
31.		33	451
32.		33	451
33.		33	451
34.		33	451
35.		33	451
36.		33	451
37.		33	451
38.		46	628
39.		79	1,079
40.		79	1,079
41.		79	1,079
42.		81	1,107
43.		81	1,107
44.		81	1,107
45.		82	1,120
46.		83	1,134
47.		84	1,148
48.		85	1,161
49.		86	1,175
50.		87	1,189
51.		88	1,202
52.		89	1,216

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
53.		90	1,230
54.		91	1,243
55.		92	1,257
56.		93	1,270
57.		94	1,284
58.		95	1,298
59.		96	1,311
60.		116	1,585
61.		117	1,598
62.		118	1,612
63.		119	1,626
64.		121	1,653
65.		122	1,667
66.		123	1,680
67.		124	1,694
68.		125	1,708
69.		125	1,708
70.		125	1,708
71.		125	1,708
72.		125	1,708
73.		125	1,708
74.		125	1,708
75.		125	1,708
76.		125	1,708
77.		125	1,708
78.		125	1,708
79.		125	1,708
80.		125	1,708
81.		125	1,708
82.		125	1,708
83.		125	1,708
84.		125	1,708
85.		126	1,721
86.		127	1,735
87.		128	1,749
88.		129	1,762
89.		130	1,776
90.		130	1,776
91.		136	1,858
92.		142	1,940
93.		144	1,967
94.		158	2,158
95.		158	2,158
96.		158	2,158
97.		158	2,158
98.		158	2,158
99.		158	2,158
100.		158	2,158
101.		158	2,158
102.		158	2,158
103.		158	2,158
104.		158	2,158
105.		158	2,158
106.		163	2,227

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
107.		163	2,227
108.		163	2,227
109.		163	2,227
110.		163	2,227
111.		56	765
112.		170	2,322
113.		57	779
114.		172	2,350
115.		65	888
116.		196	2,678
117.		216	2,951
118.		216	2,951
119.		216	2,951
120.		216	2,951
121.		216	2,951
122.		216	2,951
123.		216	2,951
124.		216	2,951
125.		216	2,951
126.		216	2,951
127.		216	2,951
128.		216	2,951
129.		216	2,951
130.		216	2,951
131.		216	2,951
132.		225	3,074
133.		226	3,087
134.		228	3,115
135.		239	3,265
136.		244	3,333
137.		244	3,333
138.		244	3,333
139.		244	3,333
140.		244	3,333
141.		244	3,333
142.		244	3,333
143.		244	3,333
144.		244	3,333
145.		244	3,333
146.		244	3,333
147.		244	3,333
148.		244	3,333
149.		244	3,333
150.		244	3,333
151.		244	3,333
152.		273	3,730
153.		276	3,770
154.		277	3,784
155.		278	3,798
156.		278	3,798
157.		280	3,825
158.		283	3,866
159.		283	3,866
160.		289	3,948

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
161.		291	3,975
162.		291	3,975
163.		291	3,975
164.		291	3,975
165.		292	3,989

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*) or ($5,000 × H2/365*), whichever applies.
* 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.		127,221	31,805
2.		112,271	28,068
3.		99,491	24,873
4.		98,663	24,666
5.		97,188	24,297
6.		95,382	23,846
7.		94,238	23,560
8.		90,399	22,600
9.		88,748	22,187
10.		86,768	21,692
11.		84,696	21,174
12.		78,569	19,642
13.		47,538	11,885
14.		67,164	16,791
15.		85,690	21,423
16.		99,405	24,851
17.		70,284	17,571
18.		89,738	22,435
19.		71,167	17,792
20.		89,250	22,313
21.		108,122	27,031
22.		121,066	30,267
23.		119,507	29,877
24.		112,282	28,071
25.		106,800	26,700
26.		104,459	26,115
27.		97,789	24,447
28.		97,610	24,403
29.		91,228	22,807
30.		91,000	22,750
31.		90,053	22,513
32.		80,351	20,088
33.		77,589	19,397
34.		76,000	19,000
35.		75,356	18,839
36.		53,471	13,368
37.		58,599	14,650

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
38.		1,379	345
39.		56,546	14,137
40.		62,693	15,673
41.		67,806	16,952
42.		81,922	20,481
43.		71,776	17,944
44.		58,524	14,631
45.		112,661	28,165
46.		82,138	20,535
47.		99,095	24,774
48.		88,713	22,178
49.		96,304	24,076
50.		93,281	23,320
51.		102,147	25,537
52.		106,706	26,677
53.		71,575	17,894
54.		97,547	24,387
55.		147,398	36,850
56.		92,886	23,222
57.		101,746	25,437
58.		125,991	31,498
59.		89,766	22,442
60.		91,451	22,863
61.		78,712	19,678
62.		81,670	20,418
63.		71,213	17,803
64.		81,233	20,308
65.		99,105	24,776
66.		21,662	5,416
67.		105,324	26,331
68.		126,877	31,719
69.		119,216	29,804
70.		109,484	27,371
71.		107,476	26,869
72.		107,121	26,780
73.		96,871	24,218
74.		95,027	23,757
75.		94,600	23,650
76.		94,504	23,626
77.		94,171	23,543
78.		92,615	23,154
79.		84,637	21,159
80.		83,842	20,961
81.		81,671	20,418
82.		77,873	19,468
83.		75,068	18,767
84.		59,946	14,987
85.		93,203	23,301
86.		98,644	24,661
87.		98,427	24,607
88.		99,058	24,765
89.		89,840	22,460
90.		67,293	16,823
91.		64,883	16,221

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
92.		43,934	10,984
93.		102,237	25,559
94.		64,900	16,225
95.		108,229	27,057
96.		70,231	17,558
97.		86,501	21,625
98.		95,535	23,884
99.		72,011	18,003
100.		74,024	18,506
101.		64,996	16,249
102.		69,153	17,288
103.		63,246	15,812
104.		75,392	18,848
105.		70,007	17,502
106.		76,282	19,071
107.		85,538	21,385
108.		91,191	22,798
109.		75,219	18,805
110.		31,988	7,997
111.		113,859	28,465
112.		85,352	21,338
113.		82,122	20,531
114.		90,857	22,714
115.		117,752	29,438
116.		61,218	15,305
117.		124,104	31,026
118.		116,263	29,066
119.		107,770	26,943
120.		104,547	26,137
121.		102,582	25,646
122.		95,223	23,806
123.		95,117	23,779
124.		91,680	22,920
125.		88,104	22,026
126.		86,777	21,694
127.		84,521	21,130
128.		83,439	20,860
129.		79,020	19,755
130.		78,851	19,713
131.		77,551	19,388
132.		78,528	19,632
133.		91,186	22,797
134.		48,408	12,102
135.		59,228	14,807
136.		147,957	36,989
137.		132,255	33,064
138.		131,253	32,813
139.		128,625	32,156
140.		121,261	30,315
141.		107,334	26,834
142.		104,822	26,206
143.		104,582	26,146
144.		103,322	25,831
145.		100,169	25,042

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
146.		99,277	24,819
147.		96,969	24,242
148.		93,161	23,290
149.		91,886	22,972
150.		90,338	22,585
151.		74,037	18,509
152.		51,831	12,958
153.		67,070	16,768
154.		66,784	16,696
155.		64,458	16,115
156.		62,916	15,729
157.		68,843	17,211
158.		46,574	11,644
159.		54,853	13,713
160.		57,339	14,335
161.		53,711	13,428
162.		48,215	12,054
163.		64,618	16,155
164.		19,189	4,797
165.		46,512	11,628

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.

For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	301		301
2.	301		301
3.	301		301
4.	301		301
5.	301		301
6.	301		301
7.	301		301
8.	301		301
9.	301		301
10.	301		301
11.	301		301
12.	301		301
13.	301		301
14.	301		301
15.	314		314
16.	314		314
17.	314		314
18.	314		314
19.	314		314

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
20.	314		314
21.	314		314
22.	451		451
23.	451		451
24.	451		451
25.	451		451
26.	451		451
27.	451		451
28.	451		451
29.	451		451
30.	451		451
31.	451		451
32.	451		451
33.	451		451
34.	451		451
35.	451		451
36.	451		451
37.	451		451
38.	345		345
39.	1,079		1,079
40.	1,079		1,079
41.	1,079		1,079
42.	1,107		1,107
43.	1,107		1,107
44.	1,107		1,107
45.	1,120		1,120
46.	1,134		1,134
47.	1,148		1,148
48.	1,161		1,161
49.	1,175		1,175
50.	1,189		1,189
51.	1,202		1,202
52.	1,216		1,216
53.	1,230		1,230
54.	1,243		1,243
55.	1,257		1,257
56.	1,270		1,270
57.	1,284		1,284
58.	1,298		1,298
59.	1,311		1,311
60.	1,585		1,585
61.	1,598		1,598
62.	1,612		1,612
63.	1,626		1,626
64.	1,653		1,653
65.	1,667		1,667
66.	1,680		1,680
67.	1,694		1,694
68.	1,708		1,708
69.	1,708		1,708
70.	1,708		1,708
71.	1,708		1,708
72.	1,708		1,708

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
73.	1,708		1,708
74.	1,708		1,708
75.	1,708		1,708
76.	1,708		1,708
77.	1,708		1,708
78.	1,708		1,708
79.	1,708		1,708
80.	1,708		1,708
81.	1,708		1,708
82.	1,708		1,708
83.	1,708		1,708
84.	1,708		1,708
85.	1,721		1,721
86.	1,735		1,735
87.	1,749		1,749
88.	1,762		1,762
89.	1,776		1,776
90.	1,776		1,776
91.	1,858		1,858
92.	1,940		1,940
93.	1,967		1,967
94.	2,158		2,158
95.	2,158		2,158
96.	2,158		2,158
97.	2,158		2,158
98.	2,158		2,158
99.	2,158		2,158
100.	2,158		2,158
101.	2,158		2,158
102.	2,158		2,158
103.	2,158		2,158
104.	2,158		2,158
105.	2,158		2,158
106.	2,227		2,227
107.	2,227		2,227
108.	2,227		2,227
109.	2,227		2,227
110.	2,227		2,227
111.	765		765
112.	2,322		2,322
113.	779		779
114.	2,350		2,350
115.	888		888
116.	2,678		2,678
117.	2,951		2,951
118.	2,951		2,951
119.	2,951		2,951
120.	2,951		2,951
121.	2,951		2,951
122.	2,951		2,951
123.	2,951		2,951
124.	2,951		2,951
125.	2,951		2,951

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
126.	2,951		2,951
127.	2,951		2,951
128.	2,951		2,951
129.	2,951		2,951
130.	2,951		2,951
131.	2,951		2,951
132.	3,074		3,074
133.	3,087		3,087
134.	3,115		3,115
135.	3,265		3,265
136.	3,333		3,333
137.	3,333		3,333
138.	3,333		3,333
139.	3,333		3,333
140.	3,333		3,333
141.	3,333		3,333
142.	3,333		3,333
143.	3,333		3,333
144.	3,333		3,333
145.	3,333		3,333
146.	3,333		3,333
147.	3,333		3,333
148.	3,333		3,333
149.	3,333		3,333
150.	3,333		3,333
151.	3,333		3,333
152.	3,730		3,730
153.	3,770		3,770
154.	3,784		3,784
155.	3,798		3,798
156.	3,798		3,798
157.	3,825		3,825
158.	3,866		3,866
159.	3,866		3,866
160.	3,948		3,948
161.	3,975		3,975
162.	3,975		3,975
163.	3,975		3,975
164.	3,975		3,975
165.	3,989		3,989

Ontario apprenticeship training tax credit (total of amounts in column N) 500 308,425 **O**

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ____ % = ... ________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

TAXES OTHER THAN INCOME TAXES

1.0 INTRODUCTION

This schedule describes Hydro One's expenses related to taxes other than income and capital taxes. These taxes consist of various property taxes, including payments for the right to cross and/or occupy land not owned by Hydro One. Sections 2.0 and 3.0 present these taxes for the Transmission and Distribution lines of business, respectively.

For both Transmission and Distribution, the forecast property tax expenses and rights payments are generally higher than historical years, as the forecast years reflect higher tax rates, increases in the assessed value of Hydro One properties, and increasing land value.

2.0 TRANSMISSION TAXES

This section provides Hydro One's taxes (other than income and capital taxes) for the transmission business.

Table 1 summarizes transmission property tax and rights payments over the historical, bridge, and test years.

Table 1 - Taxes – Transmission ($M)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Property Tax*	58.1	54.3	59.1	61.0	61.9	62.9
Rights Payments	7.2	6.5	6.3	8.1	8.3	8.5
Total	**65.3**	**60.8**	**65.4**	**69.1**	**70.2**	**71.4**

** 2019 Property Tax include Proxy tax provision adjustment of ($4.6M) and 2020 property tax include credit of ($1.1M) in terms of refunds received as result of successful property tax appeals.*

2.1 PROPERTY TAXES

Like every other land owner in Ontario, Hydro One is responsible for the payment of property taxes. Property taxes for Hydro One are regulated under Ontario's *Electricity Act, 1998*, the *Municipal Act, 2001*, the *Assessment Act*, and the *Indian Act*. Property taxes are levied on Hydro One's land and buildings, including service centre sites, transmission stations and transmission lines. Hydro One pays property tax to 385 municipalities each year. The Municipal Property Assessment Corporation (MPAC) assigns the total assessed value, which is updated utilizing the same schedule as for the rest of the province.

Notices of assessment are received and reviewed for accurate valuation and tax classification each year. Any incorrect classes or over-valuations are appealed through the MPAC or the Assessment Review Board.

A Provincial reassessment was issued for 2017 tax year, which was based on a January 1, 2016 valuation date and also applied to the 2018–2020 taxation years inclusive. Under the *Assessment Act*, an increase in assessed value between the base valuation years of January 1, 2012 and January 1, 2016 was phased in over four years, from 2017-2020. Due to COVID-19, the Government of Ontario postponed the assessment update that had been planned for 2020. The Government has indicated that property assessments for the 2021 taxation year will continue to be based on the fully phased-in January 1, 2016 current values (i.e., the same valuation date in use for the 2020 taxation year).

Property taxes are also increasing due to rate increases on an annual basis due to financial pressures on municipalities and school boards.

A summary of annual transmission property taxes is presented in Table 2 below.

Table 2 - Breakdown of Total Property Tax Expense - Transmission ($M)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Stations and Buildings, including Proxy Tax *	21.0	16.4	23.6	23.0	23.9	24.9
Transmission Lines **	37.1	37.9	35.5	38.0	38.0	38.0
Total	**58.1**	**54.3**	**59.1**	**61.0**	**61.9**	**62.9**

** 2019 property tax include Proxy tax provision adjustment of ($4.6M) and*
***2020 property tax include credit of ($1.1M) in terms of refunds received as result of successful property tax appeals.*

The components of Table 2 are discussed in the subsections below.

2.1.1 TRANSMISSION STATIONS AND BUILDINGS

Property taxes for transmission stations and buildings are the product of two separate assessment methods: one for land and one for buildings. The lands containing the transmission stations are assessed by MPAC using the current value assessment (CVA) method - the valuation method used for other property owners within the province. Other Hydro One property (i.e., real property other than transmission lines and transmission stations), is assessed using only the CVA method.

Transmission stations buildings themselves are assessed at a statutory rate of $86.11 per square metre, pursuant to the *Assessment Act*. In addition to this statutory rate, transmission stations are subject to additional property tax payments called property “proxy taxes.” These amounts are payable to the Minister of Finance under Ontario Regulation 423/11 of the *Electricity Act, 1998*. The additional tax is the difference between the statutory rate for transmission station buildings and the municipal tax that would apply to the buildings if they were taxed using the CVA method. This amount is calculated each year for each transmission station owned by Hydro One.

Ontario Power Generation Inc. (OPG) is the owner of various properties within the province, on which Hydro One's facilities are located. OPG and Hydro One entered into lease and easement agreements with respect to these properties, effective April 1, 1999. Under these agreements, Hydro One is required to pay property taxes with respect to its occupancy to OPG.

Other municipal property tax costs relate to costs on other sundry properties, such as transmission communication towers, and administrative buildings.

2.1.2 TRANSMISSION LINES

Hydro One's transmission line corridors are assessed, and municipal taxes are calculated at a rate per acre of owned corridor land. These rates are established by Ontario Regulation 387/98 (Tax Matter – Taxation of Certain Railway, Power Utility Lands) made under the *Municipal Act, 2001* and Ontario Regulation 494/98 made under the *Education Act*, all as amended. As payments are made based on an area of land multiplied by a legislated rate, appeals must be based on corrections to the area of the property, or on the decision to re-classify a property as outside the utility corridor tax class.

An additional amount is paid annually to various First Nations bands for payment in lieu of taxes with respect to transmission assets on reserves. Since June 1985, Section 83 of the *Indian Act* has provided for taxation by First Nations of property interests on their reserve lands. Hydro One makes payments in lieu of taxes similar to taxes paid to municipalities that have Hydro One Transmission facilities within their boundaries.

2.2 TRANSMISSION RIGHTS PAYMENTS

In some circumstances, Hydro One must make payments in respect of its transmission lines and facilities that cross or occupy land not owned by the company. These payments are made under agreements with railway companies (e.g., Canadian Pacific, Canadian National) and governmental bodies (e.g., Ministry of Natural Resources, Metrolinx). Hydro One also makes payments in respect of its transmission assets that cross and/or occupy First Nations Reserves and other lands held for First Nations.

Hydro One pays annual fees to railway companies and government entities for the right for transmission assets to cross and/or occupy their properties. These payments are determined according to the terms of individual agreements governing the respective assets. The agreements contain rental review provisions allowing for rent increases tied to increased land values, subject to negotiation by both parties. Hydro One anticipates increased costs as reviews within the individual agreements are triggered, due to increases in land values. The payments under these agreements are forecast to be $5.7M in the 2023 test year.

Through agreements or permits granted by Indigenous Services Canada (ISC), Hydro One has approval for its transmission and distribution facilities (that is, lines and transformer and distribution stations), to cross and/or occupy First Nation Reserves. Some of these permits and agreements require Hydro One to pay annual rental fees. Payments are administered by ISC with the exception of First Nation Bands under the First Nation Land Management Act, in which case Hydro One compensates the First Nation Band directly.

The transfer orders by which Hydro One acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer title to some assets located on lands held for First Nations under the *Indian Act*. The transfer of title to these assets did not occur because authorizations originally granted by the federal Minister of Indigenous Services Canada for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant First Nations or, in several cases, because the authorizations had either expired or had never been properly issued. The transmission portion comprises of transmission lines, primarily, held by the Ontario Electricity Financial Corporation. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of them to Hydro One. Hydro One is seeking to obtain from the relevant First Nations, the consents necessary to complete the transfer of title to these assets. The First Nations rights payments for the 2023 test year are budgeted to be $2.8M.

3.0 DISTRIBUTION TAXES

This section provides Hydro One's taxes (other than income and capital taxes) for the distribution line of business.

Table 3 summarizes distribution property tax and rights payments over the historical, bridge, and test years.

Table 3 - Taxes - Distribution ($M)

Description	Historical				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Property Tax*	4.8	4.3	5.1	5.0	5.2	5.4
Rights Payment	0.3	0.3	0.3	0.6	0.6	0.6
Total	**5.1**	**4.6**	**5.4**	**5.6**	**5.8**	**6.0**

** 2019 Property Tax include Proxy tax provision adjustment ($0.3M).*

3.1 DISTRIBUTION PROPERTY TAX

Hydro One is responsible for the payment of property taxes similar to every other land owner within the province of Ontario. Property taxes for Hydro One are regulated under the *Electricity Act, 1998*, the *Municipal Act, 2001*, and the *Assessment Act*. Property taxes are paid on company-owned distribution lands and buildings including service centre sites, distribution transformer stations, and distribution lines. Hydro One Networks Inc. makes property tax payments to 385 municipalities each year.

The total assessed property values are assigned by the MPAC and are updated utilizing the same schedule as the rest of the province. Except for distribution transformer stations (described below), all distribution properties owned by Hydro One Networks Inc. are assessed using a CVA method – the valuation method used for other property owners within the province.

As described above in Section 2.1, property tax Notices of Assessment are received and reviewed for accurate valuation and tax classification each year. Any incorrect classes and overvaluations are appealed through MAPC or the Assessment Review Board.

Property taxes are also increasing due to rate increases on an annual basis due to financial pressures on municipalities and school boards.

Similar to transmission stations, property taxes for distribution transformer stations are the product of multiple taxes. Distribution transformer station buildings are assessed at a statutory rate of $86.11 per square meter, per the *Assessment Act*. Distribution transformer stations are subject to property proxy taxes, payable to the Minister of Finance under Ontario Regulation 423/11 of the *Electricity Act, 1998*. Property proxy taxes are calculated for each distribution transformer station building owned by Hydro One Networks Inc. and are included in the property tax amount. The lands containing the distribution stations are assessed using the current value assessment (CVA) method - the valuation method used for other property owners within the province. Other Hydro One property (i.e., real property other than distribution lines and distribution stations) is assessed using only the CVA method.

3.2 RIGHTS PAYMENTS DISTRIBUTION

Through agreements or permits, Hydro One Distribution line facilities cross and/or occupy properties owned by railway companies (e.g. Canadian Pacific, Canadian National) and/or governmental bodies (e.g., Ministry of Natural Resources, Metrolinx). Per the terms of the individual agreements, Hydro One Networks Inc. pays annual fees to the railway companies and the government entities for the right to cross or occupy their properties. Similar to Transmission rights payments Hydro One anticipates increased costs as negotiations with government bodies and railway companies and reviews within the individual agreements are triggered, mainly due to increases in land values.

REGULATORY APPLICATION COSTS

1.0 OVERVIEW

For this Application, Hydro One's regulatory costs are incurred and funded by the Regulatory Affairs Division. Hydro One's regulatory costs are not amortized over the application term, but instead are recovered in the year in which they are incurred based on a forecast.

Regulatory costs associated with the preparation of this Application began in 2020 and are expected to be incurred in 2021 and 2022. Appendix 2-M filed at Attachment 1 to this Exhibit includes actual and forecasted costs incurred by the Regulatory Affairs Division, including the costs to prepare this Application. A full description of the financial attributes of the Regulatory Affairs Division are found in Exhibit E-04-02. Legal costs of the Application are included in the budget of the General Counsel Department as outlined in Exhibit E-04-02.

2.0 DIRECT APPLICATION COSTS – TRANSMISSION & DISTRIBUTION

Actual and forecasted costs associated with this Application are presented in Table 1 for Transmission and Table 2 for Distribution.

Table 1 – Direct Application Cost – Transmission ($M)

Description	2020	2021	2022
Studies and Consultants	1.0	1.2	1.7
Legal	0.9	1.5	0.8
Intervenors and Hearings			0.7
Total	**1.9**	**2.7**	**3.2**

Table 2 – Direct Application Cost – Distribution ($M)

Description	2020	2021	2022
Studies and Consultants	1.2	0.8	1.0
Legal	1.0	1.5	0.7
Intervenors and Hearings			1.0
Total	**2.2**	**2.3**	**2.7**

3.0 TYPES OF APPLICATION COSTS

The expenditures for this Application include:

- Studies and Consultants: Hydro One undertook the studies listed in Exhibit A-02-04, most of which were necessary to address the OEB's directions in the 2018-2022 Distribution and 2020-2022 Transmission decisions. Amounts include the costs to complete the studies, to respond to interrogatories and undertaking and to provide expert testimony during the proceeding.
- Legal costs: External legal counsel was retained to assist with the Application.
- Intervenor and Hearings: Intevenor cost awards are included.

Hydro One resources and staff outside of the Regulatory Affairs division, including Hydro One staff, are not cited as a direct regulatory application cost.

Appendix 2-M Transmission
Regulatory Cost Schedule
($ thousands)

	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2020 OEB Approved)	Last Rebasing Year (2020 Actual)	Forecast Year 2021	Annual % Change	2022 Bridge Year	2023 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)=[(F)-(E)]/(E)	(H)	(I)	(J) = [(I)-(H)]/(H)
Regulatory Costs (Ongoing)										
1	OEB Annual Assessment			$ 2,358	$ 2,420	$ 2,445	1%	$ 2,494	$ 2,544	2.00%
2	OEB Section 30 Costs (OEB-initiated)			$ 30	$ 32	$ 24	-25%	$ 32	$ 86	168.75%
3	Expert Witness costs for regulatory matters			$ -	$ -	$ -		$ -	$ -	
4	Legal costs for regulatory matters			$ -	$ -	$ -		$ -	$ -	
5	Consultants' costs for regulatory matters			$ 14	$ 10	$ 96	863%	$ 110	$ 212	93.65%
6	Operating expenses associated with staff resources allocated to regulatory matters			$ 4,512	$ 4,038	$ 5,048	25%	$ 5,336	$ 5,648	5.84%
7	Operating expenses associated with other resources allocated to regulatory matters [1]			$ 67	$ 5	$ 153	2959%	$ 159	$ 191	19.87%
8	Other regulatory agency fees or assessments			$ 1,025	$ 1,377	$ 1,378	0%	$ 1,406	$ 1,434	1.99%
9	Any other costs for regulatory matters (please define)			$ 27	$ 10	$ 37	259%	$ 37	$ 37	1.59%
10	Intervenor costs									
Regulatory Costs (One-Time)										
11	Expert Witness costs									
12	Legal costs									
13	Consultants' costs			$ 254	$ 950	$ 1,224	29%	$ 1,674	$ 204	-87.81%
14	Incremental operating expenses associated with staff resources allocated to this application.									
15	Incremental operating expenses associated with other resources allocated to this application. [1]					$ 24		$ 29	$ 29	0.00%
16	Intervenor costs			$ 497	$ 225	$ 218	-3%	$ 303	$ 197	-34.98%
17	OEB Section 30 Costs (application-related)			$ 180	$ 95	$ 33	-65%	$ 47	$ 20	-57.26%
18	Timing Adjustments				450		-100%			
19	Sub-total - Ongoing Costs [2]		$ -	$ 8,034	$ 7,892	$ 9,181	16.32%	$ 9,573	$ 10,152	6.04%
20	Sub-total - One-time Costs [3]		$ -	$ 931	$ 1,720	$ 1,499	-12.83%	$ 2,053	$ 450	-78.08%
21	Total		$ -	$ 8,964	$ 9,612	$ 10,680	11.11%	$ 11,627	$ 10,602	-8.81%

Application-Related One-Time Costs	Total
Total One-Time Costs Related to Application to be Amortized over IRM Period	N/A
1/5 of Total One-Time Costs	N/A

Notes:

1 Please identify the resources involved.
2 Sum of all ongoing costs.
3 Sum of all one-time costs related to this application.

Appendix 2-M Distribution
Regulatory Cost Schedule
($ thousands)

	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actual)	Most Recent Year of Actuals 2020	Forecast Year 2021	Annual % Change	2022 Bridge Year	2023 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(I)=[(G)-(F)]/(F)	(H)	(I)	(J) = [(I)-(H)]/(H)
Regulatory Costs (Ongoing)											
1	OEB Annual Assessment			$ 5,899	$ 5,489	$ 5,588	$ 5,605	0%	$ 5,717	$ 5,831	1.99%
2	OEB Section 30 Costs (OEB-initiated)			$ 34	$ 35	$ 40	$ 36	-10%	$ 48	$ 129	168.75%
3	Expert Witness costs for regulatory matters			$ -	$ -	$ -	$ -		$ -	$ -	
4	Legal costs for regulatory matters			$ -	$ -	$ -	$ -		$ -	$ -	
5	Consultants' costs for regulatory matters			$ 52	$ 57	$ 11	$ 60	443%	$ 68	$ 132	93.65%
6	Operating expenses associated with staff resources allocated to regulatory matters			$ 4,185	$ 4,085	$ 4,175	$ 3,133	-25%	$ 3,312	$ 3,506	5.84%
7	Operating expenses associated with other resources allocated to regulatory matters [1]			$ 268	$ 350	$ 5	$ 156	3030%	$ 161	$ 182	12.92%
8	Other regulatory agency fees or assessments			$ -	$ -	$ -	$ -		$ -	$ -	
9	Any other costs for regulatory matters (please define)			$ 429	$ 24	$ 11	$ 23	116%	$ 23	$ 23	1.59%
10	Intervenor costs										
Regulatory Costs (One-Time)											
11	Expert Witness costs										
12	Legal costs										
13	Consultants' costs			$ 550	$ 660	$ 1,140	$ 760	-33%	$ 1,039	$ 127	-87.81%
14	Incremental operating expenses associated with staff resources allocated to this application.										
15	Incremental operating expenses associated with other resources allocated to this application. [1]						$ 15		$ 21	$ 18	-15.25%
16	Intervenor costs			$ 1,489		$ 88	$ 327	272%	$ 455	$ 295	-35.16%
17	OEB Section 30 Costs (application-related)			$ 270	$ 211	$ 108	$ 50	-54%	$ 70	$ 30	-57.26%
18	Include other items in green cells, as applicable										
19	Sub-total - Ongoing Costs [2]		$ -	$ 10,867	$ 10,039	$ 9,829	$ 9,013	-8.30%	$ 9,329	$ 9,803	5.07%
20	Sub-total - One-time Costs [3]		$ -	$ 2,309	$ 871	$ 1,336	$ 1,152	-13.81%	$ 1,586	$ 470	-70.38%
21	Total		$ -	$ 13,176	$ 10,910	$ 11,165	$ 10,165	-8.96%	$ 10,915	$ 10,273	-5.89%

Application-Related One-Time Costs	Total
Total One-Time Costs Related to Application to be Amortized over IRM Period	N/A
1/5 of Total One-Time Costs	N/A

Notes:

1 Please identify the resources involved.
2 Sum of all ongoing costs.
3 Sum of all one-time costs related to this application.

ONE TIME COSTS

Hydro One is not seeking recovery of any one-time costs, as described in section 2.8.7 of the Filing Requirements for Electricity Transmission Applications and section 2.4.3.4 of the Filing Requirements for Electricity Distributors.

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CHARITABLE AND POLITICAL DONATIONS

Hydro One confirms that neither charitable donations nor political donations have been included in this Application for recovery. Any charitable donations made by Hydro One are allocated to its non-regulated accounting segment, not Hydro One Transmission nor Hydro One Distribution.

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Z-FACTOR CLAIMS

Hydro One is not requesting a z-factor claim for its transmission or distribution businesses in this Application. Materiality thresholds for Z-factor claims are discussed in Exhibit A-04-01.

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