RATE BASE

1.0 INTRODUCTION

This exhibit outlines Hydro One's Transmission and Distribution rate base for the test years of 2023 to 2027, provides a detailed description of each rate base component and shows a comparison between the OEB approved 2020 amounts and historical actual figures and between 2022 OEB approved and 2022 forecast figures for Transmission and Distribution.

2.0 INTRODUCTION TO TRANSMISSION RATE BASE

The Transmission rate base underlying the 2021, 2022 (bridge year) and 2023-2027 (test years) revenue requirements includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are calculated as gross plant in service minus accumulated depreciation and minus contributed capital.[1] Working capital includes an allowance for cash working capital as well as materials and supply inventory.

3.0 COMPARISON OF ACTUAL/FORECAST TRANSMISSION RATE BASE TO OEB APPROVED

Table 1 below compares 2020 figures to the 2020 rate base approved by the OEB in its Decision on Hydro One Transmission's 2020 to 2022 revenue requirement application in EB-2019-0082. Any underspending between actual and OEB approved in-service additions is tracked and recorded in the Capital In-Service Variance Account (CISVA) to ensure ratepayers are kept rate neutral. For Transmission, no amounts were recorded in this account in 2020 as actual in-service additions of $944M were greater than OEB approved of $931M.

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[1] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g., Joint Use Assets (Customer Contributions).

Table 1 - 2020 OEB-approved versus 2020 Historical Year Rate Base ($M)

Rate Base Component	2020 Actuals	2020 OEB-approved	Variance
Mid-Year Gross Plant	19,531.6	19,474.1	57.4
Less: Mid-Year Accumulated Depreciation	(7,175.9)	(7,150.5)	(25.4)
Mid-Year Net Utility Plant	**12,355.7**	**12,323.6**	**32.0**
Cash Working Capital	24.1	24.1	0
Materials & Supply Inventory	12.0	12.0	0
Total Rate Base	**12,391.8**	**12,359.6**	**32.0**

Actual Transmission rate base in 2020 is consistent with the OEB-approved total, as it is within 0.3% of the OEB-approved amount. For further details on actuals, refer to the supporting continuity schedules provided in Exhibit C-04-02 and Exhibit C-04-03.

Table 2 - 2022 OEB-approved versus 2022 Forecast Year Rate Base ($M)

Rate Base Component	2022 Forecast	2022 OEB-approved	Variance
Mid-Year Gross Plant	21,597.7	21,545.1	52.6
Less: Mid-Year Accumulated Depreciation	(7,941.4)	(7,943.9)	2.5
Mid-Year Net Utility Plant	**13,656.3**	**13,601.2**	**55.1**
Cash Working Capital	24.1	27.3	(3.2)
Materials & Supply Inventory	13.9	12.4	1.5
Total Rate Base	**13,694.2**	**13,640.9**	**53.3**

As shown in Table 2 above, the forecast for 2022 rate base is within 0.4% of the OEB-approved amount, resulting in consistent opening rate base in the 2023 test year relative to expectations in the last rate filing period.

4.0 TRANSMISSION UTILITY RATE BASE FORECAST

Utility rate base for the transmission system for the test years is filed at Exhibit C-04-01. The calculation of net utility plant is provided in Exhibits C-04-02 and C-04-03.

Hydro One Transmission's forecast rate base for the years 2021-2027 is shown in Table 3.

Table 3 - Transmission Rate Base ($M)

Description	Historical	Bridge	Test				
	2021 (Forecast)	2022	2023	2024	2025	2026	2027
Mid-Year Gross Plant	20,451.3	21,597.7	22,912.6	24,196.7	25,649.9	27,078.4	28,459.2
Mid-Year Accumulated Depreciation	(7,543.1)	(7,941.4)	(8,351.9)	(8,780.2)	(9,234.8)	(9,719.2)	(10,238.3)
Mid-Year Net Plant	**12,908.2**	**13,656.3**	**14,560.7**	**15,416.5**	**16,415.2**	**17,359.1**	**18,220.9**
Cash Working Capital	22.8	24.1	17.8	19.3	18.9	19.9	19.9
Mid-Year Materials and Supply Inventory	13.4	13.9	14.1	14.4	14.7	15.0	15.3
Transmission Rate Base	**12,944.4**	**13,694.2**	**14,592.7**	**15,450.3**	**16,448.9**	**17,394.1**	**18,256.2**
Year over year % change		5.8%	6.6%	5.9%	6.5%	5.7%	5.0%

The mid-year gross plant balance reflects the in-service additions forecast for the 2021 historical year (on a forecast basis), 2022 bridge year and 2023-2027 test years as outlined in Exhibit C-02-01.

Table 4 below provides historical and bridge year continuity of total fixed assets. The growth in gross plant primarily reflects the in-service additions made to Hydro One Transmission's rate base during the period from 2018 to 2022. Cumulatively over the 2020-2022 period, actual and forecast in-service additions of $3,332M are approximately $83M greater than OEB approved in-service additions over the same period of $3,249M, showing material alignment of envelope investments, with some annual variances in scope and timing of a limited number of investments as further described in Exhibit C-02-01.

Table 4 - Continuity of Transmission Fixed Assets Summary ($M)

Description	Historical Years and Bridge Year				
	2018	**2019**	**2020**	**2021**	**2022**
Opening Gross Asset Balance	17,076.7	18,185.0	19,093.7	19,969.4	20,933.2
In-Service Additions	1,135.6	959.5	944.3	1,006.0	1,381.6
Retirements	(10.9)	(59.7)	(59.9)	(51.1)	(53.8)
Sales	(15.9)	(6.9)	(15.5)	0.0	0.0
Transfers /Other	(0.5)	15.8	6.8	9.0	1.0
Closing Gross Asset Balance	**18,185.0**	**19,093.7**	**19,969.4**	**20,933.2**	**22,262.1**

Table 5 provides the forecast continuity of total fixed assets for the test years.

Table 5 - Forecast of Transmission Fixed Assets Summary ($M)

Description	Test				
	2023	**2024**	**2025**	**2026**	**2027**
Opening Gross Asset Balance	22,262.1	23,563.1	24,830.2	26,469.6	27,687.1
In-Service Additions	1,368.1	1,332.4	1,710.3	1,280.3	1,599.8
Retirements	(68.1)	(66.4)	(72.0)	(63.9)	(56.8)
Sales	0.0	0.0	0.0	0.0	0.0
Transfers /Other	1.0	1.0	1.1	1.1	1.1
Closing Gross Asset Balance	**23,563.1**	**24,830.2**	**26,469.6**	**27,687.1**	**29,231.2**

In-service additions reflect Hydro One Transmission's capital programs and projects coming into service and are discussed in Exhibit C-02-01.

The retirement of assets over the test years include transmission plant equipment, computer software, and other general plant equipment. Transfers/Other over the period reflect movement between the strategic spares inventory and fixed assets.

5.0 TRANSMISSION CASH WORKING CAPITAL

In 2020, Hydro One Transmission retained Guidehouse Inc. to undertake a lead-lag study. The results of the new study and the provision for working capital for the 2023 to 2027 test years have been incorporated into the amounts shown below.

The cash working capital requirement for the transmission system includes the following factors:

- the forecast of OM&A;
- capital and income taxes; and
- the net lead-lag days determined.

The application of the methodology from the lead-lag study results in a net cash working capital requirement including the impact of HST, as shown in Attachment 1 of Exhibit C-05-01 and Exhibit C-05-02.

6.0 TRANSMISSION MATERIALS AND SUPPLY INVENTORY

In addition to cash working capital, the other component of working capital is materials and supply inventory. Materials and supply inventory is discussed in further detail in Exhibit C-06-01.

7.0 INTRODUCTION TO DISTRIBUTION RATE BASE

The Distribution rate base underlying the 2021, 2022 (bridge year) and 2023-2027 (test years) revenue requirements includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are calculated as gross plant in service minus accumulated depreciation and minus contributed capital. Working capital includes an allowance for cash working capital as well as materials and supply inventory.

8.0 COMPARISON OF ACTUAL/FORECAST DISTRIBUTION RATE BASE TO OEB APPROVED

Table 6 below compares 2020 values to the 2020 rate base approved by the OEB in its Decision on Hydro One’s 2018 to 2022 Distribution rate application in EB-2017-0049. Any underspending between actual and OEB approved in-service additions are tracked and recorded in the CISVA to ensure ratepayers are kept rate neutral. For Distribution, no amounts were recorded into this account between the years 2018-2020 as actual in-service additions were in line with OEB approved in-service additions. Cumulatively over the 2018-2022 period, actual and forecast in-service additions of $3,237M are approximately $61M greater than OEB approved in-service additions of $3,177M, showing material alignment with envelope investments over the period. Increases are further detailed in Exhibit C-02-02, and primarily relate to increased investments for customer driven requests with specific obligations that Hydro One was required to meet.

Table 6 - 2020 OEB-approved versus 2020 Historical Year Rate Base ($M)

Rate Base Component	2020 Actuals	2020 OEB-approved	Variance
Mid-Year Gross Plant	12,780.9	12,924.5	(143.6)
Less: Mid-Year Accumulated Depreciation	(4,906.8)	(5,062.1)	155.3
Mid-Year Net Utility Plant	**7,874.1**	**7,862.4**	**11.7**
Cash Working Capital	306.4	306.4	0
Materials & Supply Inventory	6.5	6.5	0
Total Rate Base	**8,187.0**	**8,175.3**	**11.7**

Actual rate base in 2020 is consistent with the OEB-approved total, as it is within 0.1% of the OEB-approved amount. For further details on actuals, refer to the supporting continuity schedules provided in Exhibit C-04-02 and Exhibit C-04-03.

Table 7 - 2022 OEB-approved versus 2022 Forecast Year Rate Base ($M)

Rate Base Component	2022 Forecast	2022 OEB-approved	Variance
Mid-Year Gross Plant	13,941.7	14,152.7	(211.0)
Less: Mid-Year Accumulated Depreciation	(5,411.5)	(5,692.6)	281.1
Mid-Year Net Utility Plant	**8,530.2**	**8,460.0**	**70.2**
Cash Working Capital	308.4	338.2	(29.8)
Materials & Supply Inventory	5.9	5.5	0.4
Total Rate Base	**8,844.5**	**8,803.7**	**40.8**

As shown in Table 7 above, the forecast for 2022 rate base is 0.5% within the OEB-approved amount, resulting in materially consistent opening rate base in the 2023 test year relative to expectations in the last rate filing period.

9.0 DISTRIBUTION UTILITY RATE BASE FORECAST

Utility rate base for the distribution system for the test years is filed at Exhibit C-04-01. The calculation of net utility plant is provided in Exhibits C-04-02 and C-04-03.

Hydro One Distribution’s forecast rate base for the test years 2021-2027 is shown in Table 8.

Table 8 - Distribution Rate Base ($M)[2]

Description	Historical	Bridge	Test				
	2021 (Forecast)	2022	2023	2024	2025	2026	2027
Mid-Year Gross Plant	13,374.6	13,941.7	14,813.3	15,634.2	16,557.7	17,494.9	18,396.2
Mid-Year Accumulated Depreciation	(5,150.4)	(5,411.5)	(5,690.8)	(5,923.7)	(6,171.4)	(6,451.2)	(6,776.8)
Mid-Year Net Plant	**8,224.2**	**8,530.2**	**9,122.5**	**9,710.5**	**10,386.3**	**11,043.8**	**11,619.5**
Cash Working Capital	297.9	308.4	243.4	246.3	248.7	251.6	254.5
Mid-Year Materials and Supply Inventory	5.6	5.9	6.0	6.1	6.2	6.4	6.5
Distribution Rate Base	**8,527.7**	**8,844.5**	**9,372.0**	**9,962.9**	**10,641.2**	**11,301.8**	**11,880.5**
Year-over-year change %		3.7%	6.0%	6.3%	6.8%	6.2%	5.1%

The mid-year gross plant balance reflects the in-service additions forecast for the 2021 historical year (on a forecast basis), 2022 bridge year and 2023-2027 test years as outlined in Exhibit C-02-02.

Table 9 below provides historical and bridge year continuity of total fixed assets. The growth in gross plant primarily reflects the in-service additions made to Hydro One Distribution’s rate base during the period from 2018 to 2022.

[2] 2023-2027 figures are presented on a combined basis including Acquired Utilities

Table 9 - Continuity of Fixed Assets Summary ($M)

Description	Historical Years and Bridge Year				
	2018	2019	2020	2021	2022
Opening Gross Asset Balance	11,624.1	12,028.9	12,549.5	13,150.9	13,741.6
In-Service Additions	627.8	585.1	668.1	700.1	656.4
Retirements	(181.8)	(60.2)	(56.8)	(116.2)	(108.3)
Sales	(36.1)	(13.6)	(16.7)	0.0	0.0
Transfers/Other	(5.1)	9.2	6.9	6.8	0.8
Closing Gross Asset Balance	**12,028.9**	**12,549.5**	**13,150.9**	**13,741.6**	**14,290.5**
Less Provincial Funded Assets	(64.5)	(68.9)	(69.6)	(73.7)	(75.0)
Gross Asset Balance for Mid-Year Base	**11,964.4**	**12,480.5**	**13,081.3**	**13,667.9**	**14,215.5**

Table 10 provides the forecast continuity of total fixed assets for the test years.

Table 10 - Forecast of Fixed Assets Summary ($M)[3]

Description	Test				
	2023	2024	2025	2026	2027
Opening Gross Asset Balance	14,490.3	15,288.4	16,136.0	17,138.5	18,012.8
In-Service Additions	970.9	1,027.3	1,203.4	1,061.2	1,107.8
Retirements	(173.7)	(180.6)	(201.8)	(187.9)	(178.1)
Sales	0.0	0.0	0.0	0.0	0.0
Transfers/Other	0.9	0.9	0.9	0.9	0.9
Closing Gross Asset Balance	**15,288.4**	**16,136.0**	**17,138.5**	**18,012.7**	**18,943.3**
Less Provincial Funded Assets	(77.0)	(78.9)	(80.1)	(81.2)	(82.4)
Gross Asset Balance for Mid-Year Base	**15,211.4**	**16,057.0**	**17,058.4**	**17,931.5**	**18,861.0**

In-service additions reflect the Hydro One's Distribution capital programs and projects coming into service and are discussed in Exhibit C-02-02.

The retirement of assets over the test years include distribution plant equipment, computer software, and other general plant equipment. Transfers/Other over the period reflect movement between the strategic spares inventory and fixed assets.

[3] 2023-2027 figures are presented on a combined basis including Acquired Utilities

10.0 DISTRIBUTION CASH WORKING CAPITAL

In 2020, Hydro One Distribution retained Guidehouse Inc. to undertake a lead-lag study. The results of the new study and the provision for working capital for the 2023 to 2027 test years are incorporated.

The cash working capital requirement for the distribution system includes the following factors:

- the forecast of OM&A;
- the forecast of Cost of Power;
- capital and income taxes; and
- the net lead-lag days determined.

The application of the methodology from the lead-lag study results in a net cash working capital requirement including the impact of HST, as shown in Attachment 2 of Exhibit C-05-01 and Exhibit C-05-02.

11.0 DISTRIBUTION MATERIALS AND SUPPLY INVENTORY

In addition to cash working capital, the other component of working capital is materials and supply inventory. Materials and supply inventory is discussed in further detail in Exhibit C-06-01.

TRANSMISSION IN-SERVICE ADDITIONS

1.0 INTRODUCTION

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready to be used to serve Hydro One Transmission customers. In-service addition amounts vary from capital expenditure amounts due to the multi-year nature of capital projects.

Hydro One's in-service addition plan is developed by combining the best forecast available for all projects within its transmission portfolio that have assets planned to be ready for service during the test years. Projects in execution can encounter challenges during execution such as outage constraints, external approvals, material delivery, site conditions, evolving customer needs, changing priorities and emergent investments. These project challenges may result in changes to the timing of in-service additions.

Table 1 provides an overview of Hydro One Transmission's in-service additions over the 2018 to 2027 period, which includes historical, bridge and forecast years.

Table 1 - In-Service Capital Additions 2018 – 2027 ($M)

	Historical								Bridge		Forecast Period				
	2018		2019		2020		2021		2022		2023	2024	2025	2026	2027
OEB Category	**OEB Appr.**	**Actuals**	**OEB Appr.**	**Actuals**	**OEB Appr.**	**Actuals**	**OEB Appr.**	**Forecast**	**OEB Appr.**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
System Access	68.2	12.1	-	72.6	8.6	7.2	13.8	15.1	52.3	43.6	73.0	48.9	60.7	63.2	38.9
System Renewal	761.4	852.3	-	744.8	821.3	824.5	735.9	653.7	1,031.0	895.3	1,128.7	1,172.3	1,418.6	1,092.6	1,402.9
System Service	244.8	218.0	-	45.5	54.2	32.6	235.7	180.7	182.0	386.6	58.9	20.6	163.7	71.9	99.2
General Plant	104.0	77.9	-	96.6	75.1	79.9	134.5	156.3	82.5	80.1	162.1	151.6	128.4	113.7	119.8
Subtotal before Adjustments	**1,178.4**	**1,160.4**	**-**	**959.5**	**959.2**	**944.3**	**1,119.8**	**1,005.9**	**1,347.8**	**1,405.7**	**1,422.7**	**1,393.4**	**1,771.3**	**1,341.3**	**1,660.8**
Progressive Productivity[1]	-	-	-	-	-15.8	-	-36.3	-	-56.7	-24.1	-54.6	-61.0	-61.0	-61.0	-61.0
Other[2]	-	-	-	-	-12.9	-	-27.3	-	-28.8	-	-	-	-	-	-
Grand Total	**1,178.4**	**1,160.4**	**-**	**959.5**	**930.5**	**944.3**	**1,056.2**	**1,005.9**	**1,262.2**	**1,381.6**	**1,368.1**	**1,332.4**	**1,710.3**	**1,280.3**	**1,599.8**

[1] Progressive productivity represents commitments made during the 2020-22 transmission rate application that are sustained through the JRAP. Incremental productivity reductions for JRAP are applied to revenue requirement via productivity stretch factors, as described within the SPF Section 1.4.
[2] OEB Approved includes OPEB, pension and compensation directive adjustments

Over the 2020-2022 period, Hydro One anticipates placing in-service approximately $83M more capital than the cumulative total of $3,249M approved by the Ontario Energy Board (OEB) for the 2020-2022 period. During the current rate period, 2020-2022, variances to annual approved totals are largely as a result of the updated scope and timing of a limited number of material investments, which have been delayed by one year, based on factors external to Hydro One.

Overall, 2020 in-service additions were within 1.5% of the OEB approved total ($930.5M OEB Approved versus $944.3M actuals). This result was achieved despite the challenges posed by the COVID-19 Pandemic, which impacted work methods by requiring Hydro One to implement new health and safety protocols, and availability of system outages. Further details and variance explanations regarding 2020 performance are available in the Transmission Capital Performance Report, which is discussed in TSP Section 2.9 Attachment 2.

For 2021, Hydro One forecasts lower than OEB approved in-service additions largely as a result of the timing of System Service investments, including an updated schedule provided by NextBridge for the East-West Tie (ISD SS-03 as part of EB-2019-0082) and the integration of Watay's transmission line into the provincial transmission network (ISD SS-04 as part of EB-2019-0082). The change in schedule for these two projects accounts for approximately $100M of System Service investments which are now planned to be completed in 2022, rather than 2021. Further, the complexity of Lakeshore TS, originally presented as part of Leamington Area Transmission Reinforcements (ISD SS-13 as part of EB-2019-0082), has increased as result of IESO recommendations and increased technical requirements. This has resulted in a further $100M variance to the 2022 approved in-service additions. As a result of these increases to System Service in-service additions, the pace of System Renewal in-service additions had to be revised lower to manage within OEB approved levels, resulting in a cumulative variance over the 2020-2022 period of approximately 3%.

The 2023-27 in-service additions are expected to increase based on the capital expenditures discussed in TSP Section 2.8. The drivers of the TSP investments are included in Section 2.2

through Section 2.6. Hydro One is committed to achieving its forecast in-service capital additions at a portfolio level over the test years by using and continuing to improve its project delivery model. Hydro One's capital work execution strategy is described in detail in TSP Section 2.10, which outlines how Hydro One intends to accomplish the forecast level of in-service additions.

2.0 PERFORMANCE ANALYSIS - 2020

The Transmission Capital Performance Report provides an overview of Hydro One's performance in 2020 in relation to the overall transmission capital envelope, as well as, performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) in 2020, and demonstrates that Hydro One has delivered its capital plan both in terms of expenditures and in-service additions. The report is found at TSP Section 2.9, Attachment 2.

3.0 IN-SERVICE ADDITIONS 2023 TO 2027

Over the test period of 2023-2027, Hydro One Transmission forecasts average annual capital in-service additions of $1,458M per year.[3] This represents an increase of 16% compared to the 2022 OEB Approved amount and is based on Hydro One's proposed capital investments as discussed in TSP Section 2.8. All investments with spending greater than $3M per year are described in more detail in the Investment Summary Documents (ISDs) found in TSP Section 2.11.

System Access in-service additions are projected to average $56.9M per year over the test period and will vary from year-to-year, due to the external and customer driven nature of these investments. Material in-service additions include New Customer Connection Stations (TSP Section 2.11 T-SA-01), IAMGOLD – 115kV Mine Connection (TSP Section 2.11 T-SA-02),

[3] Average 2023-2027 ISA = (1,368.10 + 1,332.40 + 1,710.30 + 1,280.30 + 1,599.80)/5

Secondary Land Use Projects (TSP Section 2.11 T-SA-07), and Leamington Area Transformer Stations (TSP Section 2.11 T-SA-10).

System Service in-service additions are projected to average $82.9M per year over the test period and will vary from year-to-year, due to the timing and needs identified by the IESO for large, enhancement projects. Material in-service additions include reinforcement in Southwest Ontario (TSP Section 2.11 T-SS-07, T-SS-09), and the Greater Toronto Area (TSP Section 2.11 T-SS-04, T-SS-06), and further described in TSP Section 2.8 and 2.11.

System Renewal in-service additions are projected to average $1,243M per year over the test period due to ongoing reinvestment in assets that are in poor condition, have substandard performance or are obsolete. Investments with material in-service additions greater than $100M have been summarized in Table 2 below and further described in TSP Section 2.8 and 2.11.

Table 2 - 2023-2027 - Material In-Service Additions ($M)

ISD	Description	In-Service Additions
T-SR-01.24	Station Renewal - Network Stations - Merivale TS	168.4
T-SR-02.09	Station Renewal - Air Blast Circuit Breakers - Bruce A	239.5
T-SR-04	Wood Pole Structure Replacements	292.9
T-SR-05	Steel Structure Coating Program	121.8
T-SR-08	Transmission Line Insulator Replacement	396.0
T-SR-09	Station Demand and Spares and Targeted Assets	224.5
T-SR-11	Legacy SONET System Replacement	125.6
T-SR-13.5	Line Refurbishment - T33E	148.8
T-SR-18	C5E/C7E Underground Cable Replacement	108.2

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DISTRIBUTION – IN-SERVICE ADDITIONS

1.0 INTRODUCTION

In-service additions (ISAs) represent increases to rate base as a result of capital work being declared in-service and ready for use to serve Hydro One Distribution customers. The annual in-service additions vary from annual capital expenditures due to the multi-year nature of capital projects with defined in-service dates.

Hydro One Distribution's ISA plan is developed by combining the best forecast available for all distribution projects and programs that have assets planned for capitalization during the test years. It is not uncommon for projects to encounter challenges during the execution stage such as outage constraints, external approvals, material delivery, site conditions, evolving customer needs, changing priorities and emergent investments. These challenges may result in changes to the timing of in-service additions.

Table 1 provides an overview of Hydro One Distribution's in-service additions over the 2018 to 2027 period, which includes historical (2018-2021), bridge (2022), and the forecasting period (2023-2027).

Table 1 - In-Service Capital Additions 2018 – 2027 ($M)

OEB Category	2018		2019		2020		2021		2022		2023	2024	2025	2026	2027
	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	Actuals	OEB Approved	Forecast	OEB Approved	Bridge	Forecasting Period				
1. System Access	196.9	196.9	147.7	189.9	144.7	197.5	160.8	182.7	143.1	181.2	239.6	241.8	227.5	212.5	204.1
2. System Renewal	229.6	229.6	223.3	201.9	225.3	217.8	241.9	248.7	251.2	225.5	355.2	425.6	504.4	476.3	507.3
3. System Service	113.9	113.9	81.6	89.2	170.9	97.3	138.8	70.8	112.4	137.7	226.3	148.8	251.2	200.9	195.1
Subtotal Categories 1, 2, and 3	**540.4**	**540.4**	**452.6**	**481.1**	**540.9**	**512.6**	**541.4**	**502.2**	**506.7**	**544.4**	**821.0**	**816.2**	**983.1**	**889.7**	**906.5**
4. General Plant Allocated to Distribution	87.4	87.4	103.9	104.1	135.9	155.5	164.1	197.9	103.4	112.0	149.9	211.1	220.4	171.5	201.2
Grand Total	**627.8**	**627.8**	**556.5**	**585.1**	**676.8**	**668.1**	**705.5**	**700.1**	**610.1**	**656.4**	**970.9**	**1,027.3**	**1,203.4**	**1,061.2**	**1,107.8**

Over 2019 and 2020, Hydro One placed $1,253.2M[1] of incremental capital into service, which is within 1.6% of the OEB-approved plan total for those years. Section 2.0 summarizes Hydro One Distribution's in-service additions in the historical years, with further details regarding capital investments and associated variances in 2019 and 2020 outlined in the Capital Program Performance Report (DSP Section 3.9, Attachment 2).

During the 2021 forecast and 2022 bridge years, in-service additions are expected to be $1,356.5M. In 2021, a total of $700.1M is forecasted which is slightly lower than plan by $5.4M. In 2022, in-service additions is forecasted to be $46.2M higher than plan, with the annual forecast set at $656.4M. The variance between the current plan and forecast in 2022 is largely the result of increased investment within New Load Connections, Service Upgrades, Cancellations and Metering (ISD SA-04 as part of EB-2017-0049) to align with historical volumes, capital contributions and expenditures. In addition, an increased focus on the Worst Performing Feeders Program (ISD-SS-06 as part of EB-2017-0049) initiatives in 2022 represents $10M of the variance as the organization remains focused on improving reliability.

Over the test period (2023-2027), ISAs for these years are expected to total $5,370.7M, an average of $1,074.1M per year, which represents an increase when compared to assets historically in-serviced within the portfolio. This includes increased investment within the System Service category and is driven by investments that support reliability-focused initiatives, or are required to address capacity or operational constraints because of customer connections. System Renewal investments are also contributing to increased in-service requirements over the test period due to the accumulation of deteriorating assets within the distribution system. As outlined in Distribution Capital Work Execution Strategy (DSP Section 3.10), Hydro One expects to achieve forecasted in-service additions at the portfolio level by continuing to be adaptive to the non-discretionary nature of distribution work programs and maintaining portfolio level governance over the execution of the capital work programs and projects.

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[1] This includes the Distribution allocation of General Plant as shown in Table 1.

2.0 PERFORMANCE ANALYSIS 2019-2020

As described in the DSP Section 3.10, an investment plan must be executed in a manner that is flexible enough to respond to changing and unforeseen circumstances. This is due to the dynamic nature of Distribution's demand work programs that require periodic and ongoing assessment of priorities and timing for all programs and projects. Capital projects also experience changing conditions that must be managed during all phases of the project lifecycle. These changes are experienced in the form of project logistics and schedule delays, prudent cost or scope increases, or a valid redirection of projects to address new risks related to development, compliance or anticipated expenditures associated with equipment failures. Although these changes can have an impact on an individual project's in-service addition forecast, Hydro One makes tactical adjustments to minimize the overall impact to the Distribution portfolio. The Distribution Capital Performance Report (DSP Section 3.9, Attachment 2) provides an overview of Hydro One's performance in 2019 and 2020 in relation to the overall distribution capital envelope, as well as, performance of individual projects and programs. It addresses both capital expenditures and ISAs in 2019 and 2020, and demonstrates that Hydro One has delivered its capital plan both in terms of expenditures and in-service additions.

2.1 2019 IN-SERVICE ADDITION VARIANCES

In 2019, Hydro One Distribution's in-service additions exceeded the approved budget by $28.6M, or approximately 5%, as shown in Table 2.

Table 2 - OEB Category Performance (2019)

OEB Category	In-Service Additions 2019		
	DRO Plan	Actuals	Variance
1. System Access	147.7	189.9	**29%**
2. System Renewal	223.3	201.9	**-10%**
3. System Service	81.6	89.2	**9%**
Subtotal Categories 1, 2, and 3	**452.6**	**481.1**	**6%**
4. General Plant Allocated to Distribution	103.9	104.1	**0%**
Grand Total	**556.5**	**585.1**	**5%**

The largest variances over plan in 2019 were within the System Access and System Service categories, totalling an overage compared to plan of approximately $49.9M. The increased investment and associated in-service additions was driven by customer requests with specific obligations that Hydro One was required to meet. As this work was considered non-discretionary in nature there were no alternatives to the investment. The main drivers of this overage compared to the approved category plan was increased complexity of New Load Connections, Service Upgrades, Cancellations and Metering (ISD SA-04 as part of EB-2017-0049) work as well as the influx in demand of Joint Use and Line Relocations Program (ISD SA-01 as part of EB-2017-0049) requests and Distribution Lines Trouble Call and Storm Damage Response Program (ISD SR-07 as part of EB-2017-0049) requirements. This was partially offset by reductions within System Renewal, specifically the Pole Replacement Program (ISD SR-09 as part of EB-2017-0049). Further details regarding 2019 variances can be found in the Capital Program Performance Report (DSP Section 3.9, Attachment 2).

2.2 2020 IN-SERVICE ADDITION VARIANCES

In 2020, Hydro One Distribution capital in-service additions was below plan by $8.8M, or approximately 1%, as shown in Table 3.

Table 3 - OEB Category Performance (2020)

OEB Category	In-Service Additions 2020 DRO Plan	Actuals	Variance
1. System Access	144.7	197.5	**36%**
2. System Renewal	225.3	217.8	**-3%**
3. System Service	170.9	97.3	**-43%**
Subtotal Categories 1, 2, and 3	**540.9**	**512.6**	**-5%**
4. General Plant Allocated to Distribution	135.9	155.5	**14%**
Grand Total	**676.8**	**668.1**	**-1%**

Similar to 2019, Distribution increased investment in System Access category primarily driven by increases in demand in the New Load Connections, Service Upgrades, Cancellations and Metering (ISD SA-04 as part of EB-2017-0049) and Joint Use and Line Relocations Program (ISD SA-01 as part of EB-2017-0049). This was partially offset by lower than planned in-service additions in the Pole Replacement Program (ISD SR-09 as part of EB-2017-0049). Further details regarding 2020 variances can be found in the Capital Program Performance Report (DSP Section 3.9, Attachment 2).

Hydro One Distribution assets placed in-service increased by $83M or 14% in 2020 compared to 2019 primarily due to the following:

- substantial completion of the Leamington transmission station feeder development project in 2020;
- higher volume of storm related asset replacements; and
- increased expenditures within New Load Connections, Service Upgrades, Cancellations and Metering (ISD SA-04 as part of EB-2017-0049) and Joint Use and Line Relocations Program (ISD SA-01 as part of EB-2017-0049);
- partially offset by lower volume of distribution station refurbishment work and equipment replacements.

3.0 IN-SERVICE ADDITIONS 2023 TO 2027

Over the 2023–2027 Test Period, Hydro One Distribution forecasts total capital in-service additions to be $5,370.7M, an average of $1,074.1M per year. The 2023 Test Year represents an increase of 59% compared to the 2022 OEB Approved and is based on Hydro One's investment plan as discussed in DSP Section 3.8. All investments with spending greater than $1M per year are described in more detail in the Investment Summary Documents (ISDs) found in DSP Section 3.11.

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

System Renewal ISAs are projected to average $453.8M annually from 2023 to 2027, which is higher than the average of $224.7M between years 2018 through 2022. An increased focus on the Pole Sustainment Program (DSP Section 3.11, D-SR-07) program and the Advanced Meter Infrastructure 2.0 investment (DSP Section 3.11, D-SR-12) to replace Hydro One's legacy !MI 1.0 system represent the largest contributors to the in-service addition change compared to previous years.

System Service ISAs are projected to average $204.5M annually from 2023 to 2027. Increased expenditures to support investments required for Worst Performing Feeders (DSP Section 3.11, D-SS-05), Energy Storage Solution (DSP Section 3.11, D-SS-04) projects as well as significant investment within the Windsor-Essex region to address distribution system requirements to meet the increased demand for connections are the largest contributors to in-service addition requirements.

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SHARED ASSET ALLOCATION

1.0 INTRODUCTION

Hydro One Networks, including its Transmission and Distribution businesses, provides customers with value for money by operating in a coordinated manner together with its affiliates so as to maximize efficiencies through centralization of the maintenance, management and purchase of Common Fixed Assets (Shared Assets).[1]

Shared Assets include fixed assets, such as land and buildings, telecommunications equipment, computer equipment, tools, and transportation and work equipment (T&WE), as well as intangible assets such as applications software, which are held by Hydro One Networks and used for the shared benefit of its Transmission and Distribution businesses, as well as affiliates.

Hydro One is committed to ensuring its transmission revenue requirement reflects only the cost of investments in transmission-related assets, including an appropriate share of the cost of investments in Shared Assets that are used for providing transmission service. Similarly, Hydro One is committed to ensuring that its distribution customers are only asked to pay for the cost of investments in distribution-related assets, including an appropriate share of the cost of investments in Shared Assets that are used for providing distribution service.

This Exhibit describes the nature of Hydro One's Shared Assets and the methodology by which it allocates the costs of these assets to the Transmission and Distribution business units, and among affiliates, for purposes of determining its proposed Transmission and Distribution revenue requirements, and explains how transfer pricing is used to account for the use of Shared Assets by Hydro One affiliates in accordance with the OEB's *Affiliate Relationships Code for Electricity Distributors and Transmitters* (ARC).

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[1] For reference, a corporate organizational chart is provided in Attachment 1 of Exhibit A-05-01.

In its most recent Transmission and Distribution decisions, the OEB signalled its intention to undertake detailed reviews of certain allocation methodologies used by Hydro One, including that which it uses to allocate Shared Assets.[2] Hydro One therefore undertook a competitive RFP process to select an appropriate vendor to undertake detailed assessments of its Common Corporate Cost Allocation Methodology, Overhead Capitalization Methodology, and allocation of Shared Assets. Though open to engaging a new expert, after evaluating multiple proposals Hydro One selected Black & Veatch (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 Common Corporate Cost Allocation Methodology and Overhead Capitalization Methodology, are addressed in Exhibit E-04-08 and Exhibit C-08-02 respectively. The allocation of Shared Assets, including B&V's review thereof, is addressed below. A consolidated report from B&V, addressing all aspects of its review, is provided in Exhibit E-04-08, Attachment 1.

2.0 SHARED ASSET VALUES

Shared Assets within the Hydro One group of companies are held by Hydro One Networks. Within Hydro One Networks, those Shared Assets represent approximately 3.2% of the company's total assets. The remaining (non-shared) assets of Hydro One Networks are held directly by, and are for the exclusive use of, either the Transmission business or the Distribution business. Hydro One Networks' Transmission and Distribution business units, as well as its affiliates, are each allocated a portion of the value of the Shared Assets based on their respective use of those assets, as described later in this Exhibit. Table 1 summarizes the total gross fixed assets and identifies the proportions of Shared Assets that are allocated to Transmission and Distribution.

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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&!) 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.

Table 1 - Summary of Net Book Value of Fixed Assets as at March 31, 2020 ($M)[3]

Category	Transmission	%	Distribution	%	Affiliates	%	Total
Total Fixed Assets (including Shared Assets)	$12,038.3	57.7%	$7,885.2	37.8%	$936.8	4.5%	$20,860.3
Total Shared Assets	$256.1	38.4%	$404.4	60.6%	$6.7	1.0%	$667.3
Total Shared Assets as % of Total Fixed Assets	**2.1%**		**5.1%**		**1.0%**		**3.2%**

Shared Assets are divided into two categories. Major Shared Fixed Assets include both tangible and intangible assets such as land, buildings, telecommunications equipment, and applications software. Minor Shared Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2 shows the proportion of Major Shared Fixed Assets and Minor Shared Fixed Assets by Transmission, Distribution and Affiliates, and their net book value.

Table 2 - Details of Shared Net Fixed Assets as at March 31, 2020 ($M)[4]

	Net Book Value (Transmission)	Net Book Value (Distribution)	Net Book Value (Affiliates)	Total
Major Shared Fixed Assets $	162.5	221.7	6.5	390.8
Minor Shared Fixed Assets $	93.6	182.6	0.2	276.5
Total Shared Assets $	**256.1**	**404.4**	**6.7**	**667.3**

3.0 ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the evolving nature of Hydro One's business and investment priorities, Shared Assets are not subject to permanent allocation factors for the Transmission or Distribution business units. Over time, the relative use of Shared Assets may change, depending on changes in the underlying transmission and distribution work programs. Consequently, the methodology and the resulting allocation of Shared Assets to the Transmission and Distribution business units is subject to periodic review. The intent of such reviews is to ensure that the allocation of Shared

[3] Rounded numbers presented in the chart may not add to the total due to rounding
[4] Rounded numbers presented in the chart may not add to the total due to rounding

Assets continues over time to be reflective of their use and that the costs associated with those Shared Assets are allocated appropriately between the Transmission and Distribution business units and any affiliates.

In 2006, Hydro One engaged B&V (formerly R.J. Rudden Associates) to establish a methodology for allocating Shared Assets to Hydro One's Transmission and Distribution business units. This methodology was based on the identification of appropriate cost drivers to reflect cost causality and benefits received. More particularly, the 2006 B&V study concluded that Shared Assets should be allocated based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for allocating the costs associated with Hydro One's Common Corporate Functions and Services.

Hydro One has adopted and consistently applied the Shared Asset allocation methodology that was established in the 2006 B&V study as a reasonable representation of the use of Shared Assets by the relevant affiliates and business units. This methodology was utilized and subsequently endorsed by the OEB in each of the following Distribution rate decisions: RP-2005-0020/EB-2005-0378/EB-2007-0681/EB-2009-0096/EB-2013-0416/EB-2017-0049, as well as in each of the following Transmission revenue requirement decisions: EB-2006-0501/EB-2008-0272/EB-2010-0002/EB-2012-0031/EB-2014-0140/EB-2016-0160/EB-2019-0082.

The appropriate use of the Shared Asset allocation methodology for the 2023 to 2027 test years has been reviewed and confirmed by B&V, and B&V's detailed review of the methodology is included in Section 7 of the Consolidated Report, which is provided in Attachment 1 to Exhibit E-04-08. B&V's review of the methodology for the current application has 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 make up the majority (90%) of the total Shared Assets to support their use and allocation. Further, the method employed to allocate Shared Assets is in alignment with the method used to allocate Common

Corporate Costs such that, where Shared Services and Shared Assets are providing a similar service, the allocation factor is the same across the two methodologies.

4.0 TRANSFER PRICING

To account for the use of Shared Assets by its affiliates, Hydro One applies transfer pricing to allocate the portion of revenue requirement related to certain Shared Assets to its affiliates. The service level agreements between Hydro One and its affiliates, for services provided to or received from affiliates, are described in more detail in Exhibit D, Tab 2, Schedule 3. The use of transfer pricing under those agreements reduces the revenue requirements of Hydro One's Transmission and Distribution businesses. The Shared Assets allocated to affiliates include major fixed assets and intangible assets, as well as minor fixed assets. For example, one significant Shared Asset is Cornerstone, which is software that integrates work management, finance, supply chain and customer service and other enterprise software. The methodology for calculating the transfer pricing and its impact on the Transmission and Distribution Shared Asset costs are described in more detail in Section 7 of the Consolidated Report, which is provided in Attachment 1 to Exhibit E-04-08.

Hydro One has used the previously approved B&V Shared Asset allocation methodology in this proposed application, which has been subject to the detailed review described above. Table 1 above shows the Hydro One Shared Asset allocation as at March 31, 2020.

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HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Utility Rate Base
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

Particulars		**2022**		**2023**		**2024**		**2025**		**2026**		**2027**
Electric Utility Plant												
Gross plant at cost	$	22,262.1	$	23,563.1		24,830.2	$	26,469.6	$	27,687.1	$	29,231.2
Less: accumulated depreciation	$	(8,145.1)		(8,558.7)		(9,001.6)		(9,467.9)		(9,970.5)		(10,506.0)
Net plant for rate base	$	14,117.0		15,004.4		15,828.6		17,001.7		17,716.6		18,725.2
Average net plant for rate base	$			14,560.7		15,416.5		16,415.2		17,359.1		18,220.9
Average net utility plant	$		$	14,560.7	$	15,416.5	$	16,415.2	$	17,359.1	$	18,220.9
Working Capital												
Cash working capital	$			17.8		19.3		18.9		19.9		19.9
Materials and Supplies Inventory	$			14.1		14.4		14.7		15.0		15.3
Total working capital	$			31.9		33.7		33.6		34.9		35.2
Total rate base	$		$	14,592.7	$	15,450.3	$	16,448.9	$	17,394.1	$	18,256.2

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Statement of Utility Rate Base
Bridge Year (2022) and Test Years (2023 to 2027)
Year Ending December 31
($M)

Particulars		**2022**		**2023**		**2024**		**2025**		**2026**		**2027**
Electric Utility Plant												
Gross plant at cost	$	14,290.5	$	15,288.4	$	16,136.0	$	17,138.5	$	18,012.7	$	18,943.3
Less: non-regulatory		(75.0)		(77.0)		(78.9)		(80.1)		(81.2)		(82.4)
Gross plant at cost for rate base		14,215.5		15,211.4		16,057.0		17,058.4		17,931.5		18,861.0
Less: accumulated depreciation	$	(5,579.3)		(5,838.9)		(6,083.4)		(6,342.2)		(6,650.9)		(7,001.5)
Less: non-regulatory		31.6		35.5		39.4		43.4		47.4		51.5
Accumulated depreciation for rate base		(5,547.7)		(5,803.4)		(6,044.0)		(6,298.8)		(6,603.5)		(6,950.0)
Net plant for rate base	$	8,667.8		9,408.0		10,013.0		10,759.6		11,328.0		11,911.0
Average net plant for rate base	$			9,122.5		9,710.5		10,386.3		11,043.8		11,619.5
Average net utility plant	$		$	9,122.5	$	9,710.5	$	10,386.3	$	11,043.8	$	11,619.5
Working Capital												
Cash working capital	$			243.4		246.3		248.7		251.6		254.5
Materials and Supplies Inventory	$			6.0		6.1		6.2		6.4		6.5
Total working capital	$			249.4		252.4		254.9		258.0		261.0
Total rate base	$		$	9,372.0	$	9,962.9	$	10,641.2	$	11,301.8	$	11,880.5

2023-2027 figures are presented on a combined basis including Acquired Utilities. 2023 average rate base includes opening adjustment for Acquired Utilities.

Witness: Joel Jodoin

HYDRO ONE NETWORKS INC.
TRANSMISSION

Continuity of Property, Plant and Equipment
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historical								
1	2018	17,076.7	1135.6	(10.9)	(15.9)	(0.5)	18,185.0	17,630.8
2	2019	18,185.0	959.5	(59.7)	(6.9)	15.8	19,093.7	18,639.3
3	2020	19,093.7	944.3	(59.9)	(15.5)	6.8	19,969.4	19,531.5
4	2021-Forecast	19,969.4	1006.0	(51.1)		9.0	20,933.2	20,451.3
Bridge								
5	2022	20,933.2	1381.6	(53.8)		1.0	22,262.1	21,597.7
Test								
6	2023	22,262.1	1368.1	(68.1)		1.0	23,563.1	22,912.6
7	2024	23,563.1	1332.4	(66.4)		1.0	24,830.2	24,196.7
8	2025	24,830.2	1710.3	(72.0)		1.1	26,469.6	25,649.9
9	2026	26,469.6	1280.3	(63.9)		1.1	27,687.1	27,078.4
10	2027	27,687.1	1599.8	(56.8)		1.1	29,231.2	28,459.2

Witness: Samir Chhelavda

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historical								
1	2018	11,624.1	627.8	(181.8)	(36.1)	(5.1)	12,028.9	11,826.5
2	2019	12,028.9	585.1	(60.2)	(13.6)	9.2	12,549.5	12,289.2
3	2020	12,549.5	668.1	(56.8)	(16.7)	6.9	13,150.9	12,850.2
4	2021-Forecast	13,150.9	700.1	(116.2)	0.0	6.8	13,741.6	13,446.3
Bridge								
5	2022	13,741.6	656.4	(108.3)	-	0.8	14,290.5	14,016.1
Test								
6	2023	14,490.3	970.9	(173.7)	-	0.9	15,288.4	14,889.3
7	2024	15,288.4	1,027.3	(180.6)	-	0.9	16,136.0	15,712.2
8	2025	16,136.0	1,203.4	(201.8)	-	0.9	17,138.5	16,637.2
9	2026	17,138.5	1,061.2	(187.9)	-	0.9	18,012.7	17,575.6
10	2027	18,012.7	1,107.8	(178.1)	-	0.9	18,943.3	18,478.0

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.

2023 Opening Balance reflects the integration of Acquired Utilities.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out and Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historical								
1	2018	6,301.7	387.3	(10.9)	(14.6)	(1.4)	6,662.1	6,481.9
2	2019	6,662.1	406.6	(59.7)	(6.2)	0.5	7,003.2	6,832.7
3	2020	7,003.2	410.9	(59.9)	(7.4)	1.7	7,348.6	7,175.9
4	2021-Forecast	7,348.6	440.2	(51.1)			7,737.6	7,543.1
Bridge								
5	2022	7,737.6	461.2	(53.8)			8,145.1	7,941.3
Test								
6	2023	8,145.1	481.8	(68.1)			8,558.7	8,351.9
7	2024	8,558.7	509.3	(66.4)			9,001.6	8,780.2
8	2025	9,001.6	538.2	(72.0)			9,467.9	9,234.8
9	2026	9,467.9	566.6	(63.9)			9,970.5	9,719.2
10	2027	9,970.5	592.2	(56.8)			10,506.0	10,238.3

Witness: Samir Chhelavda

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
Total - Gross Balances
($M)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out and Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historical								
1	2018	4,352.5	346.1	(181.8)	(30.9)	(0.0)	4,486.0	4,419.3
2	2019	4,486.0	351.7	(60.2)	(12.3)	(0.4)	4,764.8	4,625.4
3	2020	4,764.8	355.4	(56.8)	(14.6)	0.0	5,048.8	4,906.8
4	2021-Forecast	5,048.8	370.2	(116.2)	0.0	0.0	5,302.8	5,175.8
Bridge								
5	2022	5,302.8	384.9	(108.3)	0.0	0.0	5,579.3	5,441.0
Test								
6	2023	5,609.8	402.9	(173.7)	0.0	0.0	5,838.9	5,724.3
7	2024	5,838.9	425.0	(180.6)	0.0	0.0	6,083.4	5,961.2
8	2025	6,083.4	460.6	(201.8)	0.0	0.0	6,342.2	6,212.8
9	2026	6,342.2	496.6	(187.9)	0.0	0.0	6,650.9	6,496.6
10	2027	6,650.9	528.7	(178.1)	0.0	0.0	7,001.5	6,826.2

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.

2023 Opening Balance reflects the integration of Acquired Utilities.

Witness: Samir Chhelavda

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2018

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 277	$ 35	$ -	$ 312	-$ 178	-$ 24	$ -	-$ 202	$ 110
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 284	$ 1	$ -	$ 285	-$ 0	$ -	$ -	-$ 0	$ 285
14.1	1706	Land rights	$ 247	$ 4	$ -	$ 251	-$ 61	-$ 2	$ -	-$ 63	$ 187
1	1708	Buildings and fixtures	$ 515	$ 52	-$ 1	$ 566	-$ 239	-$ 10	$ 1	-$ 248	$ 318
47	1715	Station equipment	$ 9,093	$ 725	-$ 2	$ 9,815	-$ 3,078	-$ 198	$ 3	-$ 3,273	$ 6,542
47	1720	Towers and fixtures	$ 2,548	$ 113	$ -	$ 2,661	-$ 821	-$ 33	$ -	-$ 854	$ 1,807
47	1730	Overhead conductors and devices	$ 1,775	$ 104	-$ 2	$ 1,877	-$ 626	-$ 26	$ 2	-$ 650	$ 1,227
47	1735	Underground conduit	$ 312	$ -	$ -	$ 312	-$ 106	-$ 5	$ -	-$ 111	$ 200
47	1740	Underground conductors and devices	$ 151	$ 2	$ -	$ 153	-$ 20	-$ 3	$ -	-$ 23	$ 129
17	1745	Roads and trails	$ 274	$ 29	$ -	$ 303	-$ 161	-$ 5	$ -	-$ 166	$ 137
N/A	1905	Land	$ 16	$ 1	$ -	$ 17	-$ 1	$ -	$ -	-$ 1	$ 16
47	1908	Buildings & Fixtures	$ 195	$ 14	$ -	$ 209	-$ 93	-$ 4	$ -	-$ 97	$ 112
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 9	-$ 1	$ -	-$ 10	$ 15
8	1915	Office Furniture & Equipment	$ 6	$ 1	$ -	$ 7	-$ 3	-$ 1	$ -	-$ 4	$ 3
10	1920	Computer Equipment - Hardware	$ 51	$ 10	-$ 4	$ 57	-$ 26	-$ 7	$ 4	-$ 29	$ 28
	1925	Computer software	$ 83	$ -	$ -	$ 83	-$ 62	-$ 6	$ -	-$ 68	$ 15
10	1930	Transportation Equipment	$ 86	$ 2	-$ 10	$ 77	-$ 60	-$ 7	$ 9	-$ 58	$ 19
8	1935	Stores Equipment	$ 0	$ -	$ -	$ 0	-$ 0	$ -	$ -	-$ 0	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 9	$ 1	-$ 1	$ 9	-$ 4	-$ 1	$ 1	-$ 4	$ 4
8	1945	Measurement & Testing Equipment	$ 7	$ 1	-$ 1	$ 7	-$ 4	-$ 1	$ 1	-$ 4	$ 4
8	1950	Power Operated Equipment	$ 207	$ 6	-$ 5	$ 208	-$ 118	-$ 9	$ 5	-$ 122	$ 86
8	1955	Communications Equipment	$ 444	$ 35	$ -	$ 479	-$ 257	-$ 16	$ -	-$ 273	$ 206
8	1960	Miscellaneous Equipment	$ 3	$ -	$ -	$ 3	-$ 2	$ -	$ -	-$ 2	$ 1
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 456	$ -	$ -	$ 456	-$ 363	-$ 27	$ -	-$ 390	$ 66
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 14	$ -	-$ 1	$ 13	-$ 8	-$ 1	$ 1	-$ 8	$ 4
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 17,076.7**	**$ 1,135.6**	**-$ 27.3**	**$ 18,185.0**	**-$ 6,301.7**	**-$ 387.3**	**$ 26.9**	**-$ 6,662.1**	**$ 11,523**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 17,076.7**	**$ 1,135.6**	**-$ 27.3**	**$ 18,185.0**	**-$ 6,301.7**	**-$ 387.3**	**$ 26.9**	**-$ 6,662.1**	**$ 11,523**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 387**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 387

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2019

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 312	$ 66	-$ 0	$ 378	-$ 202	-$ 24	-$ 0	-$ 226	$ 152
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -			$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -			$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 285	$ 0	-$ 17	$ 268	-$ 0	$ 0	$ -	-$ 0	$ 268
14.1	1706	Land rights	$ 251	$ 7		$ 258	-$ 63	-$ 1	$ -	-$ 64	$ 193
1	1708	Buildings and fixtures	$ 566	$ 39		$ 605	-$ 248	-$ 11	$ -	-$ 259	$ 345
47	1715	Station equipment	$ 9,815	$ 439	-$ 1	$ 10,253	-$ 3,273	-$ 181	$ 17	-$ 3,438	$ 6,815
47	1720	Towers and fixtures	$ 2,661	$ 165	-$ 8	$ 2,818	-$ 854	-$ 41	$ 1	-$ 894	$ 1,924
47	1730	Overhead conductors and devices	$ 1,877	$ 150	-$ 7	$ 2,021	-$ 650	-$ 20	$ 31	-$ 640	$ 1,381
47	1735	Underground conduit	$ 312	-$ 0		$ 311	-$ 111	-$ 24	$ -	-$ 136	$ 176
47	1740	Underground conductors and devices	$ 153	$ 1		$ 153	-$ 23	-$ 4	$ -	-$ 27	$ 126
17	1745	Roads and trails	$ 303	$ 14		$ 318	-$ 166	-$ 14	$ -	-$ 180	$ 137
N/A	1905	Land	$ 17	-$ 0		$ 16	-$ 1	$ 0	$ -	-$ 1	$ 16
47	1908	Buildings & Fixtures	$ 209	$ 20	$ 0	$ 229	-$ 97	$ 3	$ -	-$ 94	$ 135
13	1910	Leasehold Improvements	$ 26	$ 0		$ 26	-$ 10	-$ 2	$ -	-$ 12	$ 14
8	1915	Office Furniture & Equipment	$ 7	$ 0	-$ 1	$ 7	-$ 4	-$ 1	$ 1	-$ 4	$ 3
10	1920	Computer Equipment - Hardware	$ 57	$ 8	-$ 6	$ 60	-$ 29	-$ 6	$ 6	-$ 29	$ 31
	1925	Computer software	$ 83	$ 0		$ 83	-$ 68	-$ 15	$ 5	-$ 78	$ 5
10	1930	Transportation Equipment	$ 77	$ 5	-$ 5	$ 77	-$ 58	-$ 6	$ 0	-$ 64	$ 13
8	1935	Stores Equipment	$ 0		-$ 0	$ 0	-$ 0	-$ 0	$ 0	$ 0	$ 1
8	1940	Tools, Shop & Garage Equipment	$ 9	$ 1	-$ 0	$ 9	-$ 4	-$ 1	$ 2	-$ 4	$ 5
8	1945	Measurement & Testing Equipment	$ 7	$ 1	-$ 2	$ 7	-$ 4	-$ 1	$ 1	-$ 4	$ 3
8	1950	Power Operated Equipment	$ 208	$ 6	-$ 2	$ 212	-$ 122	-$ 8	$ 1	-$ 130	$ 82
8	1955	Communications Equipment	$ 479	$ 33	-$ 1	$ 511	-$ 273	$ 7	$ 1	-$ 265	$ 246
8	1960	Miscellaneous Equipment	$ 3	$ 1	-$ 1	$ 2	-$ 2	-$ 0	$ -	-$ 3	-$ 1
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 456	$ 1		$ 457	-$ 390	-$ 53	$ -	-$ 443	$ 14
47	1985	Miscellaneous Fixed Assets	$ -	-$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 13	$ 2		$ 15	-$ 8	-$ 1	$ -	-$ 9	$ 6
47	1995	Contributions & Grants	$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -			$ -	$ -	$ -	$ -		$ -
										$ -	$ -
		Sub-Total	**$ 18,185.0**	**$ 959.5**	**-$ 51.0**	**$ 19,093.7**	**-$ 6,662.1**	**-$ 406.6**	**$ 65.5**	**-$ 7,003.2**	**$ 12,090**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 18,185.0**	**$ 959.5**	**-$ 51.0**	**$ 19,093.7**	**-$ 6,662.1**	**-$ 406.6**	**$ 65.5**	**-$ 7,003.2**	**$ 12,090**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 407**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 407

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2020

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 378	$ 44	$ 2	$ 424	-$ 226	-$ 23	$ -	-$ 248	$ 176
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -			$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -			$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 268	$ 2	-$ 8	$ 263	-$ 0	$ -	$ 0	-$ 0	$ 263
14.1	1706	Land rights	$ 258	$ 1		$ 258	-$ 64	-$ 2	$ -	-$ 67	$ 192
1	1708	Buildings and fixtures	$ 605	$ 49		$ 653	-$ 259	-$ 11	$ -	-$ 271	$ 383
47	1715	Station equipment	$ 10,253	$ 515	-$ 4	$ 10,764	-$ 3,438	-$ 221	$ 8	-$ 3,651	$ 7,113
47	1720	Towers and fixtures	$ 2,818	$ 112	-$ 1	$ 2,929	-$ 894	-$ 36	$ 1	-$ 930	$ 2,000
47	1730	Overhead conductors and devices	$ 2,021	$ 114	-$ 44	$ 2,091	-$ 640	-$ 30	$ 43	-$ 626	$ 1,464
47	1735	Underground conduit	$ 311	$ 2		$ 314	-$ 136	-$ 5	$ -	-$ 141	$ 173
47	1740	Underground conductors and devices	$ 153	$ 34		$ 187	-$ 27	-$ 3	$ -	-$ 30	$ 157
17	1745	Roads and trails	$ 318	$ 9		$ 326	-$ 180	-$ 6	$ -	-$ 186	$ 140
N/A	1905	Land	$ 16	$ 0		$ 16	-$ 1	$ -	$ -	-$ 1	$ 16
47	1908	Buildings & Fixtures	$ 229	$ 18		$ 247	-$ 94	-$ 4	$ -	-$ 98	$ 149
13	1910	Leasehold Improvements	$ 26	$ 0		$ 26	-$ 12	-$ 1	$ -	-$ 13	$ 12
8	1915	Office Furniture & Equipment	$ 7	$ 0	-$ 1	$ 7	-$ 4	-$ 1	$ 1	-$ 4	$ 2
10	1920	Computer Equipment - Hardware	$ 60	$ 4	-$ 4	$ 59	-$ 29	-$ 8	$ 4	-$ 33	$ 27
	1925	Computer software	$ 83	$ 6		$ 89	-$ 78	-$ 3	$ -	-$ 81	$ 8
10	1930	Transportation Equipment	$ 77	$ 3	-$ 7	$ 73	-$ 64	-$ 6	$ 6	-$ 64	$ 9
8	1935	Stores Equipment	$ 0			$ 0	$ 0	-$ 0	$ -	$ 0	$ 1
8	1940	Tools, Shop & Garage Equipment	$ 9	$ 1	-$ 1	$ 10	-$ 4	-$ 1	$ 1	-$ 4	$ 6
8	1945	Measurement & Testing Equipment	$ 7	$ 1	-$ 1	$ 7	-$ 4	-$ 1	$ 1	-$ 4	$ 4
8	1950	Power Operated Equipment	$ 212	$ 6	-$ 1	$ 217	-$ 130	-$ 8	$ 1	-$ 137	$ 80
8	1955	Communications Equipment	$ 511	$ 18	$ 0	$ 530	-$ 265	-$ 16	-$ 0	-$ 282	$ 248
8	1960	Miscellaneous Equipment	$ 2	$ 1	-$ 0	$ 3	-$ 3	-$ 0	$ 0	-$ 3	$ 0
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 457	$ 0		$ 457	-$ 443	-$ 22	$ -	-$ 465	-$ 8
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 15	$ 3		$ 18	-$ 9	-$ 1	$ -	-$ 10	$ 8
47	1995	Contributions & Grants	$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -	$ -	$ -		$ -
		Sub-Total	**$ 19,093.7**	**$ 944.3**	**-$ 68.6**	**$ 19,969.4**	**-$ 7,003.2**	**-$ 410.9**	**$ 65.5**	**-$ 7,348.6**	**$ 12,621**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 19,093.7**	**$ 944.3**	**-$ 68.6**	**$ 19,969.4**	**-$ 7,003.2**	**-$ 410.9**	**$ 65.5**	**-$ 7,348.6**	**$ 12,621**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 411**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 411

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2021

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 424	$ 21	$ -	$ 445	-$ 248	-$ 27	$ -	-$ 275	$ 170
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 263	$ 4	$ -	$ 267	-$ 0	-$ 0	$ -	-$ 0	$ 267
14.1	1706	Land rights	$ 258	$ 9	$ -	$ 268	-$ 67	-$ 3	$ -	-$ 69	$ 198
1	1708	Buildings and fixtures	$ 653	$ 23	-$ 1	$ 676	-$ 271	-$ 12	$ 1	-$ 282	$ 394
47	1715	Station equipment	$ 10,764	$ 506	-$ 21	$ 11,249	-$ 3,651	-$ 232	$ 27	-$ 3,856	$ 7,393
47	1720	Towers and fixtures	$ 2,929	$ 207	-$ 1	$ 3,136	-$ 930	-$ 38	$ 2	-$ 966	$ 2,170
47	1730	Overhead conductors and devices	$ 2,091	$ 69	$ 0	$ 2,160	-$ 626	-$ 30	$ 1	-$ 656	$ 1,504
47	1735	Underground conduit	$ 314	$ 5	$ -	$ 318	-$ 141	-$ 5	$ -	-$ 146	$ 172
47	1740	Underground conductors and devices	$ 187	$ 6	-$ 2	$ 192	-$ 30	-$ 3	$ 2	-$ 32	$ 160
17	1745	Roads and trails	$ 326	$ 2	$ -	$ 329	-$ 186	-$ 6	$ -	-$ 192	$ 137
N/A	1905	Land	$ 16	$ -	$ -	$ 16	-$ 1	-$ 0	$ -	-$ 1	$ 16
47	1908	Buildings & Fixtures	$ 247	$ 4	$ -	$ 251	-$ 98	-$ 5	$ -	-$ 103	$ 148
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 13	-$ 1	$ -	-$ 15	$ 11
8	1915	Office Furniture & Equipment	$ 7	$ 0	-$ 2	$ 5	-$ 4	-$ 1	$ 2	-$ 3	$ 2
10	1920	Computer Equipment - Hardware	$ 59	$ 8	-$ 4	$ 63	-$ 33	-$ 10	$ 4	-$ 38	$ 25
	1925	Computer software	$ 89	$ 13	$ -	$ 102	-$ 81	-$ 4	$ -	-$ 85	$ 17
10	1930	Transportation Equipment	$ 73	$ 11	-$ 3	$ 81	-$ 64	-$ 5	$ 3	-$ 66	$ 15
8	1935	Stores Equipment	$ 0	$ 1	$ -	$ 2	$ 0	-$ 0	$ -	$ 0	$ 2
8	1940	Tools, Shop & Garage Equipment	$ 10	$ 0	-$ 4	$ 6	-$ 4	-$ 1	$ 4	-$ 1	$ 4
8	1945	Measurement & Testing Equipment	$ 7	$ 1	-$ 1	$ 7	-$ 4	-$ 1	$ 1	-$ 4	$ 3
8	1950	Power Operated Equipment	$ 217	$ -	-$ 0	$ 217	-$ 137	-$ 13	$ 0	-$ 149	$ 68
8	1955	Communications Equipment	$ 530	$ 26	$ -	$ 556	-$ 282	-$ 17	$ -	-$ 299	$ 257
8	1960	Miscellaneous Equipment	$ 3	$ 1	-$ 0	$ 3	-$ 3	-$ 1	$ 0	-$ 3	$ 0
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 457	$ 88	$ -	$ 545	-$ 465	-$ 24	$ -	-$ 489	$ 56
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 18	$ -	-$ 3	$ 15	-$ 10	-$ 1	$ 3	-$ 8	$ 7
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
										$ -	
		Sub-Total	**$ 19,969.4**	**$ 1,006.0**	**-$ 42.2**	**$ 20,933.2**	**-$ 7,348.6**	**-$ 440.2**	**$ 51.2**	**-$ 7,737.6**	**$ 13,196**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 19,969.4**	**$ 1,006.0**	**-$ 42.2**	**$ 20,933.2**	**-$ 7,348.6**	**-$ 440.2**	**$ 51.2**	**-$ 7,737.6**	**$ 13,196**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 440**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 440

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	**2022**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 445	$ 26	$ -	$ 471	-$ 275	-$ 27	$ -	-$ 302	$ 169
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 267	$ 8	$ -	$ 275	-$ 0	-$ 0	$ -	-$ 0	$ 275
14.1	1706	Land rights	$ 268	$ 16	$ -	$ 283	-$ 69	-$ 3	$ -	-$ 72	$ 211
1	1708	Buildings and fixtures	$ 676	$ 22	-$ 1	$ 696	-$ 282	-$ 12	$ 1	-$ 293	$ 403
47	1715	Station equipment	$ 11,249	$ 790	-$ 33	$ 12,006	-$ 3,856	-$ 245	$ 34	-$ 4,067	$ 7,939
47	1720	Towers and fixtures	$ 3,136	$ 299	-$ 3	$ 3,432	-$ 966	-$ 42	$ 3	-$ 1,004	$ 2,428
47	1730	Overhead conductors and devices	$ 2,160	$ 121	-$ 1	$ 2,279	-$ 656	-$ 32	$ 1	-$ 686	$ 1,593
47	1735	Underground conduit	$ 318	$ 11	$ -	$ 329	-$ 146	-$ 5	$ -	-$ 151	$ 178
47	1740	Underground conductors and devices	$ 192	$ 14	-$ 2	$ 204	-$ 32	-$ 4	$ 2	-$ 34	$ 170
17	1745	Roads and trails	$ 329	$ 5	$ -	$ 333	-$ 192	-$ 6	$ -	-$ 198	$ 136
N/A	1905	Land	$ 16	$ -	$ -	$ 16	-$ 1	-$ 0	$ -	-$ 1	$ 16
47	1908	Buildings & Fixtures	$ 251	$ 4	$ -	$ 255	-$ 103	-$ 5	$ -	-$ 108	$ 148
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 15	-$ 1	$ -	-$ 16	$ 9
8	1915	Office Furniture & Equipment	$ 5	$ 0	-$ 2	$ 4	-$ 3	-$ 1	$ 2	-$ 2	$ 2
10	1920	Computer Equipment - Hardware	$ 63	$ 7	-$ 4	$ 66	-$ 38	-$ 10	$ 4	-$ 44	$ 22
	1925	Computer software	$ 102	$ 0	$ -	$ 102	-$ 85	-$ 4	$ -	-$ 89	$ 13
10	1930	Transportation Equipment	$ 81	$ 9	-$ 3	$ 86	-$ 66	-$ 6	$ 3	-$ 69	$ 18
8	1935	Stores Equipment	$ 2	$ 2	-$ 0	$ 3	$ 0	-$ 0	$ 0	-$ 0	$ 3
8	1940	Tools, Shop & Garage Equipment	$ 6	$ 0	-$ 1	$ 5	-$ 1	-$ 1	$ 1	-$ 1	$ 4
8	1945	Measurement & Testing Equipment	$ 7	$ 2	-$ 2	$ 7	-$ 4	-$ 1	$ 2	-$ 4	$ 3
8	1950	Power Operated Equipment	$ 217	$ -	-$ 0	$ 217	-$ 149	-$ 10	$ 0	-$ 160	$ 57
8	1955	Communications Equipment	$ 556	$ 21	$ -	$ 577	-$ 299	-$ 17	$ -	-$ 316	$ 261
8	1960	Miscellaneous Equipment	$ 3	$ 2	-$ 0	$ 5	-$ 3	-$ 1	$ 0	-$ 4	$ 1
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 545	$ 24	$ -	$ 569	-$ 489	-$ 27	$ -	-$ 516	$ 53
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 15	$ -	-$ 0	$ 15	-$ 8	-$ 1	$ 0	-$ 9	$ 6
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
										$ -	
		Sub-Total	**$ 20,933.2**	**$ 1,381.6**	**-$ 52.8**	**$ 22,262.1**	**-$ 7,737.6**	**-$ 461.2**	**$ 53.7**	**-$ 8,145.1**	**$ 14,117**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 20,933.2**	**$ 1,381.6**	**-$ 52.8**	**$ 22,262.1**	**-$ 7,737.6**	**-$ 461.2**	**$ 53.7**	**-$ 8,145.1**	**$ 14,117**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 461**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 461

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2023

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1610	Intangibles	$ 471	$ 23	$ -	$ 494	-$ 302	-$ 27	$ -	-$ 330	$ 165
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 275	$ 2	$ -	$ 276	-$ 0	-$ 0	$ -	-$ 0	$ 276
14.1	1706	Land rights	$ 283	$ 7	$ -	$ 290	-$ 72	-$ 3	$ -	-$ 74	$ 215
1	1708	Buildings and fixtures	$ 696	$ 18	-$ 2	$ 712	-$ 293	-$ 13	$ 2	-$ 304	$ 408
47	1715	Station equipment	$ 12,006	$ 864	-$ 42	$ 12,828	-$ 4,067	-$ 241	$ 43	-$ 4,265	$ 8,563
47	1720	Towers and fixtures	$ 3,432	$ 203	-$ 3	$ 3,631	-$ 1,004	-$ 43	$ 4	-$ 1,044	$ 2,588
47	1730	Overhead conductors and devices	$ 2,279	$ 84	-$ 1	$ 2,362	-$ 686	-$ 30	$ 2	-$ 714	$ 1,647
47	1735	Underground conduit	$ 329	$ 3	$ -	$ 332	-$ 151	-$ 5	$ -	-$ 156	$ 176
47	1740	Underground conductors and devices	$ 204	$ 4	-$ 3	$ 205	-$ 34	-$ 4	$ 3	-$ 35	$ 170
17	1745	Roads and trails	$ 333	$ 3	$ -	$ 336	-$ 198	-$ 5	$ -	-$ 203	$ 134
N/A	1905	Land	$ 16	$ -	$ -	$ 16	-$ 1	-$ 0	$ -	-$ 1	$ 15
47	1908	Buildings & Fixtures	$ 255	$ 3	$ -	$ 259	-$ 108	-$ 5	$ -	-$ 112	$ 146
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 16	-$ 1	$ -	-$ 17	$ 8
8	1915	Office Furniture & Equipment	$ 4	$ 0	-$ 0	$ 4	-$ 2	-$ 0	$ 0	-$ 2	$ 2
10	1920	Computer Equipment - Hardware	$ 66	$ 6	-$ 6	$ 66	-$ 44	-$ 10	$ 6	-$ 48	$ 18
	1925	Computer software	$ 102	$ 7	$ -	$ 109	-$ 89	-$ 4	$ -	-$ 93	$ 16
10	1930	Transportation Equipment	$ 86	$ 19	-$ 1	$ 104	-$ 69	-$ 8	$ 1	-$ 76	$ 28
8	1935	Stores Equipment	$ 3	$ 3	-$ 0	$ 6	-$ 0	-$ 1	$ 0	-$ 1	$ 5
8	1940	Tools, Shop & Garage Equipment	$ 5	$ 0	-$ 1	$ 4	-$ 1	-$ 1	$ 1	-$ 1	$ 3
8	1945	Measurement & Testing Equipment	$ 7	$ 2	-$ 1	$ 7	-$ 4	-$ 1	$ 1	-$ 3	$ 3
8	1950	Power Operated Equipment	$ 217	$ -	$ -	$ 217	-$ 160	-$ 8	$ -	-$ 168	$ 49
8	1955	Communications Equipment	$ 577	$ 62	$ -	$ 639	-$ 316	-$ 24	$ -	-$ 341	$ 299
8	1960	Miscellaneous Equipment	$ 5	$ 2	-$ 0	$ 6	-$ 4	-$ 1	$ 0	-$ 4	$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 569	$ 55	$ -	$ 624	-$ 516	-$ 46	$ -	-$ 562	$ 62
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 15	$ -	-$ 5	$ 10	-$ 9	-$ 1	$ 5	-$ 5	$ 5
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
										$ -	
		Sub-Total	**$ 22,262.1**	**$ 1,368.1**	**-$ 67.1**	**$ 23,563.1**	**-$ 8,145.1**	**-$ 481.8**	**$ 68.1**	**-$ 8,558.7**	**$ 15,004**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 22,262.1**	**$ 1,368.1**	**-$ 67.1**	**$ 23,563.1**	**-$ 8,145.1**	**-$ 481.8**	**$ 68.1**	**-$ 8,558.7**	**$ 15,004**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 482**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 482

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2024

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 494	$ 21	$ -	$ 515	-$ 330	-$ 28	$ -	-$ 357	$ 158
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 276	$ 1	$ -	$ 277	-$ 0	-$ 0	$ -	-$ 0	$ 277
14.1	1706	Land rights	$ 290	$ 9	$ -	$ 298	-$ 74	-$ 3	$ -	-$ 77	$ 221
1	1708	Buildings and fixtures	$ 712	$ 34	-$ 2	$ 745	-$ 304	-$ 13	$ 2	-$ 316	$ 429
47	1715	Station equipment	$ 12,828	$ 801	-$ 42	$ 13,587	-$ 4,265	-$ 256	$ 43	-$ 4,478	$ 9,109
47	1720	Towers and fixtures	$ 3,631	$ 263	-$ 3	$ 3,891	-$ 1,044	-$ 46	$ 4	-$ 1,086	$ 2,805
47	1730	Overhead conductors and devices	$ 2,362	$ 55	-$ 1	$ 2,415	-$ 714	-$ 31	$ 2	-$ 744	$ 1,672
47	1735	Underground conduit	$ 332	$ 4	$ -	$ 336	-$ 156	-$ 5	$ -	-$ 161	$ 174
47	1740	Underground conductors and devices	$ 205	$ 4	-$ 3	$ 206	-$ 35	-$ 4	$ 3	-$ 35	$ 171
17	1745	Roads and trails	$ 336	$ 1	$ -	$ 337	-$ 203	-$ 5	$ -	-$ 208	$ 130
N/A	1905	Land	$ 16	$ -	$ -	$ 16	-$ 1	-$ 0	$ -	-$ 1	$ 15
47	1908	Buildings & Fixtures	$ 259	$ 15	$ -	$ 274	-$ 112	-$ 5	$ -	-$ 117	$ 157
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 17	-$ 1	$ -	-$ 18	$ 7
8	1915	Office Furniture & Equipment	$ 4	$ 0	-$ 0	$ 4	-$ 2	-$ 0	$ 0	-$ 2	$ 2
10	1920	Computer Equipment - Hardware	$ 66	$ 4	-$ 8	$ 62	-$ 48	-$ 9	$ 8	-$ 49	$ 13
	1925	Computer software	$ 109	$ 0	$ -	$ 109	-$ 93	-$ 4	$ -	-$ 98	$ 12
10	1930	Transportation Equipment	$ 104	$ 19	-$ 1	$ 122	-$ 76	-$ 11	$ 1	-$ 86	$ 36
8	1935	Stores Equipment	$ 6	$ 3	-$ 0	$ 9	-$ 1	-$ 1	$ 0	-$ 1	$ 7
8	1940	Tools, Shop & Garage Equipment	$ 4	$ 0	-$ 1	$ 3	-$ 1	-$ 1	$ 1	-$ 0	$ 3
8	1945	Measurement & Testing Equipment	$ 7	$ 2	-$ 1	$ 7	-$ 3	-$ 1	$ 1	-$ 3	$ 3
8	1950	Power Operated Equipment	$ 217	$ -	$ -	$ 217	-$ 168	-$ 7	$ -	-$ 175	$ 42
8	1955	Communications Equipment	$ 639	$ 73	$ -	$ 712	-$ 341	-$ 27	$ -	-$ 368	$ 344
8	1960	Miscellaneous Equipment	$ 6	$ 2	-$ 1	$ 7	-$ 4	-$ 1	$ 1	-$ 5	$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 624	$ 21	$ -	$ 645	-$ 562	-$ 49	$ -	-$ 612	$ 34
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 10	$ -	-$ 2	$ 8	-$ 5	-$ 1	$ 2	-$ 4	$ 4
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
										$ -	
		Sub-Total	**$ 23,563.1**	**$ 1,332.4**	**-$ 65.3**	**$ 24,830.2**	**-$ 8,558.7**	**-$ 509.3**	**$ 66.5**	**-$ 9,001.6**	**$ 15,829**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 23,563.1**	**$ 1,332.4**	**-$ 65.3**	**$ 24,830.2**	**-$ 8,558.7**	**-$ 509.3**	**$ 66.5**	**-$ 9,001.6**	**$ 15,829**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 509**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 509

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2025

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1610	Intangibles	$ 515	$ 48	$ -	$ 563	-$ 357	-$ 30	$ -	-$ 387	$ 176
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 277	$ 4	$ -	$ 281	-$ 0	-$ 0	$ -	-$ 1	$ 280
14.1	1706	Land rights	$ 298	$ 11	$ -	$ 309	-$ 77	-$ 3	$ -	-$ 80	$ 230
1	1708	Buildings and fixtures	$ 745	$ 22	-$ 2	$ 765	-$ 316	-$ 14	$ 2	-$ 328	$ 437
47	1715	Station equipment	$ 13,587	$ 935	-$ 43	$ 14,479	-$ 4,478	-$ 272	$ 44	-$ 4,706	$ 9,773
47	1720	Towers and fixtures	$ 3,891	$ 342	-$ 4	$ 4,230	-$ 1,086	-$ 50	$ 4	-$ 1,132	$ 3,098
47	1730	Overhead conductors and devices	$ 2,415	$ 81	-$ 1	$ 2,495	-$ 744	-$ 32	$ 2	-$ 774	$ 1,721
47	1735	Underground conduit	$ 336	$ 53	$ -	$ 389	-$ 161	-$ 5	$ -	-$ 166	$ 222
47	1740	Underground conductors and devices	$ 206	$ 75	-$ 3	$ 279	-$ 35	-$ 4	$ 3	-$ 37	$ 242
17	1745	Roads and trails	$ 337	$ 3	$ -	$ 341	-$ 208	-$ 5	$ -	-$ 213	$ 128
N/A	1905	Land	$ 16	$ -	$ -	$ 16	-$ 1	-$ 0	$ -	-$ 1	$ 15
47	1908	Buildings & Fixtures	$ 274	$ 5	$ -	$ 278	-$ 117	-$ 5	$ -	-$ 122	$ 157
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 18	-$ 1	$ -	-$ 20	$ 6
8	1915	Office Furniture & Equipment	$ 4	$ 0	-$ 1	$ 3	-$ 2	-$ 0	$ 1	-$ 2	$ 2
10	1920	Computer Equipment - Hardware	$ 62	$ 6	-$ 13	$ 55	-$ 49	-$ 8	$ 13	-$ 45	$ 10
	1925	Computer software	$ 109	$ 1	$ -	$ 110	-$ 98	-$ 5	$ -	-$ 102	$ 8
10	1930	Transportation Equipment	$ 122	$ 19	-$ 1	$ 141	-$ 86	-$ 13	$ 1	-$ 99	$ 43
8	1935	Stores Equipment	$ 9	$ 3	$ -	$ 11	-$ 1	-$ 1	$ -	-$ 3	$ 9
8	1940	Tools, Shop & Garage Equipment	$ 3	$ 0	-$ 1	$ 2	-$ 0	-$ 0	$ 1	-$ 0	$ 2
8	1945	Measurement & Testing Equipment	$ 7	$ 2	-$ 2	$ 7	-$ 3	-$ 1	$ 2	-$ 3	$ 4
8	1950	Power Operated Equipment	$ 217	$ -	-$ 0	$ 217	-$ 175	-$ 5	$ 0	-$ 180	$ 37
8	1955	Communications Equipment	$ 712	$ 85	$ -	$ 797	-$ 368	-$ 30	$ -	-$ 398	$ 399
8	1960	Miscellaneous Equipment	$ 7	$ 2	-$ 1	$ 7	-$ 5	-$ 1	$ 1	-$ 5	$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 645	$ 14	$ -	$ 659	-$ 612	-$ 51	$ -	-$ 662	-$ 3
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 8	$ -	-$ 0	$ 8	-$ 4	-$ 1	$ 0	-$ 4	$ 4
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
										$ -	
		Sub-Total	**$ 24,830.2**	**$ 1,710.3**	**-$ 70.9**	**$ 26,469.6**	**-$ 9,001.6**	**-$ 538.2**	**$ 71.9**	**-$ 9,467.9**	**$ 17,002**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 24,830.2**	**$ 1,710.3**	**-$ 70.9**	**$ 26,469.6**	**-$ 9,001.6**	**-$ 538.2**	**$ 71.9**	**-$ 9,467.9**	**$ 17,002**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 538**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 538

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2026

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 563	$ 25	$ -	$ 588	-$ 387	-$ 32	$ -	-$ 419	$ 168
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 281	$ 2	$ -	$ 283	-$ 1	-$ 0	$ -	-$ 1	$ 282
14.1	1706	Land rights	$ 309	$ 11	$ -	$ 320	-$ 80	-$ 3	$ -	-$ 83	$ 237
1	1708	Buildings and fixtures	$ 765	$ 24	-$ 2	$ 788	-$ 328	-$ 14	$ 2	-$ 340	$ 447
47	1715	Station equipment	$ 14,479	$ 643	-$ 44	$ 15,078	-$ 4,706	-$ 286	$ 45	-$ 4,947	$ 10,131
47	1720	Towers and fixtures	$ 4,230	$ 348	-$ 4	$ 4,575	-$ 1,132	-$ 54	$ 4	-$ 1,182	$ 3,392
47	1730	Overhead conductors and devices	$ 2,495	$ 72	-$ 2	$ 2,566	-$ 774	-$ 33	$ 2	-$ 805	$ 1,761
47	1735	Underground conduit	$ 389	$ 7	$ -	$ 396	-$ 166	-$ 6	$ -	-$ 172	$ 224
47	1740	Underground conductors and devices	$ 279	$ 7	-$ 3	$ 283	-$ 37	-$ 5	$ 3	-$ 39	$ 244
17	1745	Roads and trails	$ 341	$ 2	$ -	$ 343	-$ 213	-$ 5	$ -	-$ 218	$ 125
N/A	1905	Land	$ 16	$ -	$ -	$ 16	-$ 1	-$ 0	$ -	-$ 2	$ 15
47	1908	Buildings & Fixtures	$ 278	$ 7	$ -	$ 285	-$ 122	-$ 5	$ -	-$ 127	$ 158
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 20	-$ 1	$ -	-$ 21	$ 5
8	1915	Office Furniture & Equipment	$ 3	$ -	-$ 0	$ 3	-$ 2	-$ 0	$ 0	-$ 2	$ 1
10	1920	Computer Equipment - Hardware	$ 55	$ 6	-$ 6	$ 54	-$ 45	-$ 8	$ 6	-$ 46	$ 9
	1925	Computer software	$ 110	$ 0	$ -	$ 110	-$ 102	-$ 4	$ -	-$ 106	$ 4
10	1930	Transportation Equipment	$ 141	$ 20	-$ 1	$ 160	-$ 99	-$ 15	$ 1	-$ 112	$ 48
8	1935	Stores Equipment	$ 11	$ 3	$ -	$ 14	-$ 3	-$ 2	$ -	-$ 4	$ 10
8	1940	Tools, Shop & Garage Equipment	$ 2	$ 0	-$ 2	$ 1	$ 0	-$ 0	$ 2	$ 2	$ 2
8	1945	Measurement & Testing Equipment	$ 7	$ 2	-$ 0	$ 8	-$ 3	-$ 2	$ 0	-$ 5	$ 4
8	1950	Power Operated Equipment	$ 217	$ -	$ -	$ 217	-$ 180	-$ 4	$ -	-$ 184	$ 33
8	1955	Communications Equipment	$ 797	$ 87	$ -	$ 884	-$ 398	-$ 34	$ -	-$ 432	$ 452
8	1960	Miscellaneous Equipment	$ 7	$ 2	-$ 0	$ 9	-$ 5	-$ 2	$ 0	-$ 7	$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 659	$ 13	$ -	$ 672	-$ 662	-$ 52	$ -	-$ 714	-$ 42
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 8	$ -	$ -	$ 8	-$ 4	-$ 1	$ -	-$ 5	$ 3
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
										$ -	
		Sub-Total	**$ 26,469.6**	**$ 1,280.3**	**-$ 62.8**	**$ 27,687.1**	**-$ 9,467.9**	**-$ 566.6**	**$ 64.0**	**-$ 9,970.5**	**$ 17,717**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 26,469.6**	**$ 1,280.3**	**-$ 62.8**	**$ 27,687.1**	**-$ 9,467.9**	**-$ 566.6**	**$ 64.0**	**-$ 9,970.5**	**$ 17,717**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 567**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 567

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2027

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 588	$ 20	$ -	$ 608	-$ 419	-$ 32	$ -	-$ 451	$ 157
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1675	Generators	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1705	Land	$ 283	$ 2	$ -	$ 285	-$ 1	-$ 0	$ -	-$ 1	$ 284
14.1	1706	Land rights	$ 320	$ 13	$ -	$ 333	-$ 83	-$ 3	$ -	-$ 86	$ 247
1	1708	Buildings and fixtures	$ 788	$ 18	-$ 2	$ 804	-$ 340	-$ 14	$ 2	-$ 353	$ 451
47	1715	Station equipment	$ 15,078	$ 933	-$ 44	$ 15,967	-$ 4,947	-$ 301	$ 44	-$ 5,204	$ 10,764
47	1720	Towers and fixtures	$ 4,575	$ 413	-$ 4	$ 4,984	-$ 1,182	-$ 59	$ 4	-$ 1,237	$ 3,747
47	1730	Overhead conductors and devices	$ 2,566	$ 98	-$ 1	$ 2,663	-$ 805	-$ 34	$ 2	-$ 837	$ 1,826
47	1735	Underground conduit	$ 396	$ 4	$ -	$ 399	-$ 172	-$ 6	$ -	-$ 178	$ 221
47	1740	Underground conductors and devices	$ 283	$ 4	-$ 3	$ 285	-$ 39	-$ 5	$ 3	-$ 42	$ 243
17	1745	Roads and trails	$ 343	$ 2	$ -	$ 344	-$ 218	-$ 5	$ -	-$ 223	$ 122
N/A	1905	Land	$ 16	$ -	$ -	$ 16	-$ 2	-$ 0	$ -	-$ 2	$ 15
47	1908	Buildings & Fixtures	$ 285	$ 8	$ -	$ 293	-$ 127	-$ 5	$ -	-$ 132	$ 161
13	1910	Leasehold Improvements	$ 26	$ -	$ -	$ 26	-$ 21	-$ 1	$ -	-$ 22	$ 4
8	1915	Office Furniture & Equipment	$ 3	$ -	-$ 0	$ 3	-$ 2	-$ 0	$ 0	-$ 2	$ 1
10	1920	Computer Equipment - Hardware	$ 54	$ 6	-$ 2	$ 59	-$ 46	-$ 8	$ 2	-$ 52	$ 7
	1925	Computer software	$ 110	$ 1	$ -	$ 111	-$ 106	-$ 4	$ -	-$ 110	$ 1
10	1930	Transportation Equipment	$ 160	$ 20	-$ 0	$ 180	-$ 112	-$ 16	$ 0	-$ 128	$ 52
8	1935	Stores Equipment	$ 14	$ 3	$ -	$ 17	-$ 4	-$ 2	$ -	-$ 6	$ 11
8	1940	Tools, Shop & Garage Equipment	$ 1	$ 0	-$ 0	$ 1	$ 2	-$ 0	$ 0	$ 1	$ 2
8	1945	Measurement & Testing Equipment	$ 8	$ 2	$ -	$ 10	-$ 5	-$ 2	$ -	-$ 7	$ 3
8	1950	Power Operated Equipment	$ 217	$ -	$ -	$ 217	-$ 184	-$ 4	$ -	-$ 188	$ 29
8	1955	Communications Equipment	$ 884	$ 31	$ -	$ 915	-$ 432	-$ 36	$ -	-$ 468	$ 447
8	1960	Miscellaneous Equipment	$ 9	$ 2	$ -	$ 11	-$ 7	-$ 2	$ -	-$ 9	$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 672	$ 20	$ -	$ 692	-$ 714	-$ 53	$ -	-$ 767	-$ 75
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 8	$ -	-$ 0	$ 8	-$ 5	-$ 1	$ 0	-$ 5	$ 3
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
										$ -	
		Sub-Total	**$ 27,687.1**	**$ 1,599.8**	**-$ 55.7**	**$ 29,231.2**	**-$ 9,970.5**	**-$ 592.2**	**$ 56.7**	**-$ 10,506.0**	**$ 18,725**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 27,687.1**	**$ 1,599.8**	**-$ 55.7**	**$ 29,231.2**	**-$ 9,970.5**	**-$ 592.2**	**$ 56.7**	**-$ 10,506.0**	**$ 18,725**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 592**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 592

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
4. The additions in column (E) must not include construction work in progress (CWIP).
5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	2018

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 467	$ 67	$ -	$ 534	-$ 221	-$ 52	$ -	-$ 272	$ 262
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ 0	$ -	-$ 0	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ 0	$ -	-$ 0	$ -	-$ 0	-$ 0	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ 0	-$ 0	-$ 0	$ -	-$ 0	-$ 0	$ -	-$ 0	-$ 0
17	1675	Generators	$ 2	-$ 0	-$ 2	$ -	-$ 0	$ 0	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ 0	$ -	-$ 0	$ -	-$ 0	-$ 0	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 57	$ 0	-$ 0	$ 57	-$ 43	$ 0	$ -	-$ 43	$ 14
14.1	1806	Land rights	$ 233	$ 2	-$ 0	$ 235	-$ 79	-$ 2	$ 0	-$ 82	$ 154
47	1808	Buildings	$ 26	$ 0	$ 0	$ 26	-$ 3	-$ 0	$ -	-$ 4	$ 23
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 220	$ 8	$ -	$ 228	-$ 76	-$ 4	$ -	-$ 81	$ 148
47	1820	Distribution Station Equipment <50 kV	$ 712	$ 41	$ 2	$ 755	-$ 283	-$ 20	$ 1	-$ 301	$ 454
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,274	$ 261	-$ 38	$ 3,497	-$ 959	-$ 65	$ 29	-$ 996	$ 2,501
47	1835	Overhead Conductors & Devices	$ 2,096	$ 42	-$ 2	$ 2,136	-$ 699	-$ 33	$ 1	-$ 731	$ 1,405
47	1840	Underground Conduit	$ 24	$ 0	$ -	$ 24	-$ 14	$ 0	$ -	-$ 14	$ 10
47	1845	Underground Conductors & Devices	$ 937	$ 18	-$ 2	$ 953	-$ 503	-$ 24	$ 2	-$ 525	$ 428
47	1850	Line Transformers	$ 2,023	$ 69	-$ 18	$ 2,074	-$ 670	-$ 45	$ 17	-$ 698	$ 1,376
47	1855	Services (Overhead & Underground)	-$ 2	$ 73	$ -	$ 71	$ -	$ -	$ -	$ -	$ 71
47	1860	Meters	$ 151	-$ 4	-$ 39	$ 108	-$ 22	-$ 9	$ 39	$ 8	$ 116
47	1555	Meters (Smart Meters)	$ 433	$ -	-$ 87	$ 346	-$ 192	-$ 21	$ 87	-$ 127	$ 219
N/A	1905	Land	$ 19	$ 0	$ -	$ 20	$ -	$ -	$ -	$ -	$ 20
47	1908	Buildings & Fixtures	$ 186	$ 11	-$ 0	$ 197	-$ 78	-$ 3	$ 0	-$ 81	$ 117
13	1910	Leasehold Improvements	$ 29	$ 0	$ -	$ 29	-$ 12	-$ 2	$ -	-$ 13	$ 16
8	1915	Office Furniture & Equipment	$ 5	$ 0	-$ 0	$ 5	-$ 2	-$ 1	$ 0	-$ 3	$ 2
10	1920	Computer Equipment - Hardware	$ 31	$ 10	-$ 4	$ 37	-$ 18	-$ 6	$ 4	-$ 20	$ 18
	1925	Computer software	$ 97	$ -	$ -	$ 97	-$ 73	-$ 11	$ -	-$ 84	$ 12
10	1930	Transportation Equipment	$ 242	$ 2	-$ 19	$ 225	-$ 181	-$ 15	$ 18	-$ 177	$ 48
8	1935	Stores Equipment	$ 0	$ -	-$ 0	$ 0	$ 0	-$ 0	$ 0	$ 0	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 7	$ 1	-$ 1	$ 7	-$ 3	-$ 1	$ 1	-$ 4	$ 3
8	1945	Measurement & Testing Equipment	$ 6	$ 1	-$ 1	$ 6	-$ 3	-$ 1	$ 1	-$ 3	$ 3
8	1950	Power Operated Equipment	$ 157	$ 12	-$ 10	$ 159	-$ 81	-$ 18	$ 10	-$ 89	$ 70
8	1955	Communications Equipment	$ 38	$ 1	$ -	$ 39	-$ 32	-$ 7	$ -	-$ 25	$ 14
8	1960	Miscellaneous Equipment	$ 2	$ 0	-$ 0	$ 2	-$ 1	-$ 0	$ 0	-$ 1	$ 1
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 127	$ 9	$ -	$ 137	-$ 90	-$ 18	$ -	-$ 107	$ 29
47	1985	Miscellaneous Fixed Assets	$ 15	$ 0	-$ 0	$ 15	-$ 8	-$ 0	$ 0	-$ 8	$ 7
47	1990	Other Tangible Property	$ 10	$ 0	-$ 1	$ 9	-$ 6	-$ 1	$ 1	-$ 6	$ 3
47	1995	Contributions & Grants	$ -	$ 0	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	2440	Deferred Revenue[5]	$ -	$ 0	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
		Sub-Total	**$ 11,624.1**	**$ 627.8**	**-$ 223.0**	**$ 12,028.9**	**-$ 4,352.5**	**-$ 346.1**	**$ 212.7**	**-$ 4,486.0**	**$ 7,543.0**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	(64.5)	(0.0)		-64.5	10.7	3.9		14.6	-49.9
		Total PP&E	**$ 11,559.6**	**$ 627.8**	**-$ 223.0**	**$ 11,964.4**	**-$ 4,341.8**	**-$ 342.3**	**$ 212.7**	**-$ 4,471.4**	**$ 7,493.1**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 342**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 342

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year **2019**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 534	$ 62	-$ 0	$ 596	-$ 272	-$ 52	$ 0	-$ 324	$ 272
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 57	$ 0	-$ 0	$ 57	-$ 43	$ -	$ -	-$ 43	$ 14
14.1	1806	Land rights	$ 235	$ 6	$ -	$ 241	-$ 82	-$ 2	$ -	-$ 84	$ 157
47	1808	Buildings	$ 26	$ 0	$ -	$ 27	-$ 4	-$ 0	$ -	-$ 4	$ 22
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 228	$ 4	$ -	$ 232	-$ 81	-$ 4	$ -	-$ 85	$ 147
47	1820	Distribution Station Equipment <50 kV	$ 755	$ 47	$ 1	$ 803	-$ 301	-$ 20	$ 1	-$ 321	$ 482
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,497	$ 311	-$ 33	$ 3,774	-$ 996	-$ 72	$ 39	-$ 1,028	$ 2,746
47	1835	Overhead Conductors & Devices	$ 2,136	$ 7	-$ 1	$ 2,142	-$ 731	-$ 33	$ 1	-$ 763	$ 1,379
47	1840	Underground Conduit	$ 24	$ 0	$ -	$ 24	-$ 14	$ 0	$ 0	-$ 13	$ 11
47	1845	Underground Conductors & Devices	$ 953	$ 6	-$ 0	$ 959	-$ 525	-$ 24	$ -	-$ 549	$ 410
47	1850	Line Transformers	$ 2,074	$ 8	-$ 0	$ 2,082	-$ 698	-$ 45	$ 0	-$ 743	$ 1,339
47	1855	Services (Overhead & Underground)	$ 71	$ -	$ -	$ 71	$ -	$ -	$ -	$ -	$ 71
47	1860	Meters	$ 108	$ 84	-$ 0	$ 192	$ 8	-$ 12	$ 1	-$ 3	$ 189
47	1555	Meters (Smart Meters)	$ 346	$ -	-$ 7	$ 339	-$ 127	-$ 22	$ 7	-$ 141	$ 198
N/A	1905	Land	$ 20	$ 0	-$ 0	$ 20	$ -	$ -	$ -	$ -	$ 20
47	1908	Buildings & Fixtures	$ 197	$ 13	$ 0	$ 210	-$ 81	$ 1	$ -	-$ 80	$ 131
13	1910	Leasehold Improvements	$ 29	$ 0	$ -	$ 29	-$ 13	-$ 2	$ -	-$ 16	$ 13
8	1915	Office Furniture & Equipment	$ 5	$ 0	-$ 1	$ 5	-$ 3	-$ 1	$ 1	-$ 3	$ 2
10	1920	Computer Equipment - Hardware	$ 37	$ 8	-$ 6	$ 39	-$ 20	-$ 5	$ 6	-$ 18	$ 21
	1925	Computer software	$ 97	$ 0	$ -	$ 97	-$ 84	-$ 14	$ -	-$ 98	-$ 2
10	1930	Transportation Equipment	$ 225	$ 10	-$ 10	$ 225	-$ 177	-$ 12	$ 9	-$ 180	$ 45
8	1935	Stores Equipment	$ 0	$ -	-$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 7	$ 1	-$ 0	$ 7	-$ 4	-$ 1	$ 0	-$ 4	$ 3
8	1945	Measurement & Testing Equipment	$ 6	$ 1	-$ 2	$ 5	-$ 3	-$ 1	$ 2	-$ 2	$ 3
8	1950	Power Operated Equipment	$ 159	$ 12	-$ 3	$ 168	-$ 89	-$ 17	$ 3	-$ 104	$ 65
8	1955	Communications Equipment	$ 39	$ 1	$ -	$ 39	-$ 25	$ 8	$ -	-$ 17	$ 22
8	1960	Miscellaneous Equipment	$ 2	$ 1	-$ 1	$ 1	-$ 1	-$ 0	$ 1	$ 0	$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 137	$ 1	$ -	$ 137	-$ 107	-$ 19	-$ 0	-$ 126	$ 11
47	1985	Miscellaneous Fixed Assets	$ 15	$ 0	$ -	$ 15	-$ 8	-$ 0	$ -	-$ 9	$ 7
47	1990	Other Tangible Property	$ 9	$ 3	$ -	$ 12	-$ 6	-$ 1	$ 0	-$ 7	$ 5
47	1995	Contributions & Grants	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	2440	Deferred Revenue[5]	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -		$ 0
		Sub-Total	**$ 12,028.9**	**$ 585.1**	**-$ 64.6**	**$ 12,549.5**	**-$ 4,486.0**	**-$ 351.7**	**$ 72.9**	**-$ 4,764.8**	**$ 7,784.7**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	(64.5)	(4.4)		-68.9	14.6	4.3		18.9	-50.1
		Total PP&E	**$ 11,964.4**	**$ 580.7**	**-$ 64.6**	**$ 12,480.5**	**-$ 4,471.4**	**-$ 347.4**	**$ 72.9**	**-$ 4,745.9**	**$ 7,734.6**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 347**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 347

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	**2020**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 596	$ 79	-$ 1	$ 675	-$ 324	-$ 51	$ -	-$ 375	$ 300
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 57	$ 0	$ -	$ 57	-$ 43	$ -	$ -	-$ 43	$ 14
14.1	1806	Land rights	$ 241	$ 7	$ -	$ 247	-$ 84	-$ 2	$ -	-$ 86	$ 161
47	1808	Buildings	$ 27	$ 0	$ -	$ 27	-$ 4	-$ 0	$ -	-$ 5	$ 22
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 232	$ 4	$ -	$ 236	-$ 85	-$ 4	$ -	-$ 89	$ 147
47	1820	Distribution Station Equipment <50 kV	$ 803	$ 26	-$ 1	$ 828	-$ 321	-$ 22	-$ 0	-$ 343	$ 485
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,774	$ 366	-$ 26	$ 4,115	-$ 1,028	-$ 79	$ 31	-$ 1,075	$ 3,039
47	1835	Overhead Conductors & Devices	$ 2,142	$ 5	-$ 0	$ 2,146	-$ 763	-$ 32	$ 0	-$ 795	$ 1,351
47	1840	Underground Conduit	$ 24	$ 0	$ -	$ 24	-$ 13	$ 0	$ -	-$ 13	$ 11
47	1845	Underground Conductors & Devices	$ 959	$ 4	-$ 0	$ 963	-$ 549	-$ 24	$ 0	-$ 573	$ 390
47	1850	Line Transformers	$ 2,082	$ 9	-$ 1	$ 2,090	-$ 743	-$ 45	$ 1	-$ 787	$ 1,302
47	1855	Services (Overhead & Underground)	$ 71	$ -	$ -	$ 71	$ -	$ -	$ -	$ -	$ 71
47	1860	Meters	$ 192	$ 91	-$ 15	$ 268	-$ 3	-$ 18	$ 3	-$ 18	$ 250
47	1555	Meters (Smart Meters)	$ 339	$ -	$ -	$ 339	-$ 141	-$ 21	$ 13	-$ 149	$ 190
N/A	1905	Land	$ 20	$ 1	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 210	$ 36	$ -	$ 246	-$ 80	-$ 4	$ -	-$ 84	$ 162
13	1910	Leasehold Improvements	$ 29	$ 7	$ -	$ 37	-$ 16	-$ 2	$ -	-$ 18	$ 19
8	1915	Office Furniture & Equipment	$ 5	$ 1	-$ 1	$ 5	-$ 3	-$ 1	$ 1	-$ 3	$ 2
10	1920	Computer Equipment - Hardware	$ 39	$ 5	-$ 4	$ 40	-$ 18	-$ 7	$ 5	-$ 20	$ 19
	1925	Computer software	$ 97	$ 3	$ -	$ 100	-$ 98	-$ 4	$ -	-$ 102	-$ 2
10	1930	Transportation Equipment	$ 225	$ 5	-$ 14	$ 217	-$ 180	-$ 11	$ 12	-$ 179	$ 38
8	1935	Stores Equipment	$ 0	$ -	$ -	$ 0	$ 0	-$ 0	$ 0	$ 0	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 7	$ 1	-$ 1	$ 8	-$ 4	-$ 1	$ 1	-$ 5	$ 3
8	1945	Measurement & Testing Equipment	$ 5	$ 1	-$ 1	$ 6	-$ 2	-$ 1	$ 1	-$ 3	$ 3
8	1950	Power Operated Equipment	$ 168	$ 13	-$ 2	$ 179	-$ 104	-$ 16	$ 2	-$ 118	$ 61
8	1955	Communications Equipment	$ 39	$ 0	$ -	$ 39	-$ 17	$ 8	$ -	-$ 9	$ 30
8	1960	Miscellaneous Equipment	$ 1	$ 1	-$ 0	$ 2	$ 0	-$ 0	$ 1	$ 0	$ 3
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 137	$ 0	$ -	$ 137	-$ 126	-$ 16	$ -	-$ 142	-$ 4
47	1985	Miscellaneous Fixed Assets	$ 15	$ 0	-$ 0	$ 15	-$ 9	-$ 0	$ 0	-$ 9	$ 6
47	1990	Other Tangible Property	$ 12	$ 3	$ -	$ 14	-$ 7	-$ 1	$ -	-$ 8	$ 7
47	1995	Contributions & Grants	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	2440	Deferred Revenue[5]	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -		$ 0
		Sub-Total	**$ 12,549.5**	**$ 668.1**	**-$ 66.7**	**$ 13,150.9**	**-$ 4,764.8**	**-$ 355.4**	**$ 71.3**	**-$ 5,048.8**	**$ 8,102.1**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-68.9	-0.7		-69.6	18.9	4.4		23.3	-46.3
		Total PP&E	**$ 12,480.5**	**$ 667.4**	**-$ 66.7**	**$ 13,081.3**	**-$ 4,745.9**	**-$ 351.0**	**$ 71.3**	**-$ 5,025.5**	**$ 8,055.8**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 351**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 351

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year **2021**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 677	$ 60	$ -	$ 737	-$ 377	-$ 56	$ -	-$ 433	$ 304
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 58	$ 0	$ -	$ 59	-$ 43	$ 0	$ -	-$ 43	$ 16
14.1	1806	Land rights	$ 247	$ 4	$ -	$ 251	-$ 86	-$ 2	$ -	-$ 88	$ 162
47	1808	Buildings	$ 27	$ 32	$ -	$ 59	-$ 5	-$ 1	$ -	-$ 6	$ 53
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 236	$ 4	-$ 5	$ 236	-$ 92	-$ 5	$ 5	-$ 92	$ 143
47	1820	Distribution Station Equipment <50 kV	$ 829	$ 40	-$ 7	$ 861	-$ 344	-$ 23	$ 7	-$ 359	$ 502
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,113	$ 159	-$ 30	$ 4,242	-$ 1,035	-$ 69	$ 34	-$ 1,070	$ 3,172
47	1835	Overhead Conductors & Devices	$ 2,216	$ 98	-$ 21	$ 2,293	-$ 801	-$ 36	$ 23	-$ 813	$ 1,480
47	1840	Underground Conduit	$ 24	$ -	$ -	$ 24	-$ 15	-$ 0	$ -	-$ 15	$ 9
47	1845	Underground Conductors & Devices	$ 963	$ 18	-$ 2	$ 978	-$ 579	-$ 27	$ 3	-$ 603	$ 375
47	1850	Line Transformers	$ 2,087	$ 157	-$ 20	$ 2,224	-$ 794	-$ 50	$ 20	-$ 824	$ 1,400
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 270	$ 7	$ -	$ 277	-$ 25	-$ 23	$ -	-$ 48	$ 228
47	1555	Meters (Smart Meters)	$ 339	$ 7	$ -	$ 346	-$ 149	-$ 20	$ -	-$ 170	$ 176
N/A	1905	Land	$ 21	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 246	$ -	$ -	$ 246	-$ 85	-$ 4	$ -	-$ 89	$ 157
13	1910	Leasehold Improvements	$ 37	$ 3	$ -	$ 40	-$ 18	-$ 2	$ -	-$ 20	$ 20
8	1915	Office Furniture & Equipment	$ 5	$ 1	-$ 2	$ 3	-$ 3	-$ 1	$ 2	-$ 2	$ 2
10	1920	Computer Equipment - Hardware	$ 40	$ 6	-$ 4	$ 41	-$ 21	-$ 6	$ 4	-$ 22	$ 19
	1925	Computer software	$ 100	$ -	$ -	$ 100	-$ 102	-$ 3	$ -	-$ 105	-$ 5
10	1930	Transportation Equipment	$ 217	$ 23	-$ 9	$ 231	-$ 179	-$ 14	$ 9	-$ 185	$ 46
8	1935	Stores Equipment	$ 0	$ 1	$ -	$ 1	-$ 0	-$ 0	$ -	-$ 0	$ 1
8	1940	Tools, Shop & Garage Equipment	$ 8	$ 0	-$ 4	$ 4	-$ 5	-$ 1	$ 4	-$ 2	$ 2
8	1945	Measurement & Testing Equipment	$ 6	$ 1	-$ 1	$ 5	-$ 3	-$ 1	$ 1	-$ 2	$ 3
8	1950	Power Operated Equipment	$ 179	$ 2	-$ 0	$ 181	-$ 118	-$ 11	$ 0	-$ 129	$ 52
8	1955	Communications Equipment	$ 39	$ 8	$ -	$ 47	-$ 9	$ 8	$ -	-$ 1	$ 45
8	1960	Miscellaneous Equipment	$ 2	$ 1	-$ 0	$ 3	-$ 1	-$ 1	$ 0	-$ 1	$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 137	$ 69	$ -	$ 206	-$ 143	-$ 21	$ -	-$ 164	$ 42
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 9	-$ 0	$ -	-$ 10	$ 6
47	1990	Other Tangible Property	$ 14	$ -	-$ 3	$ 12	-$ 8	-$ 1	$ 3	-$ 6	$ 6
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
		Sub-Total	**$ 13,150.9**	**$ 700.1**	**-$ 109.4**	**$ 13,741.6**	**-$ 5,048.8**	**-$ 370.2**	**$ 116.2**	**-$ 5,302.8**	**$ 8,438.9**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	-69.6	-4.1	0	-73.7	23.3	4.1	0	27.4	-46.3
		Total PP&E	**$ 13,081.3**	**$ 696.1**	**-$ 109.4**	**$ 13,668.0**	**-$ 5,025.5**	**-$ 366.1**	**$ 116.2**	**-$ 5,275.4**	**$ 8,392.6**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 366**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 366

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	2022

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 737	$ 42	$ -	$ 779	-$ 433	-$ 60	$ -	-$ 493	$ 286
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 59	$ 1	$ -	$ 59	-$ 43	$ 0	$ -	-$ 43	$ 16
14.1	1806	Land rights	$ 251	$ 5	$ -	$ 256	-$ 88	-$ 2	$ -	-$ 91	$ 165
47	1808	Buildings	$ 59	$ 21	$ -	$ 80	-$ 6	-$ 1	$ -	-$ 7	$ 73
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 236	$ 8	-$ 4	$ 239	-$ 92	-$ 5	$ 4	-$ 93	$ 146
47	1820	Distribution Station Equipment <50 kV	$ 861	$ 31	-$ 7	$ 885	-$ 359	-$ 23	$ 7	-$ 375	$ 509
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,242	$ 163	-$ 33	$ 4,373	-$ 1,070	-$ 72	$ 33	-$ 1,108	$ 3,264
47	1835	Overhead Conductors & Devices	$ 2,293	$ 127	-$ 22	$ 2,398	-$ 813	-$ 37	$ 22	-$ 828	$ 1,570
47	1840	Underground Conduit	$ 24	$ -	$ -	$ 24	-$ 15	-$ 0	$ -	-$ 16	$ 8
47	1845	Underground Conductors & Devices	$ 978	$ 18	-$ 3	$ 993	-$ 603	-$ 27	$ 3	-$ 627	$ 366
47	1850	Line Transformers	$ 2,224	$ 168	-$ 20	$ 2,372	-$ 824	-$ 53	$ 20	-$ 857	$ 1,515
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 277	$ 7	$ -	$ 284	-$ 48	-$ 23	$ -	-$ 72	$ 213
47	1555	Meters (Smart Meters)	$ 346	$ 9	$ -	$ 355	-$ 170	-$ 21	$ -	-$ 191	$ 164
N/A	1905	Land	$ 21	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 246	$ -	$ -	$ 246	-$ 89	-$ 4	$ -	-$ 93	$ 153
13	1910	Leasehold Improvements	$ 40	$ 6	$ -	$ 46	-$ 20	-$ 2	$ -	-$ 22	$ 24
8	1915	Office Furniture & Equipment	$ 3	$ 1	-$ 2	$ 2	-$ 2	-$ 0	$ 2	-$ 0	$ 2
10	1920	Computer Equipment - Hardware	$ 41	$ 8	-$ 4	$ 45	-$ 22	-$ 6	$ 4	-$ 24	$ 22
	1925	Computer software	$ 100	$ -	$ -	$ 100	-$ 105	-$ 1	$ -	-$ 106	-$ 6
10	1930	Transportation Equipment	$ 231	$ 19	-$ 9	$ 240	-$ 185	-$ 16	$ 9	-$ 191	$ 49
8	1935	Stores Equipment	$ 1	$ 2	-$ 0	$ 2	-$ 0	-$ 0	$ 0	-$ 0	$ 2
8	1940	Tools, Shop & Garage Equipment	$ 4	$ 0	-$ 1	$ 3	-$ 2	-$ 1	$ 1	-$ 1	$ 1
8	1945	Measurement & Testing Equipment	$ 5	$ 3	-$ 2	$ 7	-$ 2	-$ 1	$ 2	-$ 2	$ 5
8	1950	Power Operated Equipment	$ 181	$ 2	-$ 0	$ 183	-$ 129	-$ 9	$ 0	-$ 138	$ 45
8	1955	Communications Equipment	$ 47	$ 9	$ -	$ 56	-$ 1	$ 9	$ -	$ 8	$ 64
8	1960	Miscellaneous Equipment	$ 3	$ 3	-$ 0	$ 6	-$ 1	-$ 1	$ 0	-$ 1	$ 5
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 206	$ 3	$ -	$ 209	-$ 164	-$ 25	$ -	-$ 189	$ 20
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 10	-$ 0	$ -	-$ 10	$ 5
47	1990	Other Tangible Property	$ 12	$ -	-$ 0	$ 12	-$ 6	-$ 1	$ 0	-$ 7	$ 5
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 13,741.6**	**$ 656.4**	**-$ 107.5**	**$ 14,290.5**	**-$ 5,302.8**	**-$ 384.9**	**$ 108.3**	**-$ 5,579.3**	**$ 8,711.2**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-73.7	(1.36)	0	-75.0	27.4	4.25	0	31.6	-43.4
		Total PP&E	**$ 13,668.0**	**$ 655.0**	**-$ 107.5**	**$ 14,215.5**	**-$ 5,275.4**	**-$ 380.7**	**$ 108.3**	**-$ 5,547.7**	**$ 8,667.8**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 381**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 381

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	2023

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 782	$ 46	$ -	$ 828	-$ 495	-$ 55	$ -	-$ 549	$ 279
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 60	$ 1	$ -	$ 60	-$ 43	-$ 1	$ -	-$ 43	$ 17
14.1	1806	Land rights	$ 256	$ 6	$ -	$ 263	-$ 91	-$ 2	$ -	-$ 93	$ 170
47	1808	Buildings	$ 81	$ 24	$ -	$ 105	-$ 7	-$ 2	$ -	-$ 9	$ 96
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 247	$ 14	-$ 8	$ 253	-$ 95	-$ 5	$ 8	-$ 92	$ 162
47	1820	Distribution Station Equipment <50 kV	$ 887	$ 50	-$ 12	$ 925	-$ 376	-$ 19	$ 12	-$ 382	$ 543
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,427	$ 241	-$ 57	$ 4,611	-$ 1,112	-$ 75	$ 58	-$ 1,130	$ 3,481
47	1835	Overhead Conductors & Devices	$ 2,435	$ 195	-$ 39	$ 2,592	-$ 832	-$ 38	$ 39	-$ 831	$ 1,761
47	1840	Underground Conduit	$ 35	$ -	$ -	$ 35	-$ 17	-$ 1	$ -	-$ 18	$ 17
47	1845	Underground Conductors & Devices	$ 1,013	$ 24	-$ 5	$ 1,032	-$ 631	-$ 25	$ 5	-$ 652	$ 380
47	1850	Line Transformers	$ 2,415	$ 198	-$ 34	$ 2,579	-$ 863	-$ 57	$ 34	-$ 885	$ 1,694
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 296	$ 16	$ -	$ 313	-$ 77	-$ 25	$ -	-$ 102	$ 210
47	1555	Meters (Smart Meters)	$ 355	$ 38	$ -	$ 394	-$ 191	-$ 22	$ -	-$ 213	$ 181
N/A	1905	Land	$ 21	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 249	$ -	$ -	$ 249	-$ 94	-$ 4	$ -	-$ 98	$ 151
13	1910	Leasehold Improvements	$ 46	$ 7	$ -	$ 53	-$ 22	-$ 2	$ -	-$ 25	$ 29
8	1915	Office Furniture & Equipment	$ 2	$ 1	-$ 0	$ 3	-$ 0	-$ 0	$ 0	-$ 0	$ 2
10	1920	Computer Equipment - Hardware	$ 46	$ 8	-$ 6	$ 47	-$ 24	-$ 7	$ 6	-$ 24	$ 23
	1925	Computer software	$ 100	$ -	$ -	$ 100	-$ 106	-$ 0	$ -	-$ 107	-$ 6
10	1930	Transportation Equipment	$ 241	$ 38	-$ 3	$ 276	-$ 191	-$ 19	$ 3	-$ 206	$ 69
8	1935	Stores Equipment	$ 2	$ 2	-$ 0	$ 4	-$ 0	-$ 0	$ 0	-$ 1	$ 3
8	1940	Tools, Shop & Garage Equipment	$ 3	$ 0	-$ 1	$ 2	-$ 2	-$ 1	$ 1	-$ 1	$ 1
8	1945	Measurement & Testing Equipment	$ 7	$ 3	-$ 1	$ 8	-$ 2	-$ 2	$ 1	-$ 2	$ 6
8	1950	Power Operated Equipment	$ 183	$ 4	$ -	$ 186	-$ 138	-$ 8	$ -	-$ 146	$ 41
8	1955	Communications Equipment	$ 57	$ 41	$ -	$ 98	$ 8	-$ 10	$ -	-$ 2	$ 96
8	1960	Miscellaneous Equipment	$ 6	$ 3	-$ 0	$ 9	-$ 1	-$ 2	$ 0	-$ 3	$ 6
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 210	$ 9	$ -	$ 219	-$ 190	-$ 22	$ -	-$ 212	$ 6
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 10	-$ 0	$ -	-$ 11	$ 5
47	1990	Other Tangible Property	$ 12	$ -	-$ 5	$ 7	-$ 7	-$ 1	$ 5	-$ 2	$ 4
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 14,490.3**	**$ 970.9**	**-$ 172.8**	**$ 15,288.4**	**-$ 5,609.8**	**-$ 402.9**	**$ 173.7**	**-$ 5,838.9**	**$ 9,449.4**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-75.0	(1.96)	0	-77.0	31.6	3.83	0	35.5	(41.51)
		Total PP&E	**$ 14,415.3**	**$ 969.0**	**-$ 172.8**	**$ 15,211.4**	**-$ 5,578.1**	**-$ 399.1**	**$ 173.7**	**-$ 5,803.5**	**9,407.93**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 399**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 399

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	2024

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 828	$ 43	$ -	$ 871	-$ 549	-$ 49	$ -	-$ 598	$ 273
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 60	$ 1	$ -	$ 61	-$ 43	-$ 1	$ -	-$ 44	$ 17
14.1	1806	Land rights	$ 263	$ 11	$ -	$ 274	-$ 93	-$ 2	$ -	-$ 96	$ 178
47	1808	Buildings	$ 105	$ 62	$ -	$ 168	-$ 9	-$ 3	$ -	-$ 12	$ 156
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 253	$ 10	-$ 8	$ 255	-$ 92	-$ 5	$ 8	-$ 88	$ 167
47	1820	Distribution Station Equipment <50 kV	$ 925	$ 67	-$ 13	$ 978	-$ 382	-$ 20	$ 13	-$ 388	$ 590
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,611	$ 232	-$ 61	$ 4,782	-$ 1,130	-$ 78	$ 61	-$ 1,147	$ 3,634
47	1835	Overhead Conductors & Devices	$ 2,592	$ 166	-$ 41	$ 2,717	-$ 831	-$ 40	$ 41	-$ 830	$ 1,888
47	1840	Underground Conduit	$ 35	$ -	$ -	$ 35	-$ 18	-$ 1	$ -	-$ 18	$ 17
47	1845	Underground Conductors & Devices	$ 1,032	$ 25	-$ 5	$ 1,052	-$ 652	-$ 25	$ 5	-$ 672	$ 380
47	1850	Line Transformers	$ 2,579	$ 193	-$ 37	$ 2,735	-$ 885	-$ 60	$ 37	-$ 909	$ 1,826
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 313	$ 19	$ -	$ 332	-$ 102	-$ 26	$ -	-$ 128	$ 204
47	1555	Meters (Smart Meters)	$ 394	$ 49	$ -	$ 442	-$ 213	-$ 24	$ -	-$ 236	$ 206
N/A	1905	Land	$ 21	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 249	$ -	$ -	$ 249	-$ 98	-$ 4	$ -	-$ 102	$ 147
13	1910	Leasehold Improvements	$ 53	$ 18	$ -	$ 72	-$ 25	-$ 3	$ -	-$ 27	$ 44
8	1915	Office Furniture & Equipment	$ 3	$ 1	-$ 0	$ 3	-$ 0	-$ 1	$ 0	-$ 1	$ 2
10	1920	Computer Equipment - Hardware	$ 47	$ 9	-$ 8	$ 49	-$ 24	-$ 7	$ 8	-$ 24	$ 25
	1925	Computer software	$ 100	$ -	$ -	$ 100	-$ 107	-$ 0	$ -	-$ 107	-$ 7
10	1930	Transportation Equipment	$ 276	$ 39	-$ 1	$ 314	-$ 206	-$ 24	$ 1	-$ 229	$ 85
8	1935	Stores Equipment	$ 4	$ 2	-$ 0	$ 6	-$ 1	-$ 1	$ 0	-$ 1	$ 5
8	1940	Tools, Shop & Garage Equipment	$ 2	$ 0	-$ 1	$ 2	-$ 1	-$ 1	$ 1	-$ 1	$ 1
8	1945	Measurement & Testing Equipment	$ 8	$ 3	-$ 1	$ 10	-$ 2	-$ 2	$ 1	-$ 3	$ 7
8	1950	Power Operated Equipment	$ 186	$ 4	$ -	$ 190	-$ 146	-$ 7	$ -	-$ 153	$ 37
8	1955	Communications Equipment	$ 98	$ 52	$ -	$ 150	-$ 2	-$ 16	$ -	-$ 18	$ 132
8	1960	Miscellaneous Equipment	$ 9	$ 3	-$ 1	$ 11	-$ 3	-$ 2	$ 1	-$ 4	$ 7
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 219	$ 18	$ -	$ 237	-$ 212	-$ 23	$ -	-$ 236	$ 1
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 11	-$ 0	$ -	-$ 11	$ 5
47	1990	Other Tangible Property	$ 7	$ -	-$ 2	$ 5	-$ 2	-$ 1	$ 2	-$ 1	$ 4
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
		Sub-Total	**$ 15,288.4**	**$ 1,027.3**	**-$ 179.7**	**$ 16,136.0**	**-$ 5,838.9**	**-$ 425.0**	**$ 180.6**	**-$ 6,083.4**	**$ 10,052.6**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-77.0	-2.0	0	-79.0	35.5	3.9	0	39.4	-39.6
		Total PP&E	**$ 15,211.4**	**$ 1,025.4**	**-$ 179.7**	**$ 16,057.0**	**-$ 5,803.5**	**-$ 421.1**	**$ 180.6**	**-$ 6,044.0**	**$ 10,013.0**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 421**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 421

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2025

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 871	$ 94	$ -	$ 965	-$ 598	-$ 53	$ -	-$ 652	$ 313
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 61	$ 1	$ -	$ 62	-$ 44	-$ 1	$ -	-$ 45	$ 18
14.1	1806	Land rights	$ 274	$ 9	$ -	$ 283	-$ 96	-$ 3	$ -	-$ 98	$ 185
47	1808	Buildings	$ 168	$ 42	$ -	$ 209	-$ 12	-$ 4	$ -	-$ 15	$ 194
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 255	$ 16	-$ 9	$ 262	-$ 88	-$ 5	$ 9	-$ 84	$ 178
47	1820	Distribution Station Equipment <50 kV	$ 978	$ 49	-$ 15	$ 1,013	-$ 388	-$ 20	$ 15	-$ 394	$ 619
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,782	$ 259	-$ 67	$ 4,974	-$ 1,147	-$ 81	$ 67	-$ 1,161	$ 3,813
47	1835	Overhead Conductors & Devices	$ 2,717	$ 218	-$ 45	$ 2,890	-$ 830	-$ 42	$ 46	-$ 826	$ 2,064
47	1840	Underground Conduit	$ 35	$ -	$ -	$ 35	-$ 18	-$ 1	$ -	-$ 19	$ 16
47	1845	Underground Conductors & Devices	$ 1,052	$ 26	-$ 5	$ 1,073	-$ 672	-$ 26	$ 5	-$ 693	$ 381
47	1850	Line Transformers	$ 2,735	$ 211	-$ 40	$ 2,906	-$ 909	-$ 64	$ 40	-$ 932	$ 1,974
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 332	$ 29	$ -	$ 361	-$ 128	-$ 27	$ -	-$ 156	$ 205
47	1555	Meters (Smart Meters)	$ 442	$ 81	$ -	$ 524	-$ 236	-$ 26	$ -	-$ 263	$ 261
N/A	1905	Land	$ 21	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 249	$ -	$ -	$ 249	-$ 102	-$ 4	$ -	-$ 106	$ 143
13	1910	Leasehold Improvements	$ 72	$ 13	$ -	$ 85	-$ 27	-$ 4	$ -	-$ 31	$ 54
8	1915	Office Furniture & Equipment	$ 3	$ 1	-$ 1	$ 3	-$ 1	-$ 1	$ 1	-$ 0	$ 2
10	1920	Computer Equipment - Hardware	$ 49	$ 12	-$ 13	$ 48	-$ 24	-$ 7	$ 13	-$ 18	$ 30
	1925	Computer software	$ 100	$ -	$ -	$ 100	-$ 107	-$ 0	$ -	-$ 108	-$ 7
10	1930	Transportation Equipment	$ 314	$ 40	-$ 2	$ 352	-$ 229	-$ 28	$ 2	-$ 255	$ 96
8	1935	Stores Equipment	$ 6	$ 2	$ -	$ 8	-$ 1	-$ 1	$ -	-$ 2	$ 6
8	1940	Tools, Shop & Garage Equipment	$ 2	$ 0	-$ 1	$ 1	-$ 1	-$ 1	$ 1	-$ 0	$ 1
8	1945	Measurement & Testing Equipment	$ 10	$ 3	-$ 2	$ 12	-$ 3	-$ 2	$ 2	-$ 4	$ 8
8	1950	Power Operated Equipment	$ 190	$ 4	-$ 0	$ 194	-$ 153	-$ 7	$ 0	-$ 160	$ 34
8	1955	Communications Equipment	$ 150	$ 87	$ -	$ 237	-$ 18	-$ 25	$ -	-$ 42	$ 195
8	1960	Miscellaneous Equipment	$ 11	$ 3	-$ 1	$ 14	-$ 4	-$ 3	$ 1	-$ 5	$ 8
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 237	$ 3	$ -	$ 240	-$ 236	-$ 24	$ -	-$ 260	-$ 20
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 11	-$ 0	$ -	-$ 11	$ 4
47	1990	Other Tangible Property	$ 5	$ -	-$ 0	$ 5	-$ 1	-$ 0	$ 0	-$ 1	$ 3
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 16,136.0**	**$ 1,203.4**	**-$ 200.9**	**$ 17,138.5**	**-$ 6,083.4**	**-$ 460.6**	**$ 201.8**	**-$ 6,342.2**	**$ 10,796.3**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-79.0	-1.1	0	-80.1	39.4	4.0	0.0	43.4	-36.7
		Total PP&E	**$ 16,057.0**	**$ 1,202.3**	**-$ 200.9**	**$ 17,058.4**	**-$ 6,044.0**	**-$ 456.6**	**$ 201.8**	**-$ 6,298.8**	**$ 10,759.6**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 457**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 457

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2026

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 965	$ 72	$ -	$ 1,037	-$ 652	-$ 58	$ -	-$ 709	$ 327
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 62	$ 1	$ -	$ 63	-$ 45	-$ 1	$ -	-$ 45	$ 18
14.1	1806	Land rights	$ 283	$ 6	$ -	$ 289	-$ 98	-$ 3	$ -	-$ 101	$ 188
47	1808	Buildings	$ 209	$ 21	$ -	$ 230	-$ 15	-$ 4	$ -	-$ 19	$ 211
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 262	$ 12	-$ 9	$ 266	-$ 84	-$ 5	$ 9	-$ 80	$ 185
47	1820	Distribution Station Equipment <50 kV	$ 1,013	$ 44	-$ 14	$ 1,042	-$ 394	-$ 21	$ 14	-$ 401	$ 641
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,974	$ 245	-$ 65	$ 5,153	-$ 1,161	-$ 85	$ 66	-$ 1,180	$ 3,973
47	1835	Overhead Conductors & Devices	$ 2,890	$ 184	-$ 44	$ 3,030	-$ 826	-$ 45	$ 44	-$ 827	$ 2,204
47	1840	Underground Conduit	$ 35	$ -	$ -	$ 35	-$ 19	-$ 1	$ -	-$ 19	$ 16
47	1845	Underground Conductors & Devices	$ 1,073	$ 25	-$ 5	$ 1,093	-$ 693	-$ 26	$ 5	-$ 714	$ 379
47	1850	Line Transformers	$ 2,906	$ 196	-$ 39	$ 3,063	-$ 932	-$ 68	$ 39	-$ 961	$ 2,102
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 361	$ 27	$ -	$ 387	-$ 156	-$ 29	$ -	-$ 185	$ 203
47	1555	Meters (Smart Meters)	$ 524	$ 74	$ -	$ 597	-$ 263	-$ 30	$ -	-$ 292	$ 305
N/A	1905	Land	$ 21	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 249	$ -	$ -	$ 249	-$ 106	-$ 4	$ -	-$ 110	$ 139
13	1910	Leasehold Improvements	$ 85	$ 7	$ -	$ 91	-$ 31	-$ 4	$ -	-$ 35	$ 56
8	1915	Office Furniture & Equipment	$ 3	$ -	-$ 0	$ 3	-$ 0	-$ 1	$ 0	-$ 1	$ 2
10	1920	Computer Equipment - Hardware	$ 48	$ 13	-$ 6	$ 54	-$ 18	-$ 8	$ 6	-$ 19	$ 35
	1925	Computer software	$ 100	$ -	$ -	$ 100	-$ 108	-$ 0	$ -	-$ 108	-$ 8
10	1930	Transportation Equipment	$ 352	$ 40	-$ 2	$ 390	-$ 255	-$ 31	$ 2	-$ 284	$ 105
8	1935	Stores Equipment	$ 8	$ 2	$ -	$ 9	-$ 2	-$ 1	$ -	-$ 3	$ 6
8	1940	Tools, Shop & Garage Equipment	$ 1	$ 0	-$ 2	-$ 0	-$ 0	-$ 0	$ 2	$ 1	$ 1
8	1945	Measurement & Testing Equipment	$ 12	$ 3	-$ 0	$ 15	-$ 4	-$ 3	$ 0	-$ 7	$ 8
8	1950	Power Operated Equipment	$ 194	$ 4	$ -	$ 198	-$ 160	-$ 6	$ -	-$ 166	$ 32
8	1955	Communications Equipment	$ 237	$ 79	$ -	$ 316	-$ 42	-$ 35	$ -	-$ 78	$ 238
8	1960	Miscellaneous Equipment	$ 14	$ 3	-$ 0	$ 17	-$ 5	-$ 3	$ 0	-$ 8	$ 8
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 240	$ 3	$ -	$ 243	-$ 260	-$ 25	$ -	-$ 285	-$ 42
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 11	-$ 0	$ -	-$ 12	$ 4
47	1990	Other Tangible Property	$ 5	$ -	$ -	$ 5	-$ 1	-$ 0	$ -	-$ 2	$ 3
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 17,138.5**	**$ 1,061.2**	**-$ 187.0**	**$ 18,012.7**	**-$ 6,342.2**	**-$ 496.6**	**$ 187.9**	**-$ 6,650.9**	**$ 11,361.8**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	-80.1	-1.1	0	-81.2	43.4	4.0	0	47.4	-33.8
		Total PP&E	**$ 17,058.4**	**$ 1,060.1**	**-$ 187.0**	**$ 17,931.5**	**-$ 6,298.8**	**-$ 492.6**	**$ 187.9**	**-$ 6,603.5**	**$ 11,328.0**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 493**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 493

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	2027

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ 1,037	$ 65	$ -	$ 1,102	-$ 709	-$ 59	$ -	-$ 769	$ 333
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1615	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1620	Buildings and fixtures	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
6	1665	Fuel holders, producers and acc.	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1675	Generators	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
17	1680	Accessory electric equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
N/A	1805	Land	$ 63	$ 1	$ -	$ 64	-$ 45	-$ 1	$ -	-$ 46	$ 18
14.1	1806	Land rights	$ 289	$ 10	$ -	$ 299	-$ 101	-$ 3	$ -	-$ 103	$ 195
47	1808	Buildings	$ 230	$ 45	$ -	$ 275	-$ 19	-$ 5	$ -	-$ 24	$ 251
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 266	$ 12	-$ 9	$ 269	-$ 80	-$ 5	$ 9	-$ 77	$ 192
47	1820	Distribution Station Equipment <50 kV	$ 1,042	$ 57	-$ 14	$ 1,085	-$ 401	-$ 22	$ 14	-$ 409	$ 676
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 5,153	$ 250	-$ 64	$ 5,339	-$ 1,180	-$ 88	$ 65	-$ 1,203	$ 4,136
47	1835	Overhead Conductors & Devices	$ 3,030	$ 187	-$ 43	$ 3,174	-$ 827	-$ 47	$ 44	-$ 830	$ 2,343
47	1840	Underground Conduit	$ 35	$ -	$ -	$ 35	-$ 19	-$ 1	$ -	-$ 20	$ 15
47	1845	Underground Conductors & Devices	$ 1,093	$ 28	-$ 5	$ 1,116	-$ 714	-$ 27	$ 5	-$ 736	$ 380
47	1850	Line Transformers	$ 3,063	$ 199	-$ 38	$ 3,224	-$ 961	-$ 71	$ 38	-$ 994	$ 2,230
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ 387	$ 26	$ -	$ 413	-$ 185	-$ 30	$ -	-$ 215	$ 198
47	1555	Meters (Smart Meters)	$ 597	$ 70	$ -	$ 667	-$ 292	-$ 33	$ -	-$ 325	$ 342
N/A	1905	Land	$ 21	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21
47	1908	Buildings & Fixtures	$ 249	$ -	$ -	$ 249	-$ 110	-$ 4	$ -	-$ 114	$ 134
13	1910	Leasehold Improvements	$ 91	$ 14	$ -	$ 106	-$ 35	-$ 5	$ -	-$ 40	$ 66
8	1915	Office Furniture & Equipment	$ 3	$ -	-$ 0	$ 2	-$ 1	-$ 1	$ 0	-$ 1	$ 1
10	1920	Computer Equipment - Hardware	$ 54	$ 14	-$ 2	$ 66	-$ 19	-$ 9	$ 2	-$ 26	$ 40
	1925	Computer software	$ 100	$ -	$ -	$ 100	-$ 108	$ -	$ -	-$ 108	-$ 8
10	1930	Transportation Equipment	$ 390	$ 42	-$ 1	$ 430	-$ 284	-$ 34	$ 1	-$ 317	$ 113
8	1935	Stores Equipment	$ 9	$ 2	$ -	$ 11	-$ 3	-$ 1	$ -	-$ 4	$ 7
8	1940	Tools, Shop & Garage Equipment	-$ 0	$ 0	-$ 0	$ 0	$ 1	-$ 0	$ 0	$ 1	$ 1
8	1945	Measurement & Testing Equipment	$ 15	$ 3	$ -	$ 18	-$ 7	-$ 4	$ -	-$ 10	$ 7
8	1950	Power Operated Equipment	$ 198	$ 4	$ -	$ 202	-$ 166	-$ 6	$ -	-$ 172	$ 30
8	1955	Communications Equipment	$ 316	$ 74	$ -	$ 391	-$ 78	-$ 45	$ -	-$ 123	$ 268
8	1960	Miscellaneous Equipment	$ 17	$ 3	$ -	$ 20	-$ 8	-$ 4	$ -	-$ 12	$ 8
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 243	$ 3	$ -	$ 246	-$ 285	-$ 25	$ -	-$ 310	-$ 64
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 12	-$ 0	$ -	-$ 12	$ 3
47	1990	Other Tangible Property	$ 5	$ -	-$ 0	$ 5	-$ 2	-$ 0	$ 0	-$ 2	$ 3
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
		Sub-Total	**$ 18,012.7**	**$ 1,107.8**	**-$ 177.2**	**$ 18,943.3**	**-$ 6,650.9**	**-$ 528.7**	**$ 178.1**	**-$ 7,001.5**	**$ 11,941.8**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-81.2	-1.1	0	-82.4	47.4	4.1	0	51.5	-30.9
		Total PP&E	**$ 17,931.5**	**$ 1,106.6**	**-$ 177.2**	**$ 18,861.0**	**-$ 6,603.5**	**-$ 524.6**	**$ 178.1**	**-$ 6,950.0**	**$ 11,911.0**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 525**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 525

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

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6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Construction Work in Progress
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
($M)

Line No.	Year	Opening Balance	Capital Expenditures	Transfers To Plant	Closing Balance
		(a)	(b)	(c)	(d)
Historical					
1	2018	1,044.1	955.1	(1,144.7)	854.6
2	2019	854.6	992.3	(1,055.4)	791.4
3	2020	791.4	1,131.1	(924.1)	998.4
4	2021-Forecast	998.4	1,141.5	(1,005.9)	1,134.0
Bridge					
5	2022	1,134.0	1,179.7	(1,381.6)	932.0
Test					
6	2023	932.0	1,434.0	(1,368.1)	997.9
7	2024	997.9	1,463.9	(1,332.4)	1,129.4
8	2025	1,129.4	1,450.4	(1,710.3)	869.5
9	2026	869.5	1,461.8	(1,280.3)	1,051.0
10	2027	1,051.0	1,448.2	(1,599.8)	899.5

Witness: Samir Chhelavda

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment - Construction Work in Progress
Historical (2018, 2019, 2020, 2021-Forecast), Bridge (2022) & Test (2023-2027) Years
Year Ending December 31
($M)

Line No.	Year	Opening Balance	Capital Expenditures	Transfers To Plant	Closing Balance
		(a)	(b)	(c)	(d)
Historical					
1	2018	196.8	530.1	(598.6)	128.4
2	2019	128.4	566.2	(548.6)	145.9
3	2020	145.9	666.2	(635.1)	177.0
4	2021-Forecast	177.0	714.0	(700.1)	190.9
Bridge					
5	2022	190.9	664.6	(656.4)	199.1
Test					
6	2023	202.2	1,005.1	(970.9)	236.4
7	2024	236.4	1,028.0	(1,027.3)	237.1
8	2025	237.1	1,120.8	(1,203.4)	154.4
9	2026	154.4	1,071.7	(1,061.2)	164.9
10	2027	164.9	1,070.9	(1,107.8)	128.0

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.

2023 Opening Balance reflects the integration of Acquired Utilities.

WORKING CAPITAL

1.0 INTRODUCTION

Working capital represents the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. Hydro One's working capital requirement for both the Transmission and Distribution businesses has been determined based on its utility-specific lead-lag study. Working capital is integral to Hydro One's financial stability in order to meet its obligations to customers.

In August 2020, Hydro One commissioned Guidehouse Inc.[1] (previously Navigant) to conduct two lead-lag studies for both the Transmission and Distribution businesses. Hydro One has used these studies to determine the net cash working capital requirements in the 2023-2027 test period. These studies use consistent methodologies that were previously approved in prior lead-lag studies filed by Hydro One Transmission and Distribution with updated information.

Consistent with past studies, Guidehouse's lead-lag studies filed in this Application for each of Transmission and Distribution take into consideration:

- the most important elements of revenue lags, including the service, billing and collection lags; and
- the most important elements of expense leads, such as payroll and benefits, cost of power (Distribution lead-lag study only), operations, maintenance, administration expenses, and taxes, including property taxes.

Both Guidehouse lead-lag studies are based on 2019 actual results, as 2019 was the latest full year of data available at the time the study was commissioned. Moreover, data from 2020

[1] Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. The local team in Toronto has been involved in the Ontario electricity sector for the past 20+ years with extensive knowledge in developing working capital lead lag studies for generation, transmission and distribution utilities and have had a team involved in developing lead lag studies in Ontario since 2009.

would not reflect normal business operations in the 2023 to 2027 rate period due to the impacts of the COVID-19 pandemic on operations in 2020, such as increased overdue accounts receivables which would increase working capital requirements.

The final lead-lag studies are included as the following attachments to this exhibit:

- Attachment 1 of Exhibit C-05-01 (Working Capital Requirements of Hydro One Networks' Transmission Business); and
- Attachment 2 of Exhibit C-05-01 (Working Capital Requirements of Hydro One Networks' Distribution Business).

2.0 TRANSMISSION

Hydro One Transmission's net cash working capital requirement for the 2023 test year is $17.8M, or 4.2% of total OM&A expenditures ($420.5M), as supported by the results of Guidehouse's study in Table 1 below. As compared with the 2019 year net cash working capital requirement of $24.8M from the prior 2017 study, the total amount of working capital proposed in 2023 is $7.0M lower. This decrease is mainly due to a reduction in revenue lag days associated with higher efficiency in collection of other revenues that are associated with services such as merchandising, jobbing, rents and leases of HONI property and increase in OM&A expense lead days. The results of Hydro One's current Transmission lead-lag study are compared to the results of Hydro One's prior Transmission lead-lag study in Section 5.1 (Comparison with Prior Study) of Attachment 1, page 5-16.

Table 1 summarizes the net cash working capital requirements for Hydro One Transmission, which are determined by using the lead-lag days from the study to reflect the 2023-2027 test year revenues, expenses and HST amounts. Table 2 shows the development of the HST working capital amounts.

Table 1 - Transmission Net Cash Working Capital Requirement

(All Data in $M Except Lead/Lag Days)

	Revenue Lag (Days)	**Expense Lead (Days)**	**Net Lag (Lead Days)**	**2023 Test Year**	**2024 Test Year**	**2025 Test Year**	**2026 Test Year**	**2027 Test Year**
	(A)	(B)	(C)=(A)-(B)	(D)	(E)	(F)	(G)	(H)
Expenses								
OM&A Expenses[2]	34.5	28.7	5.8	420.5	428.9	437.5	446.3	455.2
Income Tax	34.5	13.9	20.6	40.5	70.9	61.4	83.1	84.3
Interest Expense	34.5	11.3	23.3	330.4	349.8	372.5	393.9	413.4
Environmental Remediation	34.5	31.5	3.0	7.6	7.5	6.6	0.0	0.0
Removals	34.5	29.8	4.7	61.2	63.3	70.7	73.8	70.5
Total				**860.3**	**920.5**	**948.7**	**997.0**	**1,023.4**
HST				375.5	393.3	404.2	420.0	429.4
Total Amounts Paid/Accrued				**1,235.8**	**1,313.8**	**1,352.9**	**1,417.0**	**1,452.8**
Working Capital Required								
(Calculations based on above values, for each expense category, calculated using the following formula: For Test Years 2023 to 2027 (Col (D)*Col (C)/365))								
OM&A Expenses				6.7	6.8	6.9	7.1	7.2
Income Tax				2.3	4.0	3.5	4.7	4.8
Interest Expense				21.0	22.2	23.7	25.1	26.3
Environmental Remediation				0.1	0.1	0.1	0.0	0.0
Removals				0.8	0.8	0.9	1.0	0.9
Total				**30.9**	**33.9**	**35.1**	**37.8**	**39.2**
HST (see Table 2)				-13.1	-14.6	-16.2	-18.0	-19.4
Net Cash Working Capital Required[3]				**17.8**	**19.3**	**18.9**	**19.9**	**19.9**

**Source: Attachment 1 of Exhibit C-05-01, Tables 11 to 15, pages 4-12 to 4-14*

[2] 2024-27 OM&A Expenses are derived by escalating 2023 by 2.0% OEB-approved inflation factor per EB-2020-0202

[3] See Exhibit C-01-01 for the working capital requirement for materials and supplies.

Table 2 - Transmission Summary of HST Cash Working Capital Requirement

(All Data in $M Except Lead-Lag Days)

	HST Lead Time (Days)	Working Capital Factor	2023 Test Year	2024 Test Year	2025 Test Year	2026 Test Year	2027 Test Year
Revenue (external)	-46.6	-12.8%	-30.2	-32.1	-33.6	-35.5	-36.8
OM&A	43.7	12.0%	2.2	2.2	2.3	2.3	2.4
Environmental costs	45.4	12.4%	0.0	0.0	0.0	0.0	0.0
Removal costs	45.4	12.4%	0.1	0.1	0.1	0.1	0.1
Capital expenditures	45.4	12.4%	14.8	15.1	15.0	15.1	15.0
Total			**-13.1**	**-14.6**	**-16.2**	**-18.0**	**-19.4**

**Source: Attachment 1 of Exhibit C-05-01, Table 10, page 3-12*

Additional details of the calculation of the Transmission HST Cash Working Capital Requirement are shown on page 3-12 of Attachment 1 of Exhibit C-05-01.

3.0 DISTRIBUTION

Hydro One Distribution's net cash working capital requirement for the 2023 test year is $243.4M, or 6.1% of OM&A from revenue requirement and cost of power ($4.0B), as supported by the Guidehouse study.[4] As compared with the prior study working capital amount of $281.0M, the total amount of working capital in the test year has decreased by $37.6M mainly due to the reduction in the collections lag.[5] This reflects an improvement in Hydro One Distribution's ability to collect outstanding balances more efficiently.

Table 3 summarizes the net cash working capital requirements for Hydro One Distribution, including Acquired Utilities, which was determined by using the lead-lag days from the Guidehouse study to reflect the 2023-2027 test year revenues, expenses and HST amounts. Table 4 shows the development of the HST working capital amounts.

[4] See Attachment 2 of Exhibit C-01-05, page 4-14
[5] See Attachment 2 of Exhibit C-01-05, pages 5-17 and 5-18

Table 3 - Distribution Net Cash Working Capital Requirement

(All Data in $M Except Lead/Lag Days)

	Revenue Lag (Days)	**Expense Lag (Days)**	**Net Lag (Lead Days)**	**2023 Test Year**	**2024 Test Year**	**2025 Test Year**	**2026 Test Year**	**2027 Test Year**
	(A)	(B)	(C)=(A)-(B)	(D)	(E)	(F)	(G)	(H)
Expenses								
Cost of Power	48.4	34.2	14.2	3,422.8	3,422.5	3,419.4	3,418.7	3,418.3
OM&A Expenses[6]	48.4	29.8	18.6	597.5	608.9	620.4	632.2	644.2
Income Tax	48.4	13.9	34.5	37.2	54.6	42.4	59.2	68.7
Interest Expense	48.4	7.2	41.2	213.6	227.1	242.5	257.6	270.8
Environmental Remediation	48.4	30.0	18.3	5.5	5.4	1.0	0.0	0.0
Removals	48.4	28.1	20.3	79.2	78.5	83.9	83.4	86.6
Total				**4,355.8**	**4,396.9**	**4,409.7**	**4,451.0**	**4,488.6**
HST				1,203.3	1,215.2	1,231.2	1,240.4	1,251.8
Total Amounts Paid/Accrued				**5,559.1**	**5,612.1**	**5,640.9**	**5,691.4**	**5,740.4**
Working Capital Required								
(Calculations based on above values, for each expense category, calculated using the following formula: For Test Years 2023 to 2027 (Col (D)*Col (C)/365))								
Cost of Power				133.1	132.8	133.0	133.0	133.0
OM&A				30.5	31.0	31.7	32.3	32.9
Income & Capital Tax				3.5	5.1	4.0	5.6	6.5
Interest Expense				24.1	25.5	27.4	29.1	30.5
Environmental Costs				0.3	0.3	0.0	0.0	0.0
Removal Costs				4.4	4.4	4.7	4.6	4.8
Total				**195.9**	**199.1**	**200.7**	**204.5**	**207.7**
HST (see Table 2)				47.5	47.2	47.9	47.1	46.8
Distribution Net Cash Working Capital Required				**243.4**	**246.3**	**248.7**	**251.6**	**254.5**

**Source: Attachment 2 of Exhibit C-05-01, Tables 12 to 16, pages 4-14 to 4-16*

[6] To derive 2024-2027 values, 2023 OM&A Expenses are escalated by 1.9% (2.2% OEB-approved inflation per EB-2020-0030 less 0.3% stretch)

Table 4 - Distribution Summary of HST Cash Working Capital Requirement
(All Data in $M Except Lead-Lag Days)

	HST Lead Time (Days)	Working Capital Factor	2023 Test Year	2024 Test Year	2025 Test Year	2026 Test Year	2027 Test Year
Revenue (external)	-12.1	-3.3%	-21.7	-22.0	-22.3	-22.7	-23.1
Cost of power	46.6	12.8%	56.8	56.6	56.7	56.7	56.7
OM&A	42.9	11.8%	3.4	3.5	3.6	3.7	3.7
Removal costs	45.5	12.5%	0.1	0.1	0.2	0.2	0.2
Environmental costs	45.5	12.5%	0.0	0.0	0.0	0.0	0.0
Capital expenditures	45.5	12.5%	8.8	8.9	9.8	9.3	9.3
Total			**47.5**	**47.2**	**47.9**	**47.1**	**46.8**

**Source: Attachment 2 of Exhibit C-05-01, Table 11, page 3-13*

Additional details on the calculation of the Distribution HST Cash Working Capital Requirement is shown on page 3-13 of Attachment 2 of Exhibit C-05-01.

Working Capital Requirements of Hydro One Networks Inc.'s Transmission Business

2023 to 2027

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Disclaimer

This report (the "report") was prepared for Hydro One Networking Inc. ("HONI") by Guidehouse Inc. ("Guidehouse"). The report was prepared solely for the purposes of HONI's rate application to the Ontario Energy Board and may not be used for any other purpose. Use of this report by any third party outside of HONI's rate application is prohibited. Use of this report should not, and does not, absolve the third party from using due diligence in verifying the report's contents. Any use which a third party makes of this report, or any reliance on it, is the responsibility of the third party. Guidehouse extends no warranty to any third party.

Executive Summary

Guidehouse was retained by Hydro One Networks Inc. ("HONI") to calculate the working capital requirements of HONI's transmission business using a lead-lag study.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose. The results of this study are provided in this report.

The lead/lag days calculated in this study are based on HONI's revenue and expense data from 2019.[1] The working capital requirement of HONI's Transmission business is shown below, in Table 1.

Table 1. HONI Transmission Summary of Working Capital Requirements

Year	2023	2024	2025	2026	2027
Percentage of OM&A	4.2%	4.5%	4.3%	4.5%	4.4%
Working Capital Requirement ($M)	$17.8	$19.3	$18.9	$19.9	$19.9

The working capital requirements shown in Table 1 above are based upon the revenue lag and expense lead days shown in Table 2.

Table 2. HONI Transmission Working Lead / Lag Days (2019)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days
OM&A Expenses	34.52	28.73	5.79
Income Tax	34.52	13.92	20.61
Interest Expense	34.52	11.27	23.25
Environmental Remediation	34.52	31.54	2.98
Removals	34.52	29.77	4.75

[1] Note: Lead-lag studies use the most recent and accurate historical data available for calculating results. In this instance, revenue and expense data from 2019 was used instead of 2020, despite the recency of the 2020 data. It was Guidehouse' opinion that revenue and expense data from 2020 would not reflect "normal" business operations going forward (such as in 2023 to 2027), as operations may have been impacted by the COVID-19 pandemic in 2020.

1. Introduction and Methodology

Guidehouse Inc. was retained by Hydro One Networks Inc. ("HONI") to calculate the working capital requirements for HONI's transmission business. This report provides the results of the assessment and the working capital requirements of the transmission business.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to HONI (or "lag") together with the time between the date HONI receives goods and services from its vendors and the date that HONI pays for them (or "lead").

"Leads" and "Lags" are both measured in days and are dollar-weighted where appropriate. The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in HONI's rate base for the purpose of deriving revenue requirement.

HONI provided revenue and expense data to support the lead-lag study for both the 2018 and the 2019 calendar years.[2] Unless stated otherwise, Guidehouse leveraged the revenue and expense data for the full 2019 calendar year, as it was the most recent source of data provided.

1.1 Key Concepts

The following section outlines the key concepts used throughout this report to assess the working capital requirements of HONI's Transmission business. This include the mid-point method, statutory approach, expense lead components and dollar weighting.

1.1.1 Mid-Point Method

When a service is provided to (or by) HONI over a period of time, the service is deemed to have been provided (or received) evenly over the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using Equation 1-1.

[2] Note: Lead-lag studies use the most recent and accurate historical data available for calculating results. In this instance, revenue and expense data from 2019 was used instead of 2020, despite the recency of the 2020 data. It was Guidehouse' opinion that revenue and expense data from 2020 would not reflect "normal" business operations going forward (such as in 2023 to 2027), as operations may have been impacted by the COVID-19 pandemic in 2020.

Equation 1-1

$$Mid - Point = \frac{(Y - X) + 1}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. Equation 1-2 uses the number of days in a year ("A") and the number of periods in a year ("B"):

Equation 1-2

$$Mid - Point = \frac{A/B}{2}$$

1.1.2 Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made to (or by) HONI. In some instances, the due dates for payments are established by statute or by regulation. In these instances, the due date established by statute has been used in lieu of when payments were made.

1.1.3 Revenue Lag Components

As used in this study, revenue lags are comprised of IESO Revenues and Other Revenues. These revenue components are defined to consist of two components:

- Service Lag component (services are assumed to be provided by HONI evenly around the mid-point of the service period); and,
- Payment Lag component (the period from the end of the service period to the time payments are received and funds are available to HONI).

1.1.4 Expense Lead Components

As used in this study, expense leads are defined to consist of two components:

- Service Lead component (services are assumed to be provided to HONI evenly around the mid-point of the service period); and,
- Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left HONI's possession).

1.1.5 Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars flow.

1.2 Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated transmission business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of HONI's transmission operations, interviews with personnel within HONI's Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) HONI, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to transmission operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

2. Revenue Lags

A transmission utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by HONI until the date payments are received from customers and funds are available to HONI.

HONI receives revenue from the following funding streams:

- **IESO Revenue**; Revenue from the Independent Electric System Operator ("IESO"); and,
- **Other Revenue;** HONI staff indicated that its Transmission business receives additional funding from various sources, such as revenues from municipalities, electricity retailers and for miscellaneous services such as jobbing and contracting work performed by HONI.

A summary of the revenue lags for HONI's Transmission business is shown below.

Table 3. Summary of Retail Revenue Lag (2019)

Description	Amounts ($M)	Lag Time Days	Weighting Factor	Weighted Lag Time Days
IESO Revenue	$1,544.0	34.70	88.2%	30.61
Other Revenue	$206.5	33.19	11.8%	3.91
Total	**$1,750.5**		**100.0%**	**34.52**

2.1 IESO Revenue Lags

HONI receives revenues from the IESO monthly in a manner that is consistent with the settlement and payment procedures outlined in the IESO's tariff. Taking this information into account and using actual amounts and dates received for 2019, a revenue lag of 34.7 days was determined. The derivation is shown in Table 4 below.

Table 4: Summary of IESO Revenues (2019)

Period Beginning	Period Ending	Payment Date	Amounts ($M)	Weighting Factor	Service Lag Time	Payment Lag Time	Total Lag Time	Weighted Lag
1/1/2019	1/31/2019	2/19/2019	$134.5	8.7%	15.50	19.00	34.50	3.01
2/1/2019	2/28/2019	3/18/2019	$128.6	8.3%	14.00	18.00	32.00	2.67
3/1/2019	3/31/2019	4/18/2019	$125.3	8.1%	15.50	18.00	33.50	2.72
4/1/2019	4/30/2019	5/21/2019	$118.50	7.7%	15.00	21.00	36.00	2.76
5/1/2019	5/31/2019	6/20/2019	$107.9	7.0%	15.50	20.00	35.50	2.48
6/1/2019	6/30/2019	7/19/2019	$133.0	8.5%	15.00	19.00	34.00	2.91
7/1/2019	7/31/2019	8/21/2019	$146.4	9.5%	15.50	21.00	36.50	3.46
8/1/2019	8/31/2019	9/20/2019	$141.9	9.2%	15.50	20.00	35.50	3.26
9/1/2019	9/30/2019	10/21/2019	$128.3	8.3%	15.00	21.00	36.00	2.99
10/1/2019	10/31/2019	11/21/2019	$120.5	7.8%	15.50	21.00	36.50	2.85
11/1/2019	11/30/2019	12/19/2019	$126.6	8.2%	15.00	19.00	34.00	2.79
12/1/2019	12/31/2019	1/17/2020	$133.4	8.6%	15.50	17.00	32.50	2.80
Total			**$1,544.0**	**100.0%**				**34.70**

2.2 Other Revenue Lags

The lag time associated with other revenues is defined as the sum of an average service lag time and a dollar-weighted payment lag time. The expectation is that HONI bills monthly for services such as merchandising, jobbing, rents and leases of HONI property. Thus, the mid-point of a month (*i.e.*, 15.21 days) was used as indicative of the service lag time. Accounts receivable balances on other revenues for 2019 were reviewed to determine a dollar-weighted payment lag which was determined to be 33.19 days.

After considering both the IESO Revenue Lag and the Other Revenue Lag, the total retail revenue lag is determined as 34.52 days.

3. Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by HONI, and the lead times associated with payments for services provided to HONI. Expense Leads are defined as the time period between when a service is provided to HONI and when payment is required for that service.

The following expense leads were calculated in this study:

- Interest on HONI'S debt;
- Incomes taxes;
- Operations, Maintenance and Administration ("OM&A") expenses;
- Removal & Environmental Remediation Costs; and,
- Harmonized Sales Tax ("HST").

3.1 Interest on Debt

HONI makes interest payments on its long and short-term debt. Such payments are generally made twice a year. Considering the various bonds and other long-term debt instruments, a dollar-weighted expense lead time of 11.27 days was determined for the 2019 calendar year.

Table 5: Interest Expenses (2019)

Description	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Interest Expense	$279.8	11.27	100.0%	11.27
Total	**$279.8**		**100.0%**	**11.27**

3.2 Income Taxes

HONI is liable to make payments to the relevant taxing authorities. Typically, payments are made monthly by HONI, occurring close to the calendar end-of-month. In 2019, HONI Transmission made payments of $2,750,000 on the last day of every month in the year.

Table 6: Income Tax Expenses (2019)

Description	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Income Tax	$33.0	13.92	100.0%	13.92
Total	**$33.0**		**100.0%**	**13.92**

3.3 Operations, Maintenance and Administration ("OM&A")

The following expenses are included in the calculation of lead days for OM&A expenses:

- **Payroll and Benefits**; this line item includes basic payroll, payroll withholdings, and benefit expenses related to the regulated utility. HONI staff provided the breakdown of payroll, payroll withholding and benefits expenses for affiliate and non-affiliate staff, and an allocation factor was applied to the expenses to ensure that only expenses related to the regulated utility were included.

- **Property Tax;** this line item includes property tax payments to various municipalities or taxing authorities in the Province of Ontario. These payments are made in a given year for the given year and are typically made in installments.

- **Corporate Procurement Card**; this line item includes credit card expenses related to OM&A.

- **Lease Payments;** this line item includes payments made on the properties HONI uses for their operations. HONI has five properties that it makes monthly lease payments for.

- **Payments to Inergi;** this line item includes payments made to Inergi (a division of CapGemini) provides a number of services to HONI.

- **Consulting and Contracting Services;** this line item includes the provision of outside services to HONI.

- **Miscellaneous OM&A;** this line item includes miscellaneous OM&A expenses non-related to the procurement of Outside Services.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 28.73 days for OM&A expenses.

Table 7: Summary of OM&A Expenses (2019)

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Payroll and Benefits	$541.1	51.6%	26.33	13.57
Property Taxes	$76.7	7.3%	(23.21)	(1.70)
Corporate Procurement Card	$21.1	2.0%	30.09	0.61
Lease Payments	$7.6	0.7%	(14.20)	(0.10)
Payments to Inergi	$60.1	5.7%	75.12	4.30
Consulting and Contract Staff	$41.9	4.0%	50.80	2.03
Miscellaneous OM&A	$301.0	28.7%	34.94	10.02
Total	**$1,049.5**	**100.0%**		**28.73**

3.3.1 Payroll and Benefits

The following items were considered to be expenses related to the payroll and benefits of HONI's Transmission business:

1. Contributions made by HONI to the HONI Pension Plan[3];
2. Payments made by HONI to the Worker Safety Improvement Board ("WSIB");
3. Payments made by HONI for the Employer Health Tax ("EHT");
4. Union Benefits, Group Health, Dental, and Life Insurance related administrative fees and claims;
5. Five types of payroll including Basic & Management, Construction, CSO W2, Board of Directors and Supervisor Pension payroll; and,
6. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings for each of the payroll types.

When all payroll, withholdings and benefits were dollar-weighted using actual payment data, the weighted average expense lead time associated with payroll and benefits was determined to be 26.10 days as shown in Table 8 below.

Table 8: Summary of Payroll & Benefits Expenses (2019)

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Pensions	$35.5	6.6%	44.77	2.94
WSIB	$3.6	0.7%	42.77	0.28
Employee Health Tax	$8.7	1.6%	30.60	0.49
Group Benefits	$50.9	9.4%	9.70	0.91
Payroll	$297.9	55.1%	22.53	12.40
Payroll Withholdings	$144.5	26.7%	34.83	9.30
Total	**$541.1**	**100.0%**		**26.33**

3.3.2 Property Taxes

HONI makes property tax payments to several municipalities and taxing authorities in the Province of Ontario. These payments are made in a given year for the given year's property taxes and are typically made in installments. Using actual payment dates and amounts associated with HONI's transmission business for calendar year 2019, a dollar-weighted expense lead (-lag) time of -23.21 days was determined.

[3] Contributions made by HONI for the HONI Pension Plan were based on 2018 data (instead of 2019) as the 2018 contributions were deemed to be more indicative of what HONI Pension Plan payments are expected to be within the filing period.

3.3.3 Corporate Procurement Card

Procurement (or charge) cards are used by the HONI's employees for a variety of company related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on actual invoices from the HONI's charge card provider and payments made by HONI, a dollar-weighted expense lead time of 30.09 days was determined.

3.3.4 Lease Payments

HONI leases office space to support its ongoing transmission operations in several different locations. HONI presently has leases for Bay Street, Atrium, Barrie, Mississauga and Mural locations. HONI generally makes its lease payments on or around the end of the month prior for the current month. Taking this information into account and using actual invoices and payments for 2019, a dollar-weighted expense lead (-lag) time of -14.20 days was determined.

3.3.5 Payments to Inergi

Inergi (a division of CapGemini) provides a number of services to HONI including (and not limited to) customer service operations, finance, human resources, accounts payable, information technology, IESO settlement services, and supply management services. Based on a review of payments made by HONI to Inergi in 2019, a dollar-weighted expense lead time of 75.12 days was determined.

3.3.6 Consulting and Contract Staff

HONI engages consulting and contract staff to provide assistance in the areas of engineering, environmental services, receivables management, accounting, and general consulting. A dollar-weighted expense lead time of 50.80 days was determined based on a review of invoices rendered and payments made by HONI in 2019.

3.3.7 Miscellaneous OM&A

This category of expense includes items such as product purchases, equipment rentals, and provision of general services to HONI. Based on transactions in HONI's accounts payable system under this category, a dollar-weighted expense lead time of 34.94 days was derived.

3.4 Removal and Environmental Remediation Costs

HONI incurs costs when removing or replacing equipment from existing sites or right of ways. Further, costs relating to environmental remediation at these sites are also incurred. While costs are required to be reported as a depreciation and amortization expense for accounting purposes, there is a cash flow impact associated with HONI's expenditures on such removal and environmental remediation costs. Based upon discussions with HONI staff, estimates for the derivation of removal and environmental remediation costs were determined and summarized in Table 9 below.

Table 9: Summary of Removal and Environmental Remediation Expenses (2019)

Description	Expense Lead Time	Weighting Factor	Weighted Lead Time
Removal			
HONI Labour	26.33	60.0%	15.80
HONI Materials	34.94	40.0%	13.98
External Labour	50.80	0.0%	0.00
External Materials	34.94	0.0%	0.00
Total		**100.0%**	**29.77**
Environmental Remediation			
HONI Labour	26.33	61.5%	16.19
HONI Materials	34.94	23.0%	8.03
External Labour	50.80	12.0%	6.08
External Materials	34.94	3.6%	1.24
Total		**100.0%**	**31.54**

3.5 Harmonized Sales Tax

The expense lead times associated with the following items that attract HST were considered in HONI's transmission lead-lag study.

1. IESO Revenues;
2. OM&A[4]; and,
3. Removals, Environmental Remediation and Capital Costs.

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in Table 10. Note that the statutory approach described at the outset was used to determine the expense lead times associated with HONI's remittances and disbursements of HST (*i.e.,* both remittances and collections are generally on the last day of the month following the date of the applicable invoice).

Table 10: Summary of HST Working Capital Amounts

Description	HST Lead Time	2023 ($M)	2024 ($M)	2025 ($M)	2026 ($M)	2027 ($M)
IESO Revenues	(46.58)	($30.2)	($32.1)	($33.6)	($35.5)	($36.8)
OM&A Expenses	43.75	$2.2	$2.2	$2.3	$2.3	$2.4
Environmental Remediation	45.43	$0.0	$0.0	$0.0	$0.0	$0.0
Removals	45.43	$0.1	$0.1	$0.1	$0.1	$0.1
Capital	45.43	$14.8	$15.1	$15.0	$15.1	$15.0
Total		**($13.1)**	**($14.6)**	**($16.2)**	**($18.0)**	**($19.4)**

[4] Costs within OM&A that attract HST include Corporate Procurement Card, Trinity Lease Payments, Payments to Inergi, Consulting and Contract Staff and Miscellaneous OM&A.

4. Working Capital Requirements

Guidehouse applied the results of the revenue lags and expense leads to HONI's expenses to calculate the working capital requirements for HONI's regulated Transmission business. The working capital requirements, based on the 2019 revenue and expense data, is calculated to be $14.98 million, or 2.95% of OM&A expenses.

Table 11 to Table 15 below summarize HONI's working capital requirements for 2023 to 2027.

Table 11: HONI Working Capital Requirements (2023)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	34.52	28.73	5.79	1.6%	$420.5	$6.7
Income Tax	34.52	13.92	20.61	5.6%	$40.5	$2.3
Interest Expense	34.52	11.27	23.25	6.4%	$330.4	$21.0
Environmental Remediation	34.52	31.54	2.98	0.8%	$7.6	$0.1
Removals	34.52	29.77	4.75	1.3%	$61.2	$0.8
Total					**$860.3**	**$30.9**
HST						($13.1)
Total – Including HST						**$17.8**
Working Capital as a Percent of OM&A						**4.2%**

Table 12: HONI Working Capital Requirements (2024)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	34.52	28.73	5.79	1.6%	$428.9	$6.8
Income Tax	34.52	13.92	20.61	5.6%	$70.9	$4.0
Interest Expense	34.52	11.27	23.25	6.4%	$349.8	$22.2
Environmental Remediation	34.52	31.54	2.98	0.8%	$7.5	$0.1
Removals	34.52	29.77	4.75	1.3%	$63.3	$0.8
Total					**$920.5**	**$33.9**
HST						($14.6)
Total - Including HST						**$19.3**
Working Capital as a Percent of OM&A						**4.5%**

Table 13: HONI Working Capital Requirements (2025)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	34.52	28.73	5.79	1.6%	$437.5	$6.9
Income Tax	34.52	13.92	20.61	5.6%	$61.4	$3.5
Interest Expense	34.52	11.27	23.25	6.4%	$372.5	$23.7
Environmental Remediation	34.52	31.54	2.98	0.8%	$6.6	$0.1
Removals	34.52	29.77	4.75	1.3%	$70.7	$0.9
Total					**$948.7**	**$35.1**
HST						($16.2)
Total - Including HST						**$18.9**
Working Capital as a Percent of OM&A						**4.3%**

Table 14: HONI Working Capital Requirements (2026)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	34.52	28.73	5.79	1.6%	$446.3	$7.1
Income Tax	34.52	13.92	20.61	5.6%	$83.1	$4.7
Interest Expense	34.52	11.27	23.25	6.4%	$393.9	$25.1
Environmental Remediation	34.52	31.54	2.98	0.8%	$0.0	$0.0
Removals	34.52	29.77	4.75	1.3%	$73.8	$1.0
Total					**$997.0**	**$37.8**
HST						($18.0)
Total - Including HST						**$19.9**
Working Capital as a Percent of OM&A						**4.5%**

Table 15: HONI Working Capital Requirements (2027)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	34.52	28.73	5.79	1.6%	$455.2	$7.2
Income Tax	34.52	13.92	20.61	5.6%	$84.3	$4.8
Interest Expense	34.52	11.27	23.25	6.4%	$413.4	$26.3
Environmental Remediation	34.52	31.54	2.98	0.8%	$0.0	$0.0
Removals	34.52	29.77	4.75	1.3%	$70.5	$0.9
Total					**$1,023.4**	**$39.2**
HST						($19.4)
Total - Including HST						**$19.9**
Working Capital as a Percent of OM&A						**4.4%**

Guidehouse completed a 2017 working capital study for HONI's Transmission business, to be used in HONI's rebasing proceeding filed with the Ontario Energy Board. This prior study, based on 2017 revenue and expense data, resulted in a working capital requirement of $24.75M. The working capital requirements represented 5.90% of OM&A.

As compared with the prior study, the total amount of working capital for the current study is lower. In 2019, the working capital requirement is calculated to be $14.98M compared to $24.75M in the prior study. Additionally, the working capital as a percentage of OM&A expenses is lower (2.95% in the current study versus 5.90% in the prior study).

In this study, the OM&A expenses have increased significantly, reducing working capital as a percentage of OM&A expenses. Otherwise, HONI's operations have been consistent throughout both study periods. As such, the results of this current study are in-line with expectations based upon discussions with HONI staff.

5. Findings and Conclusions

The purpose of this section is to compare the results from this study to HONI’s prior working capital transmission study as per EB-2019-0082. In addition, this section demonstrates that the results from this study reflect the current operations of HONI.

5.1 Comparison with Prior Study

Table 16: HONI Transmission Working Capital Requirements (2019), Prior 2017 Study

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	35.52	26.76	8.76	2.4%	$419.6	$10.1
Income Tax	35.52	19.77	15.75	4.3%	$97.1	$4.2
Interest Expense	35.52	8.17	27.34	7.5%	$301.7	$22.6
Environmental Remediation	35.52	14.63	20.89	5.7%	$10.8	$0.6
Removals	35.52	23.66	11.85	3.3%	$77.5	$2.5
Total					**$906.7**	**$40.0**
HST						($15.2)
Total - Including HST						**$24.8**
Working Capital as a Percent of OM&A						**5.9%**

Table 17: HONI Transmission Working Capital Requirements (2023), Current Study

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	34.52	28.73	5.79	1.6%	$420.5	$6.7
Income Tax	34.52	13.92	20.61	5.6%	$40.5	$2.3
Interest Expense	34.52	11.27	23.25	6.4%	$330.4	$21.0
Environmental Remediation	34.52	31.54	2.98	0.8%	$7.6	$0.1
Removals	34.52	29.77	4.75	1.3%	$61.2	$0.8
Total					**$860.3**	**$30.9**
HST						($13.1)
Total – Including HST						**$17.8**
Working Capital as a Percent of OM&A						**4.2%**

Table 18: HONI Transmission Working Capital Requirements (Current versus Prior)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	(1.00)	1.97	(2.97)	(0.8%)	$0.9	($3.4)
Income Tax	(1.00)	(5.85)	4.86	1.3%	($56.6)	($1.9)
Interest Expense	(1.00)	3.10	(4.09)	(1.1%)	$28.7	($1.6)
Environmental Remediation	(1.00)	16.91	(17.91)	(4.9%)	($3.2)	($0.6)
Removals	(1.00)	6.11	(7.10)	(1.9%)	($16.3)	($1.7)
Total					**($46.4)**	**($9.1)**
HST						$2.1
Total - Including HST						**($7.0)**
Working Capital as a Percent of OM&A						**(1.7%)**

5.1.1 Revenue Lag

One of the largest drivers of working capital requirements is the revenue lag time. This line item remained consistent across the two studies, with the current result (34.52 days) representing a very slight decrease from the prior study (35.52 days). In both studies, the revenue lag is comprised of the lag time from two revenue line items: IESO Revenues and Other Revenues.

IESO Revenue lag is consistent across both study periods, with a result of 34.70 days in the current study and 33.60 days in the prior study. This represents a slight increase in lag from IESO revenues, indicating that the delay of receiving revenues from IESO has increased since the prior study.

Other Revenue lag has decreased significantly since the prior study, with a result of 33.19 days in the current study and 52.60 days in the prior study. This result is primarily driven by the collection of revenue; in the current study, a greater percentage of revenue is collected efficiently. In the prior study, there was a greater weighting of revenue in larger aging buckets (i.e. 120+ days). The large decrease in lag from Other Revenue offsets the slight increase from IESO Revenues, with a net decrease of 1 day.

5.1.2 OM&A Expenses

The weighted OM&A expense lead time has increased from 26.76 days in the prior study to 28.73 days in the current study. Below, the individual line items comprising the OM&A expense lead time are compared across the two study periods.

Table 19. OM&A Expense Lead Comparison

Description	Current Study			Prior Study		
	Lead Days	Expenses ($M)	Weighted Lead Days	Lead Days	Expenses ($M)	Weighted Lead Days
Payroll and Benefits	26.33	$541.1	13.57	20.29	$551.7	10.79
Property Taxes	(23.21)	$76.7	(1.70)	(22.24)	$51.8	(1.11)
Corporate Procurement Card	30.09	$21.1	0.61	29.58	$27.8	0.79
Lease Payments	(14.20)	$7.6	(0.10)	(14.25)	$3.8	(0.05)
Payments to Inergi	75.12	$60.1	4.30	83.12	$61.9	4.96
Consulting & Contract Staff	50.80	$41.9	2.03	(0.98)	$63.1	(0.06)
Miscellaneous OM&A	34.94	$301.0	10.02	42.79	$277.3	11.44
Total			**28.73**		**$1,037.5**	**26.76**

As shown in the table above, the majority of expenses have consistent lead times across the two studies. The most notable increase from the previous study is for Payroll and Benefits, which increases from 20.29 days in the prior study to 26.33 days in the current study.

There are three line items which contribute to the increased lead time for Payroll and Benefits. These items, listed in order of impact to the resulting lead day calculation are Payroll, Payroll Withholdings and Pensions. The increase in Payroll can be attributed to the inclusion of an annual bonus in the Basic & Management payroll data; the annual service period contributes to larger lead time. No annual bonuses were included in the prior study. The bonus has a similar impact on the Payroll Withholdings.

5.1.3 Income Tax Expense

The lead time for Income Tax Expenses decreased from 19.77 days in the prior study to 13.92 days in the current study. In the current study, the payments, on average, were paid 0.5 days prior to the end of the calendar month; in the previous study, the payments were paid 0.9 days prior to the end of the month, increasing the payment lag. However, in the prior study, an additional top-up payment was paid in September, increasing the overall lag time.

5.1.4 Interest Expense

The lead time for Interest Expenses increased from 8.17 days in the prior study to 11.27 days in the current study. This change is primarily driven by a slight increase in the frequency of payments occurring in the latter half of the year, resulting in a larger expense lead, and a slight increase in the average weighted-lead time for payments occurring in the first half of the year. For instance, the weighted lead time for January, March and April have all increased slightly from the prior study, while the frequency of payments in October, November and December slightly increased. These two factors compound to create an overall slight increase in the lead time.

Table 20. Interest Expense Lead Comparison

Month	Current Study		Prior Study	
	Frequency of Payments	Weighted Lead Time	Frequency of Payments	Weighted Lead Time
January	6	(15.12)	5	(17.84)
February	4	(4.49)	0	0.00
March	4	(6.75)	5	(7.86)
April	7	(8.36)	6	(10.19)
May	2	(2.49)	1	(2.00)
June	8	(2.93)	7	(3.05)
July	5	1.90	5	2.35
August	3	1.73	3	2.09
September	3	4.27	5	5.31
October	7	10.53	6	14.24
November	2	8.13	1	6.76
December	8	24.86	7	18.36
Total		**11.27**		**8.17**

5.1.5 Removals & Environmental Remediation

Removals and environmental remediation had a weighted expense lead days of 31.54 days and 29.77 days respectively; these items have increased by 16.91 and 6.11 days respectively in this study versus the prior study. These changes are driven by a few factors. Firstly, the HONI Labour component of both expense items has a lead time equivalent to that of Payroll and Benefits, which has increased since the prior study. Secondly, the weighting of Labour and Materials has shifted since the prior study, with a heavier weighting on the materials component, which has a larger lead time than Labour (40.7 days versus 26.3 days). In the previous study, for Removals, this weighting was 85/15 in favor of Labour; in the current study, the weighting has shifted to 60/40 in favor of Labour. These two factors combine for an increase to the expense lead time for both categories.

5.2 Comparison with the Prior Working Capital Study Using Constant Revenue Lag Days

The revenue lag day often has the largest impact on results in cash working capital studies, as the net lag day for each expense item is dependent on its value. This section has analyzed the various differences between this study and the prior study conducted for the Transmission business.

In these two studies, the revenue lag day result was largely consistent, decreasing only 1.00 day across the two study periods (35.52 in the previous study versus 34.52 in the current study). The table below analyzes the results of the current study if the revenue lag day from the prior study was held constant. Comparing this table with Table 18 demonstrates that utilizing the prior study's value would increase the difference between the two studies; the working capital result of the study would increase to $20.1M, as compared to the current result of $17.8M. The current study has a lower working capital requirement than the prior study; if the revenue lag day result was held constant at the prior study value, the working capital result would instead become larger than the prior study.

Table 21: Working Capital Requirements with Revenue Lag Days Held Constant (Current versus Prior)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
OM&A Expenses	0.00	1.97	(1.97)	(0.5%)	$0.9	($2.2)
Income Tax	0.00	(5.85)	5.85	1.6%	($56.6)	($1.8)
Interest Expense	0.00	3.10	(3.09)	(0.8%)	$28.7	($0.7)
Environmental Remediation	0.00	16.91	(16.91)	(4.6%)	($3.2)	($0.5)
Removals	0.00	6.11	(6.10)	(1.7%)	($16.3)	($1.6)
Total					**($46.4)**	**($6.8)**
HST						$2.1
Total - Including HST						**($4.6)**
Working Capital as a Percent of OM&A						**(1.1%)**

Consultants:

Name	**Craig Sabine** Director	**Andy Tam** Associate Director	**Adam Green** Senior Consultant
Business Name and Address	Guidehouse First Canadian Place, 100 King St W | Suite 4950 | Toronto, ON M5X 1B1 | Canada	Guidehouse First Canadian Place, 100 King St W | Suite 4950 | Toronto, ON M5X 1B1 | Canada	Guidehouse First Canadian Place, 100 King St W | Suite 4950 | Toronto, ON M5X 1B1 | Canada
General Areas of Expertise	• Portfolio assessment and business planning • Cost-benefit analysis • Cost Allocation and affiliates • Regulatory economics • Integrated planning • Compliance and Risk • Project due diligence • Generation procurement and divestiture	• Regulatory finance • Grid modernization • Power systems and markets	• Regulatory studies & analysis • Cost-benefit analysis • Transportation and electrification • Strategy and operations • Energy policy • Demand-side management
Professional History	• Director, Navigant / Guidehouse • Senior Manager, • MNP LLP • Manager, ICF International • Environment Canada	• Associate Director, Navigant / Guidehouse • Managing Consultant, Navigant • Senior Consultant, Navigant • Leadership Rotation Program, Hydro One Networks Inc.	• Senior Consultant, Navigant / Guidehouse • Consultant, Navigant • Sr. Technical Student, Toronto Hydro
Education	• M.B.A. Executive Program Queen's Smith School of Business, Kingston, ON • Environmental and Resource Studies. Minor, Biology University of Waterloo, ON	• M.B.A., Ivey School of Business, London, ON • B.Sc., Engineering (Computer), Queen's University, Kingston, ON • B.A., • Economics, Queens University, Kingston, ON	• B.Sc., Mechanical Engineering, University of Toronto, Toronto, ON

The lead expert on this project was: Andy Tam

Instructions Provided:
Guidehouse was requested to prepare a report that provides estimates of the level of cash working capital for Hydro One Networks regulated distribution and transmission operations.

Basis of Evidence:
The basis of evidence and assumptions have been documented in the above-noted report.

Context of Evidence:
The context of evidence has been documented in the above-noted report.

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert:
Andy Tam

Date:
July 20, 2021

FORM A

Proceeding:………………………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Andy Tam................(*name*). I live at Dubai ....(*city)*, in the N/A… (province/state) of the United Arab Emirates……

2. I have been engaged by or on behalf of ...Hydro One Networks (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: July 20, 2021

____

Signature

Working Capital Requirements of Hydro One Networks Inc.'s Distribution Business

2023 to 2027

Prepared for:

Hydro One Networks Inc.

Submitted by:
Guidehouse Inc.
100 King St. W
Suite 4950
Toronto, ON M5X 1B1

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guidehouse.com

June 15, 2021

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Disclaimer

This report (the "report") was prepared for Hydro One Networking Inc. ("HONI") by Guidehouse Inc. ("Guidehouse"). The report was prepared solely for the purposes of HONI's rate application to the Ontario Energy Board and may not be used for any other purpose. Use of this report by any third party outside of HONI's rate application is prohibited. Use of this report should not, and does not, absolve the third party from using due diligence in verifying the report's contents. Any use which a third party makes of this report, or any reliance on it, is the responsibility of the third party. Guidehouse extends no warranty to any third party.

Executive Summary

Guidehouse was retained by Hydro One Networks Inc. ("HONI") to calculate the working capital requirements of HONI's distribution business using a lead-lag study.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose. The results of this study are provided in this report.

The lead/lag days calculated in this study are based on HONI's revenue and expense data from 2019[1]. The working capital requirement of HONI's distribution business is shown below, in Table 1.

Table 1. HONI Distribution Summary of Working Capital Requirements

Year	2023	2024	2025	2026	2027
Percentage of OM&A and Cost of Power	6.1%	6.1%	6.2%	6.2%	6.3%
Working Capital Requirement ($M)	$243.4	$246.3	$248.7	$251.6	$254.5

The working capital requirements shown in Table 1 above are based upon the revenue lag and expense lead days shown in Table 2.

Table 2. HONI Distribution Working Capital Requirements (2019)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days
Cost of Power	48.38	34.19	14.20
OM&A Expenses	48.38	29.76	18.62
Income Taxes	48.38	13.92	34.47
Interest Expense	48.38	7.21	41.18
Environmental Remediation	48.38	30.04	18.34
Removals	48.38	28.09	20.29

[1] Note: Lead-lag studies use the most recent and accurate historical data available for calculating results. In this instance, revenue and expense data from 2019 was used instead of 2020, despite the recency of the 2020 data. It was Guidehouse' opinion that revenue and expense data from 2020 would not reflect "normal" business operations going forward (such as in 2023 to 2027), as operations may have been impacted by the COVID-19 pandemic in 2020.

1. Introduction and Methodology

Guidehouse Inc. was retained by Hydro One Networks Inc. ("HONI") to calculate the working capital requirements for HONI's distribution business. This report provides the results of the assessment and the working capital requirements of the distribution business.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to HONI (or "lag") together with the time between the date HONI receives goods and services from its vendors and the date that HONI pays for them (or "lead").

"Leads" and "Lags" are both measured in days and are dollar-weighted where appropriate. The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in HONI's rate base for the purpose of deriving revenue requirement.

HONI provided revenue and expense data to support the lead-lag study for both the 2018 and the 2019 calendar years.[2] Unless stated otherwise, Guidehouse leveraged the revenue and expense data for the full 2019 calendar year, as it was the most recent source of data provided.

1.1 Key Concepts

The following section outlines the key concepts used throughout this report to assess the working capital requirements of HONI's distribution business. This include the mid-point method, statutory approach, revenue lag components, expense lead components and dollar weighting.

1.1.1 Mid-Point Method

When a service is provided to (or by) HONI over a period of time, the service is deemed to have been provided (or received) evenly over the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using Equation 1-1.

[2] Note: Note: Lead-lag studies use the most recent and accurate historical data available for calculating results. In this instance, revenue and expense data from 2019 was used instead of 2020, despite the recency of the 2020 data. It was Guidehouse' opinion that revenue and expense data from 2020 would not reflect "normal" business operations going forward (such as in 2023 to 2027), as operations may have been impacted by the COVID-19 pandemic in 2020.

Equation 1-1

$$Mid - Point = \frac{(Y - X) + 1}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. Equation 1-2 uses the number of days in a year ("A") and the number of periods in a year ("B"):

Equation 1-2

$$Mid - Point = \frac{A/B}{2}$$

1.1.2 Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made to (or by) HONI. In some instances, the due dates for payments are established by statute or by regulation. In these instances, the due date established by statute has been used in lieu of when payments were made.

1.1.3 Revenue Lag Components

As used in this study, revenue lags are comprised of Retail Revenues and Other Revenues. Retail Revenues are defined to consist of four components:

- Service Lag component (the average time from the provision of electricity to a customer until the meter is read);
- Billing Lag component (the average time from when the meter is read to when the bill is generated and provided to customers);
- Collections Lag components (the average time from when a bill is provided to the customer until the customer initiates payment to the utility); and,
- Payment Lag component (the average time from when the customer provides payment to the utility until when the payment is made liquid and available to the utility).

1.1.4 Expense Lead Components

As used in this study, expense leads are defined to consist of two components:

- Service Lead component (services are assumed to be provided to HONI evenly around the mid-point of the service period); and,
- Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left HONI's possession).

1.1.5 Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars flow.

1.2 Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of HONI's distribution operations, interviews with personnel within HONI's Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) HONI, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to transmission operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

2. Revenue Lags

This section of the report provides the revenue lag days for HONI's distribution business. A revenue lag represents the number of days from the date that is service is rendered by HONI until the date payments are received and funds are available to HONI.

HONI receives revenue from the following funding streams:

- **Retail Revenue;** a distribution utility providing service to its customers typically derives its revenues from bills paid for service by its customers.
- **Other Revenue;** HONI staff indicated that its distribution business receives additional funding from various sources, such as Non-MicroFIT, MicroFIT and RRRP revenues.

A summary of the revenue lags for HONI's distribution business is shown below.

Table 3. Summary of Retail Revenue Lag (2019)

Description	Amounts ($M)	Lag Time Days	Weighting Factor	Weighted Lag Time Days
Retail Revenue	$4,299.1	47.78	136.0%	64.96
Other Revenue	($1,137.0)	46.10	(36.0%)	(16.58)
Total	**$3,162.1**		**100%**	**48.38**

2.1 Retail Revenue Lag

Retail revenue lag consists of the following components:

- Service Lag;
- Billing Lag; and,
- Collections Lag.

Service Lag
The service lag is defined as the midpoint of the service period; the halfway point between the beginning of the service period and the end of the service period. The service period end is typically defined as the date the meter is read. All HONI customers are billed monthly or quarterly; the Service Lag is calculated to be 16.32 days.

Billing Lag
The billing lag is defined as the time period from period end (meter read) to the time that the customer's bill is generated in the customer information system. An analysis of HONI meter billing data indicated that HONI customers have an average billing lag of 7.44 days.

Collections Lag
The collections lag is defined as the time period from when the bill is generated in the customer information system to the time when the customer provides payment to HONI and when that payment is recorded in HONI's billing system . The collections lag is measured by analyzing the

receivables aging data provided by HONI. HONI's collection lag was calculated to be 24.02 days.

2.2 Other Revenue Lags

HONI Distribution collects revenues from a variety of other sources, in addition to retail revenue which is discussed above. HONI staff provided monthly data and payment information for each component of the other revenue lag.

Table 4 below summarizes the amounts and revenue lag times associated with each component of the revenue lag.

Table 4. Summary of Other Revenue Lag (2019)

Description	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Non-MicroFIT	($1,296.4)	43.75	114.0%	49.89
MicroFIT	($119.4)	43.77	10.5%	4.60
RRRP	$278.8	34.19	(24.5%)	(8.38)
Total	**($1,137.0)**		**100.0%**	**46.10**

3. Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by HONI, and the lead times associated with payments for services provided to HONI. Expense Leads are defined as the time period between when a service is provided to HONI and when payment is required for that service.

The following expense leads were calculated in this study:

- Cost of Power;
- Interest on HONI'S debt;
- Income taxes;
- Operations, Maintenance and Administration ("OM&A") expenses;
- Removal & Environmental Remediation Costs; and,
- Harmonized Sales Tax ("HST").

3.1 Cost of Power

Cost of Power expenses consist of the following items:

- IESO Cost of Power Expenses (includes the purchasing of power supply requirements and IESO credits on a monthly basis from the IESO on a schedule defined by the IESO's billing and settlement procedures);
- Customer Rebates;
- Payments to Micro Feed-in Tariff Customers; and,
- Payments to Retailers.

Expense lead times were calculated individually for each of the items listed above and dollar-weighted to derive the expense lead time of 34.19 days, as seen in Table 5 below.

Table 5: Cost of Power Expenses (2019)

Delivery Month	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Jan-19	$241.2	34.50	14.6%	5.04
Feb-19	$201.3	32.00	12.2%	3.90
Mar-19	$151.9	33.50	9.2%	3.08
Apr-19	$155.6	36.00	9.4%	3.39
May-19	$54.5	35.50	3.3%	1.17
Jun-19	$109.6	34.00	6.6%	2.26
Jul-19	$95.3	36.50	5.8%	2.11
Aug-19	($10.4)	35.50	(0.6%)	(0.22)
Sep-19	$68.2	36.00	4.1%	1.49
Oct-19	$133.8	36.50	8.1%	2.96
Nov-19	$170.0	34.00	10.3%	3.50
Dec-19	$280.3	32.50	17.0%	5.52
Total	**$1,651.2**		**100.0%**	**34.19**

3.2 Interest on Debt

HONI makes interest payments on its long and short-term debt. Such payments are generally made twice a year. Considering the various bonds and other long-term debt instruments, a dollar-weighted expense lead time of 7.21 days was determined for the 2019 calendar year.

Table 6: Interest Expenses (2019)

Description	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead
Interest Expense	$178.3	7.21	100.0%	7.21
Total	**$178.3**		**100.0%**	**7.21**

3.3 Income Taxes

HONI is liable to make payments to the relevant taxing authorities. Typically, payments are made monthly by HONI, occurring close to the calendar end-of-month. In 2019, HONI Distribution made payments of $5.1M on the last day of every month in the year.

Table 7: Income Taxes Expenses (2019)

Description	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Income Tax	$61.0	13.92	100.0%	13.92
Total	**$61.0**		**100.0%**	**13.92**

3.4 Operations, Maintenance and Administration ("OM&A")

The following expenses are included in the calculation of lead days for OM&A expenses:

- **Payroll and Benefits**; this line item includes basic payroll, payroll withholdings, and benefit expenses related to the regulated utility. HONI staff provided the breakdown of payroll, payroll withholding and benefits expenses for affiliate and non-affiliate staff, and an allocation factor was applied to the expenses to ensure that only expenses related to the distribution business of the regulated utility were included.
- **Property Tax;** this line item includes property tax payments to various municipalities or taxing authorities in the Province of Ontario. These payments are made in the given year and are typically made in installments.
- **Corporate Procurement Card**; this line item includes credit card expenses related to OM&A.
- **Lease Payments;** this line item includes payments made on the properties HONI uses for their operations. HONI has five properties that it makes monthly lease payments for.
- **Payments to Inergi;** this line item includes payments made to Inergi (a division of CapGemini) provides a number of services to HONI.
- **Consulting and Contracting Services;** this line item includes the provision of outside services to HONI.
- **Miscellaneous OM&A;** this line item includes miscellaneous OM&A expenses non-related to the procurement of Outside Services.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 29.76 days for OM&A expenses.

Table 8: Summary of OM&A Expenses (2019)

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Payroll and Benefits	$680.5	64.0%	26.11	16.71
Property Taxes	$35.0	3.3%	(31.19)	(1.03)
Corporate Procurement Card	$26.9	2.5%	30.09	0.76
Lease Payments	$9.7	0.9%	(14.20)	(0.13)
Payments to Inergi	$72.4	6.8%	75.11	5.12
Consulting and Contract Staff	$53.3	5.0%	50.80	2.55
Miscellaneous OM&A	$185.2	17.4%	33.19	5.78
Total	**$1,062.9**	**100.0%**		**29.76**

3.4.1 Payroll and Benefits

The following items were considered as expenses related to the payroll and benefits of HONI's distribution business:

1. Contributions made by HONI to the HONI Pension Plan[3];
2. Payments made by Hydro One to the Worker Safety Improvement Board ("WSIB");
3. Payments made by Hydro One for the Employer Health Tax ("EHT");
4. Union Benefits, Group Health, Dental, and Life Insurance related administrative fees and claims;
5. Five types of payroll including Basic & Management, Construction, CSO W2, Board of Directors and Supervisor Pension payroll; and,
6. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings for each of the payroll types.

When all payroll, withholdings and benefits were dollar-weighted using actual payment data, the weighted average expense lead time associated with payroll and benefits was determined to be 26.11 days as shown in Table 9 below.

Table 9: Summary of Payroll & Benefits Expenses (2019)

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Pensions	$37.0	5.4%	44.77	2.44
WSIB	$4.6	0.7%	42.77	0.29
Employer Health Tax	$11.1	1.6%	30.60	0.50
Group Benefits	$64.8	9.5%	9.70	0.92
Payroll	$379.2	55.7%	22.53	12.55
Payroll Withholdings	$183.9	27.0%	34.83	9.41
Total	**$680.5**	**100.0%**		**26.11**

3.4.2 Property Taxes

HONI makes property tax payments to several municipalities and taxing authorities in the Province of Ontario. These payments are made in the given year for property taxes and are typically made in installments. Using actual payment dates and amounts associated with HONI's distribution business for calendar year 2019, a dollar-weighted expense lead (-lag) time of -31.19 days was determined.

[3] Contributions made by HONI for the HONI Pension Plan were based on 2018 data (instead of 2019) as the 2018 contributions were deemed to be more indicative of what HONI Pension Plan payments are expected to be within the filing period.

3.4.3 Corporate Procurement Card

Procurement (or charge) cards are used by the HONI's employees for a variety of company related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on actual invoices from the HONI's charge card provider and payments made by HONI, a dollar-weighted expense lead time of 30.09 days was determined.

3.4.4 Lease Payments

HONI leases office space to support its ongoing distribution operations in several different locations. HONI presently has leases for Bay Street, Atrium, Barrie, Mississauga and Mural locations. HONI generally makes its lease payments on or around the end of the month prior for the current month. Taking this information into account and using actual invoices and payments for 2019, a dollar-weighted expense lead (-lag) time of -14.20 days was determined.

3.4.5 Payments to Inergi

Inergi (a division of CapGemini) provides a number of services to HONI including (and not limited to) customer service operations, finance, human resources, accounts payable, information technology, IESO settlement services, and supply management services. Based on a review of payments made by HONI to Inergi in 2019, a dollar-weighted expense lead time of 75.11 days was determined.

3.4.6 Consulting and Contract Staff

HONI engages consulting and contract staff to provide assistance in the areas of engineering, environmental services, receivables management, accounting, and general consulting. A dollar-weighted expense lead time of 50.80 days was determined based on a review of invoices rendered and payments made by HONI in 2019.

3.4.7 Miscellaneous OM&A

This category of expense includes items such as product purchases, equipment rentals, and provision of general services to HONI. Based on transactions in HONI's accounts payable system under this category, a dollar-weighted expense lead time of 33.19 days was derived.

3.5 Removal and Environmental Remediation Costs

HONI incurs costs when removing or replacing equipment from existing sites or right of ways. Further, costs relating to environmental remediation at these sites are also incurred. While costs are required to be reported as a depreciation and amortization expense for accounting purposes, there is a cash flow impact associated with HONI's expenditures on such removal and environmental remediation costs. Based upon discussions with HONI staff, estimates for the derivation of removal and environmental remediation costs were determined and summarized in Table 10 below.

Table 10: Summary of Removal and Environmental Remediation Expenses (2019)

Description	Expense Lead Time	% of Expenses	Weighted Lead Time
Removal			
HONI Labour	26.11	72.00%	18.80
HONI Materials	33.19	28.00%	9.29
External Labour	50.80	0.00%	0.00
External Materials	33.19	0.00%	0.00
Total		**100.0%**	**28.09**
Environmental Remediation			
HONI Labour	26.11	69.26%	18.08
HONI Materials	33.19	16.51%	5.48
External Labour	50.80	9.99%	5.07
External Materials	33.19	4.24%	1.41
Total		**100.0%**	**30.04**

3.6 Harmonized Sales Tax

The expense lead times associated with the following items that attract HST were considered in HONI's distribution lead-lag study.

1. Revenues;
2. Cost of Power;
3. OM&A[4]; and,
4. Removals, Environmental Remediation and Capital Costs.

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in Table 11. Note that the statutory approach described at the outset was used to determine the expense lead times associated with HONI's remittances and disbursements of HST (*i.e.,* both remittances and collections are generally on the last day of the month following the date of the applicable invoice).

Table 11: Summary of HST Working Capital Amounts

Description	HST Lead Time	2023 ($M)	2024 ($M)	2025 ($M)	2026 ($M)	2027 ($M)
Revenues	(12.05)	($21.70)	($21.97)	($22.34)	($22.74)	($23.10)
Cost of Power	46.58	$56.79	$56.63	$56.73	$56.72	$56.71
OM&A Expenses	42.95	$3.45	$3.51	$3.58	$3.65	$3.72
Environmental Remediation	45.48	$0.15	$0.15	$0.16	$0.16	$0.16
Removals	45.48	$0.03	$0.03	$0.01	$0.00	$0.00
Capital	45.48	$8.77	$8.90	$9.78	$9.33	$9.35
Total		**$47.49**	**$47.24**	**$47.92**	**$47.12**	**$46.84**

[4] Costs within OM&A that attract HST include Corporate Procurement Card, Trinity Lease Payments, Payments to Inergi, Consulting and Contract Staff and Miscellaneous OM&A.

4. Working Capital Requirements

Using the results described under the discussion of revenue lags and expense leads, and applying them to HONI's proposed distribution expenses for the 2023 to 2027 test period, HONI's working capital requirements were determined.

Table 12 to Table 16 below summarize HONI's working capital requirements for 2023 to 2027.

Table 12: HONI Working Capital Requirements (2023)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	48.38	34.19	14.20	3.9%	$3,422.8	$133.1
OM&A Expenses	48.38	29.76	18.62	5.1%	$597.5	$30.5
Income Taxes	48.38	13.92	34.47	9.4%	$37.2	$3.5
Interest Expense	48.38	7.21	41.18	11.3%	$213.6	$24.1
Environmental Remediation	48.38	30.04	18.34	5.0%	$5.5	$0.3
Removals	48.38	28.09	20.30	5.6%	$79.2	$4.4
Total					**$4,355.8**	**$195.9**
HST						$47.5
Total - Including HST						**$243.4**
Working Capital as a Percentage of OM&A incl. Cost of Power						**6.1%**

Table 13: HONI Working Capital Requirements (2024)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	48.38	34.19	14.20	3.9%	$3,422.5	$132.8
OM&A Expenses	48.38	29.76	18.62	5.1%	$608.9	$31.0
Income Taxes	48.38	13.92	34.47	9.4%	$54.6	$5.1
Interest Expense	48.38	7.21	41.18	11.3%	$227.1	$25.5
Environmental Remediation	48.38	30.04	18.34	5.0%	$5.4	$0.3
Removals	48.38	28.09	20.30	5.6%	$78.5	$4.4
Total					**$4,396.9**	**$199.1**
HST						$47.2
Total - Including HST						**$246.3**
Working Capital as a Percentage of OM&A incl. Cost of Power						**6.1%**

Table 14: HONI Working Capital Requirements (2025)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	48.38	34.19	14.20	3.9%	$3,419.4	$133.0
OM&A Expenses	48.38	29.76	18.62	5.1%	$620.4	$31.7
Income Taxes	48.38	13.92	34.47	9.4%	$42.4	$4.0
Interest Expense	48.38	7.21	41.18	11.3%	$242.5	$27.4
Environmental Remediation	48.38	30.04	18.34	5.0%	$1.0	$0.0
Removals	48.38	28.09	20.30	5.6%	$83.9	$4.7
Total					**$4,409.7**	**$200.7**
HST						$47.9
Total - Including HST						**$248.7**
Working Capital as a Percentage of OM&A incl. Cost of Power						**6.2%**

Table 15: HONI Working Capital Requirements (2026)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	48.38	34.19	14.20	3.9%	$3,418.7	$133.0
OM&A Expenses	48.38	29.76	18.62	5.1%	$632.2	$32.3
Income Taxes	48.38	13.92	34.47	9.4%	$59.2	$5.6
Interest Expense	48.38	7.21	41.18	11.3%	$257.6	$29.1
Environmental Remediation	48.38	30.04	18.34	5.0%	$0.0	$0.0
Removals	48.38	28.09	20.30	5.6%	$83.4	$4.6
Total					**$4,451.0**	**$204.5**
HST						$47.1
Total - Including HST						**$251.6**
Working Capital as a Percentage of OM&A incl. Cost of Power						**6.2%**

Table 16: HONI Working Capital Requirements (2027)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	48.38	34.19	14.20	3.9%	$3,418.3	$133.0
OM&A Expenses	48.38	29.76	18.62	5.1%	$644.2	$32.9
Income Taxes	48.38	13.92	34.47	9.4%	$68.7	$6.5
Interest Expense	48.38	7.21	41.18	11.3%	$270.8	$30.5
Environmental Remediation	48.38	30.04	18.34	5.0%	$0.0	$0.0
Removals	48.38	28.09	20.30	5.6%	$86.6	$4.8
Total					**$4,488.6**	**$207.7**
HST						$46.8
Total - Including HST						**$254.5**
Working Capital as a Percentage of OM&A incl. Cost of Power						**6.3%**

Guidehouse completed a 2016 working capital study for HONI's distribution business, to be used in HONI's rebasing proceeding filed with the Ontario Energy Board. This prior study resulted in a working capital requirement of between $321M and $380M for the 2018 to 2022 test period. The working capital requirements represented between 7.70% and 7.74% of OM&A and Cost of Power.

As compared with the prior study, the total amount of working capital for the current study is lower (6.1% in the current study's 2023 year versus 7.7% in the prior study's 2018 year). Further details regarding the differences between the two studies are shown in the section below.

5. Findings and Conclusions

The purpose of this section is to compare the results from this study to HONI's prior working capital distribution study as per EB-2017-0049. In addition, this section demonstrates that the results from this study reflect the current operations of HONI.

5.1 Comparison with Prior Distribution Study

Table 17: HONI Distribution Working Capital Requirements (2018), Prior 2016 Study

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	51.82	32.72	19.1	5.0%	$2,994.0	$156.6
OM&A Expenses	51.82	25.13	26.69	7.0%	$591.9	$43.3
Income Taxes	51.82	13.67	38.16	10.0%	$58.0	$6.1
Interest Expense	51.82	(1.93)	53.75	15.0%	$185.5	$27.3
Environmental Remediation	51.82	16.97	34.85	10.0%	$13.2	$1.3
Removals	51.82	24.39	27.43	8.0%	$58.6	$4.4
Total					**$3,901.4**	**$239.0**
HST						$42.0
Total - Including HST						**$281.0**
Working Capital as a Percent of OM&A incl. Cost of Power						**7.8%**

Table 18: HONI Distribution Working Capital Requirements (2023), Current Study

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	48.38	34.19	14.20	3.9%	$3,422.8	$133.1
OM&A Expenses	48.38	29.76	18.62	5.1%	$597.5	$30.5
Income Taxes	48.38	13.92	34.47	9.4%	$37.2	$3.5
Interest Expense	48.38	7.21	41.18	11.3%	$213.6	$24.1
Environmental Remediation	48.38	30.04	18.34	5.0%	$5.5	$0.3
Removals	48.38	28.09	20.30	5.6%	$79.2	$4.4
Total					**$4,355.8**	**$195.9**
HST						$47.5
Total - Including HST						**$243.4**
Working Capital as a Percentage of OM&A incl. Cost of Power						**6.1%**

Table 19: HONI Distribution Working Capital Requirements (Current versus Prior)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	(3.44)	1.47	(4.90)	(1.1%)	$428.8	($23.5)
OM&A Expenses	(3.44)	4.63	(8.07)	(1.9%)	$5.6	($12.8)
Income Taxes	(3.44)	0.25	(3.69)	(0.6%)	($20.8)	($2.6)
Interest Expense	(3.44)	9.14	(12.57)	(3.7%)	$28.1	($3.2)
Environmental Remediation	(3.44)	13.07	(16.51)	(5.0%)	($7.7)	($1.0)
Removals	(3.44)	3.70	(7.14)	(2.4%)	$20.5	($0.0)
Total					**$454.4**	**($43.1)**
HST						$5.5
Total - Including HST						**($37.6)**
Working Capital as a Percent of OM&A incl. Cost of Power						**(1.8%)**

5.1.1 Revenue Lag

As shown in Table 19 above, the overall revenue lag in the current study has decreased by approximately three days since the prior study. Revenue lag has a large impact on the overall result of working capital studies, as it is considered in the working capital factor for all expense items. Minor variations in revenue lag can have large impacts on directional results. When the revenue lag is held constant at the previous study results (51.82), the working capital requirement in 2023 is approximately 0.8% lower than the working capital amount in the previous study. A significant driver of variation from the prior study to the current study is caused by the change in revenue lag. Table 20 in section 5.2 below shows this change in more detail.

The primary driver of change since the prior study is the reduction in the collections lag indicating that HONI is collecting outstanding balances more efficiently. In the current study, the Collections Lag is 24.02 days; the value in the prior study was 25.90 days. This increase in collections efficiency accounts for roughly two thirds of the revenue lag reduction.

5.1.2 Cost of Power

Cost of Power expense lead days have not changed significantly versus the prior study. HONI distribution still procures power from the IESO at the end of each month and pays the IESO approximately two weeks after the end of the prior service period (the middle of the following month). Since payment schedules have not changed since the prior study, Cost of Power expense lead days have not changed significantly either.

5.1.3 OM&A Expenses

OM&A expense lead days have increased significantly since the previous study by approximately 5 days. Factors driving this increase include longer expense lead times for Payroll & Benefits, Payments to Inergi, Property Taxes, and Miscellaneous OM&A.

Payroll & Benefits expense lead times are longer in this study compared to the previous study primarily due to a change in payment schedules for pensions. In the previous study, pension payments were made on a bi-annual basis; however, in this study pension payments are made monthly.

Another driver behind the change in OM&A expenses are Property Taxes. Property Tax payments are modelled on an annual service period, with the payment date as the variable factor. In the prior study, more property tax payments were made in the latter half of the year, increasing the overall expense lead time, as the payment lead increased. In the current study, more payments were made in the first half of the year, which resulted in an expense lead (-lag) time instead of an expense lead time.

The expense lead time for Payments to Inergi was significantly larger in this study compared to the previous study largely due to changes in agreements to fixed price contracts in 2018 over transactional pricing in the previous study. After dollar-weighting all OM&A categories however, the impact of these slightly increased expense lead times is minimal on HONI's overall working capital requirements.

5.1.4 Income Taxes

The expense lead days for Income Taxes have remained consistent with the previous study as there were no true-up payments in this study or the prior study. This aligns with what HONI subject matter experts indicated was expected from the previous study and this methodology remains consistent with Income Tax lead time calculations for other utilities across Ontario.

5.1.5 Interest Expense

Interest lead days have increased versus the prior study, as the prior study's resulting interest was an expense lag versus the expense lead in this study. The driving factor behind this change is when interest payments were made throughout the year. In the current study, just over half, 31 of 59 payments, were made in the first half of the year. In the previous study, exactly half, 26 of 52 payments, were made in the first half of the year. A larger number of payments made in the first half of the year resulted in a high interest lead time.

5.1.6 Removals & Environmental Remediation

Removals expense lead time did not change significantly from the previous study, increasing approximately 4 days. This increase is as a result of changes in Payroll & Benefits lead days; the calculation of Removals lead time is tied directly to the lead time of Payroll & Benefits. However, Environmental Remediation expense lead days increased significantly by approximately 13 days. This change is driven primarily by the change materials lead times, which are directly impacted by the miscellaneous OM&A lead days. After dollar-weighting all OM&A categories, the impact of these changes is minimal on HONI's overall working capital requirements.

5.2 Comparison with the Prior Distribution Working Capital Study Using Constant Revenue Lag Days

Since the Revenue Lag days was one of the most impactful changes since the prior study, the below table examines the resulting working capital requirements if the Revenue Lag from the prior study was held constant. Table 20 below shows that when holding revenue lag days constant at the previous study results (51.82), the working capital requirement in 2019 is approximately 0.8% lower than the amount in 2019 from the previous study.

Table 20: Working Capital Requirements with 2016 Study Revenue Lag Days Held Constant (2018 from 2016 Study versus 2023 from Current Study)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	0.00	1.47	(1.47)	(0.2%)	$428.8	$8.7
OM&A Expenses	0.00	4.63	(4.63)	(1.0%)	$5.6	($7.2)
Income Taxes	0.00	0.25	(0.26)	0.4%	($20.8)	($2.2)
Interest Expense	0.00	9.14	(9.14)	(2.8%)	$28.1	($1.2)
Environmental Remediation	0.00	13.07	(13.07)	(4.0%)	($7.7)	($0.9)
Removals	0.00	3.70	(3.70)	(1.5%)	$20.5	$0.7
Total					**$454.4**	**($2.1)**
HST						$5.5
Total - Including HST						**$3.4**
Working Capital as a Percent of OM&A incl. Cost of Power						**(0.8%)**

Consultants:

Name	**Craig Sabine** Director	**Andy Tam** Associate Director	**Adam Green** Senior Consultant
Business Name and Address	Guidehouse First Canadian Place, 100 King St W | Suite 4950 | Toronto, ON M5X 1B1 | Canada	Guidehouse First Canadian Place, 100 King St W | Suite 4950 | Toronto, ON M5X 1B1 | Canada	Guidehouse First Canadian Place, 100 King St W | Suite 4950 | Toronto, ON M5X 1B1 | Canada
General Areas of Expertise	• Portfolio assessment and business planning • Cost-benefit analysis • Cost Allocation and affiliates • Regulatory economics • Integrated planning • Compliance and Risk • Project due diligence • Generation procurement and divestiture	• Regulatory finance • Grid modernization • Power systems and markets	• Regulatory studies & analysis • Cost-benefit analysis • Transportation and electrification • Strategy and operations • Energy policy • Demand-side management
Profession al History	• Director, Navigant / Guidehouse • Senior Manager, • MNP LLP • Manager, ICF International • Environment Canada	• Associate Director, Navigant / Guidehouse • Managing Consultant, Navigant • Senior Consultant, Navigant • Leadership Rotation Program, Hydro One Networks Inc.	• Senior Consultant, Navigant / Guidehouse • Consultant, Navigant • Sr. Technical Student, Toronto Hydro
Education	• M.B.A. Executive Program Queen’s Smith School of Business, Kingston, ON • Environmental and Resource Studies. Minor, Biology University of Waterloo, ON	• M.B.A., Ivey School of Business, London, ON • B.Sc., Engineering (Computer), Queen’s University, Kingston, ON • B.A., • Economics, Queens University, Kingston, ON	• B.Sc., Mechanical Engineering, University of Toronto, Toronto, ON

The lead expert on this project was: Andy Tam

Instructions Provided:
Guidehouse was requested to prepare a report that provides estimates of the level of cash working capital for Hydro One Networks regulated distribution and transmission operations.

Basis of Evidence:
The basis of evidence and assumptions have been documented in the above-noted report.

Context of Evidence:
The context of evidence has been documented in the above-noted report.

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert:
Andy Tam

Date:
July 20, 2021

FORM A

Proceeding:………………………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Andy Tam................(*name)*. I live at Dubai ....(*city)*, in the N/A… (province/state) of the United Arab Emirates…….

2. I have been engaged by or on behalf of ...Hydro One Networks (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: July 20, 2021

____

Signature

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Working Capital
Annual Average
Historical (2021 Forecast), Bridge Year (2022) and Test Years (2023 to 2027)
($M)

Line No.	Particulars	2021 (a)	2022 (b)	2023 (c)	2024 (d)	2025 (e)	2026 (f)	2027 (g)
1	Cash Working Capital	$ 22.8	$ 24.1	$ 17.8	$ 19.3	$ 18.9	$ 19.9	$ 19.9
2	Materials and Supply Inventory	13.4	13.9	14.1	14.4	14.7	15.0	15.3
3	**Total**	**36.2**	**38.0**	**31.9**	**33.7**	**33.6**	**34.9**	**35.2**

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Statement of Working Capital
Annual Average
Historical (2021 Forecast), Bridge Year (2022) and Test Years (2023 to 2027)
($M)

Line No.	Particulars	2021 (a)	2022 (b)	2023 (c)	2024 (d)	2025 (e)	2026 (f)	2027 (g)
1	Cash Working Capital	$ 297.9	$ 308.4	$ 243.4	$ 246.3	$ 248.7	$ 251.6	$ 254.5
2	Materials and Supply Inventory	5.6	5.9	6.0	6.1	6.2	6.4	6.5
3	**Total**	**303.5**	**314.3**	**249.4**	**252.4**	**254.9**	**258.0**	**261.0**

2023-2027 figures are presented on a combined basis including Acquired Utilities.

Commodity Expense

Step 1: **2023 Forecasted Commodity Prices**

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$16.61	$16.61
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$93.05	$93.05
Adjustments ($/MWh)				
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$109.66**

Step 2: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Commodity

Customer		Revenue	Expense	2023 Test Year						
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	0		-	12,435,381,012	$ 0.01661	$ 0.10966	$1,363,683,433
Large User USofA 4020	kWh	4010	4705	13,757,255		23,821,011	32,922,863	$ 0.01661	$ 0.10966	$4,234,626
General Service	kWh	4035	4705	1,424,754,314		2,466,995,619	2,906,022,457	$ 0.01661	$ 0.10966	$383,329,022
Sentinel Lighting USofA 4030	kWh	4010	4705	-		-	14,406,680	$ 0.01661	$ 0.10966	$1,579,859
Street Lighting	kWh	4025	4705	0		-	105,989,594	$ 0.01661	$ 0.10966	$11,622,986
Sub Transmission USofA 4055	kWh	4025	4705	2,245,955,805		3,888,925,322	-	$ 0.01661	$ 0.10966	$101,913,088
	kWh	4025	4705					$ 0.01661	$ 0.10966	$0
	kWh	4025	4705					$ 0.01661	$ 0.10966	$0
	kWh	4025	4705					$ 0.01661	$ 0.10966	$0
TOTAL										**$1,866,363,014**

Class A - non-RPP Global Adjustment

Customer		Revenue	Expense		2023 Test Year kWh Volume	Hist. Avg GA/kWh ***	Amount
General Service		4035	4707		1,424,754,314	$ 0.0930	$132,572,677
Large User USofA 4020		4010	4707		13,757,255	$ 0.0930	$1,280,106
Sub Transmission USofA 4055		4010	4707		2,245,955,805	$ 0.0930	$208,985,065
				-	3,684,467,374		**$342,837,847**

Class B - non-RPP Global Adjustment

Customer		Revenue	Expense	2023 Test Year			Amount
Class Name	UoM	USA #	USA #		Class B Non-RPP Volume	GA Rate/kWh	
Residential	kWh	4006	4707		0	$ 0.09305	$0
Large User USofA 4020	kWh	4010	4707		23,821,011	$ 0.09305	$2,216,533
General Service	kWh	4035	4707		2,466,995,619	$ 0.09305	$229,552,709
Sentinel Lighting USofA 4030	kWh	4010	4707		0	$ 0.09305	$0
Street Lighting	kWh	4025	4707		0	$ 0.09305	$0
Sub Transmission USofA 4055	kWh	4025	4707		3,888,925,322	$ 0.09305	$361,862,557
	kWh	4025	4707		0	$ 0.09305	$0
	kWh	4025	4707		0	$ 0.09305	$0
Total Volume					**6,379,741,953**		
TOTAL							**$593,631,799**

*Regulated Price Plan Prices for the Period November 1, 2019 – October 31, 2020
** Enter 2023 load forecast data by class based on the most recent 12-month historic Class A and Class B RPP/Non-RPP proportions
*** Based on average $ GA per kWh billed to class A customers for most recent 12-month historical year.

Cost of Power Calculation

1. Volumns for Electricity Commodity and Global Adjustment non-RPP in kWh
2. All Volume should be loss adjusted with the exception of:
 - Volume for Electricity Commodity, Wholesale Market Services, Class A and B should loss adjusted less WMP
 - Low Voltage Charges - No loss adjustment for kWh

		2023 Test Year	RPP		2023 Test Year	non-RPP		Total	
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$	
Class per Load Forecast				-					
Residential	kWh	12,435,381,012		1,363,683,433	-		-		
Large User USofA 4020	kWh	32,922,863		3,610,373	37,578,266		624,253		
General Service	kWh	2,906,022,457		318,678,992	3,891,749,933		64,650,031		
Sentinel Lighting USofA 4030	kWh	14,406,680		1,579,859	-		-		
Street Lighting	kWh	105,989,594		11,622,986	-		-		
Sub Transmission USofA 4055	kWh	-		-	6,134,881,127		101,913,088		
-		-		-	-		-		
-		-		-	-		-		
-		-		-	-		-		
SUB-TOTAL		15,494,722,607		1,699,175,642	10,064,209,327		167,187,372	$ 1,866,363,014	OK

Global Adjustment non-RPP	Units								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total	
Residential				0					
Large User USofA 4020				0			3,496,638.8854		
General Service				0			362,125,385.3982		
Sentinel Lighting USofA 4030				0					
Street Lighting				0					
Sub Transmission USofA 4055				0			570,847,621.4559		
				0					
				0					
				0					
SUB-TOTAL		0		0			936,469,646	$ 936,469,646	OK

Transmission - Network	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	KW	26,664,646	4.8410	129,082,665			-	Forecast demand does not separate RPP vs. non RPP.
Large User USofA 4020	KW	107,929	4.8410	522,478			-	
General Service	KW	10,455,099	4.8410	50,612,786			-	
Sentinel Lighting USofA 4030	KW	14,598	4.8410	70,666			-	
Street Lighting	KW	106,367	4.8410	514,918			-	
Sub Transmission USofA 4055	KW	24,308,842	4.8410	117,678,297			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				298,481,810			-	298,481,810

Transmission - Connection	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	KW	50,760,706	1.7871	90,714,879			-	Forecast demand does not separate RPP vs. non RPP. And Volume includes both Line and Transformation
Large User USofA 4020	KW	185,228	1.7871	331,023			-	
General Service	KW	20,932,558	1.7871	37,408,748			-	
Sentinel Lighting USofA 4030	KW	29,546	1.7871	52,802			-	
Street Lighting	KW	216,224	1.7871	386,417			-	
Sub Transmission USofA 4055	KW	46,943,006	1.7871	83,892,235			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				212,786,104			-	212,786,104

Wholesale Market Service	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	12,435,381,012	0.0034	42,280,295	-	0.0034	-	
Large User USofA 4020	kWh	32,922,863	0.0034	111,938	37,578,266	0.0034	127,766	
General Service	kWh	2,906,022,457	0.0034	9,880,476	3,891,749,933	0.0034	13,231,950	
Sentinel Lighting USofA 4030	kWh	14,406,680	0.0034	48,983	-	0.0034	-	
Street Lighting	kWh	105,989,594	0.0034	360,365	-	0.0034	-	
Sub Transmission USofA 4055	kWh	-	0.0034	-	6,134,881,127	0.0034	20,858,596	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				52,682,057			34,218,312	86,900,369

Class A CBR	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate[4]	$	Total
Residential				-			-	
Large User USofA 4020				-			-	
General Service				-			-	
Sentinel Lighting USofA 4030				-			-	
Street Lighting				-			-	
Sub Transmission USofA 4055				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				-			-	-

Class B CBR	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential				-			-	
Large User USofA 4020				-			-	
General Service				-			-	
Sentinel Lighting USofA 4030				-			-	
Street Lighting				-			-	
Sub Transmission USofA 4055				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				-			-	-

RRRP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	12,435,381,012	0.0005	6,217,691	-	0.0005	-	
Large User USofA 4020	kWh	32,922,863	0.0005	16,461	37,578,266	0.0005	18,789	
General Service	kWh	2,906,022,457	0.0005	1,453,011	3,891,749,933	0.0005	1,945,875	
Sentinel Lighting USofA 4030	kWh	14,406,680	0.0005	7,203	-	0.0005	-	
Street Lighting	kWh	105,989,594	0.0005	52,995	-	0.0005	-	
Sub Transmission USofA 4055	kWh	-	0.0005	-	6,134,881,127	0.0005	3,067,441	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				7,747,361			5,032,105	12,779,466

Low Voltage - No TLF adjustment	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential				-			-	
Large User USofA 4020				-			-	
General Service				-			-	
Sentinel Lighting USofA 4030				-			-	
Street Lighting				-			-	
Sub Transmission USofA 4055				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				-			-	-

Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Total Eligible Customer Count		1,315,789	0.57	9,000,000			-	
				-			-	
				-			-	
SUB-TOTAL				9,000,000			-	9,000,000
SUB- TOTAL				2,279,872,975			1,142,907,434	3,422,780,409
OER CREDIT[3]	18.90%			(430,895,992)			0	(430,895,992)
TOTAL				**1,848,976,982**			**1,142,907,434**	**2,991,884,417**

3.The OER Credit of 18.9% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.

4. Class A CBR: use the average CBR per kWh, similar to how the Class A GA cost is calculated. A Class A customer is a customer who participate in the ICI, pays global adjustment (GA) based on their percentage contribution to the top five peak Ontario demand hours over a 12-month period

2023 Test Year - Cop	
4705 -Power Purchased	$ 1,866,363,014
4707- Global Adjustment	$ 936,469,646
4708-Charges-WMS	$ 99,679,835
4714-Charges-NW	$ 298,481,810
4716-Charges-CN	$ 212,786,104
4750-Charges-LV	$ -
4751-IESO SME	$ 9,000,000
Misc A/R or A/P	$ (430,895,992)
TOTAL	**$ 2,991,884,417**

MATERIALS AND SUPPLIES INVENTORY

1.0 OVERVIEW

Hydro One maintains and optimizes materials and supplies inventory in support of the company's reliability, system growth and customer satisfaction objectives. Maintaining inventory reduces outage restoration time and ensures material supplies for unplanned and unpredictable outages due to events such as storms or trouble calls. This evidence also discusses the materials and supplies inventory allocation between the transmission and distribution businesses.

2.0 STRATEGY

This section sets out Hydro One's strategy in relation to our materials and supply inventory. The 2018 to 2027 inventory levels reflect impacts of the increasing work programs with compressed timelines, the increasing transmission and distribution asset base and asset condition, age, and the external cost pressures offset by initiatives to manage inventory growth. Hydro One's Inventory Policy is provided as an attachment this exhibit.

Hydro One utilizes a centralized warehouse and third-party logistics to make weekly scheduled deliveries to its field locations. This helps reduce transportation costs by consolidating shipments to each location based on need dates. Additionally, through the centralized warehouse, materials and supplies quantities are closely managed to minimize waste by sending the right quantities to each location (not limited by the supplier minimum order quantity).

Having the right material at the right work location at the right time is important in meeting the aforementioned objectives and enables the restoration of power in a timely manner during unpredictable weather events.

Hydro One employs the following processes to structure and manage its inventories:

<u>Transmission</u>

- Integration of planning and procurement processes to maintain the primary strategy of securing materials for transmission capital projects directly from vendors.
- Disposition of surplus materials remaining at the conclusion of capital projects through an investment recovery program or transferred to other capital projects.

<u>Distribution</u>

- Seasonal safety stock review for each inventory storage location based on consumption patterns and usage.
- Transfer of slower moving stock to areas with pending demand.
- Vendor managed inventory program for submarine cable allows for cut lengths thus reducing scrap, reduced transportation costs moving cable directly from vendor to field location and reduced handling by field personnel.

<u>Common</u>

- Optimizing sustainment-related inventories to increase flexibility in executing maintenance protocols.
- Where overlap occurs between Distribution and Transmission materials, utilization of existing inventory to offset minimum order quantities and duplicate orders.
- The use of stock algorithms to maximize inventory performance.

! further description of Hydro One’s supply chain services initiatives is provided in Exhibit E-05-02.

3.0 PLANNED MATERIALS AND SUPPLIES INVENTORY LEVELS

This section summarizes Hydro One's inventory levels for both Transmission and Distribution. Inventory is made up of three main components:

1) Materials and supplies
    a. Definition: Materials that are used for sustainment and execution of the transmission and distribution systems, but are ultimately not installed or attached to the electrical grid.
    b. Examples: Hardhats, gloves, safety glasses, cleaning supplies, chainsaw oil, low value tools, etc.
2) Future use
    a. Definition: Materials and equipment held in inventory to be installed on the electrical grid in the future.
    b. Examples: Wire & cable, insulators, circuit breakers, transformers, etc.
3) Meters
    a. Definition: Devices that measure electricity usage digitally with the capacity to transmit information wirelessly and in some cases provide advanced capability. Additional equipment is often included to allow for network connectivity.
    b. Examples: Residential energy meters, wholesale interval meters, Power Quality meters. Related equipment includes instrument transformers, collectors, repeaters, and modems.

This evidence will focus on materials and supplies as future use assets are not a part of rate base and meters are discussed in the DSP Section 3.2.

Table 1 provides the actual and forecast year-end materials and supplies inventory levels for Hydro One Transmission and Distribution, respectively.

Table 1 - Inventory Levels 2018 – 2027 ($M)

Year	Historical				Bridge	Forecast				
Year End Balances	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**
Materials and Supplies	16.4	17.5	18.5	19.5	19.9	20.3	20.7	21.2	21.6	22.0
Allocated to Transmission	11.8	12.0	13.1	13.7	14.0	14.3	14.6	14.8	15.1	15.4
Allocated to Distribution	4.6	5.5	5.4	5.8	5.9	6.1	6.2	6.3	6.4	6.6

As shown in Table 1 above, Hydro One forecasts an increase in both Transmission and Distribution inventory from 2021 to 2027 due to inflation.

Much of Hydro One's Distribution materials and supplies are supplied directly from the centralized warehouse located in Barrie and field locations situated throughout the province. These inventories of materials and supplies are heavily relied on by the Distribution lines of business to perform routine maintenance on Distribution assets in addition to new connects, trouble calls and storm response.

While most Transmission material and supplies are supplied directly from vendors, Hydro One has been working to utilize more materials and supplies from the warehouse for materials that are common to both Distribution and Transmission. This approach helps offset minimum order quantities, increasing economies of scale in Hydro One's materials purchasing. Inventory is established to provide faster response to planned and unplanned projects and programs from inventoried stock.

The basis of forecasting inventory levels is historical consumption, planned work programs, lead time and manual intervention to eliminate known anomalies in the data (e.g., increased consumption related to a weather event).

Material purchases for major transmission projects are often shipped directly to the project sites and are not included in the planned inventory levels.

4.0 ATTACHMENTS

Attachment	Description
1	Inventory Policy

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Inventory Policy

Purpose and Scope

The Inventory Policy provides the framework for inventory management, valuation, verification and accounting in order to preserve the integrity of our financial statements.

This policy applies to Hydro One Limited and its affiliates (collectively “Hydro One”) that are involved in the valuation, verification, management and accounting for inventory. Inventory as referred to in this policy includes both Hydro One owned assets classified as "materials and supplies" and "future use fixed assets" on the corporate balance sheet. It also includes consumable inventory; strategic parts/component inventory and other inventory (i.e. Telecom).

This policy does not apply to: free issues (items that are expensed immediately); operating spares that are classified as in-service major fixed assets; minor fixed assets; or Hydro One Remote Communities' fuel inventories.

Revision Statement

This document was revised to provide clarity, consistency and simplicity, and to align to the new template as part of the Corporate Policy Project.

Principles

- Hydro One inventory is managed, verified and valued in a manner consistent with sound business practices and accounting principles. To ensure the completeness, existence and the appropriate valuation of inventory, inventories are physically verified on a periodic basis. Accounting for inventories is consistent as appropriate to the context of a rate regulated industry.
- All inventories, including future use fixed assets, will be properly controlled and costed to ensure the accuracy of records for materials, work in progress, finished or partly finished new or used goods.
- All inventories will be managed, verified and valued for accuracy with the COSO assertions of ownership, valuation, existence and completeness.

1.0 Corporate Requirements

a. Physical inventory counts will be conducted on a periodic basis to verify the physical existence and completeness of Hydro One inventory.

b. Inventory classified as "materials and supplies" is to be valued at the lower of average cost and net realizable value (NRV). New items are recorded in the inventory system at cost automatically as a result of transaction steps in the supply process. There are times when due to a timing issue, the average cost is deemed incorrect and a correction has to be made through the inventory sub-ledger.

c. Inventory that has a NRV that is less than carrying value will be written down to the NRV. If the NRV subsequently recovers, the write-down should be reversed. Corporate Finance advice should be sought before writing assets down for declines in NRV and for any subsequent reversals.

d. All inventories must be managed in accordance with good business practices balancing the need to maintain an adequate supply of materials with appropriate cost considerations.

e. All inventories must be stored in a secure location where access is limited to personnel authorized by Hydro One.

Specific Circumstances

a. Hydro One will re-deploy or dispose of surplus material in a manner to maximize the return with emphasis on reuse and environmental protection consistent with the principles of the Hydro One Health, Safety and Environmental Management System.

b. Investment Recovery (IR) is the authority to sell items that have been declared surplus in accordance with Retirement/Surplus Reporting Procedures. (Refer to SP0855 Procedure for Disposal of Surplus Materials).

c. When exercising Local Sale of Surplus and disposing goods locally, responsibility for adhering to SP0855 Procedure for Disposal of Surplus Materials rests with the line of business (LOB).

2.0 Definitions

Term	Definition
Average Cost	For inventory items that are not interchangeable, specific costs are attributed to the specific individual items of inventory. For items that are interchangeable, Hydro One has adopted weighted average cost method to determine average cost of inventory.
Consumable Inventories	Inventories used primarily in the distribution or transmission business. These goods are kept in stock to support customer requirements. Items include: transformers, wire and cable, connectors, poles/line hardware, circuit breaker parts, insulators, surge arresters, fasteners, switches, supplies (i.e. safety, metering, construction, cleaning) and equipment (i.e. lighting, survey, hoisting).
Net Realizable Value (NRV)	Based on the regulatory principle of cost recovery, net realizable value is generally equal to carrying value for inventory used in Hydro One's regulated businesses. For inventory items available for sale, net realizable value is defined as the estimated selling price in the ordinary course of business less the estimated costs necessary to complete the sale.

Term	Definition
Periodic basis	The frequency of inventory counts and the coverage of the each count will vary depending on the type of inventory and the risk of misstatement. An assessment should occur at least once per fiscal period.
Strategic Parts Inventories	Inventories used primarily in the transmission or distribution business. These goods are kept in stock to support the sustainment of major fixed assets. The parts are deemed to be critical to the functionality of Hydro One transmission and/or distribution assets. Items include: high voltage instrument transformers (HVITs), switches, insulators, bushings, tap changers, towers, relays, suspension clamps and dampers, and transmission towers for storm recovery. The asset must be maintained in a ready to deploy state.

3.0 References

1. SP0733 Inventory Procedure

2. SP0855 Procedure for Disposal of Surplus Materials

4.0 Document Management

Owner/Functional Responsibility	Director, Corporate Accounting & Reporting
Approver	VP, Corporate Controller
Approval Date	July 2021
Effective Date	July 2021
Last Reviewed Date	July 2021
Next Review Date	June 2023

5.0 Appendices

None

ECONOMIC EVALUATION TRUE-UPS/CCRA AND CCA

1.0 INTRODUCTION

Hydro One is required to perform certain load true-ups pursuant to the Transmission System Code (TSC) and Distribution System Code (DSC). This Exhibit describes the load true-up calculations that are required in respect of transmission assets for (a) Transmission connected customers, as completed by Hydro One Transmission, as well as (b) embedded Distributors and Large Customers > 5MW, as completed by Hydro One Transmission for Hydro One Distribution. Furthermore, this Exhibit provides background information in support of Hydro One’s requests for continuance of the Customer Connection and Cost Recovery Agreement True-up (CCRA) Variance Account (Transmission CCRA Variance Account) and to establish a new Distribution CCA Variance Account to track the impact of load true-ups on the Distribution revenue requirement, each as further described in Exhibit G-01-02. In the current application there are no Transmission capital contribution true ups forecasted for either Transmission customers or Distribution customers which impact the proposed rate base or revenue requirement as discussed further below.

2.0 TRUE-UP PROCEDURE FOR LOAD CUSTOMERS - TRANSMISSION

When a transmission customer requests new or modified connection facilities, the benefiting customer(s) are accountable for the cost of the required investment. If there are multiple benefiting transmission customers, each is allocated costs on the basis of incremental capacity required. Hydro One Transmission determines whether the incremental load that the customer is committing to as part of the upgrade will be sufficient to pay for the incremental costs of providing the capacity that has been requested. If the load forecast indicates that the expected load will not be sufficient, Hydro One is required to collect a capital contribution to ensure that rate payers are not subsidizing the customer. This initial calculation, called the Initial Economic Evaluation (IEE) under the TSC, is detailed in the Customer Connection and Cost Recovery Agreement (CCRA) that Hydro One Transmission enters into with the customer. An individual

CCRA is executed for each benefiting Transmission customer on each project, including where such customer is Hydro One Distribution.

To ensure that Hydro One Transmission in fact recovers the costs of the investment over time without impacting transmission rate payers (through a combination of the initial capital contribution and transmission revenues associated with the incremental load from the project), Hydro One Transmission carries out true-up calculations, based on actual customer load, at specific true-up points prescribed by section 6.5.3 of the TSC:

1. for high risk connections, at the end of each year of operation for five years;
2. for medium-high risk and medium-low risk connections, at the end of each of the third, fifth and tenth years of operation; and
3. for low risk connections, at the end of each of the fifth and tenth years of operation, and at the end of the fifteenth year of operation if actual load is 20% higher or lower than the initial load forecast at the end of the tenth year of operation.[1]

For the true-up calculation, Hydro One Transmission uses the same methodology it uses to carry out the IEE, and the same inputs except for load, as per section 6.5.4 of the TSC and as detailed in section 2.5 of Hydro One's OEB-approved Transmission Connection Procedures. Hydro One Transmission carries out true-ups with Hydro One Distribution, as it does with any other customer with whom it has entered into a CCRA.

The load used in a true-up calculation is based on the actual load up to the true-up point and an updated load forecast from the customer for the remainder of the economic evaluation period.

[1] All Ontario Distributors are considered to be low risk.

Hydro One Transmission assesses whether the updated load forecast is reasonable prior to inclusion in the true-up calculations. Only new incremental load is included in the true-up calculation, including the impact of embedded generation and conservation and demand management activities in accordance with sections 6.5.8 to 6.5.10 of the TSC.
When a load customer voluntarily and permanently disconnects its facilities from a Transmission facility prior to the last true-up point, Hydro One, at the time of disconnection, carries out a final true-up calculation in accordance with section 6.5.11 of the TSC.

When the true-up calculation shows that the customer's actual load and updated load forecast is lower than the load in the initial load forecast, and therefore has not generated the initially forecast connection rate revenues, the customer is required to make a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous capital contributions, including true-up payments, as per section 6.5.6 of the TSC. This additional capital contribution is credited against fixed assets and results in a reduction in rate base for Hydro One Transmission.

Where a true-up calculation shows that the customer's actual load and updated load forecast is higher than the load in the initial load forecast, and therefore has generated more than the initially forecast connection rate revenues, Hydro One applies this credit against any shortfall in subsequent true-up calculations (Notional Account, section 6.5.7 of TSC). After the final true-up calculation is completed, any credited amount is adjusted appropriately to reflect the time value of money and is rebated to the customer. The rebate amount will not exceed the capital contribution, adjusted to reflect the time value of money, previously paid by the customer, as per section 6.5.7 of the TSC. Once the rebate has been paid to the customer, Hydro One Transmission increases the net fixed assets of the connection facility, and thereby its rate base, by a corresponding amount.

3.0 TRUE-UP PROCEDURE FOR LOAD CUSTOMERS - DISTRIBUTION

As part of the Regional Planning and Cost Allocation Review (EB-2016-0003), the TSC and DSC were amended by the Ontario Energy Board, effective from December 18, 2018, to flow the impacts of economic evaluations that are carried out for transmission capital contributions down to any embedded distributors and distribution-connected large load customers with non-coincident peak demand exceeding 5 MW (large customers) that contribute to the need for a new or modified transmission facility.[2] The following true-up procedures are in accordance with requirements established by the Ontario Energy Board through the above-referenced amendments.

As per DSC section 3.6.1, Hydro One Distribution seeks capital contributions from embedded distributors and large customers for new or modified transmitter-owned connection facilities when Hydro One Distribution itself is required to provide a capital contribution to Hydro One Transmission.

Hydro One Distribution enters into Connection Cost Agreement (CCA) with each of its benefiting large customers or embedded distributors. Transmission costs that have been allocated to Hydro One Distribution are allocated under those CCAs to the benefiting embedded distributors and large customers according to each party's incremental capacity requirement (with the remainder being allocated to Hydro One Distribution based on its benefit). Each customer is assigned a risk classification in accordance with TSC Appendix 4. An IEE determining the required capital contribution from each party is completed by Hydro One Transmission on behalf of Hydro One Distribution (and on behalf of any other Ontario Distributors) utilizing the same methodology and process prescribed by TSC sections 6.3.2, 6.5 and Appendix 5. Any resulting

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[2] See https://www.oeb.ca/industry/policy-initiatives-and-consultations/regional-planning-and-cost-allocation-review.

capital contributions from embedded distributors or large customers are then paid to Hydro One Distribution.

The processes described in 2.0 and 3.0, above, are illustrated in Figure 1, below:

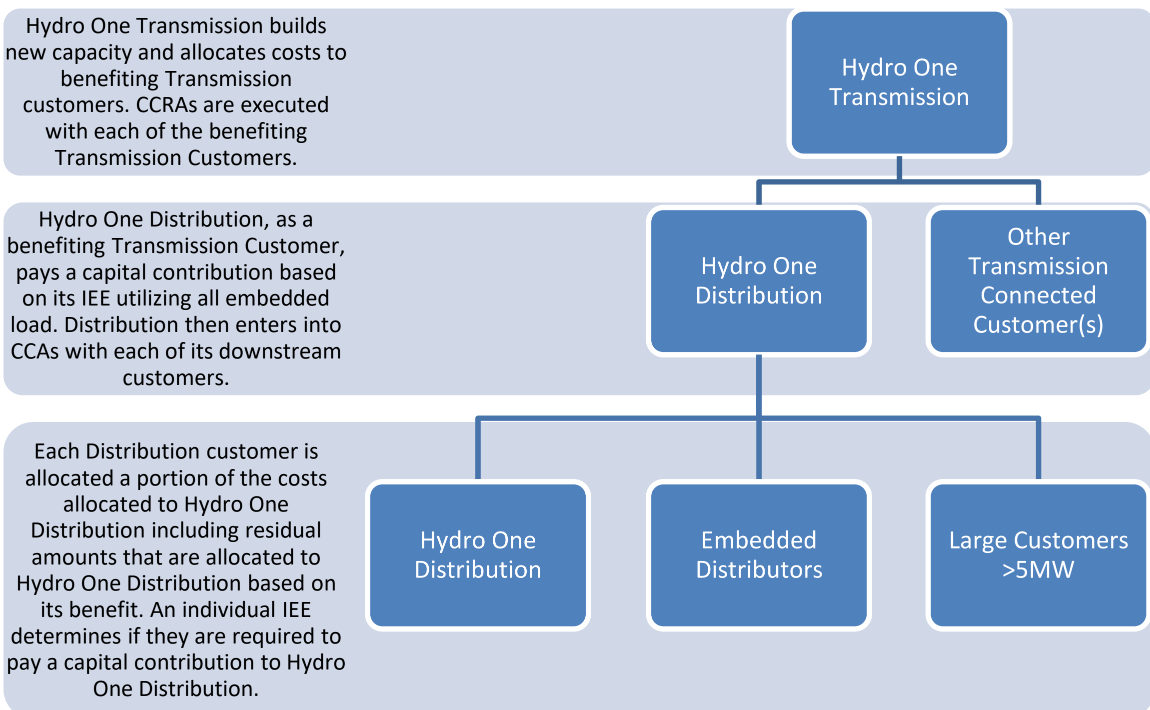

Figure 1: Visualization of True Up relationship between Transmission, Distribution and Various Customers

True ups are performed utilizing the same pre-determined intervals as used for Hydro One Transmission customers (TSC 6.3.2). Accordingly, Hydro One Transmission calculates and conducts the true up calculation in the same manner as for Transmission customers on behalf of Hydro One Distribution (and other Ontario Distributors when required) utilizing the same methodology and calculation used to carry out the IEE, and the same inputs except for load, as per section 6.5.4 of the TSC.

4.0 TRUE-UP IMPACTS ON REVENUE REQUIREMENT

As detailed in EB-2019-0082[3], capital contributions when received by Hydro One Transmission (including through load true-ups) have the effect of lowering Revenue Requirement because they lower the amount of capital on which Hydro One Transmission requires a return, along with the related impacts on revenue requirement of the gross up for corporate income taxes and a lower depreciation expense. Capital contributions when refunded by Hydro One Transmission have the opposite impact of increasing Revenue Requirement. For example, a capital contribution received by Hydro One Transmission from Hydro One Distribution would have the effect of reducing Transmission's revenue requirement and increasing Distribution's revenue requirement.

It is worth noting that capital contributions, including those resulting from CCRA load true-ups, have different income tax implications depending on when they are received. Generally, capital contributions received from customers are taxed as income at the corporate statutory tax rate (26.5%). However, if a capital contribution is received within the first three years after the related asset is put in-service, the *Income Tax Act* provides for an election whereby the capital contribution received can be treated either as taxable income at the above-noted rate or as a reduction against the tax basis of the assets (UCC Pool). Refunds to customers resulting from load true-ups are deductible and thereby result in a tax benefit.

Given the timing of the true-ups, as prescribed under the TSC and DSC, it is important to realize that Hydro One triggers a tax expense on receipt and a tax benefit when Hydro One refunds amounts to customers. Capital contributions resulting from true-ups, where received by Transmission from Distribution, would lower the regulatory taxes for Distribution ratepayers and increase the regulatory taxes for Transmission ratepayers. Hydro One previously consulted with the Canada Revenue Agency on the possibility of receiving a technical interpretation that

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[3] Exhibit C-07-01

would allow Hydro One to treat the receipts of all CCRA true ups as capital contributions for tax purposes. However, as the legislation is clear, Hydro One was advised that Canada Revenue Agency would not be able to provide the requested technical interpretation in the absence of a legislative amendment.

5.0 REQUEST FOR CONTINUANCE OF TRANSMISSION CCRA VARIANCE ACCOUNT

In EB-2019-0082, Hydro One requested and the OEB approved establishment of the Transmission CCRA Variance Account to record the difference between the revenue requirement impact of capital contributions collected and the corporate income tax payments related to load true-ups performed in accordance with Transmission System Code section 6.5.3. Hydro One Transmission proposes to continue the Transmission CCRA Variance Account so that it can continue to record the difference between the revenue requirement impact of capital contributions collected and the corporate income tax payments related to load true-ups performed in accordance with Transmission System Code section 6.5.3, as approved in EB-2019-0082. As such, Transmission capital contribution true ups have not been included in the proposed Transmission rate base and revenue requirement for the 2023-2027 test period. Formal request for continuation of the Transmission CCRA Variance Account is provided in Exhibit G-01-02.

6.0 REQUEST FOR A NEW DISTRIBUTION CCA VARIANCE ACCOUNT

Hydro One proposes to establish a new variance account, referred to as Distribution Connection Cost Agreement (CCA) Variance Account (Distribution CCA Variance Account), to track the impacts on the Distribution revenue requirement of capital contribution true-ups paid by Hydro One Distribution to Hydro One Transmission and the capital contributions collected by Hydro One Distribution from its embedded distributors and large customers. This Distribution CCA Variance Account, which is formally requested in Exhibit G-01-02, is intended to function in a similar manner as the Transmission CCRA Variance Account that was approved in EB-2019-0082.

During the five year period of this rate application, numerous CCAs, which were entered into with large distribution customers after the TSC and DSC amendments in EB-2016-0003 came into effect, are expected to require at least one load true up (mostly related to the Leamington region). For example, one CCRA between Hydro One Distribution and Transmission has resulted in 14 CCAs downstream between Hydro One Distribution and large customers (greater than 5MW) subject to the new DSC requirements with over $100M of capital associated with the economic evaluations. Due to the different risk and load profiles of the individual customers embedded in the Distribution System (Hydro One Distribution is a Low Risk Customer while embedded industrial customers have a different classifications), as well as the fact that a portion of expenditures was allocated to serve Hydro One Distribution customers less than 5MW, the quantum and timing of the capital contribution from Distribution to Transmission will not match the contributions to Distribution from large customers. The requested variance account is proposed to ensure that neither Hydro One Distribution nor its ratepayers are harmed or inappropriately benefit from these regulatory calculations. Hydro One Distribution anticipates that the amounts captured in the proposed Distribution CCA Variance Account would meet or exceed the OEB's materiality threshold for establishing new regulatory accounts. However, due to the large number of contracts across different industries the amounts cannot be forecasted and could vary significantly.

The proposed variance account will track the revenue requirement impacts of actual capital contributions received or rebates paid as a result of performing load true ups, including the one-time tax impacts. For example, a capital contribution from a large customer resulting from the true up would result in the variance account including a regulatory asset from the one-time tax paid by Hydro One on the contribution as well as an annual regulatory liability to rate payers to reflect that the revenue requirement is lower due to the reduced rate base (impacting cost of capital, depreciation and tax gross up on equity return) until the next rate application to the OEB.

The variance account will not include the impact of the Notional Account, TSC section 6.5.7, prior to the final true up. Notional Accounts do not trigger a payment by Hydro One and therefore do not adjust rate base nor result in a tax implication.

This account will also not include the impact of the IEE based upon actual costs as these will be revenue requirement and tax neutral. For capital contributions collected in accordance with TSC section 6.5.2 for the IEE as well as when the transmitter subsequently recalculates the customer capital contribution based on actual cost, these are individually disclosed for each project in the relevant Investment Summary Documents (See TSP Section 3.3.8, DSP Section 3.12, and GSP Section 4.11). Each of these capital contributions is an offset to rate base when the asset is placed into service.

As stated previously, Hydro One Distribution has not included a forecast of true up payments in its application as it does not have the information necessary to create this forecast nor the ability to acquire this information. While Hydro One Distribution is able to perform a macro forecast of the total distribution load in Ontario, an individual analysis of the forecasted true ups required during the 2023-2027 period and resulting capital contribution calculation subjects both the Company and ratepayers to a number of significant forecasting risks that are beyond the control of Hydro One. The primary risks, as previous described in EB-2019-0082 Exhibit C-07-01 for Hydro One Transmission, also apply to Hydro One Distribution, are as follows:

1. Actual load is adjusted by embedded generation and energy conservation as per TSC sections 6.5.8 to 6.5.10. Hydro One does not have access to individual company reports from the IESO on an ongoing basis and is typically provided with this information by the customer only if it is applying for load credits during the true-up point.

2. Customer load forecasts at the true-up point are subject to significant change based upon the customer's outlook of its specific operations (productivity vis-a-vis competitors, refurbishments or planned expansions to their operations etc.) These customer forecasts extend beyond the Hydro One rate setting load forecasts (i.e. an

industrial 5th year true up could submit a load forecast for a decade, years 6 to 15 as per the TSC). However, the customer forecast has an impact on the required true up capital contribution, rate base, and tax expense in the year that the true up is performed.

3. The customer load forecasts at the true up-point are subject to significant changes based upon specific market factors that the customer operates in (such as mineral pricing forecast for mining, demand for its particular product, exchange rate fluctuations etc.) of which Hydro One has limited insight into.

4. For many CCAs, there is insufficient actual load data since the latest true-up to perform a forecast for this rate filing. As many of the customers subject to the updated DSC provisions connected in 2019 and 2020, the comparison of actual versus forecast performance has a high probability of error because there is typically less than one year of actual performance data. Moreover, COVID-19 may or may not have disrupted or benefited their operations (depending on the nature of the customer's business). For example, low risk customers that connected in late 2020 will have less than one year of performance data on the IEE load forecast and will be trued up in 2025.

5. Transmission expansions or upgrades requested by industrial customers will be executed and placed in service with an IEE and load trued up within the five year rate period of this application. For example, if a mine requests a line expansion to connect their facility in the first year of the rate period and connects in the second year of the rate period, it could have several load true ups performed in the subsequent years depending upon their Risk Classification (i.e. a high risk classification could result in two load true up under this scenario).

INTEREST CAPITALIZED

Consistent with the OEB's Decision in EB-2008-0408, effective January 1, 2012, no allowance for funds used during construction (AFUDC) rate is specified for use by Hydro One. Hydro One was directed to base its interest capitalization rate on its embedded cost of debt used to finance capital expenditures. This is also consistent with Hydro One's adoption of United States Generally Accepted Accounting Principles (US GAAP) per the OEB's decision in EB-2011-0268 for Transmission and per OEB's decision in EB-2011-0399 for Distribution and US GAAP requirements for determination of interest capitalized. The rates used in calculating capitalized interest for the bridge and test years represent the effective rate of Hydro One Transmission and Distribution's forecasted average debt portfolio during the year.

Capitalized interest costs are calculated using the Company's weighted average effective cost of debt. Capitalized interest is included in the capital expenditures shown in the Transmission System Plan (the TSP), Distribution System Plan (the DSP) and the General Plant System Plan (the GSP). These expenditures are recovered through Revenue Requirement once they become in-service additions to Rate Base. Table 1 below summarizes the capitalized Interest for Transmission and Table 2 below summarizes the capitalized Interest for Distribution. The amount capitalized for Transmission is usually greater than for Distribution as a larger proportion of Transmission capital work qualifies for interest due to the generally longer duration of Transmission projects.

Table 1 - Capitalized Interest - Transmission

Year	Capitalization Rate	Transmission Capitalized Interest ($M)
2018	4.4%	45.5
2019	4.4%	40.9
2020	4.0%	40.5
2021 Forecast	4.2%	43.3
2022 Forecast	4.0%	40.2
2023 Forecast	3.9%	36.4
2024 Forecast	4.0%	40.9
2025 Forecast	4.1%	39.6
2026 Forecast	4.0%	37.0
2027 Forecast	4.4%	41.4

Table 2 - Capitalized Interest - Distribution

Year	Capitalization Rate	Distribution Capitalized Interest ($M)
2018	4.3%	8.0
2019	4.3%	6.7
2020	4.0%	8.1
2021 Forecast	4.4%	6.8
2022 Forecast	4.2%	6.9
2023 Forecast	4.1%	7.6
2024 Forecast	4.1%	8.2
2025 Forecast	4.1%	6.5
2026 Forecast	4.2%	5.3
2027 Forecast	4.1%	4.6

OVERHEAD CAPITALIZATION RATE

1.0 INTRODUCTION

To ensure that capital work reflects all of the costs incurred to enable assets to be placed into service and to operate for their intended use, Hydro One (a) capitalizes costs that are directly attributable to capital work, such as the purchase price for materials and equipment, and costs directly incurred to bring materials and equipment to work sites and to install and otherwise make them ready for service, and (b) capitalizes those of its common corporate costs, or 'overheads', that relate to its capital work. By including the portion of its overheads that relates to capital work in rate base, Hydro One aligns the recovery of its costs for capital-related work with the expected useful lives of the underlying assets, during which those assets are expected to provide benefits to customers.

Hydro One's Common Corporate Costs are costs that it incurs to provide shared services from centralized business operations (i.e. legal services, human resources, finance, etc.) to Hydro One and its affiliate companies. Those overheads are allocated to Transmission and Distribution, as well as affiliates, through the methodology described in Exhibit E-04-08. For each of Transmission and Distribution, capitalized overhead costs represent the portion of their allocated Common Corporate Costs that have been incurred to support capital expenditures and which are therefore capitalized along with the costs directly attributable to capital work.

This Exhibit describes the methodology that Hydro One uses to allocate its overhead costs to capital work, for the Transmission business and the Distribution business (the Overhead Capitalization Methodology). Generally, these costs are allocated through the application of an overhead capitalization rate, which is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year. A distinct overhead capitalization rate applies to each of Transmission and Distribution as a result of applying the proposed Overhead Capitalization Methodology. In addition, this Exhibit describes the detailed review and benchmarking of Hydro One's approach to overhead capitalization that has been performed in response to prior directives from the OEB.

2.0 OVERHEAD CAPITALIZATION METHODOLOGY

The Overhead Capitalization Methodology was developed for Hydro One by Black & Veatch (B&V, formerly RJ Rudden Associates). It was first presented in the report "Distribution Overhead Capitalization Rate Method" dated May 20, 2005 in the Distribution application for 2006 Distribution Rates and accepted by the OEB.[1] In subsequent applications, the OEB has continued to accept the recommended methodology for both Transmission and Distribution.[2] The methodology was most recently accepted by the OEB in the application for Distribution Rates for 2018 to 2022 (EB-2017-0049), as well as in the application for Transmission revenue requirement for 2020-2022 (EB-2019-0082).

In its most recent Transmission and Distribution decisions, the OEB signalled its intention to undertake detailed reviews of certain allocation methodologies used by Hydro One, including the Overhead Capitalization Methodology.[3] Hydro One therefore undertook a competitive RFP process to select an appropriate expert to undertake detailed assessments of its Common Corporate Cost Allocation Methodology, Overhead Capitalization Methodology, and methodology for allocating Shared Assets. Though open to engaging a new expert, after evaluating multiple proposals, Hydro One selected Black & Veatch (B&V) once again for this

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[1] RP-2005-0020/EB-2005-0378
[2] Refer to !p pendix '!', Table 13 of Black & Veatch's Report on Corporate Cost !llocat ion review, which is provided in Exhibit E-04-08, Attachment 1.
[3] In EB-2017-0049 the OEB directed Hydro One to file a report as part of its next rebasing application that compares Hydro One's capitalization of common corporate costs with those of other utilities in Ontario, Canada and North America, and specified that this should include utilities both under US GAAP and those using International Financial Reporting Standard (IFRS). In EB-2019-0082 the OEB directed Hydro One to provide a report comparing capitalization of common corporate costs with those of other utilities in Ontario, Canada, and North America (both under USGAAP and IFRS), and ordered that a detailed review of Hydro One's methodology regarding overhead capitalization be filed in its next rebasing application, including the revenue requirement impact and risk analysis associated with transitioning from US GAAP to MIFRS.

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 (2020 B&V Study). The Common Corporate Cost Allocation Methodology is addressed in Exhibit E-04-08. The methodology for allocating Shared Assets is addressed in Exhibit C-03-01. The Overhead Capitalization Methodology is discussed in the current exhibit.

Based on its detailed review of Hydro One's Overhead Capitalization Methodology, B&V has concluded that Hydro One's existing Overhead Capitalization Methodology continues to be appropriate because it is accurate and transparent, fairly attributes to and recovers appropriate overhead costs from capital work, and ascertains which activities have a causal link between overhead costs and capital activity. B&V also incorporated several enhancements to the methodology, including an expanded review of activities performed by all Shared Service groups, which has allowed for the direct assignment of all Shared Service activities across all Shared Service groups rather than only for Shared Services relating to customer relations, asset management and operations.

A consolidated report from B&V, addressing all aspects of its review, including with respect to the Overhead Capitalization Methodology, is provided in Exhibit E-04-08, Attachment 1.

In summary, B&V describes the Overhead Capitalization Methodology as follows:

> *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, to calculate the total Capitalized Shared Service Costs by adding (1) the portion of overhead costs directly relating to capital and (2) the Shared Service activities relating to capital, the total of*

> *which is then divided by the total Capital Expenditures to determine the Overhead Capitalization Rate.*[4]

Using the established methodology, Hydro One reviews its overhead capitalization rates on a monthly basis to determine if the rates need to be updated to reflect in-year changes in capital spending and the associated support costs. At year-end, capitalized overheads are trued-up to reflect actuals. This results in a better alignment of overhead costs with the capital work that those costs support. Although the actual overhead capitalization rates may fluctuate from month to month, the methodology that is applied each month remains consistent with that which has been accepted by the OEB in the relevant prior rate proceeding.

The Overhead Capitalization Methodology, as reviewed and set out in the 2020 B&V Study for purposes of the current application, presents a reasonable and appropriate method for allocating overhead costs to capital work for each of the Transmission and Distribution businesses. Hydro One has applied the Overhead Capitalization Methodology as recommended by the 2020 B&V Study in calculating its requested revenue requirement in this application.

Table 1, below, summarizes the overhead capitalization rates and amounts for each of the Transmission and Distribution businesses, as calculated using the methodology that has been recommended by B&V. Attachment 1 to Exhibit E-04-08 presents further details of the 2020 B&V Study.[5]

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[4] B&V Report, p. [8].
[5] Sections 6 of the B&V Report – Overhead Capitalization Rate Methodology and Appendix C – Overhead Capitalization Rate Calculation

Table 1 - Overhead Capitalization Rates and Amounts for Transmission and Distribution

Overhead Cost Category	Test Years (%)					Test Years ($M)				
	2023	**2024**	**2025**	**2026**	**2027**	**2023**	**2024**	**2025**	**2026**	**2027**
Transmission	8.0%	8.0%	9.0%	9.0%	9.0%	118.1	119.7	121.0	122.3	123.9
Distribution	9.0%	9.0%	9.0%	9.0%	9.0%	89.9	91.0	94.9	94.2	95.7

In general, the updates to the methodology employed in the 2020 B&V Study 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 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. The capitalization rates are consistent with the previous Transmission study (EB-2019-0082), while the capitalization rates are down relative to the previous Distribution study (EB-2017-0049).

3.0 OEB DIRECTIVES

In its decisions in EB-2017-0049 and EB-2019-0082, the OEB expressed concerns with Hydro One's overhead capitalization levels and directed Hydro One to provide a report that benchmarks its capitalization of overhead costs against other utilities in Ontario, Canada, and North America, both under US GAAP and IFRS. The OEB also ordered that a detailed review of Hydro One's approach to overhead capitalization be carried out.

Therefore, in addition to engaging B&V to perform a detailed review of the Overhead Capitalization Methodology, Hydro One undertook a competitive RFP process through which it selected PricewaterhouseCoopers LLP (PwC) to undertake the required benchmarking of its overhead capitalization costs, as well as to assess the reasonableness of Hydro One's approach to overhead capitalization relative to applicable regulatory and accounting guidance under both US GAAP and IFRS. These aspects of PwC's analysis are discussed below, and a copy of PwC's report, entitled *Hydro One Capitalization of Common Corporate Costs Review* (PwC Report on Capitalization of Common Corporate Costs), is provided as Attachment 2 to this Exhibit. An additional component of PwC's engagement, to assist Hydro One in responding to the OEB's further direction to examine the revenue requirement impact and risk analysis associated with transitioning from US GAAP to MIFRS, is addressed in Exhibit A-06-01 and is accompanied by a separate report, entitled *Hydro One US GAAP to IFRS Conversion Impact Review* (PwC Report on IFRS Conversion), as provided in Attachment 1 to Exhibit A-06-01.

Based on its review, PwC concluded that Hydro One's proposed methodology for capturing overhead costs and allocating such costs to capital activities is reasonable, supportable and consistent with the principle that the assignment of such costs to capital work should be based on a causal link, as well as consistent with applicable regulatory guidance from each of the OEB and Federal Energy Regulatory Commission (FERC) and accounting guidance under both US GAAP and IFRS.

3.1 BENCHMARKING REVIEW

To perform its benchmarking review of Hydro One's overhead capitalization costs, PwC identified a group of peer companies from both Canada and the United States, who report under both US GAAP and IFRS, and compared the percent of common corporate cost equivalents capitalized. For the US peers, PwC benchmarked Hydro One on the basis of common corporate cost equivalents capitalized as a % of total common corporate cost equivalents. For the Canadian peers, PwC benchmarked Hydro One on the basis of common corporate cost equivalents capitalized as a % of equivalent OM&A. The metrics used in this analysis differed because the US peers are required to report what they deem to be their common corporate cost equivalents and the amount of common corporate cost equivalents capitalized in their publicly filed FERC forms, whereas the Canadian Peers do not have the same or similar reporting requirements and these common corporate cost equivalents are instead included within OM&A. Where possible based on information available, PwC also compared Hydro One's overhead capitalization process to this peer group. PwC found the benchmarking of Hydro One's overhead capitalization against other utilities to be challenging for a number of reasons, including (i) the use of inconsistent terminology and the inclusion of different sets of costs in comparable measures, (ii) difficulties obtaining information in a form that facilitates comparison to Hydro One, (iii) differences in utility operations and processes for direct charging and allocating costs to capital or OM&A, as well as (iv) differences in the extent to which third-party contractors are used to perform capital work.

PwC summarizes the results of the benchmarking component of its analysis as follows (pg 4):

> *In our comparison of common corporate costs capitalized at Hydro One to those that are capitalized by other regulated utilities, we observed that the Company fell within the range of its Canadian peers. When compared to US utilities, while Hydro One's capitalization percentage was at the upper end of the peer group, there was a large range of results which can be attributable to factors such as company size, size of the construction program, different definitions of the costs to be considered and involvement of third-party contractors. These differing factors make a comparison between Hydro One and other utilities difficult as many are not comparable. <u>Of particular significance is that Hydro One self-constructs most of their capital work. In our experience, this is in contrast to many of its peers which generally perform more construction activity through the use of third parties. Such third-party suppliers incur their own common corporate-type costs and include such costs in their billings to the utilities, and those billings are in turn capitalized as direct costs by the utility. In either a self-constructed or outsourced situation, common corporate-type costs are incurred and included in the capital work, but there is a difference in the source of the charges (either capitalized by the utility or capitalized through the direct charging of third-party billings to capital work) and that difference has a significant impact on the utility's common corporate cost capitalization rate.</u> There are many other factors that, in our view, may have contributed to differences within the peer group and made comparisons difficult, including limitations on publicly available information, a lack of common definitions of key terms, differences in methodologies and each utility's environment and operating models. (emphasis added)*

3.2 REGULATORY AND ACCOUNTING GUIDANCE REVIEW

To perform its review of Hydro One's approach to overhead capitalization relative to regulatory and accounting guidance, PwC obtained and reviewed process and policy documentation from Hydro One, interviewed and conducted walkthroughs with Hydro One personnel responsible for cost capitalization processes, discussed the Overhead Capitalization Methodology with B&V,

reviewed a copy of the B&V report, and compared Hydro One's proposed methodology against relevant guidance from each of the OEB and FERC, as well as against relevant accounting guidance under US GAAP and IFRS. PwC also reviewed the nature of the activities in general and the description of the activities and observed a relationship to capital for those activities which had some portion allocated to capital. Based on this analysis, PwC found the proposed methodology for capitalizing overhead costs to be reasonable and consistent with the principle that any assignment of indirect costs to capital work should be based on a reasonable causal link. Furthermore, PwC found the proposed methodology to be reasonable based on the guidance issued by the OEB and FERC and consistent with the principles of both US GAAP and IFRS.

PwC summarizes the results of the regulatory and accounting guidance review component of its analysis as follows (pg 4):

> *Given the aforementioned challenges in making direct comparisons to peers, we performed additional work to understand Hydro One's process to capitalize common corporate costs and compared its process with the relevant guidance issued by the OEB and FERC and the accounting guidance under US GAAP and IFRS . . .*
>
> *. . . Based on completing these procedures and analyses, we determined Hydro One's proposed methodology for capturing common corporate costs and allocating such costs to capital activities is reasonable, supportable and consistent with the principle that the assignment of such costs to capital work should be based on a causal link. Further, the methodology follows the guidance promulgated historically by the OEB and FERC and is consistent with the practice of other utilities that apply rate regulated accounting guidance under US GAAP and IFRS.*

More particularly, based on its review of the relevant US GAAP sections, PwC found that (pg 19):

> *A regulated utility may have unique considerations in developing capitalization policies because regulators often permit recovery of costs as part of capital work that may otherwise be charged to expense in the period they are incurred. Only those costs that are probable of recovery through future rates should be capitalized as part of the utility plant…*

> *…the utility regulator has a direct impact on how certain costs are accounted for under US GAAP. If a cost supports underlying capital work, but may not be capitalized under US GAAP before the application of ASC 980, the regulator must decide if that cost should be borne by customers over the life of the underlying capital asset to match its use and the period during which customers will derive a benefit from it (i.e., capitalized) or expensed as a period cost and borne only by current period customers. <u>It is typical for regulators to allow for costs that relate to and support capital work to be charged to capital to better match the benefit received to the cost in accordance with the regulatory principle of matching costs and benefits and producing intergenerational equity.</u> (emphasis added)*

Moreover, based on its review of the relevant IFRS sections, PwC found that (pg 21):

> *Consistent with the guidance in ASC 980 under US GAAP, the regulator has a direct impact on how certain costs are accounted for. If a cost supports an underlying capital program, but may not be capitalized under IFRS before the application of IFRS 14, the regulator must decide if that cost should be borne by customers over the life of the underlying capital work to match its use and the period during which customers will derive a benefit from it (i.e., capitalized) or expensed as a period cost and borne only by current period customer.*
>
> *<u>Where IFRS 14 is applied for administrative and other general overhead costs, deferrals permitted by the regulator would be treated as a regulatory asset under IFRS whereas under US GAAP, these amounts would generally be capitalized directly to Property, Plant and Equipment (PP&E). This results in a difference in geographical presentation on the balance sheet and income statement.</u> Absent the application of IFRS 14, such costs that do not qualify for capitalization to PP&E would generally be recorded as expense in the period they are incurred. (emphasis added)*

3.3 IMPACT OF IFRS CONVERSION ON CAPITALIZED OVERHEADS

In addition to the benchmarking and the analysis of the overhead capitalization methodology proposed by B&V above, PwC performed an analysis of the implications for overhead capitalization of a conversion from US GAAP to IFRS (which is not something that Hydro One is proposing to do, and further discussed in Exhibit A-06-01) in its report, *US GAAP to IFRS Conversion Impact Review* which is provided as Attachment 1 to Exhibit A-06-01.

PwC summarizes the results of its analysis of the potential revenue requirement impacts associated with transitioning from US GAAP to IFRS in the context of capitalizing common corporate costs as follows (pg 3):

> *The guidance issued by the OEB in the Accounting Procedures Handbook For Electricity Distributors effective January 1, 2012 does not provide specific direction to utilities regarding capitalization of Common Corporate Costs as defined by Hydro One. As a result certain costs within the Common Corporate Costs capitalized in the Company's Application may no longer qualify to be capitalized on the adoption of IFRS.*
> *On transition to IFRS, Common Corporate Costs historically capitalized to Property, plant and equipment (PPE) would likely remain within PPE. Subsequent to the adoption of IFRS, these common corporate costs may be recorded as period expenses to be recovered in the company's annual revenue requirement.*
>
> *Should accounting processes be amended and updated, there may be specific components within Common Corporate Cost categories that may meet the criteria under IAS 16 to be capitalized to specific capital projects. <u>Furthermore, should additional direction be issued by the OEB, similar to the guidance applicable to entities that report to the OEB under US GAAP, certain of these costs may be recorded as regulatory assets in accordance with IFRS 14.</u> (emphasis added)*

Moreover, PwC explains (pg 6):

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

Also relevant to the consideration of the impacts of IFRS conversion on Hydro One's overhead capitalization is the fact that, as PwC observed, "Hydro One self-constructs most of their capital work. In our experience, this is in contrast to many of its peers which generally perform more construction activity through the use of third parties."[6] The analysis above regarding IFRS conversion applies primarily to utilities like Hydro One that perform the bulk of their construction work in-house. For most other utilities, which contract the majority of their capital work to third parties, a transition from US GAAP to IFRS would not be as impactful on overheads capitalized because overheads from the contractors they use would be included in the invoiced amounts and capitalized under both US GAAP and IFRS.

In addition to considering the treatment of overhead capitalization amounts between US GAAP and IFRS, PwC identified and assessed other significant adjustments in respect of financial statement presentation and updates to processes for tracking information for disclosures, which could materially impact revenue requirement components as a result of transitioning from US GAAP to IFRS, thereby supporting Hydro One's intention to remain on US G! !P. Further details are provided in the PwC's report in Attachment 1 to Exhibit A-06-01. Please refer to Exhibit A-06-01 for a detailed discussion on those other considerations.

[6] Hydro One Capitalization of Common Corporate Costs Review, p. [4].

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Appendix 2-D
Overhead Expense - Hydro One Transmission

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2018 Historical Year**	**2019 Historical Year**	**2020 Historical Year**	**2021 Historical Year**	**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
Operations	$ 53.4	$ 51.0	$ 47.9	$ 48.8	$ 48.6	$ 49.0
Customer Service	$ 11.0	$ 7.2	$ 7.0	$ 6.0	$ 6.7	$ 6.9
Planning / Asset Management	$ 31.0	$ 26.7	$ 25.3	$ 25 2	$ 26.6	$ 27.4
Information Technology (including Cornerstone)	$ 50.4	$ 53.7	$ 51.2	$ 51.4	$ 51.2	$ 53.7
Common Corporate Functions and Services	$ 92.5	$ 88.2	$ 88.6	$ 90.7	$ 94.9	$ 96.9
Internal + External Work COS	$ 8.4	$ 3.7	$ 7.7	$ 6.4	$ 4.9	$ 5.7
Property Taxes	$ 65.3	$ 60.8	$ 65.4	$ 69.1	$ 70.2	$ 71.4
Other (including overheads)	$ (2.9)	$ (31.0)	$ 13.0	$ (6.5)	$ (6.4)	$ (0.5)
Total OM&A Before Capitalization (B)	$ 543.6	$ 472.5	$ 513.8	$ 504.6	$ 513.9	$ 538.6
Check to OM&A	$ 419.2	$ 357.9	$ 398.5	$ 389.0	$ 393.4	$ 420.5

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2018 Historical Year**	**2019 Historical Year**	**2020 Historical Year**	**2021 Historical Year**	**2022 Bridge Year**	**2023 Test Year**	**Directly Attributable? (Yes/No)**	**Explanation for Change in Overhead Capitalized**
Capitalized Administrative & General Costs	$ 99.3	$ 89.5	$ 90.6	$ 91.3	$ 94.9	$ 118.1	No	No change.
Capitalized Planning, Customer and Operating Costs	$ 25.2	$ 25.2	$ 24.7	$ 24.2	$ 25.6		No	No change.
Total Capitalized OM&A (A)	$ 124.5	$ 114.6	$ 115.3	$ 115.6	$ 120.4	$ 118.1		
% of Capitalized OM&A (=A/B)	23%	24%	22%	23%	23%	22%		

Appendix 2-D
Overhead Expense - Hydro One Distribution

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format

OM&A Before Capitalization	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	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
Operations	$ 37.3	$ 36.6	$ 33.0	$ 39.7	$ 41.3	$ 40.8
Customer	$ 111.7	$ 97.8	$ 111.2	$ 108.6	$ 107.9	$ 118.3
Planning / Asset Management	$ 15.7	$ 13.5	$ 14.2	$ 13.6	$ 14.4	$ 14.9
Information Technology (including Cornerstone)	$ 73.8	$ 81.1	$ 78.4	$ 83.8	$ 81.5	$ 85.9
Common Corporate Functions and Services	$ 80.1	$ 76.9	$ 76.4	$ 83.8	$ 87.2	$ 89.1
Internal + External Work COS	$ 10.4	$ 5.3	$ 4.1	$ 4.0	$ 4.4	$ 4.4
Property Taxes	$ 5.1	$ 4.6	$ 5.4	$ 5.6	$ 5.8	$ 6.0
Other (including overheads)	-$ 18.0	-$ 28.9	-$ 8.9	-$ 28.5	-$ 29.8	$ 5.6
Total OM&A Before Capitalization (B)	$ 635.8	$ 641.1	$ 644 6	$ 620.1	$ 626.5	$ 687.4
Check to OM&A	$ 558.8	$ 559.6	$ 560.2	$ 531.4	$ 535.8	$ 597.5

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Capitalized Administrative & General Costs	$ 63.8	$ 68.2	$ 71.7	$ 73.7	$ 74.4	$ 89.9	No	No change.
Capitalized Planning, Customer and Operating Costs	$ 13.2	$ 13.4	$ 12.7	$ 15.1	$ 16.3		No	No change.
Total Capitalized OM&A (A)	$ 77.0	$ 81.5	$ 84.4	$ 88.8	$ 90.7	$ 89.9		
% of Capitalized OM&A (=A/B)	12%	13%	13%	14%	14%	13%		

Hydro One

Capitalization of Common Corporate Costs Review

June 17, 2021

pwc

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Purpose, scope and limitations of this report

At the request of Torys LLP, as counsel to Hydro One Networks Inc. (“Hydro One”, “the Company”), we have prepared this report to (i) comment on the process used by Hydro One for the capitalization of common corporate costs and (ii) compare Hydro One’s capitalization of common corporate costs with other utilities in Ontario, Canada and North America.

We understand that the purpose of this report is to assist Hydro One with its planned 2023-2027 combined Distribution and Transmission rate application (the “Application”) to be filed with the Ontario Energy Board (“OEB”) in 2021.

This report includes:

- A comparison of the percentage of common corporate costs capitalized by Hydro One to the percentage of such costs capitalized by other regulated utilities,
- An overview of the process and methodology developed for the Company by Black & Veatch that will be used by Hydro One to allocate and capitalize common corporate costs,
- PwC’s findings as to the reasonableness of the approach that Hydro One will use to capitalize common corporate costs based on the results of procedures outlined in this report, and
- A comparison of the Hydro One common corporate cost capitalization methods outlined in the Company’s Application to the guidance provided by the OEB and Federal Energy Regulatory Commission (“FERC”) as well as to the accounting guidance prescribed by the Financial Accounting Standards Board (“FASB”) for Generally Accepted Accounting Principles in the United States of America (“US GAAP”) and International Financial Reporting Standards as issued by the International Accounting Standards Board (“IFRS”).

Limitations

This report refers to the methodology outlined by Black & Veatch in its *Report on Corporate Cost Allocation Review* dated June 9, 2021 (the “B&V Report”) as filed in Hydro One’s Application for the calendar years 2023-2027, inclusive. Specifically, the report refers to the methodology for capitalizing corporate costs for the Tx and Dx businesses as described in Section 6 of that report.

Our work was limited to the procedures and analysis described herein. Our work was performed on the basis that information included in the B&V Report and other information provided to us by Hydro One was accurate and complete. Unless otherwise noted, all references in this report to Hydro One processes, methods and methodologies refer to the proposed methodology summarized in the B&V Report and not to methods that Hydro One may have used in the past. We did not review Hydro One’s revenue requirement calculations and application for the calendar years 2023-2027 nor audit, verify nor otherwise validate any data nor explanations, except as specifically noted by us in this report. Our engagement cannot be relied upon to disclose errors, irregularities or illegal acts, including fraud or defalcations that may exist. Further, this evaluation does not constitute an audit, accounting opinion, tax opinion, attest opinion nor any other form of assurance.

This report is intended solely for use by Torys LLP and Hydro One Networks Inc. under the terms of our agreement dated June 1, 2020 and is not intended or authorized for any other use or party. If any unauthorized party uses this report, in whole or in part, it is their sole responsibility and their sole and exclusive risk, that they may not rely on the report, that they do not acquire any rights as a result of such access and that PricewaterhouseCoopers LLP does not assume any duty, obligation, responsibility or liability to them.

Executive summary

In order for capital work to reflect all costs incurred to bring the assets to be capable of operating for their intended use, utility regulators permit regulated entities, such as Hydro One, to capitalize common corporate costs that relate to capital work. A widely accepted principle used to assign common corporate costs to capital work is that a reasonable causal link or an association with capital activity exists to support the assignment. Under cost of service-based regulation, regulated entities are permitted to recover their capital costs (through depreciation expense) and earn a return on the capital costs that are included in their rate base (subject to any adjustments that may apply under a related incentive regulation framework). By including these costs in rate base and recognizing and permitting recovery of depreciation expense, the capitalization of common corporate costs aligns the recovery of those common corporate costs associated with capital activity with the estimated useful life of the underlying fixed assets. Consequently, the capitalization of such common corporate costs aligns their recovery with the period of time during which customers are expected to benefit from the use of those assets, consistent with the regulatory principle of intergenerational equity.

We were engaged to identify a group of peer utilities and compare Hydro One's capitalization of common corporate costs to this group. We were also engaged to understand Hydro One's proposed methodology for the capitalization of common corporate costs allocated to Hydro One's Distribution and Transmission businesses and to compare the methodology with guidance issued by the OEB and FERC as well as the accounting guidance under US GAAP and IFRS. Black & Veatch ("B&V") has developed this methodology for the capitalization of Hydro One's common corporate costs. Hydro One's proposed overhead capitalization methodology set out in the B&V Report is based on the principle, noted above, that common corporate costs should be allocated to capital where there is a reasonable causal link to capital activity.

In our comparison of common corporate costs capitalized at Hydro One to those that are capitalized by other regulated utilities, we observed that the Company fell within the range of its Canadian peers. When compared to US utilities, while Hydro One's capitalization percentage was at the upper end of the peer group, there was a large range of results which can be attributable to factors such as company size, size of the construction program, different definitions of the costs to be considered and involvement of third-party contractors. These differing factors make a comparison between Hydro One and other utilities difficult as many are not comparable. Of particular significance is that Hydro One self-constructs most of their capital work. In our experience, this is in contrast to many of its peers which generally perform more construction activity through the use of third parties. Such third-party suppliers incur their own common corporate-type costs and include such costs in their billings to the utilities, and those billings are in turn capitalized as direct costs by the utility. In either a self-constructed or outsourced situation, common corporate-type costs are incurred and included in the capital work, but there is a difference in the source of the charges (either capitalized by the utility or capitalized through the direct charging of third-party billings to capital work) and that difference has a significant impact on the utility's common corporate cost capitalization rate. There are many other factors that, in our view, may have contributed to differences within the peer group and made comparisons difficult, including limitations on publicly available information, a lack of common definitions of key terms, differences in methodologies and each utility's environment and operating models.

Given the aforementioned challenges in making direct comparisons to peers, we performed additional work to understand Hydro One's process to capitalize common corporate costs and compared its process with the relevant guidance issued by the OEB and FERC and the accounting guidance under US GAAP and IFRS.

Our process for completing this evaluation included the following steps:

- Obtaining and reviewing process and policy documentation provided by management,
- Interviewing and conducting walkthroughs with Hydro One personnel responsible for the cost capitalization processes to understand how common corporate costs will be capitalized in the Application,
- Discussing the methodology with Black & Veatch, who were engaged by Torys LLP as counsel to Hydro One to develop the methodology for the allocation and capitalization of common corporate costs,
- Obtaining and reading the B&V Report which provides details on Hydro One's proposed methodology for allocating and capitalizing common corporate costs, and
- Comparing Hydro One's proposed method of capitalizing common corporate costs against guidance from OEB and FERC and accounting guidance, specifically US GAAP and IFRS.

Based on completing these procedures and analyses, we determined Hydro One's proposed methodology for capturing common corporate costs and allocating such costs to capital activities is reasonable, supportable and consistent with the principle that the assignment of such costs to capital work should be based on a causal link. Further, the methodology follows the guidance promulgated historically by the OEB and FERC and is consistent with the practice of other utilities that apply rate regulated accounting guidance under US GAAP and IFRS.

Comparison to other utilities

Overview and Summary

We selected a group of US and Canadian peer companies to compare to Hydro One. As it relates to the capitalization of common corporate costs, comparisons with other utilities are challenging because:

- The term “common corporate costs” is not a defined term and utilities often include different costs in their comparable measures;
- Few utilities disclose information about their costs in a way that facilitates comparison to Hydro One’s common corporate costs because disclosure of an entity’s indirect costs and overhead accounting practices is not required by either US GAAP or IFRS;
- The nature of utility activities and operations, including processes to direct charge costs to capital or OM&A and/or allocate indirect costs to capital often differ;
- The types of activities included in the pool of indirect costs to be allocated to capital often differ; and
- Utilities who use third party contractors to perform more of their capital work will have more common corporate-type costs embedded in their direct charges from third-party contractors and consequently will have less costs in their pool of common corporate costs.

We identified a group of peer companies who report under both US GAAP and IFRS and compared the percent of common corporate cost equivalents capitalized. In addition, where possible based on information available, we also compared Hydro One’s process to this peer group. We observed that the Company fell within the range of its Canadian peers. When compared to US utilities, while Hydro One’s capitalization percentage was at the upper end of the peer group, there was a large range of results which can be attributable to factors such as company size, size of the construction program, different definitions of the costs to be considered and involvement of third-party contractors. Further, the Company’s higher proportion of self constructed capital work relative to the peer group companies likely contributes to this result. In particular, we note that third-party contractors that are hired by a company to perform capital work will embed their overheads and their other indirect costs in their charges to the company. To the extent that the third party contractors hired by a company are working on capital work, the total third-party contractor cost, inclusive of these overheads and indirect costs, are also capitalized as part of the capital work. Therefore, in the case of a company who uses third party contractors more heavily than Hydro One, it is reasonable to expect that a higher proportion of their indirect costs would be directed towards activities which are done internally which may be not capital in nature. As a result, such companies would likely have a lower capitalization rate than Hydro One.

Analysis

In the following section, we describe the approach we took to identify comparable/peer companies to Hydro One and explain how Hydro One’s capitalization percentage based on the 2023 test year compares to the Canadian and US peers selected. We also considered additional information that was available from publicly available FERC forms for US utilities.

Hydro One 2023 comparative figures

In order to benchmark Hydro One’s common corporate cost capitalization percentages to other utilities, the following percentages of common corporate costs to be capitalized were provided for the 2023 test year by Hydro One and we agreed them to the B&V Report:

Table 1

Total common corporate costs capitalized within Tx and Dx as a percentage of total Tx & Dx OM&A expenses	Total common corporate costs capitalized within Tx and Dx as a percentage of total common corporate costs allocated to Tx & Dx
18%	**48%**

Approach

Comparable companies

Identifying comparable companies is challenging and an imperfect exercise as utility companies differ in many ways. Differences include, but are not limited to:

- Size (Size can be measured in many ways including number of customers, kilometres of distribution and/or transmission lines, revenue, total assets, etc.);
- Geographic region (urban, rural, terrain etc.);
- Proportion of the business that includes distribution, transmission, generation or unregulated non-utility activities;
- Number of subsidiaries under a corporate parent (including whether subsidiaries are regulated or unregulated);
- Basis of accounting (US GAAP, IFRS, other);
- Regulatory environment;
- Proportional use of third-party contractors and employees for capital construction related activities; and
- Size and nature of the company's capital program.

Further, not all companies disclose data regarding indirect costs and/or the capitalization of these costs in public filings. For example, we originally identified 13 comparable companies to include in our comparison analysis. However, based on our research, few of these original selections provided the necessary comparable capital cost allocation data in financial statements, rate case filings or other public disclosures (other than the FERC forms discussed below). As a result, we expanded our selection to choose some utilities that were less comparable, but provided more of the data necessary for this analysis. The below table details all of the companies considered in our analysis including our original selection of comparable peers and the additional utilities subsequently added based on those that disclosed relevant data.

Table 2

	Company name	Country	Basis of accounting
Original Peer Companies Identified with Relevant Quantitative Data Available			
1	Toronto Hydro	Canada	IFRS (incl. IFRS 14)
2	BC Hydro and Power Authority	Canada	IFRS (incl. IFRS 14)
3	Fortis BC	Canada	US GAAP
4	Enbridge Gas Inc.	Canada	US GAAP
5	Evergy Metro (Kansas City Power & Light)	US	US GAAP
Additional Companies Identified Based on Availability of Relevant Quantitative Data*			
6	Enmax Power Corporation	Canada	IFRS (incl. IFRS 14)
7	Southern California Edison	US	US GAAP
8	San Diego Gas and Electric Company	US	US GAAP
9	Pacific Gas & Electric Company	US	US GAAP
Original Peer Companies Identified with only Qualitative Data Available (excluded from quantitative comparison, but qualitative data is included in Appendix B)			
10	Alectra Incorporated	Canada	IFRS
11	CenterPoint Energy Houston Electric	US	US GAAP
12	Consumers Energy	US	US GAAP
13	DTE Electric Company	US	US GAAP
Original Peer Companies Identified with no Relevant Data Available (excluded from our analysis, except where specified)			
14	Hydro Québec	Canada	US GAAP
15	Wisconsin Electric Power Company	US	US GAAP
16	Arizona Public Service	US	US GAAP
17	Public Service Enterprise Group	US	US GAAP

*These four companies were not originally identified as comparable peer companies based on their size and other factors considered; however, the applicable data was available for these companies and were therefore added to our peer group.

Data comparability

The comparison analysis is further complicated by the fact that the term "common corporate costs" is not defined by IFRS, US GAAP, FERC or the OEB. When performing our research, we found that no other utility used the term "common corporate costs". To perform the comparison to other utilities, we had to analyze the data and compile costs that, in our judgment, based on publicly available information, appeared to be most comparable to "common corporate costs" as defined by Hydro One. There is no way in which to be certain that our compilations and assessments of the most comparable cost measures are accurate. As a result, in this report when we refer to common corporate costs of utilities other than Hydro One we are referring to the pool of costs that we thought best approximates Hydro One's definition of these costs.

Although FERC, the OEB and other regulators require disclosure of components of administrative and general costs or operating maintenance and administrative costs that are capitalized, the presentation, groupings and functions presented are not consistent and often lack sufficient detail of what is included in the amount to draw a direct comparison to Hydro One's categorization.

Observations

Metrics utilized

We obtained data from publicly available sources to approximate the costs reported by other utilities that are most comparable to what Hydro One defines as common corporate costs. Based on this data, we identified comparable cost pools and noted that a different metric would be appropriate for Canadian peers and US peers.

In our view, the best measure for the Canadian peers is common corporate costs capitalized as a percentage of total OM&A expenses **(Canadian company metric).** We believe this to be an appropriate metric for these companies, as it is common in the capitalization process for Canadian utilities to first charge expenses to OM&A. Subsequently, an analysis is performed to assess which of these overhead costs within OM&A can be allocated to capital.

For US companies, it is common practice to capitalize a portion of their total common corporate cost pool (often referred to as an Administrative & General cost (A&G) pool), rather than capitalizing a portion of total OM&A. This is largely driven by the FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act in Part 101 of Title 18 of the Code of Federal Regulations ("USoA") which provides specific accounts to record A&G costs and an account to reclassify certain of these costs to capital. As such, for US comparable companies, we have considered common corporate costs capitalized as a percentage of what we observed to be most equivalent to total common corporate costs as the measure to compare US utilities to Hydro One **(US company metric)**.

Neither of these metrics are defined in any guidance issued by a regulatory or accounting standards body. However, these metrics in the tables below have been calculated consistent with the metrics for Hydro One in the above table to the extent possible.

Results of our research

As noted in the table above, based on publicly available information, for certain companies we were able to obtain only qualitative data such as how "common corporate costs" were allocated by each company to capital and what types of costs were included as "common corporate costs". For others, qualitative and quantitative data were either both available or neither was available. Refer to the tables below for the quantitative data found.

Appendix B provides further information on how we used judgement in determining the appropriate metric to compare to Hydro One as well as the qualitative data identified.

Table 3

US companies

Utility name	Regulator	Basis of accounting	Common corporate cost equivalents capitalized as a % of total common corporate cost equivalents
Southern California Edison (SCE)	California Public Utilities Commission (CPUC)	US GAAP	24.05%
San Diego Gas & Electric Company (SDG&E)	California Public Utilities Commission (CPUC)	US GAAP	8.57%
Pacific Gas & Electric Company (PG&E)	California Public Utilities Commission (CPUC)	US GAAP	12.23%
Evergy (Kansas City Power & Light Company)	Kansas Corporation Commission	US GAAP	16.69%
Hydro One	Ontario Energy Board (OEB)	US GAAP	48%

From our research of US companies where quantitative information was available, our estimates suggest a wide range of capitalization rates between 8.57% and 24.05% compared to Hydro One's capitalization rate of 48%. In our experience, most US utilities use third-parties to construct capital work which is in contrast to Hydro One that primarily self-constructs their capital work. As we previously noted, this is one reasonable reason for the disparity noted.

We describe additional research performed over the US peer group below. (See discussion of FERC data analyzed)

Table 4

Canadian companies

Utility name	Regulator	Basis of accounting	Common corporate cost equivalents capitalized as a % of equivalent OM&A
FortisBC Inc.	British Columbia Utilities Commission (BCUC)	US GAAP	15%*
Enbridge Gas Inc.	Ontario Energy Board (OEB)	US GAAP	22% (*Enbridge Gas Distribution Inc. pre-amalgamation - indirect overhead as a percentage of designated overhead) 14.4% (Union Gas Limited pre-amalgamation)
Toronto Hydro Corporation	Ontario Energy Board (OEB)	IFRS	32%
Enmax Power Corporation	Alberta Utilities Commission (AUC)	IFRS	7%*
BC Hydro and Power Authority	British Columbia Utilities Commission (BCUC)	IFRS	4%*
Hydro One	Ontario Energy Board (OEB)	US GAAP	18%

*Derived – Refer to Appendix B for details

From our research of Canadian companies where quantitative information was available, we noted a wide range of capitalization rates from 4% to 32%. Splitting the comparative company results between those that report under US GAAP, the range was from 15% to 22% and those that report under IFRS the range was between 4% and 32% – compared to Hydro One's rate of 18%.

It should be noted that the types of costs included in the peer companies' methodologies (US and Canadian) are generally similar to the type of costs included in Hydro One's pool of costs to be included in the capitalization process. However, the makeup of certain cost types as described varies from company to company and therefore it is not possible to know with certainty if the activities or costs described by one company are comparable to the activities or costs described by Hydro One or any other peer to develop a meaningful comparison.

Please refer to Appendix B for additional details on these results including qualitative information about the companies identified.

Additional FERC Research Performed

In addition to looking at rate case data for the US companies in the peer group list, we reviewed each US Company's 2019 FERC Form 1, specifically looking at the allocation of A&G costs to construction accounts in accordance with the FERC USoA. In our experience, these A&G costs are similar to what Hydro One defines as common corporate costs. A&G labor and office supplies amounts are accumulated in FERC accounts 920 – Administrative and general salaries and 921 – Office supplies and expenses. FERC account 922 – Administrative expenses transferred – Credit is then used to reclassify a certain amount of these costs to construction costs. Refer to the FERC Account descriptions below:

920 Administrative and General salaries.

a. This account shall include the compensation (salaries, bonuses, and other consideration for services, but not including directors' fees) of officers, executives, and other employees of the utility properly chargeable to utility operations and not chargeable directly to a particular operating function

b. This account may be subdivided in accordance with a classification appropriate to the departmental or other functional organization of the utility

921 Office supplies and expenses.

a. This account shall include office supplies and expenses incurred in connection with the general administration of the utility's operations which are assignable to specific administrative or general departments and are not specifically provided for in other accounts. This includes the expenses of the various administrative and general departments, the salaries and wages of which are includible in account 920

b. This account may be subdivided in accordance with a classification appropriate to the departmental or other functional organization of the utility

A portion of the total balance in FERC accounts 920 and 921 is then transferred from A&G expense and allocated to construction accounts through FERC account 922 - Administrative expenses transferred - Credit. The account 922 description is below:

922 Administrative expenses transferred - Credit.

This account shall be credited with administrative expenses recorded in accounts 920 and 921 which are transferred to construction costs or to nonutility accounts. (See electric plant instruction 4.)

Of the seven US companies included in the original list of peer companies, four have comparable data in their FERC Form 1 (Consumers Energy, DTE, Evergy Metro/Kansas City Power & Light and Arizona Public Service). Three companies included in the original list of peer companies (Wisconsin Electric Company, CenterPoint Energy Houston Electric and Public Service Electric & Gas Company) did not have comparable data in their FERC Form 1 as Account 922 was either negative or not utilized by these companies. Explanations as to why the use of these accounts can vary across companies is described below. Additionally, we included the FERC data for the three additional companies we added to our original list of peer companies (Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and Pacific Gas & Electric (PG&E)) for a total of seven companies. Below is an example of the FERC Form data for Consumers Energy. As indicated in the highlighted lines below, the total A&G pool is $54,710,134 (sum of amounts in FERC accounts 920 and 921) and the amount transferred out of those accounts and into construction (i.e., capitalized) in FERC account 922 is $19,182,696.

Exhibit 1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	5,891,247	3,436,425
168	(908) Customer Assistance Expenses	157,377,172	156,669,571
169	(909) Informational and Instructional Expenses	840,614	556,107
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	164,109,033	160,662,103
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	76,777	365,144
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	76,777	365,144
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	43,323,913	43,115,738
182	(921) Office Supplies and Expenses	11,386,221	13,886,497
183	(Less) (922) Administrative Expenses Transferred-Credit	19,182,696	19,238,560
184	(923) Outside Services Employed	28,339,550	31,539,992
185	(924) Property Insurance	3,113,930	672,467
186	(925) Injuries and Damages	10,071,322	11,667,830
187	(926) Employee Pensions and Benefits	6,760,213	8,610,967
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	572,500	646,798
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	13,037,141	19,512,040
193	(931) Rents	166,781	-37,435
194	TOTAL Operation (Enter Total of lines 181 thru 193)	97,588,875	110,376,334
195	Maintenance		
196	(935) Maintenance of General Plant	4,577,531	5,887,963
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	102,166,406	116,264,297
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,672,803,758	2,809,445,278

We obtained the same FERC Form 1 data for the seven companies noted above. The data below shows the cumulative amounts in FERC accounts 920 and 921 and the amounts capitalized in FERC account 922 for each company, as well as the average percent of capitalized A&G across all seven companies, which was approximately 34%.

Table 5

Number	Utility name	A&G capitalized (FERC account 922)	Total A&G expenses – Capitalization base (Sum of FERC accounts 920 and 921)	% of total A&G capitalized
1	Southern California Edison Company	225,318,190	664,084,735	34%
2	Consumers Energy	19,182,696	54,710,134	35%
3	Pacific Gas & Electric Company	103,181,563	472,370,054	22%
4	San Diego Gas & Electric Company	13,569,700	47,785,405	28%
5	DTE Electric Company	53,923,636	193,880,305	28%
6	Evergy Metro Inc. (Kansas City Power & Light)	30,551,805	42,460,525	72%
7	Arizona Public Service	21,226,138	110,801,217	19%
	Company Average			34%
	Hydro One common corporate costs capitalized as a % of OM&A			48%

The percentages from the 2019 FERC forms noted above will differ from the percentages in the rate case filings for a variety of factors. The first is that the FERC data above is based on actual 2019 amounts while the data in a company's rate case filings is based on historical test years from years prior to 2019 or on forecasted 2019 amounts. The second is that the rate case filings may give additional information on what amounts are included in a company's A&G pool subject to capitalization, and these amounts can include more than just A&G salaries and office supplies and expenses, which are captured in FERC accounts 920 and 921. For example, SDG&E's most recent rate case uses 2016 historical test year data and specifies that 'Costs subject to capitalization include FERC Accounts 920, 921 and 923. FERC Account 923 – Outside services employed includes "the expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts". Capitalization of amounts from Account 923 should not be included in Account 922.

Additionally, as indicated in both the rate case data and the FERC data, the amount and percentage of A&G capitalized differs across companies. This can be due to several reasons, including, but not limited to:

- The size of the company
- How much of A&G is directly charged to capital work at each company as opposed to how much is charged to account 920/921 and then allocated to capital
- What costs are charged to A&G and how different capitalization factors are applied at each company
- How much construction is performed by company personnel vs. third-party contractors, which may impact the capitalization percentage
- The nature and volume of functions outsourced to third parties at each company (FERC Account 923), which is not included in the data above

We further note that while the FERC USoA is designed to create consistency between filers, how these three FERC accounts are used in practice can vary considerably. There are some companies who do not use account 922 at all to reclassify A&G costs to capital as noted by the account equaling zero for certain companies. We assume that these companies either do not allocate any of these costs to capital, which we believe is unlikely, or report the amounts in FERC accounts 920 and 921 net of amounts capitalized. Conversely, we observe that some filers allocate more than 100% of FERC accounts 920 and 921 to capital via account 922, which may indicate they are using account 922 to allocate more than just accounts 920 and 921 costs to capital (e.g., account 923 costs). That is not to say that non-account 920 and 921 type costs should not be allocated to capital, but only that the instructions for account 922 state that this account should only reflect the amount of accounts 920 and 921 costs that have been capitalized. Further, the page in the FERC Form 1 that captures this data is not subject to external audit, which may drive some of this inconsistency.

In addition to analyzing the FERC data for the seven companies included in our comparison to other utilities, we obtained the same data for all FERC Form 1 filers in the U.S. There were a total of 198 US companies that filed a FERC Form 1 in 2019. 93 of these companies had what we considered to be ‘account 922 outliers’ as discussed above (i.e., the companies did not use account 922 or the balance in the account was less than zero or more than 100% of FERC accounts 920 and 921); therefore, we excluded the data for these 93 companies in our comparisons. We looked at the percentage of A&G capitalized for the remaining 105 companies and found that capitalization percentages ranged from 1% to 83% with an average across the 105 companies of 22% and a median of 19%. As discussed above, these US companies as a general rule, do not self construct their capital work while Hydro One generally does self construct. This consideration is important to the evaluation of this data.

Our observations and conclusions

- Components of common corporate cost - the types of costs included in the peer companies’ comparable measures, are similar to the types of costs included in Hydro One’s cost pools included in the capitalization process. However, the description of cost varies from company to company and consequently it is not possible to know how comparable the results are. Please see Appendix B for further detail on this observation.
- Construction strategy - in our experience, most utilities use third-party contractors for their significant capital work. From our discussions with management, we understand that, historically, the vast majority of Tx and Dx capital work at Hydro One has been self-constructed, and not contracted to third parties. Consequently, it is reasonable to expect that Hydro One’s capital program requires significantly more support from all areas of the company, including finance, management, administration and other resources, than other utility companies that use third-party contractors. As a result, one would expect that Hydro One’s percentage of common corporate costs capitalized would be higher than many of its peers as it would require more support from various elements of the organization to complete its capital work. In addition, if such capital work was outsourced to a third party, many of these indirect costs and general and administrative overheads would be embedded in the construction costs charged by the third-party contractor, included in their billings to the Company, and capitalized as a direct cost of construction under US GAAP and IFRS. It is reasonable that utilities that perform more capital work internally will have higher percentages of indirect costs allocated to capital than those that use third-party contractors. If a utility who self-constructs a significant portion of its capital work was to not capitalize similar costs that are inherently capitalized when third-party contractors are used, it would create intergenerational inequity by having current customers pay for these costs that ultimately benefit current and future customers simply due to differences in the source of the party (the Company or third-party contractor) performing the construction activity.

Overview of process and methodology for capitalizing common corporate costs

Overview and summary

We reviewed and obtained an understanding of Hydro One's proposed method for capitalizing common corporate costs in its Application and compared this with guidance issued by the OEB and FERC as well as accounting guidance under US GAAP and IFRS. We met with the responsible individuals at Hydro One and with Black & Veatch ("B&V"), who have been engaged on behalf of Hydro One to develop its process. B&V performed a detailed activity level analysis to determine those activities that have a relationship to capital work and the method for allocating the costs for those activities to either capital or to OM&A.

Based on the methodology described to us by Hydro One and B&V and the procedures we performed, we believe that the proposed method to capitalize common corporate costs is reasonable and is consistent with the principle that any assignment of indirect costs to capital work should be based on a reasonable causal link.

Our understanding

Overview

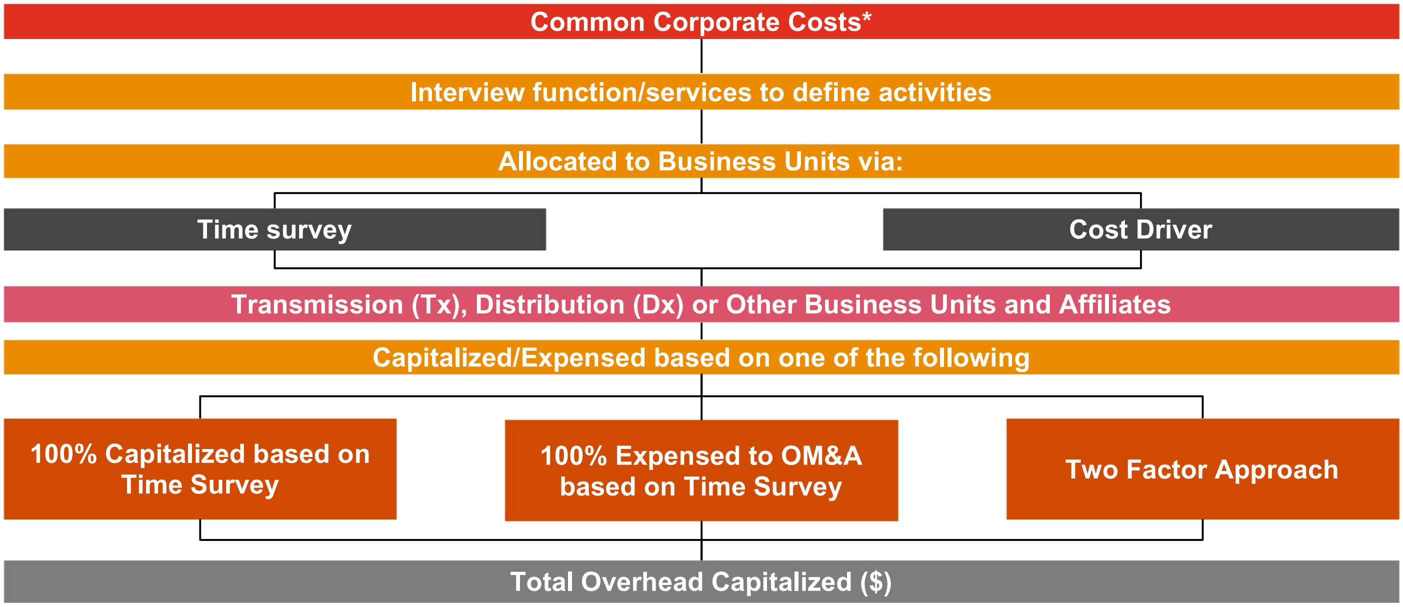
Hydro One has identified certain cost centres (e.g., Human Resources, Legal, etc.) that provide common services to multiple companies or business units within the Hydro One group. These are the costs that are referred to as common corporate costs by Hydro One. Where practical, Hydro One direct charges common corporate costs to capital or OM&A work directly depending on the nature of work being performed. However, certain cost centres may work on multiple programs/projects concurrently and/or support the business as a whole and cannot be directly charged to capital or OM&A. As a result, a method to allocate these remaining costs to the underlying business units and capital or OM&A is necessary. Within each cost centre, major activities were identified and costs for each major activity are classified as either a labour or non-labour cost, both of which follow a similar process. These activities were identified by the Company and B&V by interviewing individuals responsible for each of the cost centres.

B&V then determined how the costs of each activity should be allocated across the Company's Transmission (Tx) and Distribution (Dx) business units, as well as other business units and affiliates ("business units") that are outside the scope of this report. These costs are allocated to these business units based on the results of a time survey or a cost driver. An example of a cost driver for a given activity is the number of employees for a certain business unit compared to total employees for all business units that benefit from the given activity. This is an important step as it increases the likelihood that costs which should not be borne by Tx or Dx customers are removed from the pool of costs to be capitalized.

Once the costs have been allocated to the business units (including Tx and Dx), certain activities which are deemed to be 100% related to OM&A or 100% related to capital based on the time surveys performed by B&V are allocated accordingly. For activities which are not deemed to be 100% attributable to capital or OM&A, a two-factor general allocator, discussed below, is used to determine the costs to be allocated to capital.

The following exhibit illustrates this process.

Exhibit 2



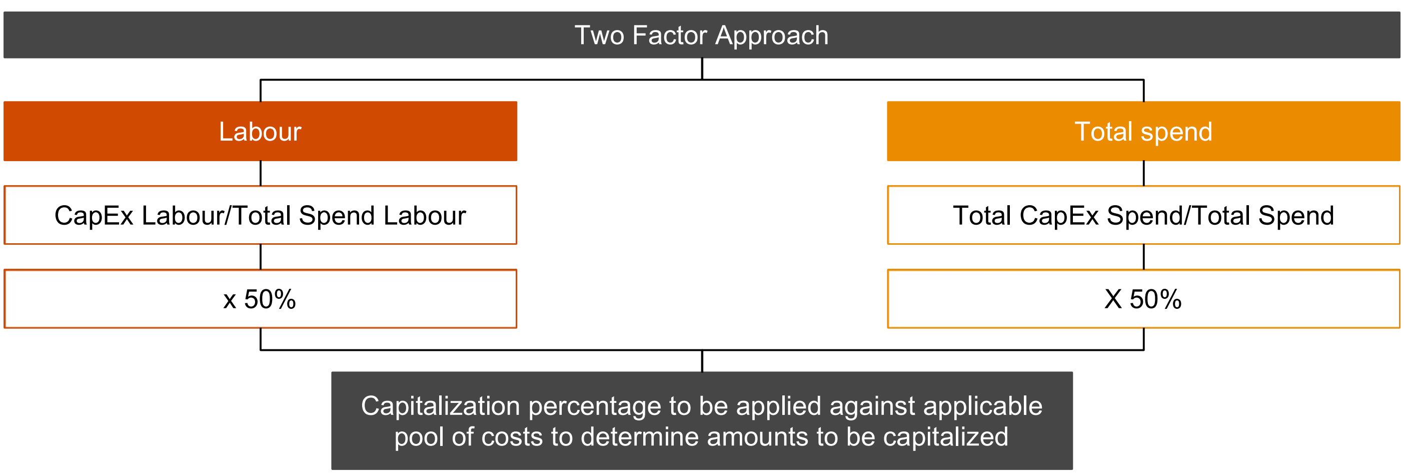
Two-factor approach

For the costs that are not allocated 100% to capital or OM&A, a two-factor approach is applied.

The two-factor approach equally weights the percentage determined using factors developed using the following methods

1. Labour content method – labour dollars capitalized as a percentage of total labour dollars within the Tx or Dx business unit; and
2. Total spend method – total capital spend dollars (including labour, materials, etc.) as a percentage of total spend dollars (capital expenditures plus OM&A expenditures) within the Tx or Dx business unit.

Exhibit 3



Based on our discussions with management, applicable common corporate costs are causally related to both labour content and total spending and both approaches produce percentages that relate to construction activities. In B&V's opinion, there is no evidence that either method is meaningfully more appropriate, thus, a 50%–50% weighting is applied.

Total common corporate cost capitalization rate

We reviewed documents provided to us, including process documents, calculations, and source transactions that result in the total overhead costs that relate to each of the cost centres/activities that comprise common corporate costs.

As shown in Exhibits 2 and 3 above, once the common corporate costs are determined for the Tx and Dx areas, the costs are then classified as either 100% capital or OM&A (based on time surveys or through the use of the two-factor allocator at the activity level). For any given period, the actual costs are multiplied by these percentages to determine a total capitalized amount.

The following table shows the common corporate costs capitalized based on the 2023 forecast. Please note that we have defined this capitalization percentage in two ways as further discussed above in our discussion of comparison to other utilities.

Table 6

	Projected 2023 capitalization % and amounts capitalized ($ Millions CAD)
Metric 1: Corporate common costs capitalized as a % of total corporate common costs	
Overhead costs capitalized	$208.0
Total common corporate costs	$432.4
Metric 1 Capitalization rate (US Metric)	**48%**
Metric 2: Corporate common costs capitalized as a % of OM&A	
Overhead costs capitalized	$208.0
Total OM&A	$1,131.0
Metric 2 Capitalization rate (Canadian Metric)	**18%**

The total common corporate costs were capitalized at a rate of 48% when compared to total common corporate costs and 18% when compared to total OM&A. Both of these metrics are for the combined Tx and Dx businesses. Please note that the denominator in Metric 1 excludes common corporate costs which are direct charged and removed from the allocation cost pool.

Our observations and conclusions

As PwC did not attend the interviews with B&V nor perform the time surveys, we cannot comment on the percentage of time these activities relate to capital. However, we reviewed the nature of the activities in general as well as the description of these activities provided to us by management and B&V and observed a relation to capital for those activities which had some portion allocated to capital.

Based on the methodology described to us by Hydro One and B&V, in our opinion the proposed method to capitalize common corporate costs is reasonable and is consistent with the principle that any assignment of indirect costs to a capital work should be based on a reasonable causal link.

Comparison to regulatory and accounting guidance

Overview and summary

There is no regulatory guideline, statement or source that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes what types of indirect costs should be considered for capitalization nor how such costs are allocated to capital. Canadian utility regulators and FERC have historically accepted that indirect activities support capital work and, to the extent that there is a causal link to the capital activities, have allowed the associated costs to be allocated to capital. US GAAP and IFRS allow for the capitalization of costs by rate regulated entities to the extent that it is probable that those costs will be recovered in future rates.

Based on our understanding we believe Hydro One's process and methodology for the capitalization of common corporate costs is reasonable based on the guidance issued by the OEB and FERC for entities that follow US GAAP and IFRS.

Comparison to OEB guidance

As part of our procedures, we reviewed the guidance issued by the OEB and compared this to the process and methodology to be used by Hydro One for allocating common corporate costs to capital.

Excerpt from Ontario Energy Board Accounting Procedures Handbook for Electric Distribution Utilities

"Overhead Charged to Construction includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of a reasonable allocation of actual costs. The records supporting the entries for overhead charged to construction costs shall be maintained so as to show the total amount for each element of overhead for the year and the basis of allocation."

Our observations

The above guidance was obtained from Appendix A of the Ontario Energy Board Accounting Procedures Handbook for Electric Distribution Utilities ("2007 Handbook") and has been applicable to Hydro One since the adoption of US GAAP on January 1, 2012. Hydro One's fillings with the OEB on adoption of US GAAP noted that US GAAP effectively continued the accounting practices previously applied under legacy Canadian GAAP pursuant to Part V of the Handbook of the Canadian Institute of Chartered Accountants and there were no accounting policy changes arising from the transition from Canadian to US GAAP that impacted Hydro One Distribution's rate base or revenue requirement (EB-2013-0416, Exhibit A, Tab 15, Schedule 2).

Consistent with the guidance described above, overhead charged to construction at Hydro One, including common corporate costs, are first direct charged to the related business unit and capital or OM&A work order when reasonably possible. Common corporate costs that cannot be directly charged are accumulated and then capitalized based on the approach discussed previously.

Consistent with the guidance as mentioned above, the common corporate cost allocations and rates determined are held within SAP, Hydro One's system of record. The common corporate cost capitalization rates are based on business plan numbers and other estimates, and both the planned and actual amounts can be automatically calculated in SAP. At year-end, capitalized overheads are trued-up to reflect actual results. The records kept supporting the methodology appear to be appropriate.

Based on the guidance described above, and our review of the Company's process and methodology for demonstrating a causal link between the cost incurred and the capital program, it is reasonable that the Company is capitalizing an allocation of such costs to capital work. We also note that this methodology is consistent with our experience with other regulated utilities that report under US GAAP in Canada and the United States.

Comparison to FERC guidance

As part of our procedures, we reviewed the FERC guidance regarding capitalization of costs and compared this to the process and methodology employed by Hydro One. While Hydro One is not required to follow the FERC guidance, it is helpful to understand how other large regulators in North America, and the utilities that they regulate, view these types of costs. FERC's accounting rules for jurisdictional electric utilities are detailed in its USoA.

Excerpts from FERC electric plant instruction number 4, overhead construction costs to its Uniform System of Accounts

a. "All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired."

b. "As far as practicable, the determination of payroll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to the construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted."

c. "For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of each overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs."

Our observations

The FERC guidelines outline that charges to plant accounts consist of direct costs and construction overheads and that construction costs should be supportable and based on cost causation.

Consistent with paragraph A of the FERC guidance, overhead costs at Hydro One, including common corporate costs, are first direct charged to the related business unit and capital or OM&A work order when reasonably possible. Common corporate costs that cannot be directly charged are accumulated and then capitalized based on the approach discussed previously.

Consistent with paragraph B of the FERC guidance, payroll charges at Hydro One are first direct charged to the related projects/programs when possible. Hydro One uses time surveys, where practicable, to allocate payroll to capital or OM&A in cases where an activity is 100% allocable to one or the other and allocates the remaining payroll charges based on the two-factor approach discussed previously.

Consistent with paragraph C of the FERC guidance as mentioned above, the common corporate cost allocations and rates determined are held within SAP, Hydro One's system of record. The common corporate cost capitalization rates are based on business plan numbers and other estimates, and both the planned and actual amounts can be automatically calculated in SAP. Hydro One reviews the overhead capitalization rate on a monthly basis (at a minimum) to determine if the overhead rate needs to be updated to reflect any changes in capital spending and associated costs. At year-end, capitalized overheads are trued-up to reflect actual results. The records kept supporting the methodology appear to be consistent with the support we observe at other utilities.

Additionally, in line with Electric Plant Instruction Number 4 of the FERC USoA, utilities generally capitalize a portion of the administrative expenses that have been recorded in FERC Accounts 920 - Administrative and general salaries and 921 - Office supplies and expenses, and record the transfer to construction costs in FERC Account 922 - Administrative expenses transferred - Credit. This process is described later in this report. These instructions further support FERC's guidance to capitalize certain administrative and general costs.

Comparison to US GAAP

We reviewed relevant US GAAP guidance, as defined by the Accounting Standards Codification ("ASC") of the Financial Accounting Standards Board ("FASB") regarding capitalization of costs and compared this to the process and methodology employed by Hydro One.

Excerpts from US GAAP Guidance

1. **FASB's ASC 360 – Property, plant and equipment**

   ASC 360–10: "Property, plant and equipment should be recorded at historical cost, which includes the costs incurred for activities to bring them to the condition and location necessary for their intended use. Interest costs incurred during the period the assets are brought to that condition and location are also included in the historical cost of acquiring the asset, if material."

2. **FASB's ASC 980 – Regulated operations**

   ASC 980-340: "25-1 Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

   a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.

   b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost."

Our observations

Based on the US GAAP sections noted above, costs incurred for activities to bring the property, plant or equipment to the condition and location necessary for their intended use should be recorded as capital assets. ASC 980 provides further guidance on the capitalization of overhead costs that are probable of future recoveries through rate base.

According to PwC's Power and Utilities Guide (Section 17.1):

> "A regulated utility should comply with U.S. GAAP applicable to entities in general with regard to its accounting and financial reporting. If it is also subject to ASC 980, the applicable provisions within that standard are applied as an adjustment to or in lieu of other U.S. GAAP (when specifically required by ASC 980)."

A regulated utility may have unique considerations in developing capitalization policies because regulators often permit recovery of costs as part of capital work that may otherwise be charged to expense in the period they are incurred. Only those costs that are probable of recovery through future rates should be capitalized as part of the utility plant.

As a result, costs that are allowed to be included in rate base by a utility's regulator are generally capitalized by utilities that use US GAAP.

As outlined in the guidance above, a company subject to the requirements of ASC 980 must first apply the accounting guidance applicable to all entities (i.e., in this case ASC 360). However, under ASC 980, the actions of the regulator often impact the accounting for certain activities.

ASC 980 provides guidance that allows for costs that may otherwise be expensed to be capitalized if it is both, 1) probable that future revenue will result from the inclusion of that cost in allowable costs for rate-making purposes and 2) the future revenue will permit the recovery of the previously incurred costs.

Consequently, the utility regulator has a direct impact on how certain costs are accounted for under US GAAP. If a cost supports underlying capital work, but may not be capitalized under US GAAP before the application of ASC 980, the regulator must decide if that cost should be borne by customers over the life of the underlying capital asset to match its use and the period during which customers will derive a benefit from it (i.e., capitalized) or expensed as a period cost and borne only by current period customers. It is typical for regulators to allow for costs that relate to and support capital work to be charged to capital to better match the benefit received to the cost in accordance with the regulatory principle of matching costs and benefits and producing intergenerational equity.

Comparison to IFRS

We reviewed relevant International Financial Report Standards (IFRS) as defined by the International Accounting Standards Board (IASB) regarding capitalization of costs and compared this to the process and methodology employed by Hydro One.

Excerpts from IAS 16 – Property, plant and equipment

Recognition

1. The cost of an item of property, plant and equipment comprises:
   a. its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
   b. any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and
   c. the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.
2. Examples of directly attributable costs are:
   a. Costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment;
   b. Costs of site preparation;
   c. Initial delivery and handling costs;
   d. Installation and assembly costs;
   e. Costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and
   f. Professional fees.
3. Examples of costs that are not costs of an item of property, plant and equipment are:
   a. Costs of opening a new facility;
   b. Costs of introducing a new product or service (including costs of advertising and promotional activities);
   c. Costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
   d. Administration and other general overhead costs.

Excerpts from IFRS 14 – Regulatory deferral accounts

IFRS 14.5 An entity is permitted to apply the requirements of this Standard in its first IFRS financial statements if and only if it:

a. Conducts rate-regulated activities; and
b. Recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP.

IFRS 14.B3 For the purposes of this Standard, a regulatory deferral account balance is defined as the balance of any expense (or income) account that would not be recognized as an asset or a liability in accordance with other Standards, but that qualifies for deferral because it is included, or is expected to be included, by the rate regulator in establishing the rate(s) that can be charged to customers. Some items of expense (income) may be outside the regulated rate(s) because, for example, the amounts are not expected to be accepted by the rate regulator or because they are not within the scope of the rate regulation. Consequently, such an item is recognized as income or expense as incurred, unless another Standard permits or requires it to be included in the carrying amount of an asset or liability.

IFRS 14.B5 – The following are examples of the types of costs that rate regulators might allow in rate-setting decisions and that an entity might, therefore, recognise in regulatory deferral account balances:

i. Volume or purchase price variances;

ii. Costs of approved 'green energy' initiatives (in excess of amounts that are capitalised as part of the cost of property, plant and equipment in accordance with IAS 16 Property, Plant and Equipment);

iii. Non-directly-attributable overhead costs that are treated as capital costs for rate regulation purposes (but are not permitted, in accordance with IAS 16, to be included in the cost of an item of property, plant and equipment); (emphasis added)

iv. Project cancellation costs;

v. Storm damage costs; and

vi. Deemed interest (including amounts allowed for funds that are used during construction that provide the entity with a return on the owner's equity capital as well as borrowings).

Our observations

Based on the IFRS sections noted above, directly attributable costs incurred for activities to bring the property, plant or equipment to the condition and location necessary for it to be capable of operating in the manner intended by management may be capitalized. Further administrative and other general overhead costs are explicitly not permitted to be capitalized. IAS 16 does not define what types of costs are considered “administrative and other general overhead costs”. While the FASB guidance under ASC 360 previously described is not as exhaustive as IAS 16 paragraph 19, the interpretation in practice in this area is largely consistent between the two frameworks and outside the application of ASC 980, administrative and other general overhead costs are not capitalized under US GAAP.

However, as we note below, in instances where IFRS 14 is applicable, when such administrative and other general overhead costs are allowed to be capitalized by a utility’s regulator, such costs would also be capitalized under IFRS, but with different presentation. A company who has adopted IFRS 14 must first apply the accounting guidance applicable to all entities (i.e., in this case IAS 16). However, under IFRS 14, the actions of the regulator impact the accounting for certain activities.

IFRS 14 provides guidance that allows any expense (or income) that would not be recognized as an asset or a liability in accordance with other Standards, to qualify for deferral if it is included, or is expected to be included, by the rate regulator in establishing the rate(s) that can be charged to customers in the future.

Consistent with the guidance in ASC 980 under US GAAP, the regulator has a direct impact on how certain costs are accounted for. If a cost supports an underlying capital program, but may not be capitalized under IFRS before the application of IFRS 14, the regulator must decide if that cost should be borne by customers over the life of the underlying capital work to match its use and the period during which customers will derive a benefit from it (i.e., capitalized) or expensed as a period cost and borne only by current period customers.

Where IFRS 14 is applied for administrative and other general overhead costs, deferrals permitted by the regulator would be treated as a regulatory asset under IFRS whereas under US GAAP, these amounts would generally be capitalized directly to Property, Plant and Equipment (PP&E). This results in a difference in geographical presentation on the balance sheet and income statement. Absent the application of IFRS 14, such costs that do not qualify for capitalization to PP&E would generally be recorded as expense in the period they are incurred.

The Regulatory Assets and Regulatory Liabilities, Exposure Draft, that was issued by the IASB on January 28, 2021 is subject to a comment period ending on June 30, 2021. The date for a final standard to be issued is uncertain and will likely depend on the significance of the comments received by the IASB. Tentatively, it has been decided that the effective date would be 18-24 months after publication of a final standard.

Our observations and conclusions

Based on our understanding we believe Hydro One’s process and methodology for the capitalization of common corporate costs is reasonable based on the guidance issued by the OEB and FERC and consistent with the principles of US GAAP and IFRS.

Appendix A – Qualifications

Eric Clarke

Eric is a utilities specialist partner with over 25 years working with utility clients in Canada, the US, UK and Europe. He joined PricewaterhouseCoopers in Edmonton, Alberta in 1993 after graduating from the University of Saskatchewan with a Bachelor of Commerce degree. On obtaining his Chartered Accountant qualification in 1996, he transferred to PricewaterhouseCoopers in London, England where he worked in PwC's energy & utilities practice from 1996 to 2003. During this period, Eric also spent one year working in Paris leading an engagement with a Fortune 500 multinational energy company. He returned to Canada in 2003 to join PricewaterhouseCoopers' utility practice in Toronto.

Eric oversees audit and advisory services to several Canadian utilities. He has a wide range of international experience in leading large and complex internal and external audit assignments, regulatory matters, IFRS and US GAAP conversion projects, due diligence and transaction services, stock exchange listings and other risk management and advisory services.

Eric is a regular instructor at the Directors Education Program of the Institute of Corporate Directors and a presenter at the Canadian Electricity Association Finance & Accounting Committee. He is a board member and Chair of the Finance Committee for the Safehaven Project for Community Living.

Eric is a Partner of PricewaterhouseCoopers LLP, based in our Toronto office whose address is 18 York Street, Suite 2600 Toronto, Ontario, M5J 0B2.

Eric Clarke as well as other PwC personnel working under his supervision and direction, have read and analyzed supporting documentation and information relevant to the issues on this engagement. He has been assisted by several other PwC professionals, including Philip Hagel and Al Felsenthal, each with applicable regulated utility knowledge and experience.

Appendix B – Results of comparison to other utilities

US Comparable Companies (Quantitative Data Available)

The table below summarizes benchmarking results of peer companies in the United States where quantitative data is available:

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of Total Corp. Common (A&G) Costs	Additional Factors	Reference
Southern California Edison (SCE), California Public Utilities Commission (CPUC). US GAAP	Administrative and General ("A&G") overhead costs are based on study approved by the regulator. SCE performs an A&G Effort Study to determine A&G capitalization rate for costs that are not already directly recorded to capital work orders. Each department that incurred expenses charged to accounts 920 and 921 estimated their A&G costs that support construction activities. Estimates were developed by reviewing employees' time and expenses related to construction activities and by reviewing the relationship between departmental functions and activities and construction activities. Overheads allocated based on cost drivers/time study and include cost of corporate functions and services like human resource, IT, corporate finance and risk assessment and strategy.	Corporate Cost – Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law, Treasurer. Strategy – General Functions and Information Technology. Operations Support – Training, Environmental, Health and Safety.	24.05%	2019 Capital Expenditures: $3.9 billion USD. Total assets = $64 billion USD at December 31, 2019 Distribution, transmission, and generation company	SCE 2018 GRC A16-09 SCE08 Volume 03, Book A Workpapers EIX 2019 10K

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of Total Corp. Common (A&G) Costs	Additional Factors	Reference
San Diego Gas & Electric Company (SDG&E), California Public Utilities Commission (CPUC). US GAAP	SDG&E and SoCalGas charge most of their operating costs directly to either capital or O&M. However, some of the A&G expenses, labor overheads (e.g. pension and benefits, injuries and damages), and clearing account costs support construction efforts.	A&G costs represent corporate services and include the following: • A&G salaries, • shared services • office supplies • expenses and outside services employed.	8.57%	2019 Capital Expenditures: 1,522 million USD Total assets = $19,225 million USD at December 31, 2019 Distribution, transmission, and generation company	SDG&E 2019 GRC A.17-10-008 Revised Workpapers SDG&E 2018 10K
Pacific Gas & Electric Company (PG&E), California Public Utilities Commission (CPUC). US GAAP	Overhead allocation is based on detailed review by Corporate Service departments to calculate the appropriate administrative and general (A&G) capital allocation. A&G costs are assigned to each operational line of business using an allocation method. Pensions and benefits are also capitalized.	A&G Department costs include costs related to the Finance Organization, Regulatory Affairs, Corporate Affairs and Executive Offices and Corporate Secretary A&G Company Wide expenses include costs related to general liability insurance, directors' and officers' insurance, non-nuclear and nuclear property insurance, and Director fees and expenses	12.23%	2019 Capital Expenditures: $6,313 million USD Total assets = $84,614 million USD at December 31, 2019 Distribution, transmission, and generation company	PG&E D.17.05.013 GRC Rev Req 2017-2019 PG&E 2019 10K
"Evergy (Kansas City Power & Light Company)" Kansas Corporation Commission	A&G expenses are allocated using a number of methods depending on the cause of the cost. (i.e. cost drivers). The indirect allocation of A&G payroll to construction activity follows the FERC USoA guidance	Indirect A&G costs include corporate services costs, executive salaries and indirect labour.	16.69%	2019 Capital Expenditures: $1,210 million USD Total assets = $25,976 million USD at December 31, 2019 Distribution, transmission, and generation company	Rate App. S20180501162757 Evergy 2019 10K
US GAAP Summary	For the peer companies observed, the common corporate costs capitalized as a percentage of total common corporate costs ranged from **8.57%-24.05%.**				

US Comparable Companies (Qualitative Information Only)

The table below summarizes benchmarking results of peer companies in the United States where only qualitative information is available:

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of Total Corp. Common (A&G) Costs	Additional Factors	Reference
CenterPoint Energy Houston Electric (CEHE), Public Utility Commission of Texas US GAAP	A&G costs are directly assigned. Allocated costs are directly assigned and based on functionalization factors. The three primary policies that determine how project costs are to be either capitalized or expensed include: various Federal Energy Regulatory Commission ("FERC") guidelines relating to capitalization and expenses; CenterPoint Energy's (CNP's) Capitalization Policy (which was developed consistent with the FERC guidelines); and CNP's Capitalization of Computer Software Policy (also developed consistent with FERC guidelines).	A&G expenses include, but are not limited to, salaries and wages, office supplies, outside services, regulatory commission expenses, rents and general maintenance. Allocated Expenses include functions such as Audit, Business & Operations Support, Communications, Executive Management, Finance, Government Affairs. Human Resources, Legal Regulatory, Technology Operations.	Capitalization rate information is not available	2019 Capital Expenditures: $1,033 million USD Total Assets = $11,262 million USD at December 31, 2019 Distribution and transmission company	2019 CenterPoint Energy Houston Electric Rate Case WP V1-L.1 Page 1 of 1 (Page 7101) CenterPoint Energy 2019 Form 10-K
Consumers Energy, Michigan Public Service Commission US GAAP	Common Corporate Service Costs are an aggregation of expenses that are not attributable to any one department but are incurred on behalf of the Company as a whole. Examples include: Corporate labor and expenses, capitalized credits to O&M, billing credits for A&G labor expenses and outside services as part of a full-cost loading adder, Senior management time and expenses and board of director costs	Capital overhead costs include those costs related to the following: •Administrative and General (A&G): Portion of Corporate Service Salary and Business Expenses •Pension/Defined Company Contribution Plan •Other Post-Employment Benefits (OPEB): Retiree Health and Life •Other Capitalized Costs (OCC): Active Health and Life,	Capitalization rate information is not available	2019 Capital Expenditures: $2,085 million USD Total assets = $23,699 million USD at December 31, 2019 Distribution and generation company	2018 Rate Case Docket U-20134-0007, Consumers Energy Testimony Consumers Energy 2019 Form 10-K

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of Total Corp. Common (A&G) Costs	Additional Factors	Reference
		Workers Comp, Injuries and Damages, 401k Savings Match and Payroll Taxes -Engineering and Supervision (E&S): portion of Distribution cost centers that support capital work; i.e. planning, design, and field supervision			
DTE Electric Company Michigan Public Service Commission US GAAP	Corporate Staff Group (CSG) is a shared services organization, DTE Energy Corporate Services LLC, which includes corporate staff functions. Corporate staff group costs are first incurred and accumulated at the DTE Energy Corporate Services LLC. Each department within a corporate staff organization identifies products and services it expects to provide to legal entities and/or business units based on the corporate staff organization's scope of work. These products and services are measured based on the most appropriate cost driver.	The organizations within the Corporate Staff Group (CSG) provide a variety of Administrative and General (A&G) type services to the Company. These include: Audit Services, Accounting and Planning, Tax, Finance and Treasury, Corporate and Governmental Affairs, Communications, Corporate Offices Supply Chain, Corporate Fleet and Facilities, Human Resources, Information Technology, Legal, Regulatory Affairs, Environmental Management and Major Enterprise Projects	Capitalization rate information is not available	2019 Capital Expenditures: $2,368 million USD Total assets = $24,588 million USD at December 31, 2019. Distribution and generation company	2019 Rate Case U-20561 Direct Testimony (TMU39-40) DTE Electric Company 2019 Form 10-K

US Comparable Companies (Data Not Available)

Data was not available for the following peer companies in the United States:

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of Total Corp. Common (A&G) Costs	Additional Factors	Reference
Wisconsin Electric Power Company, Public Service Commission of Wisconsin US GAAP	Detailed information is not available		Capitalization rate information is not available	N/A	
Arizona Public Service, Arizona Corporation Commission US GAAP	Detailed information is not available		Capitalization rate information is not available	N/A	
Public Service Enterprise Group, New Jersey Board of Public Utilities US GAAP	Detailed information is not available		Capitalization rate information is not available	N/A	

Canadian Comparable Companies (Quantitative Data Available)

The table below summarizes benchmarking results of peer companies in Canada where quantitative data is available:

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of OM&A (in millions)	Additional Factors	Reference
FortisBC Inc., British Columbia Utilities Commission US GAAP	Capitalized overheads are determined through applying a capitalization rate to gross O&M expenses. The capitalization overhead rates are assigned to regulated capital and certain other major projects. Direct costs are charged to projects and capitalized directly. Direct overhead loading costs are allocated through the estimated time to be charged to capital projects on an employee or individual cost basis. Indirect costs - net of direct costs and direct overhead loading costs and allocated through a capitalization rate determined through a survey based model to calculate the cost allocation to labour and non-labour.	Major categories of capitalized OM&A are: (1) Labour and (2) Non-labour including engineering, external relations, information systems, regulatory, legal, human resources and finance.	15% (percentage is derived)	2019 Capital expenditures = $106 million CAD Total assets = $2,326 million CAD at December 31, 2019 Distribution and transmission company	FEI-FBC 2020-2014 MRP Application Appendix D6-2 FBC OVERHEAD CAPITALIZATION METHODOLOGY REVIEW, KPMG fortisbc.com
Enbridge Gas Inc., Ontario Energy Board US GAAP	Capitalized overheads are allocated through two streams: direct and indirect. Indirect cost allocations to capital are determined based on four methods: i) time analysis, ii) work plan (allocation of time and expenses), iii) cost drivers and iv) composite ratio (corporate average or HR composite ratios). Major cost components include (i) indirect overhead allocations, (ii) Alliance partner overheads, (iii) district contract pre-work costs and (iv) administration and general overheads.	Corporate costs - Human Resources (including Pension and OPEB, Employee training, Salary wages and Benefits), Finance, IT, Legal, Executive, Supply chain, Regulatory, Direct capital support, Information service costs, Utility costs, Advertising, Insurance, Donations, Regulatory and Recovery.	22% (Enbridge Gas Distribution Inc. pre-amalgamation - indirect overhead as a percentage of designated overhead) 14.4% (Union Gas Limited pre-amalgamation)	2019 Capital expenditures = $1,109 million CAD Total assets = $24,681 million CAD at December 31, 2019 Distribution and transportation company	EB-2019-0105 EB-2019-07-17 EB-2018-0305 Exhibit I. STAFF.32 EBRO 497 EB-2011-0008-Exhibit B, Tab 4, Schedule 2 Union Gas: Overhead Capitalization Study 2017 Enbridge Gas Inc. December 31, 2019 MDA

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of OM&A (in millions)	Additional Factors	Reference
	The current method of estimating the proportion of costs that are capable of being capitalized and transferring those costs to a holding account ('blanket') that contains costs relating to capital projects. These costs are then allocated on a proportionate basis using total Capital Work in Progress (CWIP) as the driver, where the most relevant allocation driver is CWIP.				Enbridge Gas Inc. June 30, 2020 MDA EB-2011-0354 Exhibit D2 Tab 7 Schedule 1
Toronto Hydro Corporation, Ontario Energy Board (OEB) IFRS	Capitalized overheads are allocated based on cost drivers and include corporate functions and services, and employee benefits. Major cost categories include: (1) Labour (including pension and OPEB), (2) Vehicle and (3) Material handling on cost.	Corporate costs include - Finance, Payroll, Information Technology, Legal, Human Resources, Procurement, Facilities, Senior Management	32%	2019 Capital expenditures = $571 million CAD Total assets = $5,613 million CAD at December 31, 2019 Distribution company	EB-2018-0165 2017, 2018, 2019 Annual Reports 2019 Annual Financial Report
Enmax Power Corporation Alberta Utilities Commission IFRS	Capitalized overheads are determined through a combination of time studies (including estimated work effort, total headcount, vehicle count, workstation count, square footage, insurance asset value and executive head count), cost drivers and direct charges. A universal cost allocator is used for those costs that cannot be allocated reasonably using a single cost driver. Amount of annual capitalized overheads the company is permitted to capitalize is currently based on a 19% rate approved by AUC to a cap of $16M and $4M for Distribution and Transmission, respectively, in 2007, escalated by 3% annually.	Corporate costs include accounting, finance, human resources, information technology, treasury and legal services.	7% (Derived*)	2019 Capital expenditures = $444 million CAD Total assets = $6,744 million CAD at December 31, 2019 Distribution and transmission company	AUC Decision 2012-246 2007-2016 Formula Based Ratemaking March 25, 2009 23752-D01-2020

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of OM&A (in millions)	Additional Factors	Reference
BC Hydro and Power Authority, British Columbia Utilities Commission IFRS	Overheads are allocated to four main OM&A cost categories (1) Generation, (2) Transmission, (3) Distribution, (4) Customer Care, and (5) Corporate Services, using a bottom up functionalization approach. Under IFRS, the company has $67 million of planned additions to the IFRS PPE Regulatory Account for smoothing the rate impact of overhead costs not eligible for capitalization under IFRS, as they are not considered directly attributable to the construction of capital assets.	Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from OM&A to PPE. Major categories of capitalized OM&A are: (1) Generation, (2) Transmission, (3) Distribution, (4) Customer Care, and (5) Corporate Services	4% (Derived*)	2020 Capital expenditures = $2,782 million CAD Total assets = $30,730 million CAD at March 31, 2019 Distribution, transmission, and generation company	Cost of Service Study 2019 2018/19 ANNUAL SERVICE PLAN REPORT
Summary	For the peer companies observed, the common corporate costs capitalized as a percentage of total OM&A ranged from **4%-32%**.				

*Amounts noted as derived above, have been calculated as follows:

- FortisBC Inc. - amounts have been derived from “Appendix D6-2 FBC Overhead Capitalization Methodology Review, KPMG” dated March 8, 2019 (page 21), normalized for Hydro One comparable departments: Capital related costs (excluding Engineering) of $8.0 million, as a percentage of Total O&M Costs (excluding Engineering) of $53.2 million.

- Enmax Power Corporation - amounts have been derived from “AUC Decision 2012-246, Implementation of International Financial Reporting Standards”, dated September 14, 2012 (Page 15): 2012 Administrative overheads forecasted to be capitalized under IFRS of $9.1 million, as a percentage of total 2012 forecasted Administrative overheads. Total administrative overheads have been calculated based on 2012 CGAAP Capitalized administrative overheads of $23.2 million capitalized at 19%, resulting in an estimated total forecast of administrative overheads total of $122.0 million.

- BC Hydro and Power Authority - amounts have been derived from “British Columbia Hydro and Power Authority, 2019/2020 Annual Service Plan Report”, dated June 4, 2020 (pages 26, 41, 62), normalized for Hydro One comparable operating expenses: Capitalized costs of $72 million, as a percentage of Total operating expenses (excluding Electricity and gas purchases, Water rentals, Transmission charges and Amortization and depreciation) of $1,626.0 million.

Canadian Comparable Companies (Qualitative Information Only)

The table below summarizes benchmarking results of peer companies in the Canada where only qualitative information were available:

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of OM&A (in millions)	Additional Factors	Reference
Alectra Incorporated, Ontario Energy Board IFRS	New capitalization policy implemented in 2019 to align with IFRS and track through deferral accounts.	Major categories of capitalized OM&A are: (1) Direct labour costs, (2) Benefit costs, (3) Material handling costs, and (4) Fleet costs.	Capitalization rate information is not available	2019 Capital expenditures = $380 million CAD Total assets = $5,056 million CAD at December 31, 2019 Distribution company	EB-2018-0016 EB-2019-0018 December 31, 2018 MDA

Canadian Comparable Companies (Data Not Available)

Data was not available for the following peer companies in Canada:

Utility Name, Regulator and Basis of Accounting	Analysis	Overhead Cost Components	Corp Common Costs capitalized as a % of OM&A (in millions)	Additional Factors	Reference
Hydro-Québec, Government of Quebec US GAAP	Detailed information is not available		Capitalization rate information is not available	N/A	

COSTING OF WORK

1.0 OVERVIEW

Hydro One Transmission and Distribution capital work is bundled into packages of work identified as programs or projects. Programs are recurring investments characterized by largely similar work while projects are typically one-time investments that include unique combinations of elements related to the work to be executed and site conditions. Program and project costs are comprised primarily of labour, equipment and purchased materials. This Exhibit as well as Exhibit C-09-02 (Costing of Work: Labour Rate), Exhibit C-09-03 (Costing of Work: Fleet Rate), Exhibit C-09-04 (Costing of Work: Materials Surcharge) detail each of these three cost activities, and how the costs are allocated across programs and projects. The costing approach is consistent with the requirements of US Generally Accepted Accounting Principles (US GAAP).

Hydro One categorizes its costs into two major classifications: Common Corporate Costs (discussed in Exhibit E-04-08) and direct costs. The focus of this Exhibit is to describe the allocation of direct costs to programs and projects.

Direct costs are charged to work orders as the cost is incurred, and includes labour (comprised of salaries, benefits and pension costs), materials, fleet and supply chain costs. Labour costs are calculated as a product of actual time multiplied by the standard labour rate. Material costs are charged directly to the program or project. Fleet costs are charged using a fleet rate. Supply chain costs are charged via a material surcharge. The labour rate, fleet rate and material surcharge are described in detail in Exhibits C-09-02 to C-09-04.

2.0 OTHER PROGRAM AND PROJECT COSTS

Capital work also receives a monthly charge for its share of interest and overhead costs. The composition of these two cost categories and the annual calculation are explained in Exhibit C-08-01 (Interest Capitalized) and Exhibit C-08-02 (Overhead Capitalization Rate).

3.0 STANDARD RATES

Hydro One uses standard rates as a method to assign costs to work program. Standard Rates are further discussed in Exhibits C-09-02 to C-09-04.

COSTING OF WORK: LABOUR RATE

1.0 LABOUR RATE

Labour costs for Hydro One's work execution functions are distributed directly to benefiting programs and projects by using timesheets, consistent with common industry practice. Standard hourly labour rates are used to allocate costs to Hydro One's work programs and projects. This Exhibit outlines Hydro One's methodology in deriving the labour rate and provides an example of a typical rate and its components. The methodology for costing of work applies to both Transmission and Distribution.

The labour rate is fully loaded to ensure that all associated support costs required to deploy resources and equipment are accurately distributed. Hydro One's workforce planning and employee compensation strategies are discussed in Exhibit E-06-01 which outlines the total costs of compensation estimated in the Hydro One Transmission and Distribution forecast, including, but not limited to, the components of payroll obligations such as base pay, overtime, burdens, pension and OPEB and other costs like short-term incentive payments for management staff.

On an annual basis, the standard labour rates are derived based on information gathered through the annual budgeting process. The total estimated payroll and expense costs along with an assignment of support activity costs is divided by the forecast of billable hours to create the standard labour rate for each role across the Distribution and Transmission businesses. Table 1 below shows an example of the composition of a standard labour rate for one category, the Regional Maintainer Electrical Stations – Regular Staff over the 2018-2027 period.

Table 1 - Standard Hourly Labour Rate Composition

Regional Maintainer Electrical (Stations) – Regular Staff

	Historical				Bridge	Test				
	2018 Actual	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**
Payroll Obligations	78.08	76.72	78.07	78.75	79.42	80.11	80.79	81.48	82.17	82.87
Contractual time away from work	9.43	9.78	9.91	9.97	10.04	10.10	10.16	10.22	10.29	10.35
Time not directly benefiting a specific Program or Project	7.91	8.21	8.31	8.37	8.42	8.47	8.53	8.58	8.63	8.68
Field Supervision and Technical Support	14.44	14.79	14.99	15.08	15.18	15.27	15.37	15.46	15.56	15.65
Support Activities	16.14	16.50	16.72	16.83	16.94	17.04	17.15	17.25	17.36	17.46
Hourly Rate	**126.00**	**126.00**	**128.00**	**129.00**	**130.00**	**131.00**	**132.00**	**133.00**	**134.00**	**135.00**

The cost elements embedded in the standard labour rate as illustrated in Table 1 above are explained in this Exhibit, using the position of Regional Maintainer Electrical Stations – Regular Staff and its 2023 cost composition, as an example. Over the test period, an average escalation of $1 per hour is assumed which encompasses the estimated wage increase and inflation increase on other costs. When new collective agreements are reached, planning assumptions are adjusted.

1.1 PAYROLL OBLIGATIONS ($80.11)

A brief description of the cost elements included in this position category is provided below. Hydro One’s compensation, wages and benefits costs are more fully explained in Exhibit E-06-01.

a) Base Labour and Payroll Allowances (64.8% of Payroll Obligations)
   Base pay is contractually negotiated and reflected in wage schedules. Payroll allowances are also contractually negotiated and stated in collective agreements. Regular staff (e.g., PWU) is entitled to travel, footwear, and on-call allowances. Casual trades are entitled to board and travel allowances where circumstances require it.

b) Company Benefits (29.3% of Payroll Obligations)

For regular staff, this is comprised of pension and current and post-employment benefits and health, dental, etc. For non-regular staff (for example, casual trades), this is comprised of pension and welfare contributions made on behalf of the non-regular employee.

c) Government Obligations (5.9% of Payroll Obligations)

This consists of Canada Pension Plan, Employment Insurance, Employee Health Tax and Workplace Safety and Insurance Board contributions.

1.2 CONTRACTUAL TIME AWAY FROM WORK ($10.10)

This category consists primarily of employee vacation and statutory holidays, and all are established and identified in the relevant collective agreements. Sickness and accident costs are also included and are based on historical trends.

1.3 TIME NOT DIRECTLY BENEFITING A SPECIFIC PROGRAM OR PROJECT ($8.47)

This category includes time for attendance of safety meetings, housekeeping and downtime often created due to inclement weather. These estimates are based primarily on historical trends.

1.4 FIELD SUPERVISION AND TECHNICAL SUPPORT ($15.27)

This category includes the costs associated with field trades supervision and other management and technical staff providing support services to manage and monitor the status of the assigned programs and projects.

1.5 SUPPORT ACTIVITIES ($17.04)

a) Administrative Expenses and Support (68.3% of Support Activities)
These costs include administrative expenses such as travel costs, cell-phones and other miscellaneous expenses that cannot be specifically attributed to a particular program or project. Also included is an assignment of costs for clerical support activities and other centralized support to facilitate work management system requirements.

b) Work Methods and Training (14.5% of Support Activities)
These are costs to design, develop, continually update, maintain and deliver work methods and training programs. Costs are assigned based on the forecast consumption of these services as agreed to by the work methods and training function and service recipient.

c) Health, Safety and Environmental Support (17.2% of Support Activities)
These are costs to design, develop, update, maintain and deliver health, safety and environmental practices primarily for staff working in field locations. Costs are assigned based on the forecast consumption of these services as agreed to by the health, safety and environment function and the service recipient.

COSTING OF WORK: FLEET RATE

1.0 OVERVIEW: FLEET RATE

This schedule supports the standard equipment rate (Hourly Fleet Rate) that Hydro One uses to allocate the cost of fleet assets to the distribution and transmission lines of business. This section provides an overview of Hydro One's fleet assets. Section 2 summarizes the process by which the Hourly Fleet Rate is calculated. Section 3 summarizes the cost components that comprise the Hourly Fleet Rate and notable historical trends in those costs.

Hydro One owns approximately 7,000 transport and work equipment assets, 1000 small off-road equipment assets and 8 helicopters to support the company's work programs. These fleet assets are used for both distribution and transmission work and are strategically located across Hydro One's service territory. The total fleet assets decreased by 10% in 2017, and have been sustained at that level through to 2021, based on the current planned work programs. When work programs temporarily increase, Hydro One satisfies the increased demand for fleet equipment by redeploying existing equipment, renting equipment, and acquiring new assets, as appropriate. To prudently manage costs, Hydro One tries to satisfy demand increases through redeployment of existing fleet prior to renting or purchasing additional equipment (refer to GSP Section 4.2.2 for additional details).

Table 1 and Table 2 provide total expenditures of the components comprising the Hourly Fleet Rate for historic, bridge and test years for Transport and Work Equipment and Helicopter Services.

Table 1 - Transport and Work Equipment ($M)

Description	Historic				Bridge	Test
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
Operations & Repairs	67.7	71.1	77.4	76.4	79.5	82.3
Fuel Costs	27.2	24.4	22.2	26.0	26.0	26.0
Depreciation	40.3	41.8	42.6	45.3	45.3	45.8
Subtotal	**135.2**	**137.2**	**142.2**	**147.7**	**150.8**	**154.1**
Rentals	0.5	0.9	1.9	2.0	2.0	2.0
Totals	**135.7**	**138.2**	**144.1**	**149.7**	**152.8**	**156.1**

There was an overall 4% increase in fleet asset-related expenditures in 2020 from 2019 due to an increase in Operations and Repairs that was due to an increase in external labour rates and parts. Partially offsetting this increase were lower fuel prices in 2020 compared to 2019. For 2021 through 2023, Hydro One forecasts inflationary increases. Depreciation costs are expected to increase for 2021 onwards due to new asset acquisitions based on the equipment replacement strategy (refer to GSP Section 4.11, G-GP-01 for additional details).

Table 2 - Helicopter Services ($M)

Description	Historic			Bridge		Test
	2018	2019	2020	2021	2022	2023
Operations & Repairs	7.5	8.5	7.7	8.7	8.7	9.0
Fuel Costs	1.1	0.8	1.2	1.2	1.3	1.4
Depreciation	1.2	1.1	1.2	1.4	2.2	2.5
Subtotal	**9.8**	**10.4**	**10.1**	**11.3**	**12.2**	**12.9**
Rentals	0.0	0.0	0.0	0.0	0.0	0.0
Totals	**9.8**	**10.4**	**10.1**	**11.3**	**12.2**	**12.9**

Table 2 reflects the expected ongoing costs resulting from a planned equipment upgrade to newer, more modern helicopters. Increasing Operations & Repairs costs are the result of normal salary escalations plus the addition of a specialized avionics mechanic. Fuel Costs will increase with additional usage of the light twin engine helicopter. Lastly, Depreciation costs are forecasted to increase in the bridge and test year as a result of the new aircraft purchase (refer to GSP Section 4.11, G-GP-02 for additional details).

2.0 CALCULATING THE FLEET RATE

This section summarizes the process that Hydro One uses to calculate an Hourly Fleet Rate for each class of fleet asset.

Hydro One's fleet assets consist of 17 classes of equipment (not including helicopters, which have a discrete rate, as discussed below). The company calculates an Hourly Fleet Rate for each class of equipment and the lines of business will charge their hourly use against work programs and projects through their timesheets. Each rate is calculated by dividing the annual forecast cost by the annual forecast hours that the class of equipment is required to work (utilization hours).[1] Utilization hours are forecasted based on a review of historical trends and an annual review of the upcoming work program. As an example, Table 3 illustrates the composition of the Hourly Fleet Rate for a Radial Boom Derrick, which is a line maintenance truck and one of the common classes of equipment used by Hydro One.

[1] Utilization hours are defined as the hours the equipment is allocated to the work program or project.

Table 3 - Radial Boom Derrick Hourly Fleet Rate ($ per hour)

Description	Historic			Bridge		Test
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Operations & Repairs	35.1	34.1	36.8	36.6	36.6	36.5
Fuel Costs	7.0	6.5	5.7	7.1	6.7	6.7
Depreciation	14.9	16.4	15.5	15.3	16.7	16.7
Hourly Rate	**57.0**	**57.0**	**58.0**	**59.0**	**60.0**	**60.0**

The hourly rate for helicopters (Helicopter Rate) is calculated using a similar process but with discrete cost components for aircraft and pilot costs. This breakdown of cost components reflects the unique requirements of helicopter operations, which often require considerable preparation work by pilots. Since 2020, Hydro One has separated pilots' hours from general overhead costs within the Helicopter Rate. Directly charging pilots' time to specific work helps maximize the availability of aircraft and the efficient use of these resources. Prior to 2020, all the costs were tracked together.

As shown in Table 4, the Helicopter Rate consists of two components: aircraft cost and pilot cost. The current model produces the following rates:

Table 4 - Helicopter Rate ($ per hour)

Description	Historic			Bridge		Test
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Aircraft usage cost	2,720	2,650	2,246	2,596	2,700	2740
Pilot recovery cost	-	-	128	164	168	171

3.0 FLEET RATE COMPONENTS

This section describes the cost components that make up the Hourly Fleet Rate for Hydro One's fleet assets.

3.1 OPERATIONS AND REPAIRS

Operations and Repairs is the largest single cost component for fleet assets. This cost component primarily consists of repair costs (external and internal labour and parts). It also includes operational costs associated with fleet assets, as described below. Forecast Operations and Repairs costs are based on the annual maintenance schedules for each piece of equipment with consideration given to age and performance history. Throughout the year, repair costs are charged directly to each piece of equipment. Operations costs include administration staff and their allocated share of central service support costs explained in section 3.1.1 (Fleet Management Services) and 3.1.2 (Fleet Management System).

For helicopter services, Operations and Repair costs include the maintenance and operation of the aircraft based on maintenance schedules determined by the aircraft manufacturer and Transport Canada. Maintenance schedules follow both calendar and use requirements; some inspections must be completed on a calendar basis regardless of aircraft usage and others are completed based on hours flown since previous inspection or overhaul. Major components and calendar inspections such as the 12 year overhaul are capitalized.

In addition, Hydro One employs Remotely Piloted Aircraft Systems (RPAS) (also known as drones) as an asset management tool to survey both transmission and distribution infrastructure. These 'drones' will be used for line patrols, aerial inspection, vegetation management programmes, storm damage assessment as well as specific asset inspection tasks such as insulator and pole mount transformer inspections. Compared to the traditional survey methods used by the helicopter fleet, using RPAS in both line-of-sight and beyond line-of-sight applications has the potential to make the collection of asset-related data safer, more efficient and more cost effective which may result in productivity gains.

3.1.1 FLEET MANAGEMENT SERVICES

The Fleet Management Services function provides essential fleet services that include maintenance, administration, vehicle replacement and disposal. Fleet Management Services also helps ensure that environmental impacts are minimized and lines of business operate more efficiently by minimizing downtime and travel time, and by optimizing new technologies, such as electric and hybrid components and vehicles.

For Helicopter Services, these costs include maintenance and overhaul programs, and the provision of all staff and pilots. Helicopter Services provides the company's lines of business with dedicated resources for moving personnel and materiel and for supporting both transmission and distribution lines during storm or outage responses.

3.1.2 FLEET MANAGEMENT SYSTEM

Fleet Management System (FMS) is an automated system that utilizes a single credit card for each vehicle to capture operating costs including fuel, parts and repairs through the Garages Management System (excluding Helicopter Services). The FMS can also manage contracts, such as tender agreements with Hydro One's vendors, and prescribes spending approval guidelines and negotiated discounts. Hydro One's FMS measures a variety of targets that reconcile approved purchase orders, estimates versus actuals, and vendor-related expenditures, discounts and compliance on maintenance/inspection requirements.

In 2020, Hydro One awarded a five-year contract to Automotive Resources International (ARI) to support the FMS. Hydro One selected ARI through a competitive bidding process. The new contract with ARI delivers several benefits to Hydro One, including a reduction of the management fee, new reporting capabilities, improvement in the Garage Management system as well as improved visibility to external vendor vehicle downtime.

Since 2019, Hydro One has managed Helicopter services internally. Due to the nature of the aviation industry and the number of helicopters Hydro One owned, there was a greater benefit to managing the fleet internally. The company uses SAP to manage maintenance and repairs, invoices, requisitions, and approvals.

3.2 DEPRECIATION

The depreciation expense for each fleet asset class is calculated based on the current depreciation policies of Hydro One, the current composition of the fleet, and annual forecast additions and deletions.

The deprecation cost for the helicopter fleet is calculated using 15-year straight line depreciation. Major capital components and milestone calendar inspections are capitalized over the expected life of the expenditure.

3.3 FUEL COST

The fuel cost is calculated for each class of equipment based on historical consumption, current market projections, and the current composition of the class. The addition of electric vehicle assets into the fleet and the reduction of fuel spend has been added to the calculation of fuel costs through the planning period. Throughout the year, fuel costs are charged directly to the piece of equipment consuming the fuel. Fuel costs incurred by helicopter usage are tracked and included in the operating cost tracking numbers used to set the overall helicopter rate. In effect, lines of business are charged a standard rate that includes fuel costs.

3.4 EXTERNAL FLEET RENTALS

Due to the seasonal and fluctuating nature of the work programs and temporary workforce, Hydro One uses externally-owned rental equipment as a cost effective way to meet the peaks in its programs rather than have equipment that isn’t utilized. This rental equipment will also be utilized to bridge unexpected maintenance incidents and expected delivery date of replacement asset. Using a process similar to that used to cost Hydro One’s own fleet, standard rates are calculated and costs are distributed to programs and projects. This approach minimizes any additional capital requirement to address short term needs.

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COSTING OF WORK: MATERIALS SURCHARGE

1.0 OVERVIEW

This schedule describes the materials surcharge that Hydro One uses to allocate supply chain costs to the company's work programs. This overview section summarizes the materials surcharge calculation. Section 2 provides Hydro One's Supply Chain Services costs, which are recovered through the materials surcharge. Section 3 summarizes the cost management programs that Hydro One has implemented to manage the costs recovered through the surcharge.

Hydro One applies a standard material surcharge rate to material costs to capture applicable supply chain costs. Material costs charged to a project or program are based on the issue cost, which is either the "moving average price" or the direct-shipped purchase order price. Material purchase costs are surcharged with a fixed percentage cost to recover costs associated with sourcing, purchasing, transportation, support functions (e.g., Accounts Payable) and inventory management. The costs recovered in the materials surcharge include the following Hydro One costs: sourcing, purchasing, management, inspection services, warehousing and transportation of material, rental tools (Central Tool Services or CTS) and stock keeping.

Hydro One employs a range of cost reduction programs to reduce the costs recovered through the materials surcharge, including Investment Recovery, Early Pay Discounts, and Volume Discounts. Details about each program can be found in Section 3.0 below.

Hydro One acquires materials and services through a process that drives value for money, delivers transparency to its internal customers and builds mutually valuable relationships with key suppliers. Details on Hydro One's procurement policy are provided in Exhibit E-05-02.

2.0 SUPPLY CHAIN SERVICES

This section describes the budgeted cost levels and components of Supply Chain Services.

Table 1 - Supply Chain Services ($M)

Year	Historic				Bridge	Forecast Period (Planned)				
	2018 Actual	2019* Actual	2020 Actual	2021 Forecast	2022 Forecast	2023	2024	2025	2026	2027
Total	33.0	32.6	33.3	36.8	34.4	36.6	37.9	39.0	40.3	41.7

** Accounts Payable has been recovered as part of the Material Surcharge as of 2019, costs are approximately $1M annually, included in Table 1.*

Supply Chain Services is accountable for approximately $1.7 billion in procurement spend annually. As Table 1 shows, the forecast 2023 costs for supply chain services are $36.6M. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials, inspection services, transportation, inventory management, stock keeper management, and investment recovery of disposed assets.

Supply Chain Services forecasts that transportation costs will increase by 15% in 2023 in order to meet the level of capital investments set out in the Distribution System Plan. Transportation costs are forecast to continue increasing by approximately 5% annually over the 2024-2027 period due to increase work programs and anticipated price adjustment based on index trends in the current materials transportation contract (discussed in Section 2.4 below).

In late 2020, Hydro One transferred all Stock Keepers from Distribution Lines to Supply Chain Services. Although the labour costs already resided with Supply Chain services, there are other costs which have now transferred from Distribution to Supply Chain Services. Supply Chain services are now responsible for these Stock Keepers fleet and procurement card expenses.

Supply Chain Services is undergoing a transformation that will focus on driving continuous improvement in people, processes and technology while improving the service and value it delivers, particularly in the company's Category Management. A major component of this transformation is the insourcing of all Supply Chain Services functions as of November 1st, 2021, as summarized in Exhibit E-05-01. By the end of 2021, Hydro One will have insourced all Supply Chain Services functions which will result in approximately 50 full time employees added to this organization (43% Society, 53% PWU, 4% management staff). All Supply Chain Services staff will now be led by 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, Supply Chain will focus on building staff competencies to regain internal expertise. The increased efficiency gained and ability to self perform will lead to the successful execution of Supply Chain accountabilities resulting in reduced costs in 2022.

Supply Chain Services is improving the processes and technologies it employs. Hydro One's sourcing processes and contract standards will continue to improve the efficiency of all functions and streamline activities. From a technology perspective, investments in SAP Ariba, SAP Fieldglass and SAP Spend Visibility provide technology for Strategic Sourcing & Contract Management, which drives efficiencies.

The following sub-sections summarize the functions that Hydro One's Supply Chain Services organization provides.

2.1 STRATEGIC SOURCING OF MATERIALS AND SERVICES

Hydro One manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a company-wide basis using cross-functional teams to manage the supply base as a valued resource. Hydro One Supply Chain employs a Category Management Framework to source products and services. Category Management is a framework that focuses on developing comprehensive value based procurement strategies for distinct segments of organizational spend. The execution guidelines for each phase are outlined in Figure 1.

CATEGORY MANAGEMENT FRAMEWORK

5. Supplier Management
- Execute/Award Contracts
- Contract Transition
- Process / Technology Enablement
- Business Unit On Boarding
- Supplier(s) Onboarding
- Supplier Relationship/ Performance Management Process

4. Strategy Execution
- Strategy Execution
- Proposal Assessment and Evaluation
- Supplier Negotiations
- Process/ Technology Development
- Category Award Summary & Recommendation

1. Internal Analysis
- Project Kick-off
- Category Charter
- Commercial & Technical Review + Analysis
- Category Spend Analysis
- Category Process Analysis
- Category Safety Assessment
- Category Environmental Assessment
- Supplier Performance Assessment
- Category Demand Plan

2. Market Analysis
- Category Cost Analysis
- Category Market Analysis
- Category Supplier Analysis (Existing + Potential)

3. Strategy Development
- Internal Analysis Strategy Development
- Market Analysis Strategy Development
- Indigenous Inclusion Strategy
- Category Execution Plan Development
- Stakeholder Strategy Review

Figure 1: Chart depicting Hydro One Supply Chain's Category Management Framework

The sourcing of materials and services includes the following:

- Demand Management and Procurement – market intelligence with respect to commodities, processing purchase transactions, and inspecting and expediting services to ensure delivery of contract commitments; and
- Sourcing and Supplier Management – services to support sourcing all commodities and services which include managing the size and composition of the supplier base and resolving issues.

2.2 INSPECTION SERVICES

Hydro One's inspection services operations focusses on supplier qualification, supplier performance and quality assurance, and operations execution support for critical equipment.

- The Supplier Qualification process focusses around an audit program of supplier facilities to ensure suppliers of critical equipment have and maintain the capability, capacity, expertise, and quality management systems to supply the subject material & equipment.
- The Supplier Performance and Quality Assurance process focusses on individual project/order support with suppliers of critical equipment, where inspectors, in collaborations with Engineering and project teams, ensure the equipment is being manufactured in accordance with the project schedule and are manufactured in accordance with Hydro Ones specifications. This process provides oversight and support throughout the entire project/order lifecycle and ensures suppliers meet all requirements and acceptance criteria established by Hydro One prior to shipment to Hydro One.
- The Operations Execution Support process focusses on timely project/order reporting to project teams to ensure efficient planning and execution of capital work. Additionally, the inspectors perform emergency and ad-hoc inspections in supplier's facilities, to support issue identification while coordinating and monitoring non-conformance resolutions and performance issues with supplier's plants and operations.

2.3 STORAGE AND DISTRIBUTION OF MATERIALS – LOGISTICS

Hydro One's central warehouse operation in Barrie is responsible for the storage and distribution of materials for the service centres and station locations. This central warehouse serves as a hub to supply the company's further 79 field service centres, 30 station locations and nine construction sites. In addition to coordinating shipments to the previously noted locations, the warehouse also facilitates shipments to five transportation and work equipment locations, Central Maintenance Services and Remotes.

A consolidated warehouse operation provides efficiencies through focusing on activities such as:

- improving receipting efficiency by integrating with the contracted transportation company to provide visibility into the supply chain and scheduling the inbound shipment;
- centralized warehousing through a Crossdock facility hub where large supplier shipments are sorted and distributed accordingly to all field locations,

- timely receipting material orders in the system to improve processing times for supplier invoices;
- minimizing and/or consolidating order quantities to leverage discounts with suppliers;
- consolidating freight to each location to minimize the frequency and cost of deliveries;
- managing and coordinating the delivery of materials on the scheduled delivery date to service centres to ensure that field operations receives the right materials at the right time;
- ensuring the accuracy of material through the OSD&D process (Over, Short, Discrepant, and Damaged);
- providing storage for quarantined materials and equipment associated with warranty claim; and
- ensuring safe storage for specialty products such as servers and control panels that require a special temperature environment. This drastically reduced off site storage costs.

2.4 TRANSPORTATION

Transportation Services including full and less-than-truckload, flatbed, and freight management are a core services critical to the execution of Hydro One's operations all over the province. Hydro One manages its inbound and outbound transportation of materials through contracts with third parties. In 2020, Hydro One successfully negotiated a new three-year transportation contract with Manitoulin Transport Inc. for material delivery in and out of the central warehouse. This contract was previously competitively sourced and due to direct negotiations with Manitoulin, Supply Chain was able to minimize cost increases compared to the market trend and incorporated significant volume discounts. Rates are firm for the first year of the contract and the following two years will be adjusted for inflation to a maximum of +/-2%. In some instances, material is shipped directly from the supplier to the job site.

2.5 STOCK KEEPING

Hydro One's field Stock Keepers throughout the province receive material and maintain inventory at Operations Centres, and perform monthly inventory cycle counts on behalf of the Barrie Warehouse. Stock Keepers also perform material receipting, material management, and inventory counts. Benefits of the organizational structure include: standardization of training processes across the field force, centralized accountability for inventory financials and inventory stewardship, and localized point of contact for after-hours requirements contributing to outage response efforts.

2.6 WARRANTY CLAIMS & MANAGEMENT

Through its Warranty & Claims Management Process, Hydro One manages warranty issues and claims for equipment and services. Since 2017, under the Warranty Claims program, $9.8M has been recovered to date. Hydro One's Warranty Claims program is summarized in Exhibit E-05-02.

3.0 COST MANAGEMENT

This section summarizes cost management programs that Hydro One has implemented to offset the cost of materials and supply chain services. These cost management programs include Investment Recovery, Early Pay Discounts, Volume Discounts, and Sourcing Category Management. The savings from these initiatives are reflected in the investment plan.

- Investment Recovery: The final step of the supply chain is the disposal and investment recovery of end-of-life assets. This recovery is typically in the range $1.4M per year, and primarily involves vehicle and scrap metal sales. Hydro One continues to focus on extracting the maximum value possible from the sale of these assets.

- Hydro One disposes of its vehicles and miscellaneous items (e.g., tools) through auction sales. Revenue generated for vehicles sales reduces Fleet's OM&! costs while the majority of revenue generated from miscellaneous sales reduces the materials surcharge.

- For scrap metal, Hydro One’s scrap supplier picks up materials from various sites, weighs it, and issues payment less their fee. Where the site revenue exceeds $10K, the revenue is posted to the project while residual revenue is posted to Supply Chain Services thus reducing the materials surcharge.

- Early Pay Discounts: Supply Chain Services uses Taulia, an eInvoicing software, where suppliers electronically upload their invoices and can choose a discounted payment in advance of their contractual payment terms.

- Volume Discounts: During the sourcing and negotiation process, suppliers are asked to propose a tiered volume discount. Under such arrangements, Hydro One receives a rebate via cheque or credit from the supplier if certain spend thresholds are met.

- Sourcing Category Management: Category Management is a major focus for Hydro One, as the company emphasizes cost control and security of supply, while markets remain volatile and demand in the global utility sector increases. Hydro One’s Category Management framework is summarized in Exhibit E-05-02.