EXHIBIT 2

RATE BASE and CAPITAL

Festival Hydro INC.

2.2 Exhibit 2: Rate Base and Capital

Table of Contents

2.2 Exhibit 2: Rate Base and Capital 2
2.2.1 Rate Base 4
2.2.1.1 Overview 4
2.2.1.2 Variance Analysis of Rate Base 7
2.2.2 Fixed Asset Continuity Schedule 15
2.2.2.1 Fixed Asset Continuity Schedules, Excluding Work in Progress (WIP) 15
2.2.3 Gross Assets – Property Plant and Equipment and Accumulated Depreciation 27
2.2.3.1 Breakdown by Function 27
2.2.3.2 Detailed Breakdown by Major Plant Account 30
2.2.3.3 Variance Analysis on Gross Assets 33
2.2.3.4 Summary of Capital Expenditures 55
2.2.3.5 Capital Project Summary 56
2.2.4 Depreciation, Amortization and Depletion 57
2.2.4.1 Overview 57
2.2.4.2 Depreciation by Asset Group 58
2.2.4.3 Depreciation Policy 58
2.2.4.4 Changes to Depreciation Policy or Asset Service Life 71
2.2.4.5 Asset Retirement Obligations 72
2.2.4.6 Half-Year Rule 72
2.2.5 Allowance for Working Capital 72
2.2.5.1 Overview 72
2.2.5.2 Working Capital 73
2.2.5.3 Eligible Distribution Expenses 74
2.2.5.4 Cost of Power (COP) Calculations 74
2.2.5.5 Power Purchased 78
2.2.5.6 Regulatory Charges 80
2.2.5.7 Network and Connection Charges 80

2.2.5.8 Low Voltage Charges 81
2.2.5.9 Smart Meter Entity Charges 81
2.2.6 Distribution System Plan 81
2.2.7 Policy Options for the Funding of Capital 81
2.2.8 Addition of Previously Approved ACM and ICM Project Assets to Rate Base 82
2.2.9 Capitalization Policy 82
2.2.9.1 Guidelines for Capitalization 82
2.2.9.2 Capitalization by Component 83
2.2.9.3 Depreciation 83
2.2.10 Capitalization of Overhead 84
2.2.10.1 Benefit Costs and Labour Burden 84
2.2.10.2 Transportation and Fleet Costs 85
2.2.10.3 Capitalization of Overhead 85
2.2.11 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities 86

2.2.1 Rate Base

2.2.1.1 Overview

The Rate Base used for the purpose of calculating the revenue requirement in this Application follows Chapter 2 of the Filing Requirements for Electricity Distribution Applications issued by the Ontario Energy Board ("Board") on December 15, 2022 (the "Filing Requirements"). In accordance with the Filing Requirements, Festival Hydro Inc. (FHI) has calculated the Rate Base as the average of the Net Capital Balances at the beginning and the end of the 2025 Test Year plus a Working Capital Allowance, which is 7.5% of the sum of the Cost of Power and Controllable Expenses. The use of a 7.5% rate is consistent with the Board's letter of June 3, 2015, and the Filing Requirements as issued by the OEB. FHI has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this Application using the default value of 7.5%.

FHI was also not previously directed by the OEB to undertake a lead/lag study.

Net Capital Assets include in-service assets that are associated with activities that enable the conveyance of electricity for distribution purposes minus Accumulated Depreciation and Contributed Capital from third parties. For purposes of this Exhibit, Distribution Assets refer to those assets that are most directly related to the distribution system, such as poles, overhead and underground lines, and transformers. General Plant refers to assets that support the operation of the distribution system such as computer hardware and software, vehicles, buildings, and equipment. Capital Assets include Property, Plant and Equipment ("PP&E") and Intangible Assets; these are referred to as "Capital" or "Fixed Assets" throughout this evidence. The Rate Base calculation excludes any Non-Distribution Assets. FHI has not applied for, nor received, any Incremental Capital Module ("ICM") or Advanced Capital Module ("ACM") adjustments since it's last Cost of Service (COS). There was an ICM approved in 2013 for the addition construction of a new municipal transformer ("TS") station in the city of Stratford. The recovery of the related revenue from customers occurred until December 31, 2015.

In most cases, capital expenditures are equivalent to in-service additions except for large software system additions which spanned two years: SmartMAP in years 2022 and 2023, Customer Information System (CIS) and AMI 2.0 in years 2023 and 2024, and Enterprise Resource Planning System (ERP) in years 2024 and 2025. A Capital Expenditures summary has been included in Table 2-41 and is discussed further in the Distribution System Plan (DSP).

FHI does not have any in-service balances previously recorded in DVAs.

FHI has provided its Rate Base calculations for the years 2015 Board Approved, 2015 – 2023 Actual, 2024 Bridge Year and 2025 Test Year in Table 2-1 below:

Table 2-1 Summary of Rate Base

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets Opening Balance	90,816,914	55,573,235	57,050,939	59,135,138	61,614,375	64,455,048
Gross Fixed Assets Closing Balance	93,182,896	57,050,939	59,135,138	61,614,375	64,455,048	67,200,894
Average Gross Fixed Assets	**91,999,905**	**56,312,087**	**58,093,039**	**60,374,757**	**63,034,712**	**65,827,971**
Accumulated Depreciation Opening Balance	38,761,080	2,242,612	4,409,458	6,394,835	8,690,123	10,783,036
Accumulated Depreciation Closing Balance	40,895,920	4,409,458	6,394,835	8,690,123	10,783,036	12,952,345
Average Accumulated Depreciation	**39,828,500**	**3,326,035**	**5,402,146**	**7,542,479**	**9,736,579**	**11,867,691**
Average Net Book Value	**52,171,405**	**52,986,052**	**52,690,892**	**52,832,278**	**53,298,132**	**53,960,280**
Working Capital	73,902,730	76,680,740	84,312,292	76,622,312	74,377,176	76,937,488
Working Capital Allowance %	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
Working Capital Allowance	**9,607,355**	**9,968,496**	**10,960,598**	**9,960,901**	**9,669,033**	**10,001,873**
Rate Base	**61,778,759**	**62,954,548**	**63,651,490**	**62,793,179**	**62,967,165**	**63,962,153**

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets Opening Balance	67,200,894	66,981,996	69,712,958	72,673,651	76,880,111	84,377,938
Gross Fixed Assets Closing Balance	66,981,996	69,712,958	72,673,651	76,880,111	84,377,938	91,787,288
Average Gross Fixed Assets	**67,091,445**	**68,347,477**	**71,193,305**	**74,776,881**	**80,629,025**	**88,082,613**
Accumulated Depreciation Opening Balance	12,952,345	12,489,859	14,179,382	15,579,227	17,418,515	20,126,776
Accumulated Depreciation Closing Balance	12,489,859	14,179,382	15,579,227	17,418,515	20,126,776	23,149,305
Average Accumulated Depreciation	**12,721,102**	**13,334,620**	**14,879,305**	**16,498,871**	**18,772,645**	**21,638,041**
Average Net Book Value	**54,370,343**	**55,012,857**	**56,314,000**	**58,278,010**	**61,856,379**	**66,444,572**
Working Capital	78,623,069	66,713,670	64,900,191	69,807,896	67,865,459	76,387,370
Working Capital Allowance %	13.00%	13.00%	13.00%	13.00%	13.00%	7.50%
Working Capital Allowance	**10,220,999**	**8,672,777**	**8,437,025**	**9,075,026**	**8,822,510**	**5,729,053**
Rate Base	**64,591,342**	**63,685,634**	**64,751,025**	**67,353,037**	**70,678,889**	**72,173,625**

FHI calculated its 2025 Rate Base as $72.2M, an increase of $10.4M over the 2015 Board Approved Rate Base of $61.8M. This increase in Rate Base of $10.4M is attributable to an increase in the Average Net Book Value of Capital Assets of $14.3M and a decrease in the Working Capital Allowance (WCA) of $3.8M. FHI reinvested significantly in its distribution system and general plant since the last COS Application, including some significant one-time investments discussed below and this is reflected in the Net Book Value variance. FHI's WCA was previously set to 13% and was adjusted to 7.5% as part of this Application and accounts for a large portion of the WCA variance in addition to a decrease in power supply expenses.

FHI's overall capital investment plan has been historically driven by System Renewal investments followed by System Access and does not fluctuate considerably year to year. There have been some larger projects related to building renovations, software system implementations and smart meter redeployment which has significantly increased capital costs from 2023 to 2029. These projects have been discussed further below.

FHI has provided a summary of its calculations of the Cost of Power and Controllable Costs used in the calculations for determining Working Capital for the years 2015 Board Approved, 2015 – 2023 Actual, 2024 Bridge Year and 2025 Test Year in Table 2-2 below. Further details of FHI's Cost of Power calculations are provided in Table 2-56. The 2024 Bridge Year is forecast data.

Table 2-2 Summary of Working Capital Calculation

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Distribution Expenses - Operation	924,800	881,642	878,957	871,897	1,092,823	930,948
Distribution Expenses - Maintenance	1,217,983	1,255,585	1,222,910	1,347,728	1,471,361	1,436,797
Billing and Collecting	1,212,817	1,251,776	1,295,739	1,272,765	1,188,727	1,259,373
Community Relations	11,248	11,632	9,900	13,400	9,745	7,413
Administrative and General Expenses	1,789,432	1,844,086	2,284,278	2,123,899	2,528,550	2,391,868
Donations - LEAP	13,000	13,000	13,200	13,410	13,510	13,650
Taxes Other than Income Taxes	19,225	96,756	38,017	55,726	82,847	74,054
Less Allocation Depreciation	- 156,997	- 146,625	- 149,614	- 147,927	- 160,250	- 163,119
Power Supply Expenses	68,871,222	71,472,888	78,718,905	71,071,415	68,149,862	70,986,504
Total Working Capital Expenses	**73,902,730**	**76,680,740**	**84,312,292**	**76,622,312**	**74,377,176**	**76,937,488**

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Distribution Expenses - Operation	977,468	710,733	951,220	1,127,215	1,289,665	1,368,552
Distribution Expenses - Maintenance	1,495,382	1,646,168	1,865,684	1,817,483	1,959,517	2,146,761
Billing and Collecting	1,208,934	1,293,457	1,283,486	1,448,423	1,542,185	1,707,271
Community Relations	12,268	1,015	1,115	-	9,507	19,427
Administrative and General Expenses	2,334,067	2,336,495	2,638,687	3,044,852	3,409,440	4,013,523
Donations - LEAP	13,860	30,060	14,550	15,000	15,000	20,050
Taxes Other than Income Taxes	135,993	126,934	126,868	151,482	143,937	154,677
Less Allocation Depreciation	- 148,359	- 130,048	- 122,563	- 114,240	- 135,373	- 132,131
Power Supply Expenses	72,593,455	60,698,856	58,141,145	62,317,681	59,631,580	67,089,241
Total Working Capital Expenses	**78,623,069**	**66,713,670**	**64,900,191**	**69,807,896**	**67,865,459**	**76,387,370**

2.2.1.2 Variance Analysis of Rate Base

The following section sets out FHI's Rate Base and Working Capital calculations and explanations for the following variances:

- 2015 Board Approved against 2015 Actual
- 2015 Actual against 2016 Actual
- 2016 Actual against 2017 Actual
- 2017 Actual against 2018 Actual
- 2018 Actual against 2019 Actual
- 2019 Actual against 2020 Actual
- 2020 Actual against 2021 Actual
- 2021 Actual against 2022 Actual
- 2022 Actual against 2023 Actual

- 2023 Actual against 2024 Bridge Year and
- 2024 Bridge Year against 2025 Test Year

FHI has calculated the materiality threshold on its Rate Base to be $80,235 for 2025 in accordance with the Filing Requirements. On this basis, FHI has selected a materiality threshold of $80,000. This calculation is summarized in Exhibit 1 Table 1-13.

Table 2-3 2015 Board Approved vs 2015 Actual

Description	2015 Board Approved	2015 Actual	Variance from 2015 Board Approved	%
Net Capital Assets in Service				
Opening Balance	52,055,834	53,330,623	1,274,789	2.4%
Ending Balance	52,286,976	52,641,481	354,505	0.7%
Average Balance	**52,171,405**	**52,986,052**	**814,647**	**1.6%**
Working Capital Allowance	9,607,355	9,968,496	361,141	3.8%
Rate Base	**61,778,759**	**62,954,548**	**1,175,789**	**1.9%**

Total actual Rate Base for 2015 is $1,175,789 or 1.9% higher than Board approved. The main reason for the variance is due to opening balances being higher than projected. FHI's 2015 Board Approved Opening Balances that were included in the 2015 Application were not updated for the final transformer station addition costs that came in $1.2M over budget. The WCA was higher than projected due to higher cost of power amounts as shown in Table 2-56.

Table 2-4 2015 Actual vs 2016 Actual

Description	2015 Actual	2016 Actual	2016 Actual vs 2015 Actual	%
Net Capital Assets in Service				
Opening Balance	53,330,623	52,641,481	- 689,142	-1.3%
Ending Balance	52,641,481	52,740,304	98,823	0.2%
Average Balance	**52,986,052**	**52,690,892**	- 295,160	**-0.6%**
Working Capital Allowance	9,968,496	10,960,598	992,102	10.0%
Rate Base	**62,954,548**	**63,651,490**	**696,942**	**1.1%**

Total actual Rate Base for 2016 is $696,942 or 1.1% higher than 2015 Actual. The Average Net Capital Assets in Service was lower by $295K because of the decrease in Net Assets in 2015 and limited additions over amortization expense in 2016. This was offset by the WCA being higher than 2015 by $1M due to higher cost of power amounts as shown in Table 2-56.

Table 2-5 2016 Actual vs 2017 Actual

Description	2016 Actual	2017 Actual	2017 Actual vs 2016 Actual	%
Net Capital Assets in Service				
Opening Balance	52,641,481	52,740,304	98,823	0.2%
Ending Balance	52,740,304	52,924,252	183,949	0.3%
Average Balance	**52,690,892**	**52,832,278**	141,386	**0.3%**
Working Capital Allowance	10,960,598	9,960,901	- 999,697	-9.1%
Rate Base	**63,651,490**	**62,793,179**	**- 858,312**	**-1.3%**

Total actual Rate Base for 2017 is $858,312 or 1.3% lower than 2016 Actual. There was limited change to Net Capital Assets as the additions were relatively close to amortization with the ending balance in 2017 being $184K higher than the prior year.

This is offset by the WCA being lower than 2016 by $1M due to lower cost of power amounts as shown in Table 2-56.

Table 2-6 2017 Actual vs 2018 Actual

Description	2017 Actual	2018 Actual	2018 Actual vs 2017 Actual	%
Net Capital Assets in Service				
Opening Balance	52,740,304	52,924,252	183,949	0.3%
Ending Balance	52,924,252	53,672,012	747,759	1.4%
Average Balance	**52,832,278**	**53,298,132**	465,854	**0.9%**
Working Capital Allowance	9,960,901	9,669,033	- 291,868	-2.9%
Rate Base	**62,793,179**	**62,967,165**	**173,986**	**0.3%**

Total actual Rate Base for 2018 is $173,986 or 0.3% higher than 2017 Actual. There was a $466K difference in the average net asset balance due to a $748K higher ending asset balance, meaning new additions outpaced depreciation by this amount. There was a higher than budgeted amount spent on system access assets in 2018. The WCA decreased by $292K due to lower cost of power amounts as shown in Table 2-56.

Table 2-7 2018 Actual vs 2019 Actual

Description	2018 Actual	2019 Actual	2019 Actual vs 2018 Actual	%
Net Capital Assets in Service				
Opening Balance	52,924,252	53,672,012	747,759	1.4%
Ending Balance	53,672,012	54,248,548	576,536	1.1%
Average Balance	**53,298,132**	**53,960,280**	662,148	**1.2%**
Working Capital Allowance	9,669,033	10,001,873	332,841	3.4%
Rate Base	**62,967,165**	**63,962,153**	**994,988**	**1.6%**

Total actual Rate Base for 2019 is $994,988 or 1.6% higher than 2018 Actual. The average net capital assets increased by $662K due to increases in system access, system renewal and general plant in 2019 compared to budget. This is offset by the WCA being higher than 2018 by $333K due to higher cost of power amounts as shown in Table 2-56.

Table 2-8 2019 Actual vs 2020 Actual

Description	2019 Actual	2020 Actual	2020 Actual vs 2019 Actual	%
Net Capital Assets in Service				
Opening Balance	53,672,012	54,248,548	576,536	1.1%
Ending Balance	54,248,548	54,492,137	243,589	0.4%
Average Balance	**53,960,280**	**54,370,343**	410,063	**0.8%**
Working Capital Allowance	10,001,873	10,220,999	219,126	2.2%
Rate Base	**63,962,153**	**64,591,342**	**629,188**	**1.0%**

Total actual Rate Base for 2020 is $629,188 or 1.0% higher than 2019 Actual. There was an increase to average net capital assets by $410K however ending asset additions only outpaced depreciation by $244K due to some deferrals from the plan during Covid. The WCA was higher than 2019 by $219K due to higher cost of power amounts as shown in Table 2-56.

Table 2-9 2020 Actual vs 2021 Actual

Description	2020 Actual	2021 Actual	2021 Actual vs 2020 Actual	%
Net Capital Assets in Service				
Opening Balance	54,248,548	54,492,137	243,589	0.4%
Ending Balance	54,492,137	55,533,576	1,041,439	1.9%
Average Balance	**54,370,343**	**55,012,857**	642,514	**1.2%**
Working Capital Allowance	10,220,999	8,672,777	- 1,548,222	-15.1%
Rate Base	**64,591,342**	**63,685,634**	**- 905,708**	**-1.4%**

Total actual Rate Base for 2021 is $905,708 or 1.4% lower than 2020 Actual. There was an increase in the net capital assets ending balance by $1M, while most additions were planned there were some projects that were deferred from 2020 that were completed in 2021. This is offset by the WCA being much lower than 2020 by $1.5M due to lower cost of power amounts as shown in Table 2-56.

Table 2-10 2021 Actual vs 2022 Actual

Description	2021 Actual	2022 Actual	2022 Actual vs 2021 Actual	%
Net Capital Assets in Service				
Opening Balance	54,492,137	55,533,576	1,041,439	1.9%
Ending Balance	55,533,576	57,094,424	1,560,848	2.8%
Average Balance	**55,012,857**	**56,314,000**	1,301,143	**2.4%**
Working Capital Allowance	8,672,777	8,437,025	- 235,752	-2.7%
Rate Base	**63,685,634**	**64,751,025**	**1,065,391**	**1.7%**

Total actual Rate Base for 2022 is $1,065,391 or 1.7% higher than 2021 Actual. In 2022 there was an increase in additions over depreciation by $1.6M. Most of this additional work, while higher than previous years, was budgeted in both system renewal and general plant. There was also an increase of system access work coming out of the pandemic. This was offset by the WCA being lower than 2021 by $236K due to lower cost of power amounts as shown in Table 2-56.

Table 2-11 2022 Actual vs 2023 Actual

Description	2022 Actual	2023 Actual	2023 Actual vs 2022 Actual	%
Net Capital Assets in Service				
Opening Balance	55,533,576	57,094,424	1,560,848	2.8%
Ending Balance	57,094,424	59,461,597	2,367,173	4.1%
Average Balance	**56,314,000**	**58,278,010**	1,964,010	**3.5%**
Working Capital Allowance	8,437,025	9,075,026	638,002	7.6%
Rate Base	**64,751,025**	**67,353,037**	**2,602,012**	**4.0%**

Total actual Rate Base for 2023 is $2,602012 or 4.0% higher than 2022 Actual. In 2023 there were higher than historical asset additions specifically related to building renovations included in general plant. The WCA was higher than 2022 by $638K due to higher cost of power amounts as shown in Table 2-56.

Table 2-12 2023 Actual vs 2024 Bridge Year

Description	2023 Actual	2024 Bridge	2024 Bridge vs 2023 Actual	%
Net Capital Assets in Service				
Opening Balance	57,094,424	59,461,597	2,367,173	4.1%
Ending Balance	59,461,597	64,251,162	4,789,565	8.1%
Average Balance	**58,278,010**	**61,856,379**	3,578,369	**6.1%**
Working Capital Allowance	9,075,026	8,822,510	- 252,517	-2.8%
Rate Base	**67,353,037**	**70,678,889**	**3,325,852**	**4.9%**

Total actual Rate Base for 2024 is forecasted to be $3,325,852 or 4.9% higher than 2023 Actual. Included in this balance is an ending net asset balance that is $4.8M higher than depreciation. This includes the final phases of building renovations, AMI 2.0 pilot project, as well as the new CIS being in service. This is partially offset by the WCA being predicted to be lower than 2023 by $252K due to lower predicted cost of power amounts as shown in Table 2-56.

Table 2-13 2024 Bridge Year vs 2025 Test Year

Description	2024 Bridge	2025 Test	2025 Test vs 2024 Bridge	%
Net Capital Assets in Service				
Opening Balance	59,461,597	64,251,162	4,789,565	8.1%
Ending Balance	64,251,162	68,637,983	4,386,821	6.8%
Average Balance	**61,856,379**	**66,444,572**	4,588,193	**7.4%**
Working Capital Allowance	8,822,510	5,729,053	- 3,093,457	-35.1%
Rate Base	**70,678,889**	**72,173,625**	**1,494,736**	**2.1%**

Total actual Rate Base for 2025 is forecasted to be $1.5M or 2.1% higher than 2024 Bridge. Capital asset additions remained reasonably steady from 2024 with the addition of an ERP solution as well as early phases of AMI 2.0. This is offset by the WCA being lower than 2024 by $3.0M due to the change in WCA rate from 13% to 7.5% as part of this Application. The cost of power amounts is projected to increase compared to 2024 as shown in Table 2-56.

2.2.2 Fixed Asset Continuity Schedule

2.2.2.1 Fixed Asset Continuity Schedules, Excluding Work in Progress (WIP)

Opening and closing balances of gross assets and accumulated depreciation correspond to the fixed asset continuity schedules. The net book value balances, excluding work in progress and non-utility assets, are the balances included in the rate base calculation.

Table 2-14 through Table 2-24 below provide the Fixed Asset Continuity Schedules excluding WIP for each of 2015 – 2023 Actuals, 2024 Bridge Year, and 2025 Test Year and are consistent with Appendix 2-BA as required in the Filing Requirements.

The CCA classes for fixed assets agree with the CCA Class used for tax purposes in FHI's tax returns.

Under IFRS, customer contributions are recorded in Account 2440, Deferred Revenue and amortized to Other Revenue over the service life of the related asset. FHI has included Account 2440 in the continuity schedules to ensure the unamortized gross amount is presented as a reduction to rate base. The corresponding amortization of contributed capital for Account 2440 is removed at the bottom of the appendix to arrive at the gross amount of depreciation expense for ratemaking purposes. The amortized amount removed from the appendix is included with other revenue offsets in Account 4245.

For general financial reporting purposes under IFRS, FHI does not have any material retirement of assets that are not individually identified for both the 2024 Bridge Year and the 2025 Test Year.

1 **Table 2-14 Fixed Asset Continuity Schedule as at December 31, 2015 – MIFRS**

			Cost				Accumulated Depreciation			
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**
	1609	Capital Contributions Paid	$ 2,360,056	$ 70,200	-$1,463,321	$ 966,935	-$ 61,926	-$ 54,474	$ 14,746	-$ 101,654
12	1611	Computer Software (Formally known as Account 1925)	$ 370,401	$ 306,328	$ -	$ 676,729	-$ 87,364	-$ 120,293	$ -	-$ 207,657
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -
47	1808	Buildings	$ 494,571	$ -	$ -	$ 494,571	-$ 41,812	-$ 39,423		-$ 81,234
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$13,935,158	-$ 346,867	-$ 320,192		-$ 667,059
47	1820	Distribution Station Equipment <50 kV	$ 254,798	$ -	$ -	$ 254,798	-$ 27,835	-$ 27,835		-$ 55,669
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 10,264,040	$ 581,837	$ -	$10,845,877	-$ 248,505	-$ 254,718	$ -	-$ 503,223
47	1835	Overhead Conductors & Devices	$ 6,437,700	$ 347,558	$ -	$ 6,785,258	-$ 131,892	-$ 137,222	$ -	-$ 269,114
47	1840	Underground Conduit	$ 3,886,852	$ 387,924	$ -	$ 4,274,776	-$ 93,364	-$ 98,861	$ -	-$ 192,225
47	1845	Underground Conductors & Devices	$ 6,112,549	$ 490,818	$ -	$ 6,603,368	-$ 211,507	-$ 216,004	$ -	-$ 427,511
47	1850	Line Transformers	$ 5,681,103	$ 407,840	$ -	$ 6,088,943	-$ 187,657	-$ 191,869	$ -	-$ 379,526
47	1855	Services (Overhead & Underground)	$ 2,072,988	$ 193,102	$ -	$ 2,266,090	-$ 67,300	-$ 71,111	$ -	-$ 138,411
47	1860	Meters	$ 962,973	$ 26,555	-$ 4,001	$ 985,526	-$ 115,804	-$ 68,593	$ -	-$ 184,398
47	1860	Meters (Smart Meters)	$ 2,738,785	$ 47,979	-$ 2,730	$ 2,784,035	-$ 408,193	-$ 414,319	$ -	-$ 822,512
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 465,827	$ 141,389	$ -	$ 607,216	-$ 35,925	-$ 34,330	$ -	-$ 70,255
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 85,910	$ 91,504	$ -	$ 177,414	-$ 8,324	-$ 15,271	$ -	-$ 23,595
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 354,933	$ 58,144	$ -	$ 413,077	-$ 80,752	-$ 93,390	$ -	-$ 174,142
10	1930	Transportation Equipment	$ 944,582	$ 40,680	-$ 27,740	$ 957,521	-$ 115,889	-$ 118,545	$ 27,740	-$ 206,694
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 159,916	$ 15,434	$ -	$ 175,350	-$ 29,669	-$ 27,868	$ -	-$ 57,537
8	1945	Measurement & Testing Equipment	$ 9,659	$ -	$ -	$ 9,659	-$ 3,220	-$ 3,220		-$ 6,439
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 367	$ 3,501	$ -	$ 3,868	-$ 295	-$ 212	$ 26,682	$ 26,176
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 6,315	$ -	$ -	$ 6,315	-$ 943	-$ 1,102		-$ 2,045
47	1970	Load Management Controls Customer Premises	$ 43,749	$ -	$ -	$ 43,749	-$ 24,698	-$ 14,808	$ -	-$ 39,506
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 177,377	$ 98,649	$ -	$ 276,026	-$ 12,238	-$ 17,613	$ -	-$ 29,851
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 99,367	$ 99,367	$ -	$ 198,733
47	2440	Deferred Revenue[5]	$ -	-$ 333,945	$ -	-$ 333,945	$ -	$ 5,892	$ -	$ 5,892
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 55,573,235**	**$ 2,975,496**	**-$ 1,497,793**	**$ 57,050,939**	**-$ 2,242,612**	**-$ 2,236,014**	**$ 69,169**	**-$ 4,409,458**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -
		Total PP&E for Rate Base Purposes	**$ 55,573,235**	**$ 2,975,496**	**-$ 1,497,793**	**$ 57,050,939**	**-$ 2,242,612**	**-$ 2,236,014**	**$ 69,169**	**-$ 4,409,458**
		Construction Work In Progress				$ -				$ -
		Total PP&E	**$ 55,573,235**	**$ 2,975,496**	**-$ 1,497,793**	**$ 57,050,939**	**-$ 2,242,612**	**-$ 2,236,014**	**$ 69,169**	**-$ 4,409,458**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable								
		Total						**-$ 2,236,014**		

Less: Fully Allocated Depreciation	
Transportation	-$ 118,545
Stores Equipment	$ -
Tools, Shop & Garage Equipmen	-$ 27,868
Communications Equipment	-$ 212
Deferred Revenue	$ 5,892
Net Depreciation	**-$ 2,095,280**

Table 2-15 Fixed Asset Continuity Schedule as at December 31, 2016 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 101,654	-$ 54,473	$ -	-$ 156,127	$ 810,808
12	1611	Computer Software (Formally known as Account 1925)	$ 676,729	$ 232,429	-$ 70,110	$ 839,047	-$ 207,657	-$ 153,732	$ 70,110	-$ 291,280	$ 547,768
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 494,571	$ -	-$ 49,355	$ 445,216	-$ 81,234	-$ 14,747	$ 49,356	-$ 46,625	$ 398,592
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$13,935,158	-$ 667,059	-$ 320,188	$ 26,692	-$ 960,555	$ 12,974,603
47	1820	Distribution Station Equipment <50 kV	$ 254,798	$ -	-$ 28,924	$ 225,874	-$ 55,669	-$ 13,373	$ 28,923	-$ 40,120	$ 185,754
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 10,845,877	$ 411,940	$ -	$11,257,817	-$ 503,223	-$ 264,194	$ -	-$ 767,417	$ 10,490,400
47	1835	Overhead Conductors & Devices	$ 6,785,258	$ 280,767	$ -	$ 7,066,025	-$ 269,114	-$ 142,891	$ -	-$ 412,005	$ 6,654,020
47	1840	Underground Conduit	$ 4,274,776	$ 126,385	$ -	$ 4,401,161	-$ 192,225	-$ 103,793	$ -	-$ 296,018	$ 4,105,143
47	1845	Underground Conductors & Devices	$ 6,603,368	$ 460,749	$ -	$ 7,064,116	-$ 427,511	-$ 229,188	$ -	-$ 656,699	$ 6,407,417
47	1850	Line Transformers	$ 6,088,943	$ 309,192	$ -	$ 6,398,135	-$ 379,526	-$ 200,832		-$ 580,358	$ 5,817,777
47	1855	Services (Overhead & Underground)	$ 2,266,090	$ 315,975	$ -	$ 2,582,065	-$ 138,411	-$ 77,171		-$ 215,581	$ 2,366,484
47	1860	Meters	$ 985,526	$ 25,019	$ -	$ 1,010,545	-$ 184,398	-$ 69,754	$ -	-$ 254,151	$ 756,393
47	1860	Meters (Smart Meters)	$ 2,784,035	$ 79,634	-$ 6,769	$ 2,856,900	-$ 822,512	-$ 420,224	$ 3,555	-$ 1,239,181	$ 1,617,719
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 607,216	$ 146,538	-$ 10,247	$ 743,507	-$ 70,255	-$ 41,099	$ 10,247	-$ 101,107	$ 642,400
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 177,414	$ 6,485	-$ 554	$ 183,345	-$ 23,595	-$ 20,003	$ 554	-$ 43,044	$ 140,301
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 413,077	$ 116,807	-$ 51,227	$ 478,657	-$ 174,142	-$ 99,961	$ 51,227	-$ 222,876	$ 255,782
10	1930	Transportation Equipment	$ 957,521	$ 30,426	$ -	$ 987,947	-$ 206,694	-$ 121,851	$ 1,538	-$ 327,007	$ 660,940
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 175,350	$ 22,344	-$ 41,156	$ 156,538	-$ 57,537	-$ 27,377	$ 41,156	-$ 43,758	$ 112,780
8	1945	Measurement & Testing Equipment	$ 9,659	$ -	-$ 9,659	$ -	-$ 6,439	-$ 3,220	$ 9,659	-$ 0	$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,868		-$ 367	$ 3,501	$ 26,176	-$ 386	-$ 26,325	-$ 535	$ 2,965
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 6,315	$ -	$ -	$ 6,315	-$ 2,045	-$ 1,102	$ -	-$ 3,147	$ 3,168
47	1970	Load Management Controls Customer Premises	$ 43,749	$ -	-$ 43,749	$ -	-$ 39,506	-$ 4,243	$ 43,749	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 276,026	$ 38,213	$ -	$ 314,239	-$ 29,851	-$ 22,175	$ -	-$ 52,026	$ 262,213
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 198,733	$ 99,367	$ -	$ 298,100	-$ 3,201,478
47	2440	Deferred Revenue[5]	-$ 333,945	-$ 206,585	$ -	-$ 540,530	$ 5,892	$ 10,791	$ -	$ 16,683	-$ 523,847
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 57,050,939**	**$ 2,396,317**	**-$ 312,118**	**$ 59,135,138**	**-$ 4,409,458**	**-$ 2,295,820**	**$ 310,443**	**-$ 6,394,835**	**$ 52,740,304**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -			$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 57,050,939**	**$ 2,396,317**	**-$ 312,118**	**$ 59,135,138**	**-$ 4,409,458**	**-$ 2,295,820**	**$ 310,443**	**-$ 6,394,835**	**$ 52,740,304**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 57,050,939**	**$ 2,396,317**	**-$ 312,118**	**$ 59,135,138**	**-$ 4,409,458**	**-$ 2,295,820**	**$ 310,443**	**-$ 6,394,835**	**$ 52,740,304**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,295,820**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 121,851
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 27,377
Communications Equipment	-$ 386
Deferred Revenue	$ 10,791
Net Depreciation	**-$ 2,156,997**

Table 2-16 Fixed Asset Continuity Schedule as at December 31, 2017 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 156,127	-$ 54,473	$ -	-$ 210,600	$ 756,335
12	1611	Computer Software (Formally known as Account 1925)	$ 839,047	$ 282,383	-$ 34,097	$ 1,087,333	-$ 291,280	-$ 195,941	$ 34,097	-$ 453,124	$ 634,209
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 445,216	$ -	-$ 5,037	$ 440,179	-$ 46,625	-$ 14,745	$ 5,037	-$ 56,333	$ 383,846
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$13,935,158	-$ 960,555	-$ 320,188	$ -	-$ 1,280,744	$ 12,654,414
47	1820	Distribution Station Equipment <50 kV	$ 225,874	$ 34,695	$ -	$ 260,569	-$ 40,120	-$ 13,807	$ -	-$ 53,927	$ 206,642
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 11,257,817	$ 461,590	$ -	$11,719,407	-$ 767,417	-$ 272,465	$ -	-$ 1,039,882	$ 10,679,525
47	1835	Overhead Conductors & Devices	$ 7,066,025	$ 365,637	$ -	$ 7,431,662	-$ 412,005	-$ 148,682	$ -	-$ 560,687	$ 6,870,976
47	1840	Underground Conduit	$ 4,401,161	$ 108,219	$ -	$ 4,509,380	-$ 296,018	-$ 106,032	$ -	-$ 402,050	$ 4,107,330
47	1845	Underground Conductors & Devices	$ 7,064,116	$ 431,330	$ -	$ 7,495,446	-$ 656,699	-$ 241,550	$ -	-$ 898,249	$ 6,597,197
47	1850	Line Transformers	$ 6,398,135	$ 519,430	$ -	$ 6,917,565	-$ 580,358	-$ 211,189	$ -	-$ 791,547	$ 6,126,018
47	1855	Services (Overhead & Underground)	$ 2,582,065	$ 336,699	$ -	$ 2,918,765	-$ 215,581	-$ 84,656	$ -	-$ 300,238	$ 2,618,527
47	1860	Meters	$ 1,010,545	$ 79,835	$ -	$ 1,090,380	-$ 254,151	-$ 72,758	$ -	-$ 326,909	$ 763,471
47	1860	Meters (Smart Meters)	$ 2,856,900	$ 27,989	$ -	$ 2,884,888	-$ 1,239,181	-$ 425,267	$ -	-$ 1,664,448	$ 1,220,441
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 743,507	$ 126,216	-$ 11,442	$ 858,281	-$ 101,107	-$ 47,532	$ 11,442	-$ 137,198	$ 721,083
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 183,345	$ 9,962	$ -	$ 193,307	-$ 43,044	-$ 20,825	$ -	-$ 63,869	$ 129,437
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 478,657	$ 93,309	-$ 28,799	$ 543,167	-$ 222,876	-$ 107,632	$ 28,799	-$ 301,708	$ 241,459
10	1930	Transportation Equipment	$ 987,947	$ 7,390	$ -	$ 995,337	-$ 327,007	-$ 121,024	$ -	-$ 448,031	$ 547,306
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 156,538	$ 29,482	-$ 22,197	$ 163,823	-$ 43,758	-$ 26,552	$ 22,197	-$ 48,114	$ 115,709
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 535	-$ 350	$ -	-$ 886	$ 2,615
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 6,315	$ -	-$ 3,137	$ 3,178	-$ 3,147	-$ 1,102	$ 3,137	-$ 1,112	$ 2,066
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 314,239	$ 41,588	$ -	$ 355,827	-$ 52,026	-$ 24,829	$ -	-$ 76,855	$ 278,971
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 298,100	$ 99,367	$ -	$ 397,467	-$ 3,102,111
47	2440	Deferred Revenue[5]	-$ 540,530	-$ 371,810	$ -	-$ 912,339	$ 16,683	$ 12,239	$ -	$ 28,921	-$ 883,418
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 59,135,138**	**$ 2,583,945**	**-$ 104,709**	**$ 61,614,375**	**-$ 6,394,835**	**-$ 2,399,997**	**$ 104,709**	**-$ 8,690,123**	**$ 52,924,252**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 59,135,138**	**$ 2,583,945**	**-$ 104,709**	**$ 61,614,375**	**-$ 6,394,835**	**-$ 2,399,997**	**$ 104,709**	**-$ 8,690,123**	**$ 52,924,252**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 59,135,138**	**$ 2,583,945**	**-$ 104,709**	**$ 61,614,375**	**-$ 6,394,835**	**-$ 2,399,997**	**$ 104,709**	**-$ 8,690,123**	**$ 52,924,252**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,399,997**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 121,024
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 26,552
Communications Equipment	-$ 350
Deferred Revenue	$ 12,239
Net Depreciation	**-$ 2,264,309**

Table 2-17 Fixed Asset Continuity Schedule as at December 31, 2018 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 210,600	-$ 54,473	$ -	-$ 265,073	$ 701,862
12	1611	Computer Software (Formally known as Account 1925)	$ 1,087,333	$ 178,912	-$ 82,898	$ 1,183,347	-$ 453,124	-$ 227,989	$ 82,899	-$ 598,214	$ 585,133
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 440,179	$ -	-$ 1,577	$ 438,602	-$ 56,333	-$ 13,486	$ 1,577	-$ 68,242	$ 370,360
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ 5,300	$ -	$13,940,458	-$ 1,280,744	-$ 320,188	$ -	-$ 1,600,932	$ 12,339,526
47	1820	Distribution Station Equipment <50 kV	$ 260,569	$ 21,739	$ -	$ 282,308	-$ 53,927	-$ 14,512	$ -	-$ 68,439	$ 213,869
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 11,719,407	$ 530,251		$12,249,659	-$ 1,039,882	-$ 281,109	$ -	-$ 1,320,991	$ 10,928,667
47	1835	Overhead Conductors & Devices	$ 7,431,662	$ 404,796		$ 7,836,458	-$ 560,687	-$ 155,467	$ -	-$ 716,154	$ 7,120,305
47	1840	Underground Conduit	$ 4,509,380	$ 415,526		$ 4,924,906	-$ 402,050	-$ 114,756	$ -	-$ 516,806	$ 4,408,100
47	1845	Underground Conductors & Devices	$ 7,495,446	$ 736,821	-$ 529	$ 8,231,738	-$ 898,249	-$ 257,407	$ 529	-$ 1,155,127	$ 7,076,611
47	1850	Line Transformers	$ 6,917,565	$ 305,727		$ 7,223,292	-$ 791,547	-$ 221,498	$ -	-$ 1,013,044	$ 6,210,248
47	1855	Services (Overhead & Underground)	$ 2,918,765	$ 271,629		$ 3,190,393	-$ 300,238	-$ 91,652	$ -	-$ 391,889	$ 2,798,504
47	1860	Meters	$ 1,090,380	$ 132,780	-$ 547	$ 1,222,613	-$ 326,909	-$ 79,433	$ 547	-$ 405,795	$ 816,818
47	1860	Meters (Smart Meters)	$ 2,884,888	$ 114,130	-$ 5,024	$ 2,993,994	-$ 1,664,448	-$ 432,373	$ 5,024	-$ 2,091,797	$ 902,197
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 858,281	$ 183,588	-$ 11,465	$ 1,030,403	-$ 137,198	-$ 57,297	$ 11,465	-$ 183,029	$ 847,375
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 193,307	$ 9,764	-$ 13,630	$ 189,440	-$ 63,869	-$ 21,812	$ 13,630	-$ 72,051	$ 117,389
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 543,167	$ 94,549	-$ 189,680	$ 448,036	-$ 301,708	-$ 101,228	$ 189,680	-$ 213,256	$ 234,781
10	1930	Transportation Equipment	$ 995,337	$ 334,227	-$ 63,268	$ 1,266,296	-$ 448,031	-$ 135,635	$ 63,268	-$ 520,397	$ 745,899
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 163,823	$ 35,757	-$ 22,404	$ 177,176	-$ 48,114	-$ 24,265	$ 22,403	-$ 49,976	$ 127,199
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 886	-$ 350	$ -	-$ 1,236	$ 2,265
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 1,112	-$ 318	$ -	-$ 1,430	$ 1,748
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 355,827	$ 42,534	-$ 1,025	$ 397,335	-$ 76,855	-$ 27,645	$ 1,027	-$ 103,474	$ 293,862
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 397,467	$ 99,945	$ -	$ 497,411	-$ 3,002,167
47	2440	Deferred Revenue[5]	-$ 912,339	-$ 585,308	$ -	-$ 1,497,647	$ 28,921	$ 47,985	$ -	$ 76,906	-$ 1,420,741
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 61,614,375**	**$ 3,232,721**	**-$ 392,049**	**$ 64,455,048**	**-$ 8,690,123**	**-$ 2,484,963**	**$ 392,050**	**-$ 10,783,036**	**$ 53,672,012**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 61,614,375**	**$ 3,232,721**	**-$ 392,049**	**$ 64,455,048**	**-$ 8,690,123**	**-$ 2,484,963**	**$ 392,050**	**-$ 10,783,036**	**$ 53,672,012**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 61,614,375**	**$ 3,232,721**	**-$ 392,049**	**$ 64,455,048**	**-$ 8,690,123**	**-$ 2,484,963**	**$ 392,050**	**-$ 10,783,036**	**$ 53,672,012**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,484,963**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 135,635
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 24,265
Communications Equipment	-$ 350
Deferred Revenue	$ 47,985
Net Depreciation	**-$ 2,372,698**

Table 2-18 Fixed Asset Continuity Schedule as at December 31, 2019 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 265,073	-$ 54,473	$ -	-$ 319,546	$ 647,389
12	1611	Computer Software (Formally known as Account 1925)	$ 1,183,347	$ 226,526	-$ 183,294	$ 1,226,579	-$ 598,214	-$ 240,992	$ 183,294	-$ 655,913	$ 570,667
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ 3,150	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	-$ 68,242	-$ 13,171	$ -	-$ 81,413	$ 357,189
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 13,940,458	$ 35,855	$ -	$13,976,313	-$ 1,600,932	-$ 321,261	$ -	-$ 1,922,193	$ 12,054,120
47	1820	Distribution Station Equipment <50 kV	$ 282,308	$ 17,481	$ -	$ 299,789	-$ 68,439	-$ 15,003	$ -	-$ 83,442	$ 216,347
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 12,249,659	$ 500,051	$ -	$12,749,710	-$ 1,320,991	-$ 290,850	$ -	-$ 1,611,841	$ 11,137,869
47	1835	Overhead Conductors & Devices	$ 7,836,458	$ 431,387	$ -	$ 8,267,845	-$ 716,154	-$ 162,945	$ -	-$ 879,099	$ 7,388,747
47	1840	Underground Conduit	$ 4,924,906	$ 140,926	$ -	$ 5,065,832	-$ 516,806	-$ 120,322	$ -	-$ 637,128	$ 4,428,704
47	1845	Underground Conductors & Devices	$ 8,231,738	$ 724,236	-$ 1,191	$ 8,954,782	-$ 1,155,127	-$ 278,531	$ 1,898	-$ 1,431,759	$ 7,523,023
47	1850	Line Transformers	$ 7,223,292	$ 415,768	$ -	$ 7,639,061	-$ 1,013,044	-$ 230,516	$ -	-$ 1,243,561	$ 6,395,500
47	1855	Services (Overhead & Underground)	$ 3,190,393	$ 209,405	-$ 27,973	$ 3,371,826	-$ 391,889	-$ 97,374	$ 27,973	-$ 461,291	$ 2,910,535
47	1860	Meters	$ 1,222,613	$ 117,399	-$ 2,977	$ 1,337,035	-$ 405,795	-$ 86,579	$ 2,977	-$ 489,397	$ 847,638
47	1860	Meters (Smart Meters)	$ 2,993,994	$ 375,266	-$ 14,439	$ 3,354,820	-$ 2,091,797	-$ 452,950	$ 14,439	-$ 2,530,307	$ 824,513
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 1,030,403	$ 223,823	$ -	$ 1,254,226	-$ 183,029	-$ 71,088		-$ 254,116	$ 1,000,110
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 189,440	$ 1,274	$ -	$ 190,714	-$ 72,051	-$ 19,637	$ -	-$ 91,689	$ 99,026
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 448,036	$ 75,790	-$ 85,226	$ 438,600	-$ 213,256	-$ 88,664	$ 85,226	-$ 216,693	$ 221,907
10	1930	Transportation Equipment	$ 1,266,296	$ 56,425	-$ 106,342	$ 1,216,379	-$ 520,397	-$ 139,728	$ 106,341	-$ 553,784	$ 662,595
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 177,176	$ 29,367	$ -	$ 206,543	-$ 49,976	-$ 23,040	$ -	-$ 73,017	$ 133,526
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 1,236	-$ 350	$ -	-$ 1,586	$ 1,915
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 1,430	-$ 318	$ -	-$ 1,748	$ 1,431
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 397,335	$ 27,123	-$ 234	$ 424,224	-$ 103,474	-$ 29,756	$ 234	-$ 132,996	$ 291,228
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 497,411	$ 99,945	$ -	$ 597,356	-$ 2,902,222
47	2440	Deferred Revenue[5]	-$ 1,497,647	-$ 443,731		-$ 1,941,379	$ 76,906	$ 45,912	$ -	$ 122,818	-$ 1,818,561
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 64,455,048**	**$ 3,167,521**	**-$ 421,675**	**$ 67,200,894**	**-$ 10,783,036**	**-$ 2,591,692**	**$ 422,383**	**-$ 12,952,345**	**$ 54,248,548**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 64,455,048**	**$ 3,167,521**	**-$ 421,675**	**$ 67,200,894**	**-$ 10,783,036**	**-$ 2,591,692**	**$ 422,383**	**-$ 12,952,345**	**$ 54,248,548**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 64,455,048**	**$ 3,167,521**	**-$ 421,675**	**$ 67,200,894**	**-$ 10,783,036**	**-$ 2,591,692**	**$ 422,383**	**-$ 12,952,345**	**$ 54,248,548**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,591,692**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 139,728
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 23,040
Communications Equipment	-$ 350
Deferred Revenue	$ 45,912
Net Depreciation	**-$ 2,474,485**

Table 2-19 Fixed Asset Continuity Schedule as at December 31, 2020 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 319,546	-$ 54,473	$ -	-$ 374,019	$ 592,916
12	1611	Computer Software (Formally known as Account 1925)	$ 1,226,579	$ 216,420	-$ 306,328	$ 1,136,672	-$ 655,913	-$ 236,325	$ 306,328	-$ 585,910	$ 550,762
CEC	1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	-$ 81,413	-$ 13,171		-$ 94,584	$ 344,019
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 13,976,313	$ 72,697	$ -	$14,049,010	-$ 1,922,193	-$ 324,551	$ -	-$ 2,246,744	$ 11,802,266
47	1820	Distribution Station Equipment <50 kV	$ 299,789	$ 227,076	-$ 10,170	$ 516,695	-$ 83,442	-$ 18,060	$ 10,170	-$ 91,331	$ 425,364
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 12,749,710	$ 283,463	-$ 39,887	$12,993,286	-$ 1,611,841	-$ 299,041	$ -	-$ 1,910,882	$ 11,082,403
47	1835	Overhead Conductors & Devices	$ 8,267,845	$ 261,099	$ -	$ 8,528,945	-$ 879,099	-$ 169,193	$ -	-$ 1,048,292	$ 7,480,653
47	1840	Underground Conduit	$ 5,065,832	$ 532,871	$ -	$ 5,598,703	-$ 637,128	-$ 127,059	$ -	-$ 764,188	$ 4,834,515
47	1845	Underground Conductors & Devices	$ 8,954,782	$ 555,305	-$ 2,087	$ 9,508,000	-$ 1,431,759	-$ 296,124	$ 2,087	-$ 1,725,796	$ 7,782,204
47	1850	Line Transformers	$ 7,639,061	$ 305,450	$ -	$ 7,944,510	-$ 1,243,561	-$ 239,531	$ -	-$ 1,483,092	$ 6,461,418
47	1855	Services (Overhead & Underground)	$ 3,371,826	$ 229,210	$ -	$ 3,601,036	-$ 461,291	-$ 97,834	$ -	-$ 559,126	$ 3,041,910
47	1860	Meters	$ 1,337,035	$ 132,394	-$ 1,902	$ 1,467,527	-$ 489,397	-$ 92,750	$ 1,902	-$ 580,246	$ 887,281
47	1860	Meters (Smart Meters)	$ 3,354,820	$ 131,206	-$2,406,014	$ 1,080,013	-$ 2,530,307	-$ 293,196	$2,406,014	-$ 417,489	$ 662,524
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 1,254,226	$ 156,731	$ -	$ 1,410,958	-$ 254,116	-$ 83,263	$ -	-$ 337,379	$ 1,073,578
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 190,714	$ -	-$ 4,802	$ 185,913	-$ 91,689	-$ 19,332	$ 4,802	-$ 106,219	$ 79,694
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 438,600	$ 60,194	-$ 58,144	$ 440,649	-$ 216,693	-$ 87,925	$ 58,144	-$ 246,473	$ 194,176
10	1930	Transportation Equipment	$ 1,216,379	$ -	-$ 137,828	$ 1,078,552	-$ 553,784	-$ 122,917	$ 137,828	-$ 538,873	$ 539,679
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 206,543	$ 26,793	-$ 9,837	$ 223,499	-$ 73,017	-$ 25,092	$ 9,837	-$ 88,272	$ 135,227
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 1,586	-$ 350	$ -	-$ 1,936	$ 1,565
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 1,748	-$ 318	$ -	-$ 2,066	$ 1,113
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 424,224	$ 33,569	-$ 549	$ 457,245	-$ 132,996	-$ 31,740	$ 549	-$ 164,187	$ 293,057
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 597,356	$ 99,945	$ -	$ 697,301	-$ 2,802,277
47	2440	Deferred Revenue[5]	-$ 1,941,379	-$ 465,828	$ -	-$ 2,407,207	$ 122,818	$ 57,127	$ -	$ 179,945	-$ 2,227,262
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 67,200,894**	**$ 2,758,650**	**-$ 2,977,547**	**$ 66,981,996**	**-$ 12,952,345**	**-$ 2,475,174**	**$ 2,937,660**	**-$ 12,489,859**	**$ 54,492,137**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 67,200,894**	**$ 2,758,650**	**-$ 2,977,547**	**$ 66,981,996**	**-$ 12,952,345**	**-$ 2,475,174**	**$ 2,937,660**	**-$ 12,489,859**	**$ 54,492,137**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 67,200,894**	**$ 2,758,650**	**-$ 2,977,547**	**$ 66,981,996**	**-$ 12,952,345**	**-$ 2,475,174**	**$ 2,937,660**	**-$ 12,489,859**	**$ 54,492,137**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,475,174**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 122,917
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 25,092
Communications Equipment	-$ 350
Deferred Revenue	$ 57,127
Net Depreciation	**-$ 2,383,942**

Table 2-20 Fixed Asset Continuity Schedule as at December 31, 2021 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 374,019	-$ 54,473	$ -	-$ 428,492	$ 538,443
12	1611	Computer Software (Formally known as Account 1925)	$ 1,136,672	$ 66,063	-$ 232,429	$ 970,306	-$ 585,910	-$ 210,698	$ 232,429	-$ 564,178	$ 406,128
CEC	1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	-$ 94,584	-$ 13,171	$ -	-$ 107,755	$ 330,848
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 14,049,010	$ 143,417	$ -	$14,192,427	-$ 2,246,744	-$ 334,173	$ -	-$ 2,580,917	$ 11,611,510
47	1820	Distribution Station Equipment <50 kV	$ 516,695	$ 1,887	-$ 9,671	$ 508,911	-$ 91,331	-$ 19,469	$ 9,671	-$ 101,129	$ 407,782
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 12,993,286	$ 663,008	$ -	$13,656,294	-$ 1,910,882	-$ 307,556	$ -	-$ 2,218,439	$ 11,437,855
47	1835	Overhead Conductors & Devices	$ 8,528,945	$ 318,477	$ -	$ 8,847,421	-$ 1,048,292	-$ 174,321	$ -	-$ 1,222,612	$ 7,624,809
47	1840	Underground Conduit	$ 5,598,703	$ 283,236	$ -	$ 5,881,939	-$ 764,188	-$ 127,059	$ -	-$ 891,247	$ 4,990,692
47	1845	Underground Conductors & Devices	$ 9,508,000	$ 851,058	-$ 2,590	$10,356,468	-$ 1,725,796	-$ 315,583	$ 2,590	-$ 2,038,789	$ 8,317,679
47	1850	Line Transformers	$ 7,944,510	$ 407,561	$ -	$ 8,352,072	-$ 1,483,092	-$ 248,444	$ -	-$ 1,731,536	$ 6,620,536
47	1855	Services (Overhead & Underground)	$ 3,601,036	$ 350,012	$ -	$ 3,951,047	-$ 559,126	-$ 104,707	$ -	-$ 663,832	$ 3,287,215
47	1860	Meters	$ 1,467,527	$ 46,318	-$ 15,012	$ 1,498,833	-$ 580,246	-$ 97,070	$ 15,012	-$ 662,304	$ 836,529
47	1860	Meters (Smart Meters)	$ 1,080,013	$ 53,232	-$ 203,333	$ 929,912	-$ 417,489	-$ 106,440	$ 203,333	-$ 320,596	$ 609,316
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 1,410,958	$ 477,555	-$ 6,795	$ 1,881,717	-$ 337,379	-$ 96,716	$ 6,795	-$ 427,301	$ 1,454,417
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 185,913	$ 8,348	-$ 12,585	$ 181,676	-$ 106,219	-$ 18,751	$ 12,585	-$ 112,385	$ 69,292
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 440,649	$ 275,021	-$ 116,806	$ 598,864	-$ 246,473	-$ 103,951	$ 116,806	-$ 233,618	$ 365,245
10	1930	Transportation Equipment	$ 1,078,552	$ 16,511	$ -	$ 1,095,062	-$ 538,873	-$ 103,650	$ -	-$ 642,523	$ 452,539
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 223,499	$ 26,796	-$ 26,344	$ 223,951	-$ 88,272	-$ 25,697	$ 26,344	-$ 87,625	$ 136,326
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 1,936	-$ 700	$ -	-$ 2,636	$ 865
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 2,066	-$ 318	$ -	-$ 2,383	$ 795
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 457,245	$ 11,881	-$ 20,459	$ 448,667	-$ 164,187	-$ 33,177	$ 20,459	-$ 176,906	$ 271,761
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	-$ 141,936	$ -	-$ 3,641,514	$ 697,301	$ 99,945	$ -	$ 797,245	-$ 2,844,269
47	2440	Deferred Revenue[5]	-$ 2,407,207	-$ 481,457	$ -	-$ 2,888,664	$ 179,945	$ 60,633	$ -	$ 240,578	-$ 2,648,086
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 66,981,996**	**$ 3,376,986**	**-$ 646,024**	**$ 69,712,958**	**-$ 12,489,859**	**-$ 2,335,547**	**$ 646,024**	**-$ 14,179,382**	**$ 55,533,576**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 66,981,996**	**$ 3,376,986**	**-$ 646,024**	**$ 69,712,958**	**-$ 12,489,859**	**-$ 2,335,547**	**$ 646,024**	**-$ 14,179,382**	**$ 55,533,576**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 66,981,996**	**$ 3,376,986**	**-$ 646,024**	**$ 69,712,958**	**-$ 12,489,859**	**-$ 2,335,547**	**$ 646,024**	**-$ 14,179,382**	**$ 55,533,576**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,335,547**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 103,650
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 25,697
Communications Equipment	-$ 700
Deferred Revenue	$ 60,633
Net Depreciation	**-$ 2,266,132**

Table 2-21 Fixed Asset Continuity Schedule as at December 31, 2022 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 428,492	-$ 54,473	$ -	-$ 482,965	$ 483,970
12	1611	Computer Software (Formally known as Account 1925)	$ 970,306	$ 299,790	-$ 282,383	$ 987,713	-$ 564,178	-$ 173,656	$ 282,384	-$ 455,451	$ 532,262
CEC	1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	-$ 107,755	-$ 13,171	$ -	-$ 120,925	$ 317,677
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 14,192,427	$ 86,263	$ -	$14,278,690	-$ 2,580,917	-$ 345,657	$ -	-$ 2,926,575	$ 11,352,116
47	1820	Distribution Station Equipment <50 kV	$ 508,911	$ -	-$ 1,769	$ 507,142	-$ 101,129	-$ 19,370	$ 1,769	-$ 118,730	$ 388,412
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 13,656,294	$ 763,001	$ -	$14,419,295	-$ 2,218,439	-$ 318,606	$ -	-$ 2,537,045	$ 11,882,250
47	1835	Overhead Conductors & Devices	$ 8,847,421	$ 392,360	$ -	$ 9,239,782	-$ 1,222,612	-$ 181,457	$ -	-$ 1,404,069	$ 7,835,713
47	1840	Underground Conduit	$ 5,881,939	$ 66,651	$ -	$ 5,948,590	-$ 891,247	-$ 135,220	$ -	-$ 1,026,468	$ 4,922,123
47	1845	Underground Conductors & Devices	$ 10,356,468	$ 804,724	-$ 12,294	$11,148,898	-$ 2,038,789	-$ 346,462	$ 12,294	-$ 2,372,957	$ 8,775,940
47	1850	Line Transformers	$ 8,352,072	$ 374,144	$ -	$ 8,726,215	-$ 1,731,536	-$ 258,215	$ -	-$ 1,989,752	$ 6,736,464
47	1855	Services (Overhead & Underground)	$ 3,951,047	$ 317,708	$ -	$ 4,268,755	-$ 663,832	-$ 112,455	$ -	-$ 776,287	$ 3,492,468
47	1860	Meters	$ 1,498,833	$ 207,453	-$ 214,520	$ 1,491,766	-$ 662,304	-$ 102,652	$ 214,520	-$ 550,437	$ 941,330
47	1860	Meters (Smart Meters)	$ 929,912	$ 190,502	-$ 68,716	$ 1,051,698	-$ 320,596	-$ 104,200	$ 68,716	-$ 356,080	$ 695,618
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 1,881,717	$ 357,228	-$ 27,578	$ 2,211,367	-$ 427,301	-$ 120,660	$ 27,578	-$ 520,382	$ 1,690,985
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 181,676	$ 8,676	-$ 2,545	$ 187,807	-$ 112,385	-$ 18,845	$ 2,545	-$ 128,685	$ 59,122
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 598,864	$ 176,461	-$ 93,310	$ 682,015	-$ 233,618	-$ 128,088	$ 93,310	-$ 268,396	$ 413,618
10	1930	Transportation Equipment	$ 1,095,062	$ 68,635	-$ 257,102	$ 906,595	-$ 642,523	-$ 96,226	$ 257,102	-$ 481,647	$ 424,948
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 223,951	$ 28,200	-$ 22,851	$ 229,300	-$ 87,625	-$ 25,987	$ 22,851	-$ 90,761	$ 138,539
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 2,636	-$ 350	$ -	-$ 2,986	$ 515
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 2,383	-$ 318	$ -	-$ 2,701	$ 477
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 448,667	$ 33,563	-$ 30,123	$ 452,107	-$ 176,906	-$ 33,782	$ 30,123	-$ 180,565	$ 271,542
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,641,514	$ 141,936	$ -	-$ 3,499,578	$ 797,245	$ 99,945	$ -	$ 897,190	-$ 2,602,388
47	2440	Deferred Revenue[5]	-$ 2,888,664	-$ 343,410	$ -	-$ 3,232,074	$ 240,578	$ 76,869	$ -	$ 317,447	-$ 2,914,627
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 69,712,958**	**$ 3,973,884**	**-$ 1,013,191**	**$ 72,673,651**	**-$ 14,179,382**	**-$ 2,413,037**	**$ 1,013,191**	**-$ 15,579,228**	**$ 57,094,424**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 69,712,958**	**$ 3,973,884**	**-$ 1,013,191**	**$ 72,673,651**	**-$ 14,179,382**	**-$ 2,413,037**	**$ 1,013,191**	**-$ 15,579,228**	**$ 57,094,424**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 69,712,958**	**$ 3,973,884**	**-$ 1,013,191**	**$ 72,673,651**	**-$ 14,179,382**	**-$ 2,413,037**	**$ 1,013,191**	**-$ 15,579,228**	**$ 57,094,424**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,413,037**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 96,226
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 25,987
Communications Equipment	-$ 350
Deferred Revenue	$ 76,869
Net Depreciation	**-$ 2,367,343**

Table 2-22 Fixed Asset Continuity Schedule as at December 31, 2023 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 482,965	-$ 54,473	$ -	-$ 537,438	$ 429,497
12	1611	Computer Software (Formally known as Account 1925)	$ 987,713	$ 551,449	-$ 178,912	$ 1,360,249	-$ 455,451	-$ 157,468	$ 178,912	-$ 434,007	$ 926,243
CEC	1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	-$ 120,925	-$ 13,171	$ -	-$ 134,096	$ 304,507
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 14,278,690	$ 212,043	$ -	$14,490,733	-$ 2,926,575	-$ 358,236	$ -	-$ 3,284,811	$ 11,205,922
47	1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ 507,142	-$ 118,730	-$ 19,345	$ -	-$ 138,075	$ 369,067
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 14,419,295	$ 617,447	$ 3,114	$15,039,856	-$ 2,537,045	-$ 330,763	$ -	-$ 2,867,808	$ 12,172,047
47	1835	Overhead Conductors & Devices	$ 9,239,782	$ 409,824	$ -	$ 9,649,606	-$ 1,404,069	-$ 188,525	$ -	-$ 1,592,595	$ 8,057,011
47	1840	Underground Conduit	$ 5,948,590	$ 288,698	$ -	$ 6,237,288	-$ 1,026,468	-$ 138,719	$ -	-$ 1,165,187	$ 5,072,101
47	1845	Underground Conductors & Devices	$ 11,148,898	$ 427,299	-$ 47,073	$11,529,123	-$ 2,372,957	-$ 353,138	$ 47,073	-$ 2,679,022	$ 8,850,101
47	1850	Line Transformers	$ 8,726,215	$ 553,413	$ -	$ 9,279,629	-$ 1,989,752	-$ 269,810	$ -	-$ 2,259,561	$ 7,020,067
47	1855	Services (Overhead & Underground)	$ 4,268,755	$ 242,624	$ -	$ 4,511,379	-$ 776,287	-$ 118,793	$ -	-$ 895,080	$ 3,616,299
47	1860	Meters	$ 1,491,766	$ 433,583	-$ 197,415	$ 1,727,934	-$ 550,437	-$ 108,521	$ 197,415	-$ 461,542	$ 1,266,391
47	1860	Meters (Smart Meters)	$ 1,051,698			$ 1,051,698	-$ 356,080	-$ 108,509		-$ 464,590	$ 587,108
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 2,211,367	$ 1,060,506	-$ 7,732	$ 3,264,141	-$ 520,382	-$ 156,767	$ 7,732	-$ 669,418	$ 2,594,723
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 187,807	$ -	-$ 3,684	$ 184,123	-$ 128,685	-$ 18,968	$ 3,684	-$ 143,968	$ 40,154
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 682,015	$ 290,629	-$ 94,549	$ 878,095	-$ 268,396	-$ 156,011	$ 94,549	-$ 329,858	$ 548,237
10	1930	Transportation Equipment	$ 906,595	$ 92,935	-$ 108,265	$ 891,265	-$ 481,647	-$ 86,852	$ 108,265	-$ 460,234	$ 431,031
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 229,300	$ 36,453	-$ 20,797	$ 244,956	-$ 90,761	-$ 27,038	$ 20,797	-$ 97,002	$ 147,954
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 2,986	-$ 350	$ -	-$ 3,336	$ 165
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 2,701	-$ 318	$ -	-$ 3,019	$ 159
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 452,107	$ 120,308	-$ 28,656	$ 543,758	-$ 180,565	-$ 37,410	$ 28,656	-$ 189,319	$ 354,440
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 897,190	$ 99,945	$ -	$ 997,135	-$ 2,502,443
47	2440	Deferred Revenue[5]	-$ 3,232,074	-$ 446,781	$ -	-$ 3,678,854	$ 317,447	$ 76,869	$ -	$ 394,316	-$ 3,284,538
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 72,673,651**	**$ 4,890,430**	**-$ 683,970**	**$ 76,880,111**	**-$ 15,579,228**	**-$ 2,526,371**	**$ 687,084**	**-$ 17,418,515**	**$ 59,461,596**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 72,673,651**	**$ 4,890,430**	**-$ 683,970**	**$ 76,880,111**	**-$ 15,579,228**	**-$ 2,526,371**	**$ 687,084**	**-$ 17,418,515**	**$ 59,461,596**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 72,673,651**	**$ 4,890,430**	**-$ 683,970**	**$ 76,880,111**	**-$ 15,579,228**	**-$ 2,526,371**	**$ 687,084**	**-$ 17,418,515**	**$ 59,461,596**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,526,371**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 86,852
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 27,038
Communications Equipment	-$ 350
Deferred Revenue	$ 76,869
Net Depreciation	**-$ 2,489,000**

Table 2-23 Fixed Asset Continuity Schedule as at December 31, 2024 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 537,438	-$ 54,473	$ -	-$ 591,911	$ 375,024
12	1611	Computer Software (Formally known as Account 1925)	$ 1,360,249	$ 1,219,598	$ -	$ 2,579,847	-$ 434,007	-$ 152,761	$ -	-$ 586,768	$ 1,993,080
CEC	1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	-$ 134,096	-$ 13,171	$ -	-$ 147,267	$ 291,336
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 14,490,733	$ 150,000	$ -	$14,640,733	-$ 3,284,811	-$ 327,720	$ -	-$ 3,612,531	$ 11,028,202
47	1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ 507,142	-$ 138,075	-$ 19,392	$ -	-$ 157,467	$ 349,675
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 15,039,856	$ 85,000	$ -	$15,124,856	-$ 2,867,808	-$ 328,762	$ -	-$ 3,196,571	$ 11,928,285
47	1835	Overhead Conductors & Devices	$ 9,649,606	$ 1,592,273	$ -	$11,241,879	-$ 1,592,595	-$ 254,842	$ -	-$ 1,847,437	$ 9,394,442
47	1840	Underground Conduit	$ 6,237,288	$ 895,500	$ -	$ 7,132,788	-$ 1,165,187	-$ 154,608	$ -	-$ 1,319,795	$ 5,812,993
47	1845	Underground Conductors & Devices	$ 11,529,123	$ 30,000	$ -	$11,559,123	-$ 2,679,022	-$ 351,032	$ -	-$ 3,030,054	$ 8,529,069
47	1850	Line Transformers	$ 9,279,629	$ 415,000	$ -	$ 9,694,629	-$ 2,259,561	-$ 281,864	$ -	-$ 2,541,425	$ 7,153,203
47	1855	Services (Overhead & Underground)	$ 4,511,379	$ -	$ -	$ 4,511,379	-$ 895,080	-$ 116,033	$ -	-$ 1,011,113	$ 3,500,266
47	1860	Meters	$ 1,727,934	$ 400,000	$ -	$ 2,127,934	-$ 461,542	-$ 140,891	$ -	-$ 602,433	$ 1,525,501
47	1860	Meters (Smart Meters)	$ 1,051,698		$ -	$ 1,051,698	-$ 464,590	-$ 103,932	$ -	-$ 568,522	$ 483,176
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 3,264,141	$ 2,165,000	$ -	$ 5,429,141	-$ 669,418	-$ 216,845	$ -	-$ 886,263	$ 4,542,879
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 184,123	$ -	$ -	$ 184,123	-$ 143,968	-$ 16,192	$ -	-$ 160,161	$ 23,962
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 878,095	$ 193,069	$ -	$ 1,071,164	-$ 329,858	-$ 177,088	$ -	-$ 506,946	$ 564,218
10	1930	Transportation Equipment	$ 891,265	$ 450,000	$ -	$ 1,341,265	-$ 460,234	-$ 106,226	$ -	-$ 566,461	$ 774,804
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 244,956	$ 45,000	$ -	$ 289,956	-$ 97,002	-$ 28,796	$ -	-$ 125,798	$ 164,158
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 3,336	-$ 350	$ -	-$ 3,686	-$ 185
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 3,019	-$ 159	$ -	-$ 3,178	$ 0
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 543,758	$ 76,500	$ -	$ 620,258	-$ 189,319	-$ 39,932	$ -	-$ 229,250	$ 391,008
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 997,135	$ 99,945	$ -	$ 1,097,080	-$ 2,402,498
47	2440	Deferred Revenue[5]	-$ 3,678,854	-$ 219,113	$ -	-$ 3,897,968	$ 394,316	$ 76,864	$ -	$ 471,180	-$ 3,426,788
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 76,880,111**	**$ 7,497,827**	**$ -**	**$ 84,377,938**	**-$ 17,418,515**	**-$ 2,708,261**	**$ -**	**-$ 20,126,777**	**$ 64,251,162**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 76,880,111**	**$ 7,497,827**	**$ -**	**$ 84,377,938**	**-$ 17,418,515**	**-$ 2,708,261**	**$ -**	**-$ 20,126,777**	**$ 64,251,162**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 76,880,111**	**$ 7,497,827**	**$ -**	**$ 84,377,938**	**-$ 17,418,515**	**-$ 2,708,261**	**$ -**	**-$ 20,126,777**	**$ 64,251,162**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,708,261**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 106,226
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 28,796
Communications Equipment	-$ 350
Deferred Revenue	$ 76,864
Net Depreciation	**-$ 2,649,753**

Table 2-24 Fixed Asset Continuity Schedule as at December 31, 2025 – MIFRS

			Cost				Accumulated Depreciation				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	-$ 591,911	-$ 54,473	$ -	-$ 646,384	$ 320,551
12	1611	Computer Software (Formally known as Account 1925)	$ 2,579,847	$ 905,000	$ -	$ 3,484,847	-$ 586,768	-$ 245,042	$ -	-$ 831,810	$ 2,653,037
CEC	1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
N/A	1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202	$ -	$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	-$ 147,267	-$ 13,171	$ -	-$ 160,437	$ 278,165
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 14,640,733	$ 274,600	$ -	$14,915,333	-$ 3,612,531	-$ 333,569	$ -	-$ 3,946,100	$ 10,969,233
47	1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ 507,142	-$ 157,467	-$ 19,392	$ -	-$ 176,859	$ 330,283
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 15,124,856	$ 75,000	$ -	$15,199,856	-$ 3,196,571	-$ 330,325	$ -	-$ 3,526,896	$ 11,672,960
47	1835	Overhead Conductors & Devices	$ 11,241,879	$ 2,000,455	$ -	$13,242,334	-$ 1,847,437	-$ 307,830	$ -	-$ 2,155,267	$ 11,087,067
47	1840	Underground Conduit	$ 7,132,788	$ 1,294,850	$ -	$ 8,427,638	-$ 1,319,795	-$ 165,772	$ -	-$ 1,485,567	$ 6,942,071
47	1845	Underground Conductors & Devices	$ 11,559,123	$ 50,000	$ -	$11,609,123	-$ 3,030,054	-$ 350,732	$ -	-$ 3,380,787	$ 8,228,336
47	1850	Line Transformers	$ 9,694,629	$ 595,000	$ -	$10,289,629	-$ 2,541,425	-$ 293,676	$ -	-$ 2,835,102	$ 7,454,527
47	1855	Services (Overhead & Underground)	$ 4,511,379	$ -	$ -	$ 4,511,379	-$ 1,011,113	-$ 115,234	$ -	-$ 1,126,347	$ 3,385,032
47	1860	Meters	$ 2,127,934	$ 1,427,297	$ -	$ 3,555,231	-$ 602,433	-$ 224,226	$ -	-$ 826,659	$ 2,728,572
47	1860	Meters (Smart Meters)	$ 1,051,698		$ -	$ 1,051,698	-$ 568,522	-$ 98,781	$ -	-$ 667,304	$ 384,394
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 5,429,141	$ 505,000	$ -	$ 5,934,141	-$ 886,263	-$ 241,024	$ -	-$ 1,127,286	$ 4,806,855
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 184,123	$ -	$ -	$ 184,123	-$ 160,161	-$ 9,026	$ -	-$ 169,187	$ 14,936
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,071,164	$ 296,636	$ -	$ 1,367,800	-$ 506,946	-$ 220,106	$ -	-$ 727,052	$ 640,748
10	1930	Transportation Equipment	$ 1,341,265	$ 125,000	$ -	$ 1,466,265	-$ 566,461	-$ 101,501	$ -	-$ 667,962	$ 798,303
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 289,956	$ 46,200	$ -	$ 336,156	-$ 125,798	-$ 30,455	$ -	-$ 156,253	$ 179,903
8	1945	Measurement & Testing Equipment	$ -		$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	-$ 3,686	-$ 175	$ -	-$ 3,861	-$ 360
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	-$ 3,178	$ -	$ -	-$ 3,178	$ 0
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 620,258	$ 141,500	$ -	$ 761,758	-$ 229,250	-$ 46,736	$ -	-$ 275,986	$ 485,772
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	$ 1,097,080	$ 99,945	$ -	$ 1,197,024	-$ 2,302,554
47	2440	Deferred Revenue[5]	-$ 3,897,968	-$ 327,188	$ -	-$ 4,225,156	$ 471,180	$ 78,773	$ -	$ 549,953	-$ 3,675,203
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 84,377,938**	**$ 7,409,350**	**$ -**	**$ 91,787,288**	**-$ 20,126,777**	**-$ 3,022,529**	**$ -**	**-$ 23,149,306**	**$ 68,637,982**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 84,377,938**	**$ 7,409,350**	**$ -**	**$ 91,787,288**	**-$ 20,126,777**	**-$ 3,022,529**	**$ -**	**-$ 23,149,306**	**$ 68,637,982**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 84,377,938**	**$ 7,409,350**	**$ -**	**$ 91,787,288**	**-$ 20,126,777**	**-$ 3,022,529**	**$ -**	**-$ 23,149,306**	**$ 68,637,982**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,022,529**			

Less: *Fully Allocated Depreciation*	
Transportation	-$ 101,501
Stores Equipment	$ -
Tools, Shop & Garage Equipment	-$ 30,455
Communications Equipment	-$ 175
Deferred Revenue	$ 78,773
Net Depreciation	**-$ 2,969,170**

2.2.3 Gross Assets – Property Plant and Equipment and Accumulated Depreciation

2.2.3.1 Breakdown by Function

Table 2-25 below categorizes FHI's assets into four categories: Transmission Assets, Distribution Assets, General Plant and Contributions and Grants. In accordance with the Uniform System of Accounts ("USoA"), FHI has included Gross Assets as follows:

- Transmission Assets are included in OEB Accounts 1808, 1815 and 1820. They consist of the buildings and equipment of the transmission assets of FHI. FHI owns and operates one transformer station with six feeders. The remaining transmission assets that supply the service territory are owned by Hydro One. FHI's transmission assets are deemed as distribution assets.
- Distribution Plant Asset Accounts include USoA 1830 to 1860 and USoA 1612 - this account includes assets such as the poles, wires, transformers, and meters.
- General Plant Asset Accounts include USoA 1908 to 1980 and USoA 1611 - this account includes assets such as office furniture, computer software and hardware, transportation equipment, and tools.
- Contributions and Grants includes USoA account 2440 – this account includes all contributions in aid of capital that FHI has received or forecasted to be received as per the Distribution System Code ("DSC").

This table excludes Work in Progress (WIP) – USoA 2055. The WIP account includes all costs related to assets that are not considered in service as of December 31st of the applicable fiscal year. Costs are transferred out of WIP and into the appropriate category above once designated in-service in the field. These costs are also not included in rate base.

FHI has not applied for any ACM or ICM adjustments as part of a previous IRM application since the last COS.

Table 2-25 summarizes the categories by year. All closing balances agree to required filing Appendix 2-BA which is filed in live Excel format (FHI_2025_Filing_Requirements_Chapter2_Appendices_1.0_20240426) and shown in Attachment 2-1.

Table 2-25 – Gross Assets by Category

Gross Assets

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Transmission Assets	14,963,575	14,189,956	14,161,032	14,195,727	14,222,766	14,276,102
Distribution Assets	75,537,522	42,380,646	44,334,182	46,659,876	49,563,858	52,434,866
General Plant	6,963,989	3,346,925	3,713,097	4,203,755	4,698,714	4,963,946
Contributions and Grants	-4,280,005	-2,866,588	-3,073,173	-3,444,982	-4,030,290	-4,474,021
Total Excluding WIP	**93,185,081**	**57,050,939**	**59,135,138**	**61,614,375**	**64,455,048**	**67,200,894**

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Transmission Assets	14,565,705	14,701,338	14,785,832	14,997,875	15,147,875	15,422,475
Distribution Assets	52,415,974	55,167,941	57,988,954	60,720,467	64,138,240	69,580,842
General Plant	4,940,166	5,406,923	5,663,582	7,373,267	11,522,434	13,541,770
Contributions and Grants	-4,939,850	-5,563,243	-5,764,717	-6,211,498	-6,430,611	-6,757,799
Total Excluding WIP	**66,981,996**	**69,712,958**	**72,673,651**	**76,880,111**	**84,377,938**	**91,787,288**

Accumulated Depreciation

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Transmission Assets	-1,471,042	-722,728	-1,000,675	-1,334,670	-1,669,371	-2,005,635
Distribution Assets	-36,282,544	-2,998,154	-4,468,035	-6,040,343	-7,679,846	-9,365,797
General Plant	-4,628,611	-791,547	-1,084,780	-1,530,897	-1,743,063	-1,981,541
Contributions and Grants	1,486,278	102,971	158,656	215,788	309,244	400,628
Total Excluding WIP	**-40,895,920**	**-4,409,458**	**-6,394,835**	**-8,690,123**	**-10,783,036**	**-12,952,345**

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Transmission Assets	-2,338,075	-2,682,047	-3,045,305	-3,422,886	-3,769,998	-4,122,958
Distribution Assets	-8,583,694	-9,857,111	-11,134,020	-12,519,481	-14,264,617	-16,164,364
General Plant	-2,071,315	-2,249,555	-2,131,575	-2,330,161	-3,068,510	-3,962,576
Contributions and Grants	503,226	609,331	731,672	854,013	976,348	1,100,593
Total Excluding WIP	**-12,489,859**	**-14,179,382**	**-15,579,228**	**-17,418,515**	**-20,126,776**	**-23,149,306**

Net Fixed Assets

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Transmission Assets	13,492,533	13,467,228	13,160,357	12,861,057	12,553,395	12,270,467
Distribution Assets	39,254,978	39,382,492	39,866,147	40,619,533	41,884,012	43,069,070
General Plant	2,335,378	2,555,378	2,628,316	2,672,857	2,955,651	2,982,405
Contributions and Grants	-2793727	-2763616.6	-2914516.7	-3229194.1	-3721046.2	-4073393.5
Total Excluding WIP	**52,289,162**	**52,641,481**	**52,740,304**	**52,924,252**	**53,672,012**	**54,248,548**

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Transmission Assets	12,227,630	12,019,291	11,740,527	11,574,989	11,377,877	11,299,516
Distribution Assets	43,832,280	45,310,830	46,854,934	48,200,986	49,873,623	53,416,478
General Plant	2,868,851	3,157,368	3,532,008	5,043,106	8,453,924	9,579,194
Contributions and Grants	-4436623.4	-4953912.4	-5033045	-5357484.8	-5454262.3	-5657206
Total Excluding WIP	**54,492,137**	**55,533,576**	**57,094,424**	**59,461,597**	**64,251,162**	**68,637,982**

2.2.3.2 Detailed Breakdown by Major Plant Account

Table 2-26 below provides a detailed breakdown by Major Plant account for each functionalized plant item. Each plant item is accompanied by a description in accordance with the Board's USoA, including the 2025 Test Year. FHI has also included a breakdown of Accumulated Amortization in the same format in Table 2-27 and a breakdown of Net Fixed assets in Table 2-28.

Table 2-26 – Detailed Gross Assets

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Transmission Assets												
1815 - Transformer Station Equipment >50 kV	13,961,840	13,935,158	13,935,158	13,935,158	13,940,458	13,976,313	14,049,010	14,192,427	14,278,690	14,490,733	14,640,733	14,915,333
1820 - Distribution Station Equipment <50 kV	1,001,735	254,798	225,874	260,569	282,308	299,789	516,695	508,911	507,142	507,142	507,142	507,142
Subtotal Transmission Assets	**14,963,575**	**14,189,956**	**14,161,032**	**14,195,727**	**14,222,766**	**14,276,102**	**14,565,705**	**14,701,338**	**14,785,832**	**14,997,875**	**15,147,875**	**15,422,475**
Distribution Assets												
1805 - Land	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202
1612 - Land Rights	-	-	-	-	-	3,150	3,150	3,150	3,150	3,150	3,150	3,150
1808 - Buildings	1,471,352	494,571	445,216	440,179	438,602	438,602	438,602	438,602	438,602	438,602	438,602	438,602
1830 - Poles, Towers & Fixtures	16,585,303	10,845,877	11,257,817	11,719,407	12,249,659	12,749,710	12,993,286	13,656,294	14,419,295	15,039,856	15,124,856	15,199,856
1835 - Overhead Conductors & Devices	9,764,081	6,785,258	7,066,025	7,431,662	7,836,458	8,267,845	8,528,945	8,847,421	9,239,782	9,649,606	11,241,879	13,242,334
1840 - Underground Conduit	5,862,529	4,274,776	4,401,161	4,509,380	4,924,906	5,065,832	5,598,703	5,881,939	5,948,590	6,237,288	7,132,788	8,427,638
1845 - Underground Conductors & Devices	17,859,164	6,603,368	7,064,116	7,495,446	8,231,738	8,954,782	9,508,000	10,356,468	11,148,898	11,529,123	11,559,123	11,609,123
1850 - Line Transformers	12,258,550	6,088,943	6,398,135	6,917,565	7,223,292	7,639,061	7,944,510	8,352,072	8,726,215	9,279,629	9,694,629	10,289,629
1855 - Services (Overhead & Underground)	5,060,768	2,266,090	2,582,065	2,918,765	3,190,393	3,371,826	3,601,036	3,951,047	4,268,755	4,511,379	4,511,379	4,511,379
1860 - Meters	5,423,573	985,526	1,010,545	1,090,380	1,222,613	1,337,035	1,467,527	1,498,833	1,491,766	1,727,934	2,127,934	3,555,231
1860 - Meters (Smart Meters)	-	2,784,035	2,856,900	2,884,888	2,993,994	3,354,820	1,080,013	929,912	1,051,698	1,051,698	1,051,698	1,051,698
Subtotal Distribution Assets	**75,537,522**	**42,380,646**	**44,334,182**	**46,659,876**	**49,563,858**	**52,434,866**	**52,415,974**	**55,167,941**	**57,988,954**	**60,720,467**	**64,138,240**	**69,580,842**
General Plant												
1905 - Land	17,041	-	-	-	-	-	-	-	-	-	-	-
1908 - Buildings & Fixtures	691,155	607,216	743,507	858,281	1,030,403	1,254,226	1,410,958	1,881,717	2,211,367	3,264,141	5,429,141	5,934,141
1910 - Leasehold Improvements	21,798	-	-	-	-	-	-	-	-	-	-	-
1920 - Computer Hardware	547,819	413,077	478,657	543,167	448,036	438,600	440,649	598,864	682,015	878,095	1,071,164	1,367,800
1925/1611 - Computer Software	1,012,009	676,729	839,047	1,087,333	1,183,347	1,226,579	1,136,672	970,306	987,713	1,360,249	2,579,847	3,484,847
1915 - Office Furniture & Equipment	128,061	177,414	183,345	193,307	189,440	190,714	185,913	181,676	187,807	184,123	184,123	184,123
1930 - Transportation Equipment	3,157,023	957,521	987,947	995,337	1,266,296	1,216,379	1,078,552	1,095,062	906,595	891,265	1,341,265	1,466,265
1935 - Stores Equipment	36,199	-	-	-	-	-	-	-	-	-	-	-
1940 - Tools, Shop & Garage Equipment	537,541	175,350	156,538	163,823	177,176	206,543	223,499	223,951	229,300	244,956	289,956	336,156
1945 - Measurement & Testing Equipment	39,170	9,659	-	-	-	-	-	-	-	-	-	-
1955 - Communications Equipment	45,860	3,868	3,501	3,501	3,501	3,501	3,501	3,501	3,501	3,501	3,501	3,501
1960 - Miscellaneous Equipment	7,842	6,315	6,315	3,178	3,178	3,178	3,178	3,178	3,178	3,178	3,178	3,178
1970 - Load Management Controls Customer Premises	245,119	43,749	-	-	-	-	-	-	-	-	-	-
1980 - System Supervisor Equipment	477,351	276,026	314,239	355,827	397,335	424,224	457,245	448,667	452,107	543,758	620,258	761,758
Subtotal General Plant	**6,963,989**	**3,346,925**	**3,713,097**	**4,203,755**	**4,698,714**	**4,963,946**	**4,940,166**	**5,406,923**	**5,663,582**	**7,373,267**	**11,522,434**	**13,541,770**
Contribution and Grants												
1609 - Capital Contributions Paid	916,468	966,935	966,935	966,935	966,935	966,935	966,935	966,935	966,935	966,935	966,935	966,935
1995 - Contributions & Grants	-5,196,473	-3,499,578	-3,499,578	-3,499,578	-3,499,578	-3,499,578	-3,499,578	-3,641,514	-3,499,578	-3,499,578	-3,499,578	-3,499,578
2440 - Deferred Revenue	-	-333,945	-540,530	-912,339	-1,497,647	-1,941,379	-2,407,207	-2,888,664	-3,232,074	-3,678,854	-3,897,968	-4,225,156
Subtotal Contribution and Grants	**-4,280,005**	**-2,866,588**	**-3,073,173**	**-3,444,982**	**-4,030,290**	**-4,474,021**	**-4,939,850**	**-5,563,243**	**-5,764,717**	**-6,211,498**	**-6,430,611**	**-6,757,799**
Gross Assets for Rate Base	**93,185,081**	**57,050,939**	**59,135,138**	**61,614,375**	**64,455,048**	**67,200,894**	**66,981,996**	**69,712,958**	**72,673,651**	**76,880,111**	**84,377,938**	**91,787,288**

Table 2-27 – Detailed Accumulated Depreciation

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Transmission Assets												
1815 - Transformer Station Equipment >50 kV	-667,057	-667,059	-960,555	-1,280,744	-1,600,932	-1,922,193	-2,246,744	-2,580,917	-2,926,575	-3,284,811	-3,612,531	-3,946,100
1820 - Distribution Station Equipment <50 kV	-803,985	-55,669	-40,120	-53,927	-68,439	-83,442	-91,331	-101,129	-118,730	-138,075	-157,467	- 176,859
Subtotal Transmission Assets	**-1,471,042**	**-722,728**	**-1,000,675**	**-1,334,670**	**-1,669,371**	**-2,005,635**	**-2,338,075**	**-2,682,047**	**-3,045,305**	**-3,422,886**	**-3,769,998**	**-4,122,958**
Distribution Assets												
1805 - Land	-	-	-	-	-	-	-	-	-	-	-	-
1612 - Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
1808 - Buildings	-1,055,627	-81,234	-46,625	-56,333	-68,242	-81,413	-94,584	-107,755	-120,925	-134,096	-147,267	-160,437
1830 - Poles, Towers & Fixtures	-6,073,719	-503,223	-767,417	-1,039,882	-1,320,991	-1,611,841	-1,910,882	-2,218,439	-2,537,045	-2,867,808	-3,196,571	-3,526,896
1835 - Overhead Conductors & Devices	-3,426,901	-269,114	-412,005	-560,687	-716,154	-879,099	-1,048,292	-1,222,612	-1,404,069	-1,592,595	-1,847,437	-2,155,267
1840 - Underground Conduit	-1,935,328	-192,225	-296,018	-402,050	-516,806	-637,128	-764,188	-891,247	-1,026,468	-1,165,187	-1,319,795	-1,485,567
1845 - Underground Conductors & Devices	-11,813,463	-427,511	-656,699	-898,249	-1,155,127	-1,431,759	-1,725,796	-2,038,789	-2,372,957	-2,679,022	-3,030,054	-3,380,787
1850 - Line Transformers	-6,696,731	-379,526	-580,358	-791,547	-1,013,044	-1,243,561	-1,483,092	-1,731,536	-1,989,752	-2,259,561	-2,541,425	-2,835,102
1855 - Services (Overhead & Underground)	-2,875,559	-138,411	-215,581	-300,238	-391,889	-461,291	-559,126	-663,832	-776,287	-895,080	-1,011,113	-1,126,347
1860 - Meters	-2,405,216	-184,398	-254,151	-326,909	-405,795	-489,397	-580,246	-662,304	-550,437	-461,542	-602,433	-826,659
1860 - Meters (Smart Meters)	-	-822,512	-1,239,181	-1,664,448	-2,091,797	-2,530,307	-417,489	-320,596	-356,080	-464,590	-568,522	-667,304
Subtotal Distribution Assets	**-36,282,544**	**-2,998,154**	**-4,468,035**	**-6,040,343**	**-7,679,846**	**-9,365,797**	**-8,583,694**	**-9,857,111**	**-11,134,020**	**-12,519,481**	**-14,264,617**	**-16,164,364**
General Plant												
1905 - Land	-17,041	-	-	-	-	-	-	-	-	-	-	-
1908 - Buildings & Fixtures	-182,973	-70,255	-101,107	-137,198	-183,029	-254,116	-337,379	-427,301	-520,382	-669,418	-886,263	-1,127,286
1910 - Leasehold Improvements	-21,798	-	-	-	-	-	-	-	-	-	-	-
1920 - Computer Hardware	-367,272	-174,142	-222,876	-301,708	-213,256	-216,693	-246,473	-233,618	-268,396	-329,858	-506,946	-727,052
1925/1611 - Computer Software	-577,038	-207,657	-291,280	-453,124	-598,214	-655,913	-585,910	-564,178	-455,451	-434,007	-586,768	-831,810
1915 - Office Furniture & Equipment	-105,220	-23,595	-43,044	-63,869	-72,051	-91,689	-106,219	-112,385	-128,685	-143,968	-160,161	-169,187
1930 - Transportation Equipment	-2,298,759	-206,694	-327,007	-448,031	-520,397	-553,784	-538,873	-642,523	-481,647	-460,234	-566,461	-667,962
1935 - Stores Equipment	-36,199	-	-	-	-	-	-	-	-	-	-	-
1940 - Tools, Shop & Garage Equipment	-403,833	-57,537	-43,758	-48,114	-49,976	-73,017	-88,272	-87,625	-90,761	-97,002	-125,798	-156,253
1945 - Measurement & Testing Equipment	-35,951	-6,439	-	-	-	-	-	-	-	-	-	-
1955 - Communications Equipment	-45,824	26,176	-535	-886	-1,236	-1,586	-1,936	-2,636	-2,986	-3,336	-3,686	-3,861
1960 - Miscellaneous Equipment	-6,273	-2,045	-3,147	-1,112	-1,430	-1,748	-2,066	-2,383	-2,701	-3,019	-3,178	-3,178
1970 - Load Management Controls Utility Premises	-240,876	-39,506	-	-	-	-	-	-	-	-	-	-
1980 - System Supervisor Equipment	-289,552	-29,851	-52,026	-76,855	-103,474	-132,996	-164,187	-176,906	-180,565	-189,319	-229,250	-275,986
Subtotal General Plant	**-4,628,611**	**-791,547**	**-1,084,780**	**-1,530,897**	**-1,743,063**	**-1,981,541**	**-2,071,315**	**-2,249,555**	**-2,131,575**	**-2,330,161**	**-3,068,510**	**-3,962,576**
Contribution and Grants												
1609 - Capital Contributions Paid	-116,371	-101,654	-156,127	-210,600	-265,073	-319,546	-374,019	-428,492	-482,965	-537,438	-591,911	-646,384
1995 - Contributions & Grants	1,602,649	198,733	298,100	397,467	497,411	597,356	697,301	797,245	897,190	997,135	1,097,080	1,197,024
2440 - Deferred Revenue	-	5,892	16,683	28,921	76,906	122,818	179,945	240,578	317,447	394,316	471,180	549,953
Subtotal Contribution and Grants	**1,486,278**	**102,971**	**158,656**	**215,788**	**309,244**	**400,628**	**503,226**	**609,331**	**731,672**	**854,013**	**976,348**	**1,100,593**
Gross Assets for Rate Base	**- 40,895,920**	**- 4,409,458**	**- 6,394,835**	**- 8,690,123**	**- 10,783,036**	**- 12,952,345**	**- 12,489,859**	**- 14,179,382**	**- 15,579,228**	**- 17,418,515**	**- 20,126,777**	**- 23,149,306**

Table 2-28 – Detailed Net Fixed Assets

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Transmission Assets												
1815 - Transformer Station Equipment >50 kV	13,294,783	13,268,099	12,974,603	12,654,414	12,339,526	12,054,120	11,802,266	11,611,510	11,352,116	11,205,922	11,028,202	10,969,233
1820 - Distribution Station Equipment <50 kV	197,750	199,129	185,754	206,642	213,869	216,347	425,364	407,782	388,412	369,067	349,675	330,283
Subtotal Transmission Assets	**13,492,533**	**13,467,228**	**13,160,357**	**12,861,057**	**12,553,395**	**12,270,467**	**12,227,630**	**12,019,291**	**11,740,527**	**11,574,989**	**11,377,877**	**11,299,516**
Distribution Assets												
1805 - Land	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202	1,252,202
1612 - Land Rights	-	-	-	-	-	3,150	3,150	3,150	3,150	3,150	3,150	3,150
1808 - Buildings	415,725	413,337	398,592	383,846	370,360	357,189	344,019	330,848	317,677	304,507	291,336	278,165
1830 - Poles, Towers & Fixtures	10,511,584	10,342,654	10,490,400	10,679,525	10,928,667	11,137,869	11,082,403	11,437,855	11,882,250	12,172,047	11,928,285	11,672,960
1835 - Overhead Conductors & Devices	6,337,180	6,516,144	6,654,020	6,870,976	7,120,305	7,388,747	7,480,653	7,624,809	7,835,713	8,057,011	9,394,442	11,087,067
1840 - Underground Conduit	3,927,201	4,082,550	4,105,143	4,107,330	4,408,100	4,428,704	4,834,515	4,990,692	4,922,123	5,072,101	5,812,993	6,942,071
1845 - Underground Conductors & Devices	6,045,701	6,175,857	6,407,417	6,597,197	7,076,611	7,523,023	7,782,204	8,317,679	8,775,940	8,850,101	8,529,069	8,228,336
1850 - Line Transformers	5,561,819	5,709,417	5,817,777	6,126,018	6,210,248	6,395,500	6,461,418	6,620,536	6,736,464	7,020,067	7,153,203	7,454,527
1855 - Services (Overhead & Underground)	2,185,209	2,127,680	2,366,484	2,618,527	2,798,504	2,910,535	3,041,910	3,287,215	3,492,468	3,616,299	3,500,266	3,385,032
1860 - Meters	3,018,357	801,128	756,393	763,471	816,818	847,638	887,281	836,529	941,330	1,266,391	1,525,501	2,728,572
1860 - Meters (Smart Meters)	-	1,961,523	1,617,719	1,220,441	902,197	824,513	662,524	609,316	695,618	587,108	483,176	384,394
Subtotal Distribution Assets	**39,254,978**	**39,382,492**	**39,866,147**	**40,619,533**	**41,884,012**	**43,069,070**	**43,832,280**	**45,310,830**	**46,854,934**	**48,200,986**	**49,873,623**	**53,416,478**
General Plant												
1905 - Land	-	-	-	-	-	-	-	-	-	-	-	-
1908 - Buildings & Fixtures	508,182	536,961	642,400	721,083	847,375	1,000,110	1,073,578	1,454,417	1,690,985	2,594,723	4,542,879	4,806,855
1910 - Leasehold Improvements	-0	-	-	-	-	-	-	-	-	-	-	-
1920 - Computer Hardware	180,547	238,935	255,782	241,459	234,781	221,907	194,176	365,245	413,618	548,237	564,218	640,748
1925/1611 - Computer Software	434,971	469,071	547,768	634,209	585,133	570,667	550,762	406,128	532,262	926,243	1,993,080	2,653,037
1915 - Office Furniture & Equipment	22,841	153,819	140,301	129,437	117,389	99,026	79,694	69,292	59,122	40,154	23,962	14,936
1930 - Transportation Equipment	858,264	750,827	660,940	547,306	745,899	662,595	539,679	452,539	424,948	431,031	774,804	798,303
1935 - Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-
1940 - Tools, Shop & Garage Equipment	133,708	117,812	112,780	115,709	127,199	133,526	135,227	136,326	138,539	147,954	164,158	179,903
1945 - Measurement & Testing Equipment	3,219	3,220	-	-	-	-	-	-	-	-	-	-
1955 - Communications Equipment	36	30,044	2,965	2,615	2,265	1,915	1,565	865	515	165	-185	-360
1960 - Miscellaneous Equipment	1,569	4,270	3,168	2,066	1,748	1,431	1,113	795	477	159	0	0
1970 - Load Management Controls Utility Premises	4,243	4,243	-	-	-	-	-	-	-	-	-	-
1980 - System Supervisor Equipment	187,799	246,175	262,213	278,971	293,862	291,228	293,057	271,761	271,542	354,440	391,008	485,772
Subtotal General Plant	**2,335,378**	**2,555,378**	**2,628,316**	**2,672,857**	**2,955,651**	**2,982,405**	**2,868,851**	**3,157,368**	**3,532,008**	**5,043,106**	**8,453,924**	**9,579,194**
Contribution and Grants												
1609 - Capital Contributions Paid	800,097	865,281	810,808	756,335	701,862	647,389	592,916	538,443	483,970	429,497	375,024	320,551
1995 - Contributions & Grants	-3,593,824	-3,300,845	-3,201,478	-3,102,111	-3,002,167	-2,902,222	-2,802,277	-2,844,269	-2,602,388	-2,502,443	-2,402,498	-2,302,554
2440 - Deferred Revenue	-	-328,054	-523,847	-883,418	-1,420,741	-1,818,561	-2,227,262	-2,648,086	-2,914,627	-3,284,538	-3,426,788	-3,675,203
Subtotal Contribution and Grants	**-2,793,727**	**-2,763,617**	**-2,914,517**	**-3,229,194**	**-3,721,046**	**-4,073,394**	**-4,436,623**	**-4,953,912**	**-5,033,045**	**-5,357,485**	**-5,454,262**	**-5,657,206**
Gross Assets for Rate Base	**52,289,162**	**52,641,481**	**52,740,304**	**52,924,252**	**53,672,012**	**54,248,548**	**54,492,137**	**55,533,576**	**57,094,424**	**59,461,597**	**64,251,162**	**68,637,982**

2.2.3.3 Variance Analysis on Gross Assets

Table 2-29 below shows the gross asset variance for each asset.

Table 2-29 – 2015-2025 Gross Asset Variance

Description	2015 Board Approved	2015 Actual	Variance from 2016 Board Approved	2016 Actual	Variance from 2015 Actual	2017 Actual	Variance from 2016 Actual	2018 Actual	Variance from 2017 Actual	2019 Actual	Variance from 2018 Actual
Reporting Basis	MIFRS	MIFRS		MIFRS		MIFRS		MIFRS		MIFRS	
Land & Buildings											
1805 - Land	1,252,202	1,252,202	-0	1,252,202	-	1,252,202	-	1,252,202	-	1,252,202	-
1612 - Land Rights	-	-	-	-	-	-	-	-	-	3,150	3,150
1808 - Buildings	1,471,352	494,571	-976,781	445,216	-49,355	440,179	-5,037	438,602	-1,577	438,602	-
1905 - Land	17,041	-	-17,041	-	-	-	-	-	-	-	-
1908 - Buildings & Fixtures	691,155	607,216	-83,939	743,507	136,291	858,281	114,774	1,030,403	172,123	1,254,226	223,823
1910 - Leasehold Improvements	21,798	-	-21,798	-	-	-	-	-	-	-	-
Subtotal Land & Buildings	**3,453,548**	**2,353,989**	**-1,099,559**	**2,440,925**	**86,936**	**2,550,662**	**109,737**	**2,721,208**	**170,546**	**2,948,181**	**226,973**
Transmission & Distribution Stations											
1815 - Transformer Station Equipment >50 kV	13,961,840	13,935,158	-26,682	13,935,158	-	13,935,158	-	13,940,458	5,300	13,976,313	35,855
1820 - Distribution Station Equipment <50 kV	1,001,735	254,798	-746,937	225,874	-28,924	260,569	34,695	282,308	21,739	299,789	17,481
Subtotal Transmission & Distribution Stations	**14,963,575**	**14,189,956**	**-773,619**	**14,161,032**	**-28,924**	**14,195,727**	**34,695**	**14,222,766**	**27,039**	**14,276,102**	**53,336**
Poles & Wires											
1830 - Poles, Towers & Fixtures	16,585,303	10,845,877	-5,739,426	11,257,817	411,940	11,719,407	461,590	12,249,659	530,251	12,749,710	500,051
1835 - Overhead Conductors & Devices	9,764,081	6,785,258	-2,978,823	7,066,025	280,767	7,431,662	365,637	7,836,458	404,796	8,267,845	431,387
1840 - Underground Conduit	5,862,529	4,274,776	-1,587,753	4,401,161	126,385	4,509,380	108,219	4,924,906	415,526	5,065,832	140,926
1845 - Underground Conductors & Devices	17,859,164	6,603,368	-11,255,796	7,064,116	460,749	7,495,446	431,330	8,231,738	736,292	8,954,782	723,045
Subtotal Poles & Wires	**50,071,077**	**28,509,279**	**-21,561,798**	**29,789,119**	**1,279,840**	**31,155,896**	**1,366,777**	**33,242,761**	**2,086,865**	**35,038,170**	**1,795,409**
Line Transformers											
1850 - Line Transformers	12,258,550	6,088,943	-6,169,607	6,398,135	309,192	6,917,565	519,430	7,223,292	305,727	7,639,061	415,768
Subtotal Line Transformers	**12,258,550**	**6,088,943**	**-6,169,607**	**6,398,135**	**309,192**	**6,917,565**	**519,430**	**7,223,292**	**305,727**	**7,639,061**	**415,768**
Services & Meters											
1855 - Services (Overhead & Underground)	5,060,768	2,266,090	-2,794,678	2,582,065	315,975	2,918,765	336,699	3,190,393	271,629	3,371,826	181,432
1860 - Meters	5,423,573	985,526	-4,438,047	1,010,545	25,019	1,090,380	79,835	1,222,613	132,233	1,337,035	114,422
1860 - Meters (Smart Meters)	-	2,784,035	2,784,035	2,856,900	72,865	2,884,888	27,989	2,993,994	109,106	3,354,820	360,826
Subtotal Services & Meters	**10,484,341**	**6,035,651**	**-4,448,690**	**6,449,510**	**413,859**	**6,894,033**	**444,524**	**7,407,000**	**512,967**	**8,063,681**	**656,681**
IT Assets											
1920 - Computer Hardware	547,819	413,077	-134,741	478,657	65,580	543,167	64,510	448,036	-95,131	438,600	-9,436
1925/1611 - Computer Software	1,012,009	676,729	-335,280	839,047	162,318	1,087,333	248,286	1,183,347	96,014	1,226,579	43,232
Subtotal IT Assets	**1,559,828**	**1,089,806**	**-470,022**	**1,317,704**	**227,898**	**1,630,501**	**312,796**	**1,631,384**	**883**	**1,665,179**	**33,796**
Equipment											
1915 - Office Furniture & Equipment	128,061	177,414	49,353	183,345	5,931	193,307	9,962	189,440	-3,866	190,714	1,274
1930 - Transportation Equipment	3,157,023	957,521	-2,199,502	987,947	30,426	995,337	7,390	1,266,296	270,959	1,216,379	-49,917
1935 - Stores Equipment	36,199	-	-36,199	-	-	-	-	0	-	0	-
1940 - Tools, Shop & Garage Equipment	537,541	175,350	-362,191	156,538	-18,812	163,823	7,285	177,176	13,352	206,543	29,367
1945 - Measurement & Testing Equipment	39,170	9,659	-29,511	-	-9,659	-	-	0	-	0	-
1955 - Communications Equipment	45,860	3,868	-41,992	3,501	-367	3,501	-	3,501	-	3,501	-
1960 - Miscellaneous Equipment	7,842	6,315	-1,527	6,315	-	3,178	-3,137	3,178	-	3,178	-
1970 - Load Management Controls Customer Premises	245,119	43,749	-201,370	-	-43,749	-	-	-	-	0	-
Subtotal Equipment	**4,196,815**	**1,373,877**	**-2,822,939**	**1,337,646**	**-36,230**	**1,359,146**	**21,500**	**1,639,591**	**280,445**	**1,620,316**	**-19,276**
Other Distribution Assets											
1980 - System Supervisor Equipment	477,351	276,026	-201,325	314,239	38,213	355,827	41,588	397,335	41,509	424,224	26,889
1609 - Capital Contributions Paid	916,468	966,935	50,467	966,935	-	966,935	-	966,935	-	966,935	-
1995 - Contributions & Grants	-5,196,473	-3,499,578	1,696,895	-3,499,578	-	-3,499,578	-	-3,499,578	-	-3,499,578	-
2440 - Deferred Revenue	-	-333,945	-333,945	-540,530	-206,585	-912,339	-371,810	-1,497,647	-585,308	-1,941,379	-443,731
Subtotal Other Distribution Assets	**-3,802,654**	**-2,590,562**	**1,212,092**	**-2,758,934**	**-168,372**	**-3,089,155**	**-330,222**	**-3,632,955**	**-543,799**	**-4,049,797**	**-416,842**
Gross Assets for Rate Base	**93,185,081**	**57,050,939**	**- 36,134,142**	**59,135,138**	**2,084,200**	**61,614,375**	**2,479,237**	**64,455,048**	**2,840,673**	**67,200,894**	**2,745,846**

Description	2020 Actual	Variance from 2019 Actual	2021 Actual	Variance from 2020 Actual	2022 Actual	Variance from 2021 Actual	2023 Actual	Variance from 2022 Actual	2024 Bridge	Variance from 2023 Actual	2025 Test	Variance from 2024 Forecast
Reporting Basis	**MIFRS**		**MIFRS**		**MIFRS**		**MIFRS**		**MIFRS**		**MIFRS**	
Land & Buildings												
1805 - Land	1,252,202	-	1,252,202	-	1,252,202	-	1,252,202	-	1,252,202	-	1,252,202	-
1612 - Land Rights	3,150	-	3,150	-	3,150	-	3,150	-	3,150	-	3,150	-
1808 - Buildings	438,602	-	438,602	-	438,602	-	438,602	-	438,602	-	438,602	-
1905 - Land	-	-	-	-	-	-	-	-	-	-	-	-
1908 - Buildings & Fixtures	1,410,958	156,731	1,881,717	470,760	2,211,367	329,650	3,264,141	1,052,774	5,429,141	2,165,000	5,934,141	505,000
1910 - Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Land & Buildings	**3,104,912**	**156,731**	**3,575,672**	**470,760**	**3,905,321**	**329,650**	**4,958,096**	**1,052,774**	**7,123,096**	**2,165,000**	**7,628,096**	**505,000**
Transmission & Distribution Stations												
1815 - Transformer Station Equipment >50 kV	14,049,010	72,697	14,192,427	143,417	14,278,690	86,263	14,490,733	212,043	14,640,733	150,000	14,915,333	274,600
1820 - Distribution Station Equipment <50 kV	516,695	216,906	508,911	-7,784	507,142	-1,769	507,142	-	507,142	-	507,142	-
Subtotal Transmission & Distribution Stations	**14,565,705**	**289,603**	**14,701,338**	**135,633**	**14,785,832**	**84,495**	**14,997,875**	**212,043**	**15,147,875**	**150,000**	**15,422,475**	**274,600**
Poles & Wires												
1830 - Poles, Towers & Fixtures	12,993,286	243,576	13,656,294	663,008	14,419,295	763,001	15,039,856	620,561	15,124,856	85,000	15,199,856	75,000
1835 - Overhead Conductors & Devices	8,528,945	261,099	8,847,421	318,477	9,239,782	392,360	9,649,606	409,824	11,241,879	1,592,273	13,242,334	2,000,455
1840 - Underground Conduit	5,598,703	532,871	5,881,939	283,236	5,948,590	66,651	6,237,288	288,698	7,132,788	895,500	8,427,638	1,294,850
1845 - Underground Conductors & Devices	9,508,000	553,217	10,356,468	848,468	11,148,898	792,430	11,529,123	380,225	11,559,123	30,000	11,609,123	50,000
Subtotal Poles & Wires	**36,628,933**	**1,590,763**	**38,742,122**	**2,113,189**	**40,756,564**	**2,014,442**	**42,455,873**	**1,699,309**	**45,058,646**	**2,602,773**	**48,478,951**	**3,420,305**
Line Transformers												
1850 - Line Transformers	7,944,510	305,450	8,352,072	407,561	8,726,215	374,144	9,279,629	553,413	9,694,629	415,000	10,289,629	595,000
Subtotal Line Transformers	**7,944,510**	**305,450**	**8,352,072**	**407,561**	**8,726,215**	**374,144**	**9,279,629**	**553,413**	**9,694,629**	**415,000**	**10,289,629**	**595,000**
Services & Meters												
1855 - Services (Overhead & Underground)	3,601,036	229,210	3,951,047	350,012	4,268,755	317,708	4,511,379	242,624	4,511,379	-	4,511,379	-
1860 - Meters	1,467,527	130,492	1,498,833	31,306	1,491,766	-7,067	1,727,934	236,167	2,127,934	400,000	3,555,231	1,427,297
1860 - Meters (Smart Meters)	1,080,013	-2,274,807	929,912	-150,101	1,051,698	121,786	1,051,698	-	1,051,698	-	1,051,698	-
Subtotal Services & Meters	**6,148,576**	**-1,915,105**	**6,379,792**	**231,216**	**6,812,220**	**432,427**	**7,291,011**	**478,791**	**7,691,011**	**400,000**	**9,118,308**	**1,427,297**
IT Assets												
1920 - Computer Hardware	440,649	2,049	598,864	158,214	682,015	83,151	878,095	196,080	1,071,164	193,069	1,367,800	296,636
1925/1611 - Computer Software	1,136,672	-89,908	970,306	-166,366	987,713	17,407	1,360,249	372,537	2,579,847	1,219,598	3,484,847	905,000
Subtotal IT Assets	**1,577,321**	**-87,858**	**1,569,170**	**-8,151**	**1,669,727**	**100,558**	**2,238,344**	**568,617**	**3,651,011**	**1,412,667**	**4,852,647**	**1,201,636**
Equipment												
1915 - Office Furniture & Equipment	185,913	-4,802	181,676	-4,237	187,807	6,130	184,123	-3,684	184,123	-	184,123	-
1930 - Transportation Equipment	1,078,552	-137,828	1,095,062	16,511	906,595	-188,467	891,265	-15,330	1,341,265	450,000	1,466,265	125,000
1935 - Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-
1940 - Tools, Shop & Garage Equipment	223,499	16,956	223,951	452	229,300	5,349	244,956	15,656	289,956	45,000	336,156	46,200
1945 - Measurement & Testing Equipment	-	-	-	-	-	-	-	-	-	-	-	-
1955 - Communications Equipment	3,501	-	3,501	-	3,501	-	3,501	-	3,501	-	3,501	-
1960 - Miscellaneous Equipment	3,178	-	3,178	-	3,178	-	3,178	-	3,178	-	3,178	-
1970 - Load Management Controls Customer Premises	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Equipment	**1,494,643**	**-125,673**	**1,507,369**	**12,726**	**1,330,381**	**-176,988**	**1,327,023**	**-3,358**	**1,822,023**	**495,000**	**1,993,223**	**171,200**
Other Distribution Assets												
1980 - System Supervisor Equipment	457,245	33,020	448,667	-8,578	452,107	3,440	543,758	91,651	620,258	76,500	761,758	141,500
1609 - Capital Contributions Paid	966,935	-	966,935	-	966,935	-	966,935	-	966,935	-	966,935	-
1995 - Contributions & Grants	-3,499,578	-	-3,641,514	-141,936	-3,499,578	141,936	-3,499,578	-	-3,499,578	-	-3,499,578	-
2440 - Deferred Revenue	-2,407,207	-465,828	-2,888,664	-481,457	-3,232,074	-343,410	-3,678,854	-446,781	-3,897,968	-219,113	-4,225,156	-327,188
Subtotal Other Distribution Assets	**-4,482,605**	**-432,808**	**-5,114,577**	**-631,972**	**-5,312,610**	**-198,034**	**-5,667,739**	**-355,129**	**-5,810,353**	**-142,613**	**-5,996,041**	**-185,688**
Gross Assets for Rate Base	**66,981,996**	**- 218,898**	**69,712,958**	**2,730,963**	**72,673,651**	**2,960,693**	**76,880,111**	**4,206,460**	**84,377,938**	**7,497,827**	**91,787,288**	**7,409,350**

There are no disposals of sold assets forecast in the 2024 Bridge Year or the 2025 Test Year.

Variance explanations for each year are described below. As per section 2.2.1.2. FHI has used a materiality level of $80,000 for its analysis:

Table 2-30– 2015 Board Approved vs 2015 Actual

Description	2015 Board Approved	2015 Actual	Variance from 2015 Board Approved	%
Reporting Basis	**MIFRS**	**MIFRS**		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	13,961,840	13,935,158	-26,682	-0.2%
1820 - Distribution Station Equipment <50 kV	1,001,735	254,798	-746,937	-74.6%
Subtotal Transmission Assets	**14,963,575**	**14,189,956**	**-773,619**	**-5.2%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0%
1806/1612 - Land Rights	-	-	-	0%
1808 - Buildings	1,471,352	494,571	-976,781	-66%
1830 - Poles, Towers & Fixtures	16,585,303	10,845,877	-5,739,426	-35%
1835 - Overhead Conductors & Devices	9,764,081	6,785,258	-2,978,823	-31%
1840 - Underground Conduit	5,862,529	4,274,776	-1,587,753	-27%
1845 - Underground Conductors & Devices	17,859,164	6,603,368	-11,255,796	-63%
1850 - Line Transformers	12,258,550	6,088,943	-6,169,607	-50%
1855 - Services (Overhead & Underground)	5,060,768	2,266,090	-2,794,678	-55%
1860 - Meters	5,423,573	985,526	-4,438,047	-82%
1860 - Meters (Smart Meters)	-	2,784,035	2,784,035	100%
Subtotal Distribution Assets	**75,537,522**	**42,380,646**	**-33,156,876**	**-44%**
General Plant				
1905 - Land	17,041	-	-17,041	-100%
1908 - Buildings & Fixtures	691,155	607,216	-83,939	-12%
1910 - Leasehold Improvements	21,798	-	-21,798	-100%
1920 - Computer Hardware	547,819	413,077	-134,741	-25%
1925/1611 - Computer Software	1,012,009	676,729	-335,280	-33%
1915 - Office Furniture & Equipment	128,061	177,414	49,353	39%
1930 - Transportation Equipment	3,157,023	957,521	-2,199,502	-70%
1935 - Stores Equipment	36,199	-	-36,199	-100%
1940 - Tools, Shop & Garage Equipment	537,541	175,350	-362,191	-67%
1945 - Measurement & Testing Equipment	39,170	9,659	-29,511	-75%
1955 - Communications Equipment	45,860	3,868	-41,992	-92%
1960 - Miscellaneous Equipment	7,842	6,315	-1,527	-19%
1970 - Load Management Controls Customer Premises	245,119	43,749	-201,370	-82%
1980 - System Supervisor Equipment	477,351	276,026	-201,325	-42%
Subtotal General Plant	**6,963,989**	**3,346,925**	**-3,617,064**	**-52%**
Contribution and Grants				
1609 - Capital Contributions Paid	916,468	966,935	50,467	6%
1995 - Contributions & Grants	-5,196,473	-3,499,578	1,696,895	-33%
2440 - Deferred Revenue	0	-333,945	-333,945	100%
Subtotal Contribution and Grants	**-4,280,005**	**-2,866,588**	**1,413,417**	**-33%**
Gross Assets for Rate Base	**93,185,081**	**57,050,939**	**- 36,134,142**	**-39%**

Gross assets decreased by $36.1M in 2015 due to the change from CGAAP to MIFRS in 2015 as fully depreciated assets were removed from the opening balances. In 2015, $2.2M was spend on distribution assets including overhead pole line rebuilds (M8 Feeder, Elgin St, Jarvis St) reinsulating, underground cable replacement (Greenwood, Glastonbury), switchgear replacements, small capital replacements and customer driven work for new services and subdivisions. General plant additions were $600K for Service Centre upgrades and IT projects (iXp Upgrade, New Website and Locator App).

Table 2-31– 2015 Actual vs 2016 Actual

Description	2015 Actual	2016 Actual	Variance from 2015 Actual	%
Reporting Basis	**MIFRS**	**MIFRS**		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	13,935,158	13,935,158	-	0.0%
1820 - Distribution Station Equipment <50 kV	254,798	225,874	-28,924	-11.4%
Subtotal Transmission Assets	**14,189,956**	**14,161,032**	**-28,924**	**-0.2%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	-	-	-	0.0%
1808 - Buildings	494,571	445,216	-49,355	-10.0%
1830 - Poles, Towers & Fixtures	10,845,877	11,257,817	411,940	3.8%
1835 - Overhead Conductors & Devices	6,785,258	7,066,025	280,767	4.1%
1840 - Underground Conduit	4,274,776	4,401,161	126,385	3.0%
1845 - Underground Conductors & Devices	6,603,368	7,064,116	460,749	7.0%
1850 - Line Transformers	6,088,943	6,398,135	309,192	5.1%
1855 - Services (Overhead & Underground)	2,266,090	2,582,065	315,975	13.9%
1860 - Meters	985,526	1,010,545	25,019	2.5%
1860 - Meters (Smart Meters)	2,784,035	2,856,900	72,865	2.6%
Subtotal Distribution Assets	**42,380,646**	**44,334,182**	**1,953,537**	**4.6%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	607,216	743,507	136,291	22.4%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	413,077	478,657	65,580	15.9%
1925/1611 - Computer Software	676,729	839,047	162,318	24.0%
1915 - Office Furniture & Equipment	177,414	183,345	5,931	3.3%
1930 - Transportation Equipment	957,521	987,947	30,426	3.2%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	175,350	156,538	-18,812	-10.7%
1945 - Measurement & Testing Equipment	9,659	-	-9,659	-100.0%
1955 - Communications Equipment	3,868	3,501	-367	-9.5%
1960 - Miscellaneous Equipment	6,315	6,315	-	0.0%
1970 - Load Management Controls Customer Premises	43,749	-	-43,749	-100.0%
1980 - System Supervisor Equipment	276,026	314,239	38,213	13.8%
Subtotal General Plant	**3,346,925**	**3,713,097**	**366,172**	**10.9%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-333,945	-540,530	-206,585	61.9%
Subtotal Contribution and Grants	**-2,866,588**	**-3,073,173**	**-206,585**	**7.2%**
Gross Assets for Rate Base	**57,050,939**	**59,135,138**	**2,084,200**	**3.7%**

2016 gross assets increased from 2015 by $2.1M. Of this, $2M related to Distribution asset additions including overhead pole line rebuilds (Forman Ave, Britannia St, Given Rd), reinsulating, underground cable replacement (MS9 Cable Replacement phase 1), switchgear replacements, small capital replacements and customer driven work for new services and subdivisions. The capital additions for general plant included Service Centre building upgrades (HVAC replacements) and IT projects (GIS System, locator software).

Table 2-32– 2016 Actual vs 2017 Actual

Description	2016 Actual	2017 Actual	Variance from 2016 Actual	%
Reporting Basis	**MIFRS**	**MIFRS**		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	13,935,158	13,935,158	-	0.0%
1820 - Distribution Station Equipment <50 kV	225,874	260,569	34,695	15.4%
Subtotal Transmission Assets	**14,161,032**	**14,195,727**	34,695	**0.2%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	-	-	-	0.0%
1808 - Buildings	445,216	440,179	-5,037	-1.1%
1830 - Poles, Towers & Fixtures	11,257,817	11,719,407	461,590	4.1%
1835 - Overhead Conductors & Devices	7,066,025	7,431,662	365,637	5.2%
1840 - Underground Conduit	4,401,161	4,509,380	108,219	2.5%
1845 - Underground Conductors & Devices	7,064,116	7,495,446	431,330	6.1%
1850 - Line Transformers	6,398,135	6,917,565	519,430	8.1%
1855 - Services (Overhead & Underground)	2,582,065	2,918,765	336,699	13.0%
1860 - Meters	1,010,545	1,090,380	79,835	7.9%
1860 - Meters (Smart Meters)	2,856,900	2,884,888	27,989	1.0%
Subtotal Distribution Assets	**44,334,182**	**46,659,876**	**2,325,693**	**5.2%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	743,507	858,281	114,774	15.4%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	478,657	543,167	64,510	13.5%
1925/1611 - Computer Software	839,047	1,087,333	248,286	29.6%
1915 - Office Furniture & Equipment	183,345	193,307	9,962	5.4%
1930 - Transportation Equipment	987,947	995,337	7,390	0.7%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	156,538	163,823	7,285	4.7%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	6,315	3,178	-3,137	-49.7%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	314,239	355,827	41,588	13.2%
Subtotal General Plant	**3,713,097**	**4,203,755**	**490,658**	**13.2%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-540,530	-912,339	-371,810	68.8%
Subtotal Contribution and Grants	**-3,073,173**	**-3,444,982**	**-371,810**	**12.1%**
Gross Assets for Rate Base	**59,135,138**	**61,614,375**	**2,479,237**	**4.2%**

In 2017, total additions for distribution infrastructure work were $2.3M. This included overhead pole line rebuilds (Romeo St, Jones St, James St), reinsulating, underground cable replacement (MS9 cable replacement phase 2), switchgear replacements, small capital replacements and customer driven work for new services and subdivisions. The capital additions for general was $500K. This included Service Centre building upgrades (HVAC replacements) and IT projects (GIS System, locator software).

Table 2-33– 2017 Actual vs 2018 Actual

Description	2017 Actual	2018 Actual	Variance from 2016 Actual	%
Reporting Basis	MIFRS	MIFRS		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	13,935,158	13,940,458	5,300	0.0%
1820 - Distribution Station Equipment <50 kV	260,569	282,308	21,739	8.3%
Subtotal Transmission Assets	**14,195,727**	**14,222,766**	**27,039**	**0.2%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	-	-	-	0.0%
1808 - Buildings	440,179	438,602	-1,577	-0.4%
1830 - Poles, Towers & Fixtures	11,719,407	12,249,659	530,251	4.5%
1835 - Overhead Conductors & Devices	7,431,662	7,836,458	404,796	5.4%
1840 - Underground Conduit	4,509,380	4,924,906	415,526	9.2%
1845 - Underground Conductors & Devices	7,495,446	8,231,738	736,292	9.8%
1850 - Line Transformers	6,917,565	7,223,292	305,727	4.4%
1855 - Services (Overhead & Underground)	2,918,765	3,190,393	271,629	9.3%
1860 - Meters	1,090,380	1,222,613	132,233	12.1%
1860 - Meters (Smart Meters)	2,884,888	2,993,994	109,106	3.8%
Subtotal Distribution Assets	**46,659,876**	**49,563,858**	**2,903,982**	**6.2%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	858,281	1,030,403	172,123	20.1%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	543,167	448,036	-95,131	-17.5%
1925/1611 - Computer Software	1,087,333	1,183,347	96,014	8.8%
1915 - Office Furniture & Equipment	193,307	189,440	-3,866	-2.0%
1930 - Transportation Equipment	995,337	1,266,296	270,959	27.2%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	163,823	177,176	13,352	8.2%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	355,827	397,335	41,509	11.7%
Subtotal General Plant	**4,203,755**	**4,698,714**	**494,959**	**11.8%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-912,339	-1,497,647	-585,308	64.2%
Subtotal Contribution and Grants	**-3,444,982**	**-4,030,290**	**-585,308**	**17.0%**
Gross Assets for Rate Base	**61,614,375**	**64,455,048**	**2,840,673**	**4.6%**

In 2018, total additions for distribution infrastructure work were $2.9M. This included overhead pole line rebuilds (Monteith Ave, James St, St. Vincent), underground cable replacement (68M4 Feeder upgrade Ph 1), switchgear replacements, small capital replacements, meter replacements for reverifications, and customer driven work for new services and subdivisions. The capital spending for general plant was $500K. This included a new single bucket truck, and buildings (security system upgrades).

Table 2-34– 2018 Actual vs 2019 Actual

Description	2018 Actual	2019 Actual	Variance from 2018 Actual	%
Reporting Basis	**MIFRS**	**MIFRS**		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	13,940,458	13,976,313	35,855	0.3%
1820 - Distribution Station Equipment <50 kV	282,308	299,789	17,481	6.2%
Subtotal Transmission Assets	**14,222,766**	**14,276,102**	**53,336**	**0.4%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	-	3,150	3,150	0.0%
1808 - Buildings	438,602	438,602	-	0.0%
1830 - Poles, Towers & Fixtures	12,249,659	12,749,710	500,051	4.1%
1835 - Overhead Conductors & Devices	7,836,458	8,267,845	431,387	5.5%
1840 - Underground Conduit	4,924,906	5,065,832	140,926	2.9%
1845 - Underground Conductors & Devices	8,231,738	8,954,782	723,045	8.8%
1850 - Line Transformers	7,223,292	7,639,061	415,768	5.8%
1855 - Services (Overhead & Underground)	3,190,393	3,371,826	181,432	5.7%
1860 - Meters	1,222,613	1,337,035	114,422	9.4%
1860 - Meters (Smart Meters)	2,993,994	3,354,820	360,826	12.1%
Subtotal Distribution Assets	**49,563,858**	**52,434,866**	**2,871,009**	**5.8%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	1,030,403	1,254,226	223,823	21.7%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	448,036	438,600	-9,436	-2.1%
1925/1611 - Computer Software	1,183,347	1,226,579	43,232	3.7%
1915 - Office Furniture & Equipment	189,440	190,714	1,274	0.7%
1930 - Transportation Equipment	1,266,296	1,216,379	-49,917	-3.9%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	177,176	206,543	29,367	16.6%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	397,335	424,224	26,889	6.8%
Subtotal General Plant	**4,698,714**	**4,963,946**	**265,232**	**5.6%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-1,497,647	-1,941,379	-443,731	29.6%
Subtotal Contribution and Grants	**-4,030,290**	**-4,474,021**	**-443,731**	**11.0%**
Gross Assets for Rate Base	**64,455,048**	**67,200,894**	**2,745,846**	**4.3%**

In 2019, total additions for distribution infrastructure work were $2.9M. This included overhead pole line rebuilds (Chalk St, Guelph/Taylor St), reinsulating, underground cable replacement (68M4 Feeder upgrade Ph 2, Campbell Court), switchgear replacements, small capital replacements, meter replacements for reverifications, and customer driven work for new services and subdivisions. Capital additions for general plant was $300K. This included IT projects (cybersecurity enhancements, CIS upgrades, asset management hardware) and buildings (replacement of portion of service centre roof, building and storage upgrades).

Table 2-35– 2019 Actual vs 2020 Actual

Description	2019 Actual	2020 Actual	Variance from 2019 Actual	%
Reporting Basis	MIFRS	MIFRS		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	13,976,313	14,049,010	72,697	0.5%
1820 - Distribution Station Equipment <50 kV	299,789	516,695	216,906	72.4%
Subtotal Transmission Assets	**14,276,102**	**14,565,705**	**289,603**	**2.0%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	3,150	3,150	-	0.0%
1808 - Buildings	438,602	438,602	-	0.0%
1830 - Poles, Towers & Fixtures	12,749,710	12,993,286	243,576	1.9%
1835 - Overhead Conductors & Devices	8,267,845	8,528,945	261,099	3.2%
1840 - Underground Conduit	5,065,832	5,598,703	532,871	10.5%
1845 - Underground Conductors & Devices	8,954,782	9,508,000	553,217	6.2%
1850 - Line Transformers	7,639,061	7,944,510	305,450	4.0%
1855 - Services (Overhead & Underground)	3,371,826	3,601,036	229,210	6.8%
1860 - Meters	1,337,035	1,467,527	130,492	9.8%
1860 - Meters (Smart Meters)	3,354,820	1,080,013	-2,274,807	-67.8%
Subtotal Distribution Assets	**52,434,866**	**52,415,974**	**-18,892**	**0.0%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	1,254,226	1,410,958	156,731	12.5%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	438,600	440,649	2,049	0.5%
1925/1611 - Computer Software	1,226,579	1,136,672	-89,908	-7.3%
1915 - Office Furniture & Equipment	190,714	185,913	-4,802	-2.5%
1930 - Transportation Equipment	1,216,379	1,078,552	-137,828	-11.3%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	206,543	223,499	16,956	8.2%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	424,224	457,245	33,020	7.8%
Subtotal General Plant	**4,963,946**	**4,940,166**	**-23,780**	**-0.5%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-1,941,379	-2,407,207	-465,828	24.0%
Subtotal Contribution and Grants	**-4,474,021**	**-4,939,850**	**-465,828**	**10.4%**
Gross Assets for Rate Base	**67,200,894**	**66,981,996**	**- 218,898**	**-0.3%**

In 2020, total spending on regular capital budget for distribution infrastructure work was $2.4M. This included overhead pole line rebuilds (Church St, East Gore) reinsulating, underground cable replacement (68M4 Feeder upgrade Ph 3, Campbell Court Ph 2), switchgear replacements, small capital replacements, DS ground grid upgrades, and customer driven work for new services and subdivisions. This was offset by a reduction to smart meters by $2.3M due to the removal of fully depreciated assets. General plant also decreased by $24K due to the removal of fully depreciated assets offset but purchases in the year.

Table 2-36– 2020 Actual vs 2021 Actual

Description	2020 Actual	2021 Actual	Variance from 2020 Actual	%
Reporting Basis	MIFRS	MIFRS		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	14,049,010	14,192,427	143,417	1.0%
1820 - Distribution Station Equipment <50 kV	516,695	508,911	-7,784	-1.5%
Subtotal Transmission Assets	**14,565,705**	**14,701,338**	**135,633**	**0.9%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	3,150	3,150	-	0.0%
1808 - Buildings	438,602	438,602	-	0.0%
1830 - Poles, Towers & Fixtures	12,993,286	13,656,294	663,008	5.1%
1835 - Overhead Conductors & Devices	8,528,945	8,847,421	318,477	3.7%
1840 - Underground Conduit	5,598,703	5,881,939	283,236	5.1%
1845 - Underground Conductors & Devices	9,508,000	10,356,468	848,468	8.9%
1850 - Line Transformers	7,944,510	8,352,072	407,561	5.1%
1855 - Services (Overhead & Underground)	3,601,036	3,951,047	350,012	9.7%
1860 - Meters	1,467,527	1,498,833	31,306	2.1%
1860 - Meters (Smart Meters)	1,080,013	929,912	-150,101	-13.9%
Subtotal Distribution Assets	**52,415,974**	**55,167,941**	**2,751,967**	**5.3%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	1,410,958	1,881,717	470,760	33.4%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	440,649	598,864	158,214	35.9%
1925/1611 - Computer Software	1,136,672	970,306	-166,366	-14.6%
1915 - Office Furniture & Equipment	185,913	181,676	-4,237	-2.3%
1930 - Transportation Equipment	1,078,552	1,095,062	16,511	1.5%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	223,499	223,951	452	0.2%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	457,245	448,667	-8,578	-1.9%
Subtotal General Plant	**4,940,166**	**5,406,923**	**466,757**	**9.4%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,641,514	-141,936	4.1%
2440 - Deferred Revenue	-2,407,207	-2,888,664	-481,457	20.0%
Subtotal Contribution and Grants	**-4,939,850**	**-5,563,243**	**-623,394**	**12.6%**
Gross Assets for Rate Base	**66,981,996**	**69,712,958**	**2,730,963**	**4.1%**

In 2021, total spending on regular capital budget for distribution infrastructure work was $3.0M. This included overhead pole line rebuilds (Warwick St, Philip/Fried St, Burritt St) reinsulating, underground cable replacement (68M4 Feeder upgrade Ph 4), switchgear replacements, small capital replacements, TS relay replacements, and customer driven work for new services and subdivisions. There was a decrease in smart meters due to the removal of fully depreciated assets. The capital additions for general plant (Vehicles, Land and Computer Equipment) were $467K. This included IT projects (website upgrades, server upgrades and replacements) and buildings (admin building bathroom renovation, service centre HVAC and electrical upgrades) offset partially by removal of fully depreciated software costs.

Table 2-37– 2021 Actual vs 2022 Actual

Description	2021 Actual	2022 Actual	Variance from 2021 Actual	%
Reporting Basis	MIFRS	MIFRS		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	14,192,427	14,278,690	86,263	0.6%
1820 - Distribution Station Equipment <50 kV	508,911	507,142	-1,769	-0.3%
Subtotal Transmission Assets	**14,701,338**	**14,785,832**	**84,495**	**0.6%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	3,150	3,150	-	0.0%
1808 - Buildings	438,602	438,602	-	0.0%
1830 - Poles, Towers & Fixtures	13,656,294	14,419,295	763,001	5.6%
1835 - Overhead Conductors & Devices	8,847,421	9,239,782	392,360	4.4%
1840 - Underground Conduit	5,881,939	5,948,590	66,651	1.1%
1845 - Underground Conductors & Devices	10,356,468	11,148,898	792,430	7.7%
1850 - Line Transformers	8,352,072	8,726,215	374,144	4.5%
1855 - Services (Overhead & Underground)	3,951,047	4,268,755	317,708	8.0%
1860 - Meters	1,498,833	1,491,766	-7,067	-0.5%
1860 - Meters (Smart Meters)	929,912	1,051,698	121,786	13.1%
Subtotal Distribution Assets	**55,167,941**	**57,988,954**	**2,821,013**	**5.1%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	1,881,717	2,211,367	329,650	17.5%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	598,864	682,015	83,151	13.9%
1925/1611 - Computer Software	970,306	987,713	17,407	1.8%
1915 - Office Furniture & Equipment	181,676	187,807	6,130	3.4%
1930 - Transportation Equipment	1,095,062	906,595	-188,467	-17.2%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	223,951	229,300	5,349	2.4%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	448,667	452,107	3,440	0.8%
Subtotal General Plant	**5,406,923**	**5,663,582**	**256,659**	**4.7%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,641,514	-3,499,578	141,936	-3.9%
2440 - Deferred Revenue	-2,888,664	-3,232,074	-343,410	11.9%
Subtotal Contribution and Grants	**-5,563,243**	**-5,764,717**	**-201,474**	**3.6%**
Gross Assets for Rate Base	**69,712,958**	**72,673,651**	**2,960,693**	**4.2%**

In 2022, total net additions for distribution infrastructure work were $2.9M. This included overhead pole line rebuilds (Romeo St, Blake St, Coleman St) reinsulating, underground cable replacement (68M4 Feeder upgrade Ph 5, Erie/St Patrick St), switchgear replacements, small capital replacements, metering, and customer driven work for new services and subdivisions. The capital additions for general plant were $257K. This included a new pickup truck, IT projects (SmartMAP software purchase, new hypervisor, and server hardware) and buildings (service centre vertical lift gates, washroom upgrades) offset by the removal of fully depreciated assets in the vehicles account.

1 **Table 2-38– 2022 Actual vs 2023 Actual**

Description	2022 Actual	2023 Actual	Variance from 2022 Actual	%
Reporting Basis	MIFRS	MIFRS		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	14,278,690	14,490,733	212,043	1.5%
1820 - Distribution Station Equipment <50 kV	507,142	507,142	-	0.0%
Subtotal Transmission Assets	**14,785,832**	**14,997,875**	**212,043**	**1.4%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	3,150	3,150	-	0.0%
1808 - Buildings	438,602	438,602	-	0.0%
1830 - Poles, Towers & Fixtures	14,419,295	15,039,856	620,561	4.3%
1835 - Overhead Conductors & Devices	9,239,782	9,649,606	409,824	4.4%
1840 - Underground Conduit	5,948,590	6,237,288	288,698	4.9%
1845 - Underground Conductors & Devices	11,148,898	11,529,123	380,225	3.4%
1850 - Line Transformers	8,726,215	9,279,629	553,413	6.3%
1855 - Services (Overhead & Underground)	4,268,755	4,511,379	242,624	5.7%
1860 - Meters	1,491,766	1,727,934	236,167	15.8%
1860 - Meters (Smart Meters)	1,051,698	1,051,698	-	0.0%
Subtotal Distribution Assets	**57,988,954**	**60,720,467**	**2,731,513**	**4.7%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	2,211,367	3,264,141	1,052,774	47.6%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	682,015	878,095	196,080	28.8%
1925/1611 - Computer Software	987,713	1,360,249	372,537	37.7%
1915 - Office Furniture & Equipment	187,807	184,123	-3,684	-2.0%
1930 - Transportation Equipment	906,595	891,265	-15,330	-1.7%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	229,300	244,956	15,656	6.8%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	452,107	543,758	91,651	20.3%
Subtotal General Plant	**5,663,582**	**7,373,267**	**1,709,685**	**30.2%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-3,232,074	-3,678,854	-446,781	13.8%
Subtotal Contribution and Grants	**-5,764,717**	**-6,211,498**	**-446,781**	**7.8%**
Gross Assets for Rate Base	**72,673,651**	**76,880,111**	**4,206,460**	**5.8%**

2

In 2023, total net additions for distribution infrastructure work were $2.9M. This included overhead pole line rebuilds (Griffith Rd, Oak St, Railway St) reinsulating, underground cable replacement (Elgin/Cain/Hillside), small capital replacements, metering, TS upgrades (new RTU, relay replacement) and customer driven work for new services and subdivisions. The capital additions for general plant were $1.7M. This included a new pickup truck, IT projects (CIS software upgrade, network access control upgrades, hardware replacements) and buildings (admin building renovation to customer service and finance area).

Table 2-39– 2023 Actual vs 2024 Bridge Year

Description	2023 Actual	2024 Bridge	Variance from 2023 Actual	%
Reporting Basis	MIFRS	MIFRS		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	14,490,733	14,640,733	150,000	1.0%
1820 - Distribution Station Equipment <50 kV	507,142	507,142	-	0.0%
Subtotal Transmission Assets	**14,997,875**	**15,147,875**	**150,000**	**1.0%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	3,150	3,150	-	0.0%
1808 - Buildings	438,602	438,602	-	0.0%
1830 - Poles, Towers & Fixtures	15,039,856	15,124,856	85,000	0.6%
1835 - Overhead Conductors & Devices	9,649,606	11,241,879	1,592,273	16.5%
1840 - Underground Conduit	6,237,288	7,132,788	895,500	14.4%
1845 - Underground Conductors & Devices	11,529,123	11,559,123	30,000	0.3%
1850 - Line Transformers	9,279,629	9,694,629	415,000	4.5%
1855 - Services (Overhead & Underground)	4,511,379	4,511,379	-	0.0%
1860 - Meters	1,727,934	2,127,934	400,000	23.1%
1860 - Meters (Smart Meters)	1,051,698	1,051,698	-	0.0%
Subtotal Distribution Assets	**60,720,467**	**64,138,240**	**3,417,773**	**5.6%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	3,264,141	5,429,141	2,165,000	66.3%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	878,095	1,071,164	193,069	22.0%
1925/1611 - Computer Software	1,360,249	2,579,847	1,219,598	89.7%
1915 - Office Furniture & Equipment	184,123	184,123	-	0.0%
1930 - Transportation Equipment	891,265	1,341,265	450,000	50.5%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	244,956	289,956	45,000	18.4%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	543,758	620,258	76,500	14.1%
Subtotal General Plant	**7,373,267**	**11,522,434**	**4,149,167**	**56.3%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-3,678,854	-3,897,968	-219,113	6.0%
Subtotal Contribution and Grants	**-6,211,498**	**-6,430,611**	**-219,113**	**3.5%**
Gross Assets for Rate Base	**76,880,111**	**84,377,938**	**7,497,827**	**9.8%**

In 2024, budgeted net additions for distribution infrastructure work are $3.4M. This includes overhead pole line rebuilds (Highway 83, Industrial Rd, Griffith Rd) reinsulating, underground cable replacement (Maxwell, Hibernia/Galt), small capital replacements, metering and beginning the AMI 2.0 deployment, TS upgrades, and customer driven work for new services and subdivisions.

The budgeted addition for general plant is $4.1M. This includes a new 42' single bucket truck, IT projects (finish CIS software upgrade, ERP software upgrade, hardware replacements) and buildings (finish admin building renovation for IT, meeting rooms, engineering, and metering).

Table 2-40– 2024 Bridge Year vs 2025 Test Year

Description	2024 Bridge	2025 Test	Variance from 2024 Forecast	%
Reporting Basis	MIFRS	MIFRS		
Transmission Assets				
1815 - Transformer Station Equipment >50 kV	14,640,733	14,915,333	274,600	1.9%
1820 - Distribution Station Equipment <50 kV	507,142	507,142	-	0.0%
Subtotal Transmission Assets	**15,147,875**	**15,422,475**	**274,600**	**1.8%**
Distribution Assets				
1805 - Land	1,252,202	1,252,202	-	0.0%
1806/1612 - Land Rights	3,150	3,150	-	0.0%
1808 - Buildings	438,602	438,602	-	0.0%
1830 - Poles, Towers & Fixtures	15,124,856	15,199,856	75,000	0.5%
1835 - Overhead Conductors & Devices	11,241,879	13,242,334	2,000,455	17.8%
1840 - Underground Conduit	7,132,788	8,427,638	1,294,850	18.2%
1845 - Underground Conductors & Devices	11,559,123	11,609,123	50,000	0.4%
1850 - Line Transformers	9,694,629	10,289,629	595,000	6.1%
1855 - Services (Overhead & Underground)	4,511,379	4,511,379	-	0.0%
1860 - Meters	2,127,934	3,555,231	1,427,297	67.1%
1860 - Meters (Smart Meters)	1,051,698	1,051,698	-	0.0%
Subtotal Distribution Assets	**64,138,240**	**69,580,842**	**5,442,602**	**8.5%**
General Plant				
1905 - Land	-	-	-	0.0%
1908 - Buildings & Fixtures	5,429,141	5,934,141	505,000	9.3%
1910 - Leasehold Improvements	-	-	-	0.0%
1920 - Computer Hardware	1,071,164	1,367,800	296,636	27.7%
1925/1611 - Computer Software	2,579,847	3,484,847	905,000	35.1%
1915 - Office Furniture & Equipment	184,123	184,123	-	0.0%
1930 - Transportation Equipment	1,341,265	1,466,265	125,000	9.3%
1935 - Stores Equipment	-	-	-	0.0%
1940 - Tools, Shop & Garage Equipment	289,956	336,156	46,200	15.9%
1945 - Measurement & Testing Equipment	-	-	-	0.0%
1955 - Communications Equipment	3,501	3,501	-	0.0%
1960 - Miscellaneous Equipment	3,178	3,178	-	0.0%
1970 - Load Management Controls Customer Premises	-	-	-	0.0%
1980 - System Supervisor Equipment	620,258	761,758	141,500	22.8%
Subtotal General Plant	**11,522,434**	**13,541,770**	**2,019,336**	**17.5%**
Contribution and Grants				
1609 - Capital Contributions Paid	966,935	966,935	-	0.0%
1995 - Contributions & Grants	-3,499,578	-3,499,578	-	0.0%
2440 - Deferred Revenue	-3,897,968	-4,225,156	-327,188	8.4%
Subtotal Contribution and Grants	**-6,430,611**	**-6,757,799**	**-327,188**	**5.1%**
Gross Assets for Rate Base	**84,377,938**	**91,787,288**	**7,409,350**	**8.8%**

In 2025, budgeted net additions for distribution infrastructure work are $5.7M. This includes overhead pole line rebuilds (Highway 83, Birch St, Romeo St) reinsulating, underground cable replacement (Maxwell St, Peel St, Ingersoll St), small capital replacements, switchgear replacements, year 1 of AMI 2.0 mass deployment, TS upgrades to replace the primary metering units, distribution automation investments, and customer driven work for new services and subdivisions. The budgeted addition for general plant is $2.0M. This includes the purchase of a forklift and passenger vehicle, IT projects (finish ERP software upgrade, OT hardware replacements) and buildings (roof replacement of admin building).

2.2.3.4 Summary of Capital Expenditures

For the purposes of Appendix 2-AB, FHI included all capital expenditures incurred in the year based on the projects that were undertaken and money that has been spent. The variances in 2021 and 2022 between the annual capital expenditures totals in Appendix 2-AB and Table 2-41 and the total fixed asset additions in the fixed asset continuity schedules (Appendix 2-BA) are due to an adjustment that was not made until 2022. The variances between the two years net to 0. Variances between actual and plan are included in Section 5.4.1.1 of the DSP.

Table 2-41– Capital Expenditure Summary (2-AB)

OEB Investment Category	Historical Period														
	2015			2016			2017			2018			2019		
	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %
System Access	322	713	121.7%	328	583	77.6%	335	733	119.3%	341	1,378	304.1%	348	1,200	245.3%
System Renewal	1,490	1,706	14.5%	1,513	1,427	-5.7%	1,539	1,644	6.8%	1,565	1,565	0.0%	1,592	1,768	11.1%
System Service	310	238	-23.3%	314	38	-87.8%	316	29	-90.7%	318	38	-88.1%	320	30	-90.7%
General Plant	500	653	30.7%	427	555	30.0%	826	549	-33.6%	445	837	88.0%	415	613	47.8%
Totals	**2,622**	**3,309**	**26.2%**	**2,582**	**2,603**	**0.8%**	**3,016**	**2,956**	**-2.0%**	**2,669**	**3,818**	**43.1%**	**2,675**	**3,611**	**35.0%**
Capital Contributions	120	334	178.3%	120	207	72.2%	120	372	209.8%	120	585	387.8%	120	444	269.8%
Net Capital Expenditures	**2,502**	**2,975**	**18.9%**	**2,462**	**2,396**	**-2.7%**	**2,896**	**2,584**	**-10.8%**	**2,549**	**3,233**	**26.8%**	**2,555**	**3,168**	**24.0%**
Total O&M	**2,104**	**2,156**	**2.4%**	**2,085**	**2,133**	**2.3%**	**2,124**	**2,269**	**6.8%**	**2,171**	**2,602**	**19.9%**	**2,591**	**2,408**	**-7.1%**

OEB Investment Category	Historical Period												Bridge Year		
	2020			2021			2022			2023			2024		
	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Actual	Var %	Plan	Budget	Var %
System Access	721	1,086	50.8%	712	1,091	53.2%	863	1,013	17.4%	805	1,186	47.4%	1,212	1,212	0.0%
System Renewal	1,935	1,627	-15.9%	1,866	2,027	8.6%	2,044	2,222	8.7%	2,469	2,114	-14.4%	2,236	2,236	0.0%
System Service	55	51	-7.5%	55	6	-89.7%	55	34	-38.5%	75	110	46.9%	77	77	0.0%
General Plant	973	460	-52.7%	1,040	876	-15.7%	969	907	-6.4%	1,665	1,927	15.8%	4,193	4,193	0.0%
Totals	**3,683**	**3,225**	**-12.5%**	**3,673**	**4,000**	**8.9%**	**3,931**	**4,175**	**6.2%**	**5,014**	**5,337**	**6.4%**	**7,717**	**7,717**	**0.0%**
Capital Contributions	200	466	132.8%	200	481	140.7%	200	343	71.7%	400	447	11.7%	219	219	0.0%
Net Capital Expenditures	**3,483**	**2,759**	**-20.8%**	**3,473**	**3,519**	**1.3%**	**3,731**	**3,832**	**2.7%**	**4,614**	**4,891**	**6.0%**	**7,498**	**7,498**	**0.0%**
Total O&M	**2,678**	**2,601**	**-2.9%**	**2,642**	**2,445**	**-7.5%**	**2,845**	**2,904**	**2.1%**	**3,087**	**3,049**	**-1.2%**	**3,352**	**3,352**	**0.0%**

OEB Investment Category	Test Year	Forecast Period			
	2025	2026	2027	2028	2029
	Budget	Forecast	Forecast	Forecast	Forecast
System Access	2,399	2,463	2,531	2,601	1,743
System Renewal	3,101	3,351	3,421	3,505	3,590
System Service	359	374	384	397	409
General Plant	1,878	1,299	1,262	1,274	1,585
Totals	**7,737**	**7,487**	**7,598**	**7,777**	**7,327**
Capital Contributions	327	332	338	345	352
Net Capital Expenditures	**7,410**	**7,156**	**7,260**	**7,432**	**6,974**
Total O&M	**3,515**	**3,620**	**3,729**	**3,841**	**3,956**

2.2.3.5 Capital Project Summary

Table 2-42 provides a summary of all capital projects for the years 2015 through 2023 Actual, the 2024 Bridge Year and the 2025 Test Year. All projects above FHI's materiality threshold of $80,000 have been listed individually within the DSP categories and all individual projects below the threshold have been grouped together as miscellaneous within the applicable category. FHI's DSP, found in Attachment 2-2, provides capital project summaries that provide a full description and justification of all individual material projects listed in Table 2-42 for the 2025 Test Year. These summaries are found in Appendix A of Attachment 2-2. Table 2-42 is consistent with the Board's Appendix 2-AA, Capital Projects Table. The variances in 2021 and 2022 between the annual totals in Appendix 2-AA and Table 2-41 and the total fixed asset additions in the fixed asset continuity schedules (Appendix 2-BA) are due to an adjustment that was not made until 2022. The variances between the two years net to 0.

Table 2-42 – Summary of Capital Projects (2-AA)

Projects	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access											
Subdivisions	377,707	229,754	118,894	550,809	89,052	455,635	232,456	222,963	379,021	369,616	406,900
New Services	231,003	248,664	471,580	419,148	453,933	335,760	478,141	410,285	371,154	300,295	375,000
Metering	70,980	104,045	104,360	230,484	492,665	207,219	96,889	362,299	314,013	200,000	112,000
AMI 2.0	0	0	0	0	0	0	0	0	96,466	200,000	1,316,337
Other Recoverable Work	33,028	0	38,660	177,542	164,262	87,661	283,622	17,442	25,636	142,000	189,000
System Access Capital Contributions	-333,945	-206,585	-371,810	-585,308	-443,731	-465,828	-481,457	-343,410	-446,781	-219,113	-327,188
Sub-Total	**378,772**	**375,878**	**361,684**	**792,676**	**756,182**	**620,447**	**609,651**	**669,579**	**739,510**	**992,798**	**2,072,049**
System Renewal											
Animal Mitigation	89,260	39,935	14,565	3,142	80,356	30,343	65,811	81,197	65,101	85,000	75,000
UG Renewal	379,235	280,541	360,585	426,276	422,449	364,501	441,142	708,274	541,750	808,898	1,188,450
OH Renewal	627,854	571,314	813,336	654,019	623,620	326,703	443,455	673,465	873,796	636,999	847,750
Switchgear Replacement	170,280	153,073	136,109	172,642	361,225	224,129	297,367	112,104	41,930	205,800	244,200
System Re-establishment	0	0	0	0	0	0	0	0	0	0	122,000
TS Renewal	0	0	0	5,300	35,855	72,697	137,501	86,263	212,043	150,000	274,600
Small Replacements	296,539	386,386	272,113	247,255	222,157	381,714	505,533	324,643	379,065	349,164	348,965
DS Renewal	0	0	0	0	17,481	227,076	1,887	0	0	0	0
Misc/Other	142,411	-4,053	47,427	56,833	5,260	0	134,657	235,832	0	0	0
Sub-Total	**1,705,580**	**1,427,197**	**1,644,134**	**1,565,466**	**1,768,402**	**1,627,164**	**2,027,352**	**2,221,777**	**2,113,684**	**2,235,861**	**3,100,965**
System Service											
Voltage Conversion	0	0	0	0	0	0	0	0	0	0	217,000
Grid Modernization	167,466	38,213	29,385	37,782	27,144	50,900	5,689	33,846	110,159	76,500	141,500
Misc/Other	70,200	0	0	0	2,589	0	0	0	0	0	0
Sub-Total	**237,666**	**38,213**	**29,385**	**37,782**	**29,733**	**50,900**	**5,689**	**33,846**	**110,159**	**76,500**	**358,500**
General Plant											
Fleet	40,680	30,426	7,390	334,227	56,425	0	16,511	68,635	92,935	450,000	125,000
Tools	15,434	22,344	29,482	35,757	29,367	26,793	26,796	28,200	36,453	45,000	46,200
Building&Equipment	232,893	153,023	136,178	193,352	225,097	156,731	491,840	365,904	1,060,506	2,165,000	505,000
IT Hardware	306,328	115,873	93,309	94,549	75,790	60,193	275,020	176,461	290,629	193,069	296,636
IT Software	58,144	233,363	282,383	178,912	226,526	216,420	66,063	267,546	446,552	464,598	30,000
ERP	0	0	0	0	0	0	0	0	0	875,000	875,000
Sub-Total	**653,478**	**555,029**	**548,742**	**836,796**	**613,205**	**460,137**	**876,230**	**906,745**	**1,927,075**	**4,192,667**	**1,877,836**
Total											
Less Renewable Generation Facility Assets and Other Non-Rate- Regulated Utility Assets (input as negative)	0	0	0	0	0	0	0	0	0	0	0
Total	**2,975,496**	**2,396,317**	**2,583,945**	**3,232,721**	**3,167,521**	**2,758,649**	**3,518,922**	**3,831,948**	**4,890,428**	**7,497,827**	**7,409,350**

2.2.4 Depreciation, Amortization and Depletion

2.2.4.1 Overview

In the 2025 Test Year, FHI proposes to record opening accumulated depreciation of $2.2M and a closing balance of $23.2M. FHI's accumulated depreciation increased along with capital investment in 2015 – 2025. FHI completed the transition to IFRS in the last COS Application so there are no further adjustments required.

2.2.4.2 Depreciation by Asset Group

International Accounting Standard 16 'Property, Plant and Equipment (PP&E)' ("IAS 16") requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the item to be depreciated separately. These components chosen by FHI reflect a rational and systematic allocation of cost over future periods appropriate to the nature of the property, plant, and equipment.

The only items of Property, Plant and Equipment that are not depreciated are Land Rights (Account 1612), Land (Account 1805) and Construction Work in Progress (CWIP - Account 2055). CWIP is not included for ratemaking purposes. Other Tangible Property is used to record major spare parts and standby equipment, which are reclassified from inventory and included with capital assets.

2.2.4.3 Depreciation Policy

The components of assets and related useful lives were determined as part of EB-2014-0073 with reference to the Depreciation Study for Use by Electricity Distributors (EB-2010-0178) (the "Kinectrics Report"). The useful lives chosen for FHI's assets are within the ranges suggested as a guideline by the Kinectrics Report with the exception of Residential Energy Meters, Industrial/ Commercial Meters, and Data Collectors – Smart Metering. Smart Meters are depreciated over 10 years which makes up the majority of meters. The meters included in 1860 in Residential Energy Meters and Industrial/ Commercial Meters are all depreciated over 10 years because all meters that are put into service since 2010 are smart meters and should depreciate over the same life. Data collectors related to smart meters are also depreciated over 10 years because FHI believes that they include the same technology as the smart meters and should have the same useful life. The only new depreciation change that was made was the addition of a

Software category for Large Software Projects which is described further below. Presented in Table 2-43 below is OEB Appendix 2-BB ‘Service Life Comparison’ which provides a summary comparison of the Kinectrics ranges, and the useful life chosen by FHI for each component. The two changes from the last COS 2-BB are highlighted in blue.

Table 2-43 –Service Life Comparison 2-BB

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles	45	2%	45	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles	40	3%	40	3%	No	No
				Steel	30	70	95	1830	Poles	40	3%	40	3%	No	No
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles	60	2%	60	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles	40	3%	40	3%	No	No
				Steel	30	70	95	1830	Poles	40	3%	40	3%	No	No
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	60	2%	60	2%	No	No
		OH Services			no guideline			1855	Services	60	2%	60	2%	no guideline	
	9	OH Transformers & Voltage Regulators			30	40	60								
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall - DS		30	45	60	1820	Distribution Station Equipment <50 kV	40	3%	40	3%	No	No
			Overall -TS		30	45	60	1815	Transformer Station Equipment >50 kV	40	3%	40	3%	No	No
			Bushing		10	20	30	1815	Transformer Station Equipment >50 kV	20	5%	20	5%	No	No
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1815	Transformer Station Equipment >50 kV	45	2%	45	2%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60	1815	Transformer Station Equipment >50 kV	50	2%	50	2%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45	1815	Transformer Station Equipment >50 kV	15	7%	15	7%	No	No
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60	1815	Transformer Station Equipment >50 kV	55	2%	55	2%	No	No
	23	Steel Structure			35	50	90	1815	Transformer Station Equipment >50 kV	60	2%	60	2%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (Non-TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30	1845	Underground Conductors and Devices	25	4%	25	4%	No	No
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Underground Conductors and Devices	25	4%	25	4%	No	No
	28	Primary TR XLPE Cables Direct Buried			25	30	35								
	29	Primary TR XLPE Cables in Duct			35	40	55	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40								
	32	Secondary Cables in Duct			35	40	60	1855	Services	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	40	3%	40	3%	No	No
	36	UG Foundation			35	55	70	1850	Line Transformers	40	3%	40	3%	No	No
	37	UG Vaults	Overall		40	60	80	1850	Line Transformers	40	3%	40	3%	No	No
			Roof		20	30	45	1850	Line Transformers	40	3%	40	3%	No	No
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	30	3%	30	3%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	50	2%	50	2%	No	No
	41	Concrete Encased Duct Banks			35	55	80	1840	Underground Conduit	50	2%	50	2%	No	No
	42	Cable Chambers			50	60	80	1840	Underground Conduit	50	2%	50	2%	No	No
S	43	Remote SCADA			15	20	30	1980	System Supervisory Equipment	15	7%	15	7%	No	No

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current Years	Current Rate	Proposed Years	Proposed Rate	Outside Range of Min, Max TUL? Below Min Range	Outside Range of Min, Max TUL? Above Max Range
1	Office Equipment		5	15								
2	Vehicles	Trucks & Buckets	5	15								
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings	Buildings	50	75	1808	Buildings and Fixtures	60	2%	60	2%	No	No
		Buildings	no guideline		1809	Buildings and Fixtures	60	2%	60	2%	no guideline	
		HVAC equipment	no guideline		1908	Buildings and Fixtures	10	10%	10	10%	no guideline	
		Buildings	no guideline		1908	Buildings and Fixtures	60	2%	60	2%	no guideline	
		Parking	25	30	1908	Buildings and Fixtures	30	3%	30	3%	No	No
		Fence	25	60	1908	Buildings and Fixtures	30	3%	30	3%	No	No
		Roof	20	30	1908	Buildings and Fixtures	20	5%	20	5%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leasehold improvements	5	20%	5	20%	Yes	Yes
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	60	2%	60	2%	No	No
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - hardware	5	20%	5	20%	No	No
		Software	2	5	1611	Computer Software	5	20%	5	20%	No	No
		Software - ERP/CIS	no guideline		1611	Computer Software	10	10%	10	10%	no guideline	
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and garage equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measure & testing Equipment	8	13%	8	13%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters	10	10%	10	10%	Yes	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	10	10%	10	10%	Yes	No
	Primary Energy Meters		no guideline		1860	Meters	20	5%	20		no guideline	
11	Wholesale Energy Meters		15	30	1860	Meters	20	5%	20	5%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	40	3%	40	3%	No	No
13	Smart Meters		5	15	1880	Smart meters	10	10%	10	10%	No	No
14	Repeaters - Smart Metering		10	15	1880	Smart meters	10	10%	10	10%	No	No
15	Data Collectors - Smart Metering		15	20	1880	Smart meters	10	10%	10	10%	Yes	No

Starting with Table 2-44 below, OEB Appendix 2-C ‘Depreciation and Amortization Expense’ is provided from 2015 actuals to the 2025 Test Year which outlines the asset components and related depreciation rates used by FHI.

The depreciation expense amounts in OEB Appendix 2-C ‘Depreciation and Amortization Expense’ for each year reconciles with the accumulated depreciation balances in the fixed asset continuity schedules from 2015 to the 2025 Test Year found in Appendix 2-BA.

Table 2-44 – 2015 Depreciation and Amortization Expense (2-C)

Year 2015

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 2,360,056	$ -	$ 70,200	$ 1,463,321	$ 931,835	17.11	5.85%	**$ 54,474**	$ 54,474	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 370,401	$ -	$ 306,328	$ -	$ 523,565	4.35	22.98%	**$ 120,293**	$ 120,293	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 494,571	$ -	$ -	$ -	$ 494,571	12.55	7.97%	**$ 39,423**	$ 39,423	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$ -	$ 13,935,158	43.52	2.30%	**$ 320,192**	$ 320,192	**$ -**
1820	Distribution Station Equipment <50 kV	$ 254,798	$ -	$ -	$ -	$ 254,798	9.15	10.92%	**$ 27,835**	$ 27,835	**$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 10,264,040	$ -	$ 581,837	$ -	$ 10,554,959	41.44	2.41%	**$ 254,718**	$ 254,718	**$ -**
1835	Overhead Conductors & Devices	$ 6,437,700	$ -	$ 347,558	$ -	$ 6,611,479	48.18	2.08%	**$ 137,222**	$ 137,222	**$ -**
1840	Underground Conduit	$ 3,886,852	$ -	$ 387,924	$ -	$ 4,080,814	41.28	2.42%	**$ 98,861**	$ 98,861	**$ -**
1845	Underground Conductors & Devices	$ 6,112,549	$ -	$ 490,818	$ -	$ 6,357,959	29.43	3.40%	**$ 216,004**	$ 216,004	**$ -**
1850	Line Transformers	$ 5,681,103	$ -	$ 407,840	$ -	$ 5,885,023	30.67	3.26%	**$ 191,869**	$ 191,869	**$ -**
1855	Services (Overhead & Underground)	$ 2,072,988	$ -	$ 193,102	$ -	$ 2,169,539	30.51	3.28%	**$ 71,111**	$ 71,111	**$ -**
1860	Meters	$ 962,973	$ -	$ 26,555	$ 4,001	$ 972,249	14.17	7.06%	**$ 68,593**	$ 68,593	**$ -**
1860	Meters (Smart Meters)	$ 2,738,785	$ -	$ 47,979	$ 2,730	$ 2,760,045	6.66	15.01%	**$ 414,319**	$ 414,319	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 465,827	$ -	$ 141,389	$ -	$ 536,521	15.63	6.40%	**$ 34,330**	$ 34,330	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 85,910	$ -	$ 91,504	$ -	$ 131,662	8.62	11.60%	**$ 15,271**	$ 15,271	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 354,933	$ -	$ 58,144	$ -	$ 384,005	4.11	24.32%	**$ 93,390**	$ 93,390	**-$ 0**
1930	Transportation Equipment	$ 944,582	$ 27,740	$ 40,680	$ -	$ 937,181	7.91	12.65%	**$ 118,545**	$ 118,545	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 159,916	$ -	$ 15,434	$ -	$ 167,633	6.02	16.62%	**$ 27,868**	$ 27,868	**$ -**
1945	Measurement & Testing Equipment	$ 9,659	$ -	$ -	$ -	$ 9,659	3.00	33.33%	**$ 3,220**	$ 3,220	**$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 367	$ -	$ 3,501	$ -	$ 2,117	10.01	9.99%	**$ 212**	$ 212	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 6,315	$ -	$ -	$ -	$ 6,315	5.73	17.45%	**$ 1,102**	$ 1,102	**$ -**
1970	Load Management Controls Customer Premises	$ 43,749	$ -	$ -	$ -	$ 43,749	2.95	33.85%	**$ 14,808**	$ 14,808	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 177,377	$ -	$ 98,649	$ -	$ 226,701	12.87	7.77%	**$ 17,613**	$ 17,613	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.22	2.84%	**-$ 99,367**	-$ 99,367	**$ -**
2440	Deferred Revenue	$ -	$ -	-$ 333,945	$ -	-$ 166,973	28.34	3.53%	**-$ 5,892**	-$ 5,892	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 55,573,235**	**$ 27,740**	**$ 2,975,496**		**$ 54,631,355**	**$ 469**		**$ 2,236,014**	**$ 2,236,014**	**-$ 0**

Table 2-45 – 2016 Depreciation and Amortization Expense (2-C)

Year 2016

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 676,729	$ 70,110	$ 232,429	$ -	$ 722,833	4.70	21.27%	**$ 153,732**	$ 153,732	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 494,571	$ 49,355	$ -	$ -	$ 445,216	30.19	3.31%	**$ 14,747**	$ 14,747	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$ -	$ 13,935,158	43.52	2.30%	**$ 320,188**	$ 320,188	**$ -**
1820	Distribution Station Equipment <50 kV	$ 254,798	$ 28,924	$ -	$ -	$ 225,874	16.89	5.92%	**$ 13,373**	$ 13,373	**-$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 10,845,877	$ -	$ 415,993	$ 4,053	$ 11,049,821	41.82	2.39%	**$ 264,194**	$ 264,194	**$ -**
1835	Overhead Conductors & Devices	$ 6,785,258	$ -	$ 280,767	$ -	$ 6,925,642	48.47	2.06%	**$ 142,891**	$ 142,891	**$ -**
1840	Underground Conduit	$ 4,274,776	$ -	$ 126,385	$ -	$ 4,337,968	41.79	2.39%	**$ 103,793**	$ 103,793	**$ 0**
1845	Underground Conductors & Devices	$ 6,603,368	$ -	$ 460,749	$ -	$ 6,833,742	29.82	3.35%	**$ 229,188**	$ 229,188	**$ -**
1850	Line Transformers	$ 6,088,943	$ -	$ 309,192	$ -	$ 6,243,539	31.09	3.22%	**$ 200,832**	$ 200,832	**$ -**
1855	Services (Overhead & Underground)	$ 2,266,090	$ -	$ 315,975	$ -	$ 2,424,078	31.41	3.18%	**$ 77,171**	$ 77,171	**$ -**
1860	Meters	$ 985,526	$ -	$ 25,019	$ -	$ 998,035	14.31	6.99%	**$ 69,754**	$ 69,754	**$ -**
1860	Meters (Smart Meters)	$ 2,784,035	$ -	$ 79,634	$ 6,769	$ 2,817,083	6.70	14.92%	**$ 420,224**	$ 420,224	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 607,216	$ 10,247	$ 146,538	$ -	$ 670,238	16.31	6.13%	**$ 41,099**	$ 41,099	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 177,414	$ 554	$ 6,485	$ -	$ 180,103	9.00	11.11%	**$ 20,003**	$ 20,003	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 413,077	$ 51,227	$ 116,807	$ -	$ 420,254	4.20	23.79%	**$ 99,961**	$ 99,961	**$ -**
1930	Transportation Equipment	$ 957,521	$ -	$ 61,189	$ 30,764	$ 957,352	7.86	12.73%	**$ 121,851**	$ 121,851	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 175,350	$ 41,156	$ 22,344	$ -	$ 145,366	5.31	18.83%	**$ 27,377**	$ 27,377	**$ -**
1945	Measurement & Testing Equipment	$ 9,659	$ 6,439	$ -	$ -	$ 3,220	1.00	100.00%	**$ 3,220**	$ 3,220	**-$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,868	$ -	$ -	$ 367	$ 3,501	9.06	11.03%	**$ 386**	$ 386	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 6,315	$ -	$ -	$ -	$ 6,315	5.73	17.45%	**$ 1,102**	$ 1,102	**$ -**
1970	Load Management Controls Customer Premises	$ 43,749	$ 39,506	$ -	$ -	$ 4,243	1.00	100.00%	**$ 4,243**	$ 4,243	**$ 0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 276,026	$ -	$ 38,213	$ -	$ 295,132	13.31	7.51%	**$ 22,175**	$ 22,175	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.22	2.84%	**-$ 99,367**	-$ 99,367	**$ -**
2440	Deferred Revenue	-$ 333,945	$ -	-$ 206,585	$ -	-$ 437,237	40.52	2.47%	**-$ 10,791**	-$ 10,791	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 57,050,939**	**$ 297,519**	**$ 2,431,134**		**$ 56,960,099**	**$ 507**		**$ 2,295,820**	**$ 2,295,820**	**$ 0**

Table 2-46 – 2017 Depreciation and Amortization Expense (2-C)

Year 2017

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 839,047	$ 34,097	$ 282,383	$ -	$ 946,142	4.83	20.71%	**$ 195,941**	$ 195,941	**$ 0**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 445,216	$ 5,037	$ -	$ -	$ 440,179	29.85	3.35%	**$ 14,745**	$ 14,745	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$ -	$ 13,935,158	43.52	2.30%	**$ 320,188**	$ 320,188	**$ -**
1820	Distribution Station Equipment <50 kV	$ 225,874	$ -	$ 34,695	$ -	$ 243,222	17.62	5.68%	**$ 13,807**	$ 13,807	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 11,257,817	$ -	$ 461,590	$ -	$ 11,488,612	42.17	2.37%	**$ 272,465**	$ 272,465	**$ -**
1835	Overhead Conductors & Devices	$ 7,066,025	$ -	$ 365,637	$ -	$ 7,248,844	48.75	2.05%	**$ 148,682**	$ 148,682	**$ -**
1840	Underground Conduit	$ 4,401,161	$ -	$ 108,219	$ -	$ 4,455,270	42.02	2.38%	**$ 106,032**	$ 106,032	**$ -**
1845	Underground Conductors & Devices	$ 7,064,116	$ -	$ 431,330	$ -	$ 7,279,781	30.14	3.32%	**$ 241,550**	$ 241,550	**$ -**
1850	Line Transformers	$ 6,398,135	$ -	$ 519,430	$ -	$ 6,657,850	31.53	3.17%	**$ 211,189**	$ 211,189	**$ -**
1855	Services (Overhead & Underground)	$ 2,582,065	$ -	$ 336,699	$ -	$ 2,750,415	32.49	3.08%	**$ 84,656**	$ 84,656	**$ -**
1860	Meters	$ 1,010,545	$ -	$ 79,835	$ -	$ 1,050,463	14.44	6.93%	**$ 72,758**	$ 72,758	**$ -**
1860	Meters (Smart Meters)	$ 2,856,900	$ -	$ 27,989	$ -	$ 2,870,894	6.75	14.81%	**$ 425,267**	$ 425,267	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 743,507	$ 11,442	$ 126,216	$ -	$ 795,173	16.73	5.98%	**$ 47,532**	$ 47,532	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 183,345	$ -	$ 9,962	$ -	$ 188,326	9.04	11.06%	**$ 20,825**	$ 20,825	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 478,657	$ 28,799	$ 93,309	$ -	$ 496,513	4.61	21.68%	**$ 107,632**	$ 107,632	**$ -**
1930	Transportation Equipment	$ 987,947	$ -	$ 7,390	$ -	$ 991,642	8.19	12.20%	**$ 121,024**	$ 121,024	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 156,538	$ 22,197	$ 29,482	$ -	$ 149,082	5.61	17.81%	**$ 26,552**	$ 26,552	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 6,315	$ 3,137	$ -	$ -	$ 3,178	2.88	34.67%	**$ 1,102**	$ 1,102	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 314,239	$ -	$ 41,588	$ -	$ 335,033	13.49	7.41%	**$ 24,829**	$ 24,829	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.22	2.84%	**-$ 99,367**	-$ 99,367	**$ -**
2440	Deferred Revenue	-$ 540,530	$ -	-$ 371,810	$ -	-$ 726,435	59.36	1.68%	**-$ 12,239**	-$ 12,239	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 59,135,138**	**$ 104,709**	**$ 2,583,945**		**$ 59,355,467**	**$ 527**		**$ 2,399,997**	**$ 2,399,997**	**$ 0**

Table 2-47 – 2018 Depreciation and Amortization Expense (2-C)

Year 2018

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed**	**Variance [4]**
		a	**b**	**c**	**d**	**e = a-b+0.5*c-d**	**f**	**g = 1/f**	**h = e/f**	**i**	**j = i-h**
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 1,087,333	$ 82,898	$ 178,912	$ -	$ 1,093,891	4.80	20.84%	**$ 227,989**	$ 227,989	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 440,179	$ 1,577	$ -	$ -	$ 438,602	32.52	3.07%	**$ 13,486**	$ 13,486	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ 5,300	$ -	$ 13,937,808	43.53	2.30%	**$ 320,188**	$ 320,188	**$ -**
1820	Distribution Station Equipment <50 kV	$ 260,569	$ -	$ 21,739	$ -	$ 271,439	18.70	5.35%	**$ 14,512**	$ 14,512	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 11,719,407	$ -	$ 530,251	$ -	$ 11,984,533	42.63	2.35%	**$ 281,109**	$ 281,109	**$ -**
1835	Overhead Conductors & Devices	$ 7,431,662	$ -	$ 404,796	$ -	$ 7,634,060	49.10	2.04%	**$ 155,467**	$ 155,467	**$ -**
1840	Underground Conduit	$ 4,509,380	$ -	$ 415,526	$ -	$ 4,717,143	41.11	2.43%	**$ 114,756**	$ 114,756	**$ -**
1845	Underground Conductors & Devices	$ 7,495,446	$ 529	$ 736,821	$ -	$ 7,863,327	30.55	3.27%	**$ 257,407**	$ 257,407	**$ -**
1850	Line Transformers	$ 6,917,565	$ -	$ 305,727	$ -	$ 7,070,429	31.92	3.13%	**$ 221,498**	$ 221,498	**$ -**
1855	Services (Overhead & Underground)	$ 2,918,765	$ -	$ 271,629	$ -	$ 3,054,579	33.33	3.00%	**$ 91,652**	$ 91,652	**$ -**
1860	Meters	$ 1,090,380	$ 547	$ 132,780	$ -	$ 1,156,223	14.56	6.87%	**$ 79,433**	$ 79,433	**$ -**
1860	Meters (Smart Meters)	$ 2,884,888	$ 5,024	$ 114,130	$ -	$ 2,936,929	6.79	14.72%	**$ 432,373**	$ 432,373	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 858,281	$ 11,465	$ 183,588	$ -	$ 938,609	16.38	6.10%	**$ 57,297**	$ 57,297	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 193,307	$ 13,630	$ 9,764	$ -	$ 184,559	8.46	11.82%	**$ 21,812**	$ 21,812	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 543,167	$ 189,680	$ 94,549	$ -	$ 400,762	3.96	25.26%	**$ 101,228**	$ 101,228	**$ -**
1930	Transportation Equipment	$ 995,337	$ 63,268	$ 334,227	$ -	$ 1,099,183	8.10	12.34%	**$ 135,635**	$ 135,635	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 163,823	$ 22,404	$ 35,757	$ -	$ 159,297	6.56	15.23%	**$ 24,265**	$ 24,265	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 355,827	$ 1,025	$ 42,534	$ -	$ 376,069	13.60	7.35%	**$ 27,645**	$ 27,645	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 912,339	$ -	-$ 585,308	$ -	-$ 1,204,993	25.11	3.98%	**-$ 47,985**	-$ 47,985	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 61,614,375**	**$ 392,049**	**$ 3,232,721**		**$ 61,871,752**	**$ 504**		**$ 2,484,963**	**$ 2,484,963**	**$ -**

Table 2-48 – 2019 Depreciation and Amortization Expense (2-C)

Year 2019

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 1,183,347	$ 183,294	$ 226,526	$ -	$ 1,113,316	4.62	21.65%	**$ 240,992**	$ 240,992	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ 3,150	$ -	$ 1,575		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,940,458	$ -	$ 35,855	$ -	$ 13,958,386	43.45	2.30%	**$ 321,261**	$ 321,261	**$ -**
1820	Distribution Station Equipment <50 kV	$ 282,308	$ -	$ 17,481	$ -	$ 291,049	19.40	5.15%	**$ 15,003**	$ 15,003	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 12,249,659	$ -	$ 500,051	$ -	$ 12,499,684	42.98	2.33%	**$ 290,850**	$ 290,850	**$ -**
1835	Overhead Conductors & Devices	$ 7,836,458	$ -	$ 431,387	$ -	$ 8,052,152	49.42	2.02%	**$ 162,945**	$ 162,945	**$ -**
1840	Underground Conduit	$ 4,924,906	$ -	$ 140,926	$ -	$ 4,995,369	41.52	2.41%	**$ 120,322**	$ 120,322	**$ -**
1845	Underground Conductors & Devices	$ 8,231,738	$ 1,191	$ 724,236	$ -	$ 8,592,664	30.85	3.24%	**$ 278,531**	$ 278,531	**$ -**
1850	Line Transformers	$ 7,223,292	$ -	$ 415,768	$ -	$ 7,431,177	32.24	3.10%	**$ 230,516**	$ 230,516	**-$ 0**
1855	Services (Overhead & Underground)	$ 3,190,393	$ 27,973	$ 209,405	$ -	$ 3,267,123	33.55	2.98%	**$ 97,374**	$ 97,374	**-$ 0**
1860	Meters	$ 1,222,613	$ 2,977	$ 117,399	$ -	$ 1,278,336	14.76	6.77%	**$ 86,579**	$ 86,579	**$ -**
1860	Meters (Smart Meters)	$ 2,993,994	$ 14,439	$ 375,266	$ -	$ 3,167,187	6.99	14.30%	**$ 452,950**	$ 452,950	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 1,030,403	$ -	$ 223,823	$ -	$ 1,142,315	16.07	6.22%	**$ 71,088**	$ 71,088	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 189,440	$ -	$ 1,274	$ -	$ 190,077	9.68	10.33%	**$ 19,637**	$ 19,637	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 448,036	$ 85,226	$ 75,790	$ -	$ 400,705	4.52	22.13%	**$ 88,664**	$ 88,664	**$ -**
1930	Transportation Equipment	$ 1,266,296	$ 106,342	$ 56,425	$ -	$ 1,188,167	8.50	11.76%	**$ 139,728**	$ 139,728	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 177,176	$ -	$ 29,367	$ -	$ 191,859	8.33	12.01%	**$ 23,040**	$ 23,040	**$ 0**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 397,335	$ 234	$ 27,123	$ -	$ 410,663	13.80	7.25%	**$ 29,756**	$ 29,756	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 1,490,314	$ -	-$ 443,731	$ -	-$ 1,712,180	37.29	2.68%	**-$ 45,912**	-$ 45,912	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 64,462,381**	**$ 421,675**	**$ 3,167,521**		**$ 64,657,531**	**$ 524**		**$ 2,591,692**	**$ 2,591,692**	**-$ 0**

Table 2-49 – 2020 Depreciation and Amortization Expense (2-C)

Year 2020

Account	Description	Book Values				Service Lives		Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 1,226,579	$ 306,328	$ 216,420	$ -	$ 1,028,462	4.35	22.98%	**$ 236,325**	$ 236,325	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,976,313	$ -	$ 72,697	$ -	$ 14,012,662	43.18	2.32%	**$ 324,551**	$ 324,551	**$ -**
1820	Distribution Station Equipment <50 kV	$ 299,789	$ 10,170	$ 227,076	$ -	$ 403,157	22.32	4.48%	**$ 18,060**	$ 18,060	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 12,749,710	$ -	$ 283,463	$ 39,887	$ 12,851,554	42.98	2.33%	**$ 299,041**	$ 299,041	**$ -**
1835	Overhead Conductors & Devices	$ 8,267,845	$ -	$ 261,099	$ -	$ 8,398,395	49.64	2.01%	**$ 169,193**	$ 169,193	**$ -**
1840	Underground Conduit	$ 5,065,832	$ -	$ 532,871	$ -	$ 5,332,268	41.97	2.38%	**$ 127,059**	$ 127,059	**$ -**
1845	Underground Conductors & Devices	$ 8,954,782	$ 2,087	$ 555,305	$ -	$ 9,230,348	31.17	3.21%	**$ 296,124**	$ 296,124	**$ -**
1850	Line Transformers	$ 7,639,061	$ -	$ 305,450	$ -	$ 7,791,786	32.53	3.07%	**$ 239,531**	$ 239,531	**-$ 0**
1855	Services (Overhead & Underground)	$ 3,371,826	$ -	$ 229,210	$ -	$ 3,486,431	35.64	2.81%	**$ 97,834**	$ 97,834	**-$ 0**
1860	Meters	$ 1,337,035	$ 1,902	$ 132,394	$ -	$ 1,401,330	15.11	6.62%	**$ 92,750**	$ 92,750	**$ -**
1860	Meters (Smart Meters)	$ 3,354,820	$ 2,406,014	$ 131,206	$ -	$ 1,014,410	3.46	28.90%	**$ 293,196**	$ 293,196	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 1,254,226	$ -	$ 156,731	$ -	$ 1,332,592	16.00	6.25%	**$ 83,263**	$ 83,263	**-$ 0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 190,714	$ 4,802	$ -	$ -	$ 185,913	9.62	10.40%	**$ 19,332**	$ 19,332	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 438,600	$ 58,144	$ 60,194	$ -	$ 410,552	4.67	21.42%	**$ 87,925**	$ 87,925	**$ -**
1930	Transportation Equipment	$ 1,216,379	$ 137,828	$ -	$ -	$ 1,078,552	8.77	11.40%	**$ 122,917**	$ 122,917	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 206,543	$ 9,837	$ 26,793	$ -	$ 210,103	8.37	11.94%	**$ 25,092**	$ 25,092	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	9.99	10.01%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 424,224	$ 549	$ 33,569	$ -	$ 440,460	13.88	7.21%	**$ 31,740**	$ 31,740	**$ 0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 1,934,045	$ -	-$ 465,828	$ -	-$ 2,166,959	37.93	2.64%	**-$ 57,127**	-$ 57,127	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 67,208,227**	**$ 2,937,660**	**$ 2,758,650**		**$ 64,643,069**	**$ 528**		**$ 2,475,174**	**$ 2,475,174**	**-$ 0**

Table 2-50 – 2021 Depreciation and Amortization Expense (2-C)

Year 2021

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 1,136,672	$ 232,429	$ 66,063	$ -	$ 937,274	4.45	22.48%	**$ 210,698**	$ 210,698	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ 9,671	$ -	$ -	$ 428,932	32.57	3.07%	**$ 13,171**	$ 13,171	**$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 14,049,010	$ -	$ 143,417	$ -	$ 14,120,718	42.26	2.37%	**$ 334,173**	$ 334,173	**$ -**
1820	Distribution Station Equipment <50 kV	$ 516,695	$ -	$ 1,887	$ -	$ 517,638	26.59	3.76%	**$ 19,469**	$ 19,469	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 12,993,286	$ 2,590	$ 663,008	$ -	$ 13,322,200	43.32	2.31%	**$ 307,556**	$ 307,556	**$ -**
1835	Overhead Conductors & Devices	$ 8,528,945	$ -	$ 318,477	$ -	$ 8,688,183	49.84	2.01%	**$ 174,321**	$ 174,321	**$ -**
1840	Underground Conduit	$ 5,598,703	$ -	$ 283,236	$ -	$ 5,740,321	45.18	2.21%	**$ 127,059**	$ 127,059	**$ -**
1845	Underground Conductors & Devices	$ 9,508,000	$ 15,012	$ 851,058	$ -	$ 9,918,517	31.43	3.18%	**$ 315,583**	$ 315,583	**$ -**
1850	Line Transformers	$ 7,944,510	$ 203,333	$ 407,561	$ -	$ 7,944,958	31.98	3.13%	**$ 248,444**	$ 248,444	**$ -**
1855	Services (Overhead & Underground)	$ 3,601,036	$ -	$ 350,012	$ -	$ 3,776,041	36.06	2.77%	**$ 104,707**	$ 104,707	**$ -**
1860	Meters	$ 1,467,527	$ 6,795	$ 46,318	$ -	$ 1,483,891	15.29	6.54%	**$ 97,070**	$ 97,070	**$ -**
1860	Meters (Smart Meters)	$ 1,080,013	$ -	$ 53,232	$ -	$ 1,106,629	10.40	9.62%	**$ 106,440**	$ 106,440	**$ -**
1905	Land	$ -	$ 12,585	$ -	$ -	-$ 12,585		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 1,410,958	$ -	$ 477,555	$ -	$ 1,649,735	17.06	5.86%	**$ 96,716**	$ 96,716	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 185,913	$ -	$ 8,348	$ -	$ 190,087	10.14	9.86%	**$ 18,751**	$ 18,751	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ 116,806	$ -	$ -	-$ 116,806		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 440,649	$ 26,344	$ 275,021	$ -	$ 551,815	5.31	18.84%	**$ 103,951**	$ 103,951	**$ -**
1930	Transportation Equipment	$ 1,078,552	$ -	$ 16,511	$ -	$ 1,086,807	10.49	9.54%	**$ 103,650**	$ 103,650	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 223,499	$ -	$ 26,796	$ -	$ 236,897	9.22	10.85%	**$ 25,697**	$ 25,697	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	5.00	20.00%	**$ 700**	$ 700	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ 20,459	$ -	$ -	-$ 20,459		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 457,245	$ -	$ 11,881	$ -	$ 463,185	13.96	7.16%	**$ 33,177**	$ 33,177	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	-$ 141,936	$ -	-$ 3,570,546	35.73	2.80%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 2,399,873	$ -	-$ 481,457	$ -	-$ 2,640,602	43.55	2.30%	**-$ 60,633**	-$ 60,633	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 66,989,329**	**$ 646,024**	**$ 3,376,986**		**$ 67,064,863**	**$ 548**		**$ 2,335,547**	**$ 2,335,547**	**-$ 0**

Table 2-51 – 2022 Depreciation and Amortization Expense (2-C)

Year 2022

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed**	**Variance [4]**
		a	**b**	**c**	**d**	**e = a-b+0.5*c-d**	**f**	**g = 1/f**	**h = e/f**	**i**	**j = i-h**
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 970,306	$ 282,383	$ 299,790	$ -	$ 837,818	4.82	20.73%	**$ 173,656**	$ 173,656	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 14,192,427	$ -	$ 86,263	$ -	$ 14,235,558	41.18	2.43%	**$ 345,657**	$ 345,657	**$ -**
1820	Distribution Station Equipment <50 kV	$ 508,911	$ 1,769	$ -	$ -	$ 507,142	26.18	3.82%	**$ 19,370**	$ 19,370	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 13,656,294	$ -	$ 763,001	$ -	$ 14,037,794	44.06	2.27%	**$ 318,606**	$ 318,606	**$ -**
1835	Overhead Conductors & Devices	$ 8,847,421	$ -	$ 392,360	$ -	$ 9,043,602	49.84	2.01%	**$ 181,457**	$ 181,457	**$ -**
1840	Underground Conduit	$ 5,881,939	$ -	$ 66,651	$ -	$ 5,915,265	43.75	2.29%	**$ 135,220**	$ 135,220	**$ -**
1845	Underground Conductors & Devices	$ 10,356,468	$ 12,294	$ 804,724	$ -	$ 10,746,536	31.02	3.22%	**$ 346,462**	$ 346,462	**$ -**
1850	Line Transformers	$ 8,352,072	$ -	$ 374,144	$ -	$ 8,539,144	33.07	3.02%	**$ 258,215**	$ 258,215	**-$ 0**
1855	Services (Overhead & Underground)	$ 3,951,047	$ -	$ 317,708	$ -	$ 4,109,901	36.55	2.74%	**$ 112,455**	$ 112,455	**$ -**
1860	Meters	$ 1,498,833	$ 214,520	$ 207,453	$ -	$ 1,388,040	13.52	7.40%	**$ 102,652**	$ 102,652	**$ -**
1860	Meters (Smart Meters)	$ 929,912	$ 68,716	$ 190,502	$ -	$ 956,447	9.18	10.89%	**$ 104,200**	$ 104,200	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 1,881,717	$ 27,578	$ 357,228	$ -	$ 2,032,753	16.85	5.94%	**$ 120,660**	$ 120,660	**-$ 0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 181,676	$ 2,545	$ 8,676	$ -	$ 183,469	9.74	10.27%	**$ 18,845**	$ 18,845	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 598,864	$ 93,310	$ 176,461	$ -	$ 593,784	4.64	21.57%	**$ 128,088**	$ 128,088	**$ -**
1930	Transportation Equipment	$ 1,095,062	$ 257,102	$ 68,635	$ -	$ 872,278	9.06	11.03%	**$ 96,226**	$ 96,226	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 223,951	$ 22,851	$ 28,200	$ -	$ 215,200	8.28	12.08%	**$ 25,987**	$ 25,987	**-$ 0**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	9.99	10.01%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 448,667	$ 30,123	$ 33,563	$ -	$ 435,325	12.89	7.76%	**$ 33,782**	$ 33,782	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,641,514	$ -	$ 141,936	$ -	-$ 3,570,546	35.73	2.80%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 2,881,331	$ -	-$ 343,410	$ -	-$ 3,053,036	39.72	2.52%	**-$ 76,869**	-$ 76,869	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 69,720,292**	**$ 1,013,191**	**$ 3,973,884**		**$ 69,727,107**	**$ 541**		**$ 2,413,037**	**$ 2,413,037**	**-$ 0**

Table 2-52 – 2023 Depreciation and Amortization Expense (2-C)

Year 2023

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 987,713	-$ 178,912	$ 551,449	$ -	$ 1,442,350	9.16	10.92%	**$ 157,468**	$ 157,468	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 14,278,690	$ -	$ 212,043	$ -	$ 14,384,711	40.15	2.49%	**$ 358,236**	$ 358,236	**$ -**
1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ -	$ 507,142	26.22	3.81%	**$ 19,345**	$ 19,345	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 14,419,295	$ -	$ 617,447	$ -	$ 14,728,018	44.53	2.25%	**$ 330,763**	$ 330,763	**$ -**
1835	Overhead Conductors & Devices	$ 9,239,782	$ -	$ 409,824	$ -	$ 9,444,694	50.10	2.00%	**$ 188,525**	$ 188,525	**$ -**
1840	Underground Conduit	$ 5,948,590	$ -	$ 288,698	$ -	$ 6,092,939	43.92	2.28%	**$ 138,719**	$ 138,719	**$ -**
1845	Underground Conductors & Devices	$ 11,148,898	-$ 47,073	$ 427,299	$ -	$ 11,409,620	32.31	3.10%	**$ 353,138**	$ 353,138	**$ -**
1850	Line Transformers	$ 8,726,215	$ -	$ 553,413	$ -	$ 9,002,922	33.37	3.00%	**$ 269,810**	$ 269,810	**$ -**
1855	Services (Overhead & Underground)	$ 4,268,755	$ -	$ 242,624	$ -	$ 4,390,067	36.96	2.71%	**$ 118,793**	$ 118,793	**$ -**
1860	Meters	$ 1,491,766	-$ 197,415	$ 433,583	$ -	$ 1,905,973	17.56	5.69%	**$ 108,521**	$ 108,521	**$ -**
1860	Meters (Smart Meters)	$ 1,051,698	$ -	$ -	$ -	$ 1,051,698	9.69	10.32%	**$ 108,509**	$ 108,509	**$ 0**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 2,211,367	-$ 7,732	$ 1,060,506	$ -	$ 2,749,352	17.54	5.70%	**$ 156,767**	$ 156,767	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 187,807	-$ 3,684	$ -	$ -	$ 191,491	10.10	9.91%	**$ 18,968**	$ 18,968	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 682,015	-$ 94,549	$ 290,629	$ -	$ 921,879	5.91	16.92%	**$ 156,011**	$ 156,011	**$ -**
1930	Transportation Equipment	$ 906,595	-$ 108,265	$ 92,935	$ -	$ 1,061,327	12.22	8.18%	**$ 86,852**	$ 86,852	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 229,300	-$ 20,797	$ 36,453	$ -	$ 268,324	9.92	10.08%	**$ 27,038**	$ 27,038	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 452,107	-$ 28,656	$ 120,308	$ -	$ 540,917	14.46	6.92%	**$ 37,410**	$ 37,410	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 3,224,740	$ -	-$ 446,781	$ -	-$ 3,448,131	44.86	2.23%	**-$ 76,869**	-$ 76,869	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 72,680,985**	**-$ 687,084**	**$ 4,890,430**		**$ 74,846,348**	**$ 565**		**$ 2,526,371**	**$ 2,526,371**	**$ 0**

Table 2-53 – 2024 Depreciation and Amortization Expense (2-C)

Year 2024

		Book Values				Service Lives		Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets,**	**Variance [4]**
		a	**b**	**c**	**d = a-b+0.5*c**	**e**	**f = 1/e**	**g = d/e**	**h**	**q = h-g**
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 2,579,847	$ -	$ 905,000	$ 3,032,347	19.85	5.04%	**$ 152,761**	$ 152,761	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 14,640,733	$ -	$ 274,600	$ 14,778,033	45.09	2.22%	**$ 327,720**	$ 327,720	**$ -**
1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ 507,142	26.15	3.82%	**$ 19,392**	$ 19,392	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 15,121,742	$ -	$ 75,000	$ 15,159,242	46.11	2.17%	**$ 328,762**	$ 328,762	**$ -**
1835	Overhead Conductors & Devices	$ 11,241,879	$ -	$ 2,000,455	$ 12,242,106	48.04	2.08%	**$ 254,842**	$ 254,842	**$ -**
1840	Underground Conduit	$ 7,132,788	$ -	$ 1,294,850	$ 7,780,213	50.32	1.99%	**$ 154,608**	$ 154,608	**$ -**
1845	Underground Conductors & Devices	$ 11,559,123	$ -	$ 50,000	$ 11,584,123	33.00	3.03%	**$ 351,032**	$ 351,032	**$ -**
1850	Line Transformers	$ 9,694,629	$ -	$ 595,000	$ 9,992,129	35.45	2.82%	**$ 281,864**	$ 281,864	**$ -**
1855	Services (Overhead & Underground)	$ 4,511,379	$ -	$ -	$ 4,511,379	38.88	2.57%	**$ 116,033**	$ 116,033	**-$ 0**
1860	Meters	$ 2,127,934	$ -	$ 1,427,297	$ 2,841,582	20.17	4.96%	**$ 140,891**	$ 140,891	**$ -**
1860	Meters (Smart Meters)	$ 1,051,698	$ -	$ -	$ 1,051,698	10.12	9.88%	**$ 103,932**	$ 103,932	**-$ 0**
1905	Land	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 5,429,141	$ -	$ 505,000	$ 5,681,641	26.20	3.82%	**$ 216,845**	$ 216,845	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 184,123	$ -	$ -	$ 184,123	11.37	8.79%	**$ 16,192**	$ 16,192	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,071,164	$ -	$ 296,636	$ 1,219,482	6.89	14.52%	**$ 177,088**	$ 177,088	**$ -**
1930	Transportation Equipment	$ 1,341,265	$ -	$ 125,000	$ 1,403,765	13.21	7.57%	**$ 106,226**	$ 106,226	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 289,956	$ -	$ 46,200	$ 313,056	10.87	9.20%	**$ 28,796**	$ 28,796	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	20.00	5.00%	**$ 159**	$ 159	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 620,258	$ -	$ 141,500	$ 691,008	17.30	5.78%	**$ 39,932**	$ 39,932	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 3,890,621	$ -	-$ 219,113	-$ 4,000,177	52.04	1.92%	**-$ 76,864**	-$ 76,864	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 84,382,171**	**$ -**	**$ 7,517,425**	**$ 87,173,948**	**$ 627**		**$ 2,708,261**	**$ 2,708,261**	**-$ 0**

Table 2-54 – 2025 Depreciation and Amortization Expense (2-C)

Year 2025

		Book Values				Service Lives		Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets,**	**Variance [4]**
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	17.75	5.63%	$ 54,473	$ 54,473	-$ 0
1611	Computer Software (Formally known as Account 1925)	$ 2,579,847	$ -	$ 905,000	$ 3,032,347	12.37	8.08%	$ 245,042	$ 245,042	$ -
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150		0.00%	$ -	$ -	$ -
1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202		0.00%	$ -	$ -	$ -
1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	33.30	3.00%	$ 13,171	$ 13,171	-$ 0
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 14,640,733	$ -	$ 274,600	$ 14,778,033	44.30	2.26%	$ 333,569	$ 333,569	$ -
1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ 507,142	26.15	3.82%	$ 19,392	$ 19,392	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 15,121,742	$ -	$ 75,000	$ 15,159,242	45.89	2.18%	$ 330,325	$ 330,325	$ -
1835	Overhead Conductors & Devices	$ 11,241,879	$ -	$ 2,000,455	$ 12,242,106	39.77	2.51%	$ 307,830	$ 307,830	$ -
1840	Underground Conduit	$ 7,132,788	$ -	$ 1,294,850	$ 7,780,213	46.93	2.13%	$ 165,772	$ 165,772	$ -
1845	Underground Conductors & Devices	$ 11,559,123	$ -	$ 50,000	$ 11,584,123	33.03	3.03%	$ 350,732	$ 350,732	-$ 0
1850	Line Transformers	$ 9,694,629	$ -	$ 595,000	$ 9,992,129	34.02	2.94%	$ 293,676	$ 293,676	$ 0
1855	Services (Overhead & Underground)	$ 4,511,379	$ -	$ -	$ 4,511,379	39.15	2.55%	$ 115,234	$ 115,234	$ -
1860	Meters	$ 2,127,934	$ -	$ 1,427,297	$ 2,841,582	12.67	7.89%	$ 224,226	$ 224,226	$ -
1860	Meters (Smart Meters)	$ 1,051,698	$ -	$ -	$ 1,051,698	10.65	9.39%	$ 98,781	$ 98,781	$ -
1905	Land	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 5,429,141	$ -	$ 505,000	$ 5,681,641	23.57	4.24%	$ 241,024	$ 241,024	-$ 0
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 184,123	$ -	$ -	$ 184,123	20.40	4.90%	$ 9,026	$ 9,026	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,071,164	$ -	$ 296,636	$ 1,219,482	5.54	18.05%	$ 220,106	$ 220,106	$ -
1930	Transportation Equipment	$ 1,341,265	$ -	$ 125,000	$ 1,403,765	13.83	7.23%	$ 101,501	$ 101,501	$ -
1935	Stores Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 289,956	$ -	$ 46,200	$ 313,056	10.28	9.73%	$ 30,455	$ 30,455	$ -
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	20.00	5.00%	$ 175	$ 175	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178		0.00%	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 620,258	$ -	$ 141,500	$ 691,008	14.79	6.76%	$ 46,736	$ 46,736	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	35.02	2.86%	-$ 99,945	-$ 99,945	$ -
2440	Deferred Revenue	-$ 3,890,621	$ -	-$ 325,018	-$ 4,053,130	51.45	1.94%	-$ 78,773	-$ 78,773	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 84,382,171**	**$ -**	**$ 7,411,520**	**$ 87,120,996**	**$ 591**		**$ 3,022,529**	**$ 3,022,529**	**-$ 0**

2.2.4.4 Changes to Depreciation Policy or Asset Service Life

FHI has not made any changes to its depreciation policy or asset service lives since the last rebasing Application (EB-2014-0073) except for a new asset class for Large Software Projects. Typically, FHI's Software assets are depreciated over five years however for large corporate software systems, such as CIS and ERP, FHI expects that these systems will last longer than five years and are larger investments than typical and therefore are being depreciated over 10 years. Depreciating these assets over 10 years also smooths the rate impact for customers. Kinectrics does not include separate types of software in its report and therefore there is no separate TUL for Large Corporate Software assets.

2.2.4.5 Asset Retirement Obligations

FHI does not have any asset retirement obligations and therefore there is no corresponding depreciation amount included for the 2025 Test Year.

2.2.4.6 Half-Year Rule

FHI follows the “half-year” rule where capital additions in the 2024 Bridge Year and the 2025 Test Year attract six months of depreciation expense. FHI has consistently used the half year rule since its last COS.

2.2.5 Allowance for Working Capital

2.2.5.1 Overview

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital: the default value of 7.5% Allowance or the filing of a lead/lag study. Using the 7.5% Allowance, the WCA is calculated to be 7.5% of the sum of Cost of Power plus Eligible Distribution Expenses.

FHI has not completed a lead-lag study to support a different rate, and therefore submits this Application using the default WCA rate of 7.5%. The use of a 7.5% rate is consistent with the Ontario Energy Board's ("OEB") letter dated June 3, 2015, and the Chapter 2 Filing Requirements as issued by the OEB.

Table 2-55 summarizes FHI’s WCA calculations by year.

Table 2-55 – Working Capital Allowance

Description	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
Distribution Expenses - Operation	924,800	881,642	878,957	871,897	1,092,823	930,948
Distribution Expenses - Maintenance	1,217,983	1,255,585	1,222,910	1,347,728	1,471,361	1,436,797
Billing and Collecting	1,212,817	1,251,776	1,295,739	1,272,765	1,188,727	1,259,373
Community Relations	11,248	11,632	9,900	13,400	9,745	7,413
Administrative and General Expenses	1,789,432	1,844,086	2,284,278	2,123,899	2,528,550	2,391,868
Donations - LEAP	13,000	13,000	13,200	13,410	13,510	13,650
Taxes Other Than Income Taxes	19,225	96,756	38,017	55,726	82,847	74,054
Less Allocated Depreciation	-156,997	-146,625	-149,614	-147,927	-160,250	-163,119
Total Distribution Expenses	**5,031,508**	**5,207,852**	**5,593,388**	**5,550,898**	**6,227,314**	**5,950,984**
Power Supply Expenses	68,871,222	71,472,888	78,718,905	71,071,415	68,149,862	70,986,504
Total Working Capital Expenses	**73,902,730**	**76,680,740**	**84,312,292**	**76,622,312**	**74,377,176**	**76,937,488**
Workin Capital Factor	13%	13%	13%	13%	13%	13%
Total Working Capital Allowance	**9,607,355**	**9,968,496**	**10,960,598**	**9,960,901**	**9,669,033**	**10,001,873**

Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Distribution Expenses - Operation	977,468	710,733	951,220	1,127,215	1,289,665	1,368,552
Distribution Expenses - Maintenance	1,495,382	1,646,168	1,865,684	1,817,483	1,959,517	2,146,761
Billing and Collecting	1,208,934	1,293,457	1,283,486	1,448,423	1,542,185	1,707,271
Community Relations	12,268	1,015	1,115	0	9,507	19,427
Administrative and General Expenses	2,334,067	2,336,495	2,638,687	3,044,852	3,409,440	4,013,523
Donations - LEAP	13,860	30,060	14,550	15,000	15,000	20,050
Taxes Other Than Income Taxes	135,993	126,934	126,868	151,482	143,937	154,677
Less Allocated Depreciation	-148,359	-130,048	-122,563	-114,240	-135,373	-132,131
Total Distribution Expenses	**6,029,614**	**6,014,814**	**6,759,045**	**7,490,214**	**8,233,879**	**9,298,129**
Power Supply Expenses	72,593,455	60,698,856	58,141,145	62,317,681	59,631,580	67,089,241
Total Working Capital Expenses	**78,623,069**	**66,713,670**	**64,900,191**	**69,807,896**	**67,865,459**	**76,387,370**
Workin Capital Factor	13%	13%	13%	13%	13%	7.5%
Total Working Capital Allowance	**10,220,999**	**8,672,777**	**8,437,025**	**9,075,026**	**8,822,510**	**5,729,053**

The WCA decreased significantly from $9.6M in the 2015 OEB approved to $5.8M in the 2025 Test Year for a variance of $3.9M, or 40%. This is primarily due to the change in the WCA rate from 13% approved in the 2015 COS to 7.5% used in the 2025 Test Year, which is partially offset by an increase in working capital expenses of $2.5M over the same period.

2.2.5.2 Working Capital

FHI's working capital is comprised of Cost of Power plus Eligible Distribution Expenses.

2.2.5.3 Eligible Distribution Expenses

Eligible Distribution Expenses include the amounts for Operations, Maintenance, Billing & Collecting, Community Relations, Administration & General, and Taxes Other Than Income Taxes. These amounts agree to the OM&A categories in Exhibit 4, and the amount for Taxes Other Than Income Taxes agrees to Exhibit 6.

2.2.5.4 Cost of Power (COP) Calculations

FHI has calculated COP for the 2025 Test Year based upon the 2025 load forecast, adjusted for the impact of Conservation and Demand Management activities and in accordance with the Board's Filing Requirements.

FHI has two customers that are wholesale market participants. Both are in the General Service >50 kW rate class. For purposes of calculating the power supply expenses, the load attributable to these two customers has been removed from the following components: Commodity, Global Adjustment, Wholesale Market Service, Rural Rate Protection and Capacity Based Recovery. The load is removed in acknowledgement that Bluewater does not incur pass-through charges for these components from these customers, therefore the amounts should not be included in the calculation of working capital allowance**.**

Table 2-56 presents the year over year summary for total Cost of Power.

Table 2-56 – Summary of Total Cost of Power Expenses

Cost of Power	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual
4705 - Power Purchased	58,061,155	27,778,361	28,617,754	24,576,758	26,626,314	24,752,758
4707 - Global Adjustment	-	33,130,930	39,265,042	36,032,633	31,703,430	36,519,897
4708 - Charges - WMS	3,469,063	3,189,388	3,561,005	3,352,629	2,310,277	2,237,470
4712-Charges - one time	-	-	-	-	-	-
4714 - Charges - Network	4,251,510	4,202,641	4,092,169	3,998,781	4,041,390	4,101,877
4716 - Charges - Connection	2,687,683	2,722,327	2,726,727	2,665,416	3,098,257	2,944,252
4750 - Charges - LV	209,813	260,331	265,606	252,864	233,372	289,104
4751 - Smart Meter Entity Charge	191,998	188,910	190,601	192,335	136,823	141,148
Total	**68,871,222**	**71,472,888**	**78,718,905**	**71,071,415**	**68,149,862**	**70,986,504**
Cost of Power	**2020 Actual**	**2021 Actual**	**2022 Actual**	**2023 Actual**	**2024 Bridge**	**2025 Test**
4705 - Power Purchased	29,283,484	26,844,833	32,341,931	29,517,746	23,193,308	37,182,259
4707 - Global Adjustment	33,569,183	22,570,951	12,835,739	20,292,858	27,518,730	21,380,058
4708 - Charges - WMS	1,998,156	2,748,169	3,643,438	2,609,993	2,186,830	3,623,502
4712-Charges - one time	-	-	-	-	-	-5,764,251
4714 - Charges - Network	4,249,704	5,077,405	5,702,445	6,003,499	3,566,341	6,441,013
4716 - Charges - Connection	2,983,477	2,947,796	3,252,523	3,520,739	2,747,083	3,809,402
4750 - Charges - LV	364,763	374,874	301,407	304,667	302,912	302,912
4751 - Smart Meter Entity Charge	144,689	134,828	63,662	68,179	116,376	114,346
Total	**72,593,455**	**60,698,856**	**58,141,145**	**62,317,681**	**59,631,580**	**67,089,241**

Presented in Table 2-57 is the required OEB Appendix 2-ZB, which provides the detailed calculations for each of the COP categories for the 2025 Test Year.

Table 2-57 – Cost of Power Calculation (2-ZB)

		2025 Test Year	RPP		2025 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	154,873,125		17,198,661	2,870,942		91,267	
GS < 50	kWh	49,319,113		5,476,887	14,706,738		467,527	
GS > 50	kWh	16,707,585		1,855,377	346,520,867		11,015,898	
Large Use	kWh	0		-	29,216,275		928,785	
Street Light	kWh	95,113		10,562	2,331,227		74,110	
Sentinel Light	kWh	97,679		10,847	0		-	
Unmetered Scattered Load	kWh	326,877		36,300	504,447		16,036	
Wholesale Market Participant	kWh	0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
SUB-TOTAL				24,588,634			12,593,624	$ 37,182,259
Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential - Class B	kWh			0			209,177	
GS < 50 - Class B	kWh			0			1,071,533	
GS > 50 - Class B	kWh			0			7,709,517	
Large Use - Class B	kWh			0			-	
Street Light - Class B	kWh			0			169,853	
Sentinel Light - Class B	kWh			0			-	
Unmetered Scattered Load - Class B	kWh			0			36,754	
Wholesale Market Participant - Class B	kWh			0			-	
				0			-	
				0			-	
				0			-	
General Service > 50 to 4999 kW - Class A	kWh			0			10,829,395	
Large Use - Class A	kWh			0			1,353,828	
				0			-	
				0			-	
				0			-	
SUB-TOTAL				0			21,380,058	$ 21,380,058
Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	154,873,125	0.0108	1,676,775	2,870,942	0.0108	31,083	
GS < 50	kWh	49,319,113	0.0095	467,909	14,706,738	0.0095	139,528	
GS > 50	kW	49,833	4.3275	215,652	830,714	4.3275	3,594,889	
Large Use	kW	-	4.7913	-	44,439	4.7913	212,925	
Street Light	kW	215	3.0725	661	5,796	3.0725	17,807	
Sentinel Light	kW	264	3.0883	817	-	3.0883	-	
Unmetered Scattered Load	kWh	326,877	0.0095	3,101	504,447	0.0095	4,786	
Wholesale Market Participant	kW	-	4.3275	-	17,350	4.3275	75,080	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				2,364,915			4,076,098	6,441,013
Transmission - Connection								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0063	973,080	2,870,942	0.0063	18,038	
GS < 50	kWh	49,319,113	0.0057	282,694	14,706,738	0.0057	84,298	
GS > 50	kW	49,833	2.5668	127,912	830,714	2.5668	2,132,279	
Large Use	kW	-	2.9351	-	44,439	2.9351	130,433	
Street Light	kW	215	1.8100	389	5,796	1.8100	10,490	
Sentinel Light	kW	264	1.8480	489	-	1.8480	-	
Unmetered Scattered Load	kWh	326,877	0.0057	1,874	504,447	0.0057	2,891	
Wholesale Market Participant	kW	-	2.5668	-	17,350	2.5668	44,533	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				1,386,438			2,422,964	3,809,402

Wholesale Market Service								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0041	634,980	2,870,942	0.0041	11,771	
GS < 50	kWh	49,319,113	0.0041	202,208	14,706,738	0.0041	60,298	
GS > 50	kWh	16,707,585	0.0041	68,501	346,520,867	0.0041	1,420,736	
Large Use	kWh	-	0.0041	-	29,216,275	0.0041	119,787	
Street Light	kWh	95,113	0.0041	390	2,331,227	0.0041	9,558	
Sentinel Light	kWh	97,679	0.0041	400	-	0.0041	-	
Unmetered Scattered Load	kWh	326,877	0.0041	1,340	504,447	0.0041	2,068	
Wholesale Market Participant	kWh	-	0.0041	-	-	0.0041	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				907,820			1,624,217	2,532,037

Class A CBR								
Class per Load Forecast							$	Total
Residential	kWh	-	-	-	-	-	-	
GS < 50	kWh	-	-	-	-	-	-	
GS > 50	kWh	-	-	-	240,708,111	0.0003203	77,102	
Large Use	kWh	-	-	-	29,216,275	0.0003665	10,707	
Street Light	kWh	-	-	-	-	-	-	
Sentinel Light	kWh	-	-	-	-	-	-	
Unmetered Scattered Load	kWh	-	-	-	-	-	-	
Wholesale Market Participant	kWh	-	-	-	-	-	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				-			87,809	87,809

Class B CBR								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0004	61,949	2,870,942	0.0004	1,148	
GS < 50	kWh	49,319,113	0.0004	19,728	14,706,738	0.0004	5,883	
GS > 50	kWh	16,707,585	0.0004	6,683	105,812,755.46	0.0004	42,325	
Large Use	kWh	-	0.0004	-	-	0.0004	-	
Street Light	kWh	95,113	0.0004	38	2,331,227	0.0004	932	
Sentinel Light	kWh	97,679	0.0004	39	-	0.0004	-	
Unmetered Scattered Load	kWh	326,877	0.0004	131	504,447	0.0004	202	
Wholesale Market Participant	kWh	-	0.0004	-	-	0.0004	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				88,568			50,490	139,058

RRRP								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0014	216,822	2,870,942	0.0014	4,019	
GS < 50	kWh	49,319,113	0.0014	69,047	14,706,738	0.0014	20,589	
GS > 50	kWh	16,707,585	0.0014	23,391	346,520,867	0.0014	485,129	
Large Use	kWh	-	0.0014	-	29,216,275	0.0014	40,903	
Street Light	kWh	95,113	0.0014	133	2,331,227	0.0014	3,264	
Sentinel Light	kWh	97,679	0.0014	137	-	0.0014	-	
Unmetered Scattered Load	kWh	326,877	0.0014	458	504,447	0.0014	706	
Wholesale Market Participant	kWh	-	0.0014	-	-	0.0014	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				309,987			554,611	864,598

Low Voltage - No TLF adjustment								
Class per Load Forecast							$	Total
Residential	kWh	150,904,341	0.0005	77,376	2,797,371	0.0005	1,434	
GS < 50	kWh	48,055,259	0.0005	22,479	14,329,863	0.0005	6,703	
GS > 50	kW	49,833	0.2041	10,171	830,714	0.2041	169,553	
Large Use	kW	-	0.2334	-	44,439	0.2334	10,372	
Street Light	kW	215	0.1439	31	5,796	0.1439	834	
Sentinel Light	kW	264	0.1469	39	-	0.1469	-	
Unmetered Scattered Load	kWh	318,500	0.0005	149	491,520	0.0005	230	
Wholesale Market Participant	kW	-	0.2041	-	17,350	0.2041	3,541	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				110,245			192,667	302,912

Smart Meter Entity Charge								
Class per Load Forecast							$	Total
Residential		20,167	0.42	101,643	374	0.42	1,885	
GS < 50		1,653	0.42	8,333	493	0.42	2,485	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				109,976			4,370	114,346
SUB- TOTAL				29,866,584			42,986,908	72,853,492
OER CREDIT	19.3%			(5,764,251)			0	(5,764,251)
TOTAL				**24,102,333**			**42,986,908**	**67,089,241**

3.The OER Credit 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

2025 Test Year - Cop		
4705 -Power Purchased	$	37,182,259
4707- Global Adjustment	$	21,380,058
4708-Charges-WMS	$	3,623,502
4714-Charges-NW	$	6,441,013
4716-Charges-CN	$	3,809,402
4750-Charges-LV	$	302,912
4751-IESO SME	$	114,346
Misc A/R or A/P	$	(5,764,251)
TOTAL	**$**	**67,089,241**

-

2.2.5.5 Power Purchased

In accordance with the Filing Requirements, the commodity price estimate used to calculate COP was determined in a way that bases the split between Regulated Price Plan ("RPP") and non-RPP customers on actual historical data and uses the most current RPP price.

The RPP and non-RPP price was obtained from the Regulated Price Plan Report for the period of November 1, 2023, to October 31, 2024, published October 19, 2023. For the purposes of calculating the 2025 Test Year, FHI has used an estimate of $0.11105 per kWh for RPP customers. For non- RPP customers, FHI has used $0.10465 per kWh which includes $0.03179 per KWh for the Wholesale Electricity Price and $0.07286 per kWh for Global Adjustment charges.

FHI understands that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to the approval of the Application.

Presented in Table 2-58 is the required OEB Appendix 2-ZA which provides the detailed calculations for the gross amount of Power Purchased for the 2025 Test Year, which also support the amounts presented in Appendix 2-ZB.

Table 2-58 – Commodity Expense (2-ZA)

Step 1: **Commodity Pricing**

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		**non-RPP**	**RPP**
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$31.79	$31.79
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$72.86	$72.86
Adjustments ($/MWh)				$6.40
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$111.05**

Step 2: **Commodity Expense**

(volumes for the test year is loss adjusted)

Commodity

Customer		**Revenue**	**Expense**	**2025 Test Year**						
Class Name	UoM	USoA #	USoA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		2,870,942	154,873,125	$ 0.03179	$ 0.11105	$17,289,928
GS < 50	kWh	4010	4705	-		14,706,738	49,319,113	$ 0.03179	$ 0.11105	$5,944,415
GS > 50	kWh	4035	4705	240,708,111		105,812,755	16,707,585	$ 0.03179	$ 0.11105	$12,871,276
Large Use	kWh	4010	4705	29,216,275		-	-	$ 0.03179	$ 0.11105	$928,785
Street Light	kWh	4025	4705	-		2,331,227	95,113	$ 0.03179	$ 0.11105	$84,672
Sentinel Light	kWh	4025	4705	-		-	97,679	$ 0.03179	$ 0.11105	$10,847
Unmetered Scattered Load	kWh	4025	4705	-		504,447	326,877	$ 0.03179	$ 0.11105	$52,336
Wholesale Market Participant	kWh	4025	4705	-		-	-	$ 0.03179	$ 0.11105	$0
	kWh	4025	4705					$ 0.03179	$ 0.11105	$0
	kWh	4025	4705					$ 0.03179	$ 0.11105	$0
	kWh	4025	4705					$ 0.03179	$ 0.11105	$0
TOTAL				**269,924,387**		**126,226,110**	**221,419,491**			**$37,182,259**

Class A - non-RPP Global Adjustment

Customer		**Revenue**	**Expense**	**2025**			**Hist. Avg GA/kWh *****	**Amount**
					kWh Volume			
General Service > 50 to 4999 kW		4035	4707		240,708,111		0.044989740	$10,829,395
Large Use		4010	4707		29,216,275		0.046338161	$1,353,828
		4010	4707					$0
		4010	4707					$0
		4010	4707					$0
				-	269,924,387			**$12,183,224**

Class B - non-RPP Global Adjustment

Customer		**Revenue**	**Expense**	**2025**						**Amount**
Class Name	UoM	USoA #	USoA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			2,870,942			$ 0.07286	$209,177
GS < 50	kWh	4010	4707			14,706,738			$ 0.07286	$1,071,533
GS > 50	kWh	4035	4707			105,812,755			$ 0.07286	$7,709,517
Large Use	kWh	4010	4707			0			$ 0.07286	$0
Street Light	kWh	4025	4707			2,331,227			$ 0.07286	$169,853
Sentinel Light	kWh	4025	4707			0			$ 0.07286	$0
Unmetered Scattered Load	kWh	4025	4707			504,447			$ 0.07286	$36,754
Wholesale Market Participant	kWh	4025	4707			0			$ 0.07286	$0
	kWh	4025	4707			0			$ 0.07286	$0
	kWh	4025	4707			0			$ 0.07286	$0
	kWh	4025	4707			0			$ 0.07286	$0
Total Volume						**126,226,110**				
TOTAL										**$9,196,834**

2.2.5.6 Regulatory Charges

Regulatory charges include the Wholesale Market Service (“WMS”) Charge, the Rural Rate Protection Charge, and the Capacity Based Recovery Charge.

These regulatory charges for the 2025 Test Year were calculated based on the OEB Decision and Order (EB-2023-0268) establishing that the Wholesale Market Service (WMS) rate used by rate-regulated distributors to bill their customers shall be $0.0041 per kilowatt-hour, effective January 1, 2024. For Class B customers a Capacity Base Recovery (CBR) component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0045 per kilowatt-hour. Also, as part of this Decision and Order, the RRRP charge used by rate-regulated distributors to bill their customers shall be $0.0014 per kilowatt-hour for electricity consumers on or after January 1, 2024. This unit rate shall apply to a customer’s metered energy consumption adjusted by the distributor’s OEB-approved Total Loss Factor.

These rates were applied to the forecasted power purchases for the 2025 Test Year.

2.2.5.7 Network and Connection Charges

For the purposes of determining the wholesale Transmission Network and Connection cost for the 2025 Test Year, FHI used the current 2024 Uniform Transmission Rates (“UTR”), and Hydro One Sub-Transmission Rates to derive proposed Retail Transmission Service Rates (“RTSR”) by rate class. The updated RTSR rates were multiplied by the 2025 forecasted billing determinants to produce the Network and Connection charges for the pass-through charges. FHI will update its Network and Connection Charges on its Draft Rate Order if there are more current RTSRs available when the OEB renders its decision.

2.2.5.8 Low Voltage Charges

For the purposes of determining the wholesale Low Voltage ("LV") charges for the 2025 Test Year, FHI determined updated LV rates using the LV tab in the RTSR workform. The 2025 charges were calculated by taking the 2023 volumes and multiplying them by the 2024 rates. The allocation was based on the RTSR connection revenue. The allocation percentages were multiplied by the 2025 loss adjusted volume.

The details of the calculations of the RTSR rates and LV rates are outlined in Exhibit 8 – Rate Design.

2.2.5.9 Smart Meter Entity Charges

On March 1, 2018, the OEB issued a Decision and Order (EB-2017-0290) approving a Smart Metering Entity ("SME") charge of $0.57 per month for Residential and General Service < 50 kW customers. That rate decreased to $0.43 per month on an interim basis ending December 31, 2022 (EB-2022-0137), and by letter dated September 8, 2022, the OEB approved a final rate of $0.42 per smart meter per month effective January 1, 2023, to December 31, 2027.

2.2.6 Distribution System Plan

In accordance with the Chapter 2 Filing Requirements, FHI is filing its Distribution System Plan ("DSP") as a stand-alone and self-sufficient element filed as part of this Application. FHI has prepared its DSP in accordance with the Chapter 5 Filing Requirements, dated December 15, 2022.

2.2.7 Policy Options for the Funding of Capital

FHI does not have any ACM or ICM projects as capital projects have been paced as much as possible, therefore this is not applicable.

2.2.8 Addition of Previously Approved ACM and ICM Project Assets to Rate Base

FHI has not had any previously approved ACM or ICM projects since its last COS, therefore this is not applicable.

2.2.9 Capitalization Policy

FHI's current capitalization policies and principles are based on IFRS, and guidelines set out by the Ontario Energy Board, where applicable. FHI converted to IFRS on January 1, 2015, and as such the capitalization policy is in effect for all the historical and forecast years in this Application. FHI's external auditors have also deemed FHI's capitalization policy, including the overhead policy, to align with IFRS standards. There have been no changes to the capitalization policy since FHI's last COS.

FHI's capital assets are recorded and recognized at cost, and include direct labour and benefits, materials, fleet costs and contractor costs, which are incurred during the development, implementation, or construction phase of the asset.

Certain capital assets may be funded or paid for by a customer or third-party developer through capital contributions. Under IFRS, the capital contributions that are recognized as deferred revenue have been reclassified as a reduction to rate base under MIFRS.

2.2.9.1 Guidelines for Capitalization

Capital Assets include property, plant, and equipment that are held for use in the production or supply of goods and services and provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets.

Intangible assets are also considered capital assets and are defined as assets that lack physical substance. They include goodwill, patents, copyrights, and computer software.

Betterment – a "betterment" is a cost which enhances the service potential of a capital asset and/or increases its value and is therefore capitalized. A betterment includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life. A betterment does not include general maintenance-related actions that seek to sustain an asset's current value.

Repairs - a repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs is expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and are charged to an operating account.

2.2.9.2 Capitalization by Component

When parts or components of an item of property, plant and equipment have different useful lives, they are accounted for as individual items (major components) of property, plant, and equipment. Component costs must be significant in relation to the total cost of the item and depreciated separately over the component's useful life. Components are those which: a) are significant in relation to the total cost of the item and b) have different depreciation methods or useful life.

Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge. Parts of the item that are not individually significant (remainder of the items) are combined and categorized as a single component best suited for the sum of the parts.

2.2.9.3 Depreciation

Depreciation is recognized on a straight-line basis over the estimated useful life of each significant identifiable component of an item of property, plant, and equipment. Land and Land Rights are not depreciated. Construction in progress assets are not depreciated until the project is complete and in service.

2.2.10 Capitalization of Overhead

FHI's overhead policy has been reviewed by its external auditors and has been deemed IFRS compliant. There have been no changes to the overhead policy since FHI's last COS.

2.2.10.1 Benefit Costs and Labour Burden

Employee benefit costs represent the costs associated with employee pensions, vacations, sick leave, insurable benefits etc. For each hour of regular time recorded, via a timesheet, charged directly to a capital project, FHI adds a benefit rate per regular labour dollar that allocates the estimated annual costs per employee type. Under IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management.

A fixed percentage of overhead and administration costs, referred to as "labour burden", is allocated to direct labour costs, and forms part of the cost of an asset. These costs include a portion of the labour costs, related benefits and other costs of the engineering group and operations management.

Burden rates are reviewed annually to determine that they align with actual costs.

Burden rates included in the Test Year are as follows:

Labour benefits – 48%

Engineering – 60%

Operations Management – 22%

Burden rates in 2015 are as follows:

Labour benefits – 52%

Engineering – 36%

Operations Management – 18%

2.2.10.2 Transportation and Fleet Costs

These costs include the costs associated with maintaining automobiles, trucks and equipment, trailers, and other fleet equipment. Some of these costs include depreciation expense of the fleet vehicles, fuel costs, repairs, and parts, insurance, and all other items of expense necessary to keep the rolling stock in service. These costs can also include the labour costs and the associated benefits of the staff directly involved in rolling stock maintenance (mechanics and other garage staff) as tracked via timesheets. FHI contracts out the maintenance of vehicles and therefore reduced substantially the maintenance performed on vehicles by FHI employees. A fleet rate is determined on an annual basis for each vehicle group by dividing the directly attributable annual costs accumulated for each vehicle type by their annual usage. When a vehicle is used for a capital project, a fleet rate is charged based on the type of vehicle used multiplied by hourly usage of the vehicle. Under IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management.

2.2.10.3 Capitalization of Overhead

Table 2-59 provided below, which is consistent with Board Appendix 2-D, has been completed to show FHI's OM&A costs prior to, and after, the allocation of costs for the Benefit and Labour Costs and Transportation and Fleet Costs to capital construction projects.

Table 2-59 – Overhead Expense (2-D)

OM&A Before Capitalization	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Historical Year	2024 Bridge Year	2025 Test Year
Operations Expense	$ 1,221,497	$ 1,254,466	$ 1,240,603	$ 1,479,406	$ 1,162,812	$ 1,359,468	$ 1,154,952	$ 1,375,403	$ 1,567,662	$ 1,771,299	$ 1,902,585
Maintenance Expense	$ 1,689,049	$ 1,608,783	$ 1,784,230	$ 1,930,411	$ 1,829,483	$ 1,775,631	$ 2,058,804	$ 2,255,610	$ 2,229,552	$ 2,405,272	$ 2,653,668
Billing & Collections Expense	$ 1,251,776	$ 1,295,739	$ 1,272,765	$ 1,188,727	$ 1,259,373	$ 1,208,934	$ 1,293,457	$ 1,283,486	$ 1,448,423	$ 1,542,185	$ 1,707,271
Community Relations Expense	$ 11,632	$ 9,900	$ 13,400	$ 9,745	$ 7,413	$ 12,268	$ 1,015	$ 1,115	$ -	$ 9,507	$ 19,427
Administration & General	$ 2,130,943	$ 2,511,500	$ 2,361,487	$ 2,821,357	$ 2,639,221	$ 2,585,385	$ 2,645,657	$ 2,945,305	$ 3,396,030	$ 3,772,182	$ 4,408,728
LEAP	$ 13,000	$ 13,200	$ 13,410	$ 13,510	$ 13,650	$ 13,860	$ 30,060	$ 14,550	$ 15,000	$ 15,630	$ 20,050
Total OM&A Before Capitalization (B)	$ 6,317,897	$ 6,693,588	$ 6,685,895	$ 7,443,156	$ 6,911,952	$ 6,955,547	$ 7,183,945	$ 7,875,468	$ 8,656,666	$ 9,516,074	$ 10,711,729

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	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Historical Year	2024 Bridge Year	2025 Test Year	Directly Attributable? (Yes/No)
employee benefits												
costs of site preparation												
initial delivery and handling costs												
costs of testing whether the asset is functioning properly												
professional fees												
Benefit Costs and Labour Burden	$ 797,106	$ 806,296	$ 823,669	$ 895,063	$ 662,220	$ 675,392	$ 899,310	$ 865,124	$ 928,945	$ 1,015,801	$ 1,124,749	Yes
Transportation and Fleet Costs	$ 166,314	$ 144,291	$ 163,402	$ 160,529	$ 135,630	$ 102,182	$ 139,773	$ 128,736	$ 123,267	$ 131,022	$ 156,719	Yes
Total Capitalized OM&A (A)	$ 963,420	$ 950,586	$ 987,071	$ 1,055,592	$ 797,850	$ 777,574	$ 1,039,082	$ 993,860	$ 1,052,213	$ 1,146,823	$ 1,281,468	
% of Capitalized OM&A (=A/B)	15%	14%	15%	14%	12%	11%	14%	13%	12%	12%	12%	

2.2.11 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

As noted in the Filing Requirements under section 2.2.2.7 “For any costs incurred to make investments that are eligible for rate protection as described in section 79.1 of the Ontario 5 Energy Board Act, 1998 (OEB Act) and O.Reg. 330/09 under the OEB Act, including any facilities forecast to enter service beyond the test year, the distributor may seek approval to recover the rate protection component of the costs.”

FHI has not identified any material eligible investments for which rate protection is required. As such FHI has not completed Appendices 2-FA through 2-FC.

Attachment 2 - 1

Required OEB Appendices

Ontario Energy Board

Chapter 2 Appendices

Filing Requirements for Electricity Distribution Rate Applications

Version 1.0 (2025)

Utility Name	Festival Hydro Inc.
Assigned EB Number	EB-2024-0023
Name of Contact and Title	Alyson Conrad, Chief Financial Officer
Phone Number	519-271-4700 ext. 221
Email Address	aconrad@festivalhydro.com
Test Year	2025
Bridge Year	2024
Last Rebasing Year	2015
Identify the accounting standard used for the test year	MIFRS
Did Festival Hydro Inc. update its depreciation and capitalization policies?	Yes

If "yes" to cell E34, were the changes in policies reflected in a prior rebasing application?	Yes
When did Festival Hydro Inc. update its actual depreciation and capitalization policies?	**January 1** **2013**
Identify the year the applicant adopted IFRS for financial reporting purposes	2014
Is Festival Hydro Inc. applying for cost recovery for the test and/or future year(s) for Green Energy initiatives?	No
Is Festival Hydro Inc. an embedded distributor?	Partial

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table 2-42
Page:	57
Date:	2024-04-26
Net Capital/Gross Capital	**Net Capital**

Appendix 2-AA
Capital Projects Table

Projects	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year	2026
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access												
Subdivisions	377,707	229,754	118,894	550,809	89,052	455,635	232,456	222,963	379,021	369,616	406,900	312,000
New Services	231,003	248,664	471,580	419,148	453,933	335,760	478,141	410,285	371,154	300,295	375,000	378,750
Metering	70,980	104,045	104,360	230,484	492,665	207,219	96,889	362,299	314,013	200,000	112,000	122,595
AMI 2.0	0	0	0	0	0	0	0	0	96,466	200,000	1,316,337	1,540,000
Other Recoverable Work	33,028	0	38,660	177,542	164,262	87,661	283,622	17,442	25,636	142,000	189,000	110,000
System Access Gross Expenditures	712,717	582,463	733,494	1,377,984	1,199,913	1,086,275	1,091,108	1,012,989	1,186,291	1,211,911	2,399,237	2,463,345
System Access Capital Contributions	333,945	206,585	371,810	585,308	443,731	465,828	481,457	343,410	446,781	219,113	327,188	331,500
Sub-Total	378,772	375,878	361,684	792,676	756,182	620,447	609,651	669,579	739,510	992,798	2,072,049	2,131,845
System Renewal												
Animal Mitigation	89,260	39,935	14,565	3,142	80,356	30,343	65,811	81,197	65,101	85,000	75,000	75,000
UG Renewal	379,235	280,541	360,585	426,276	422,449	364,501	441,142	708,274	541,750	808,898	1,188,450	1,231,500
OH Renewal	627,854	571,314	813,336	654,019	623,620	326,703	443,455	673,465	873,796	636,999	847,750	1,081,663
Switchgear Replacement	170,280	153,073	136,109	172,642	361,225	224,129	297,367	112,104	41,930	205,800	244,200	244,200
System Re-establishment	0	0	0	0	0	0	0	0	0	0	122,000	90,000
TS Renewal	0	0	0	5,300	35,855	72,697	137,501	86,263	212,043	150,000	274,600	272,600
Small Replacements	296,539	386,386	272,113	247,255	222,157	381,714	505,533	324,643	379,065	349,164	348,965	355,944
DS Renewal	0	0	0	0	17,481	227,076	1,887	0	0	0	0	0
Misc/Other	142,342	-4,053	47,427	56,833	5,260	0	134,657	235,832	0	0	0	0
System Renewal Gross Expenditures	1,705,511	1,427,197	1,644,134	1,565,466	1,768,402	1,627,164	2,027,352	2,221,777	2,113,684	2,235,861	3,100,965	3,350,907
System Renewal Capital Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	1,705,511	1,427,197	1,644,134	1,565,466	1,768,402	1,627,164	2,027,352	2,221,777	2,113,684	2,235,861	3,100,965	3,350,907
System Service												
Voltage Conversion	0	0	0	0	0	0	0	0	0	0	217,000	223,510
Distribution Automation	167,466	38,213	29,385	37,782	27,144	50,900	5,689	33,846	110,159	76,500	141,500	149,984
Misc/Other	70,200	0	0	0	2,589	0	0	0	0	0	0	0
System Service Gross Expenditures	237,666	38,213	29,385	37,782	29,733	50,900	5,689	33,846	110,159	76,500	358,500	373,494
System Service Capital Contributions												
Sub-Total	237,666	38,213	29,385	37,782	29,733	50,900	5,689	33,846	110,159	76,500	358,500	373,494
General Plant												
Fleet	40,680	30,426	7,390	334,227	56,425	0	16,511	68,635	92,935	450,000	125,000	575,000
Tools	15,434	22,344	29,482	35,757	29,367	26,793	26,796	28,200	36,453	45,000	46,200	47,436
Building&Equipment	232,893	153,023	136,178	193,352	225,097	156,731	491,840	365,904	1,060,506	2,165,000	505,000	315,000
IT Hardware	306,328	115,873	93,309	94,549	75,790	60,193	275,020	176,461	290,629	193,069	296,636	288,892
IT Software	58,144	233,363	282,383	178,912	226,526	216,420	66,063	267,546	446,552	464,598	30,000	72,223
ERP	0	0	0	0	0	0	0	0	0	875,000	875,000	0
General Plant Gross Expenditures	653,478	555,029	548,742	836,796	613,205	460,137	876,230	906,745	1,927,075	4,192,667	1,877,836	1,298,551
General Plant Capital Contributions												
Sub-Total	653,478	555,029	548,742	836,796	613,205	460,137	876,230	906,745	1,927,075	4,192,667	1,877,836	1,298,551
Miscellaneous												
Total	**2,975,427**	**2,396,317**	**2,583,945**	**3,232,721**	**3,167,521**	**2,758,649**	**3,518,922**	**3,831,948**	**4,890,428**	**7,497,827**	**7,409,350**	**7,154,797**

Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***												
Total	**2,975,427**	**2,396,317**	**2,583,945**	**3,232,721**	**3,167,521**	**2,758,649**	**3,518,922**	**3,831,948**	**4,890,428**	**7,497,827**	**7,409,350**	**7,154,797**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

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

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table 2-41
Page:	56
Date:	2024-04-26
Capital Expnditures = In Service Additions	**No**

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2025

Historical Period (previous plan[1] & actual)

CATEGORY	2015 Plan	2015 Actual	2015 Var	2016 Plan	2016 Actual	2016 Var	2017 Plan	2017 Actual	2017 Var
	$ '000		%	$ '000		%	$ '000		%
System Access	322	713	121.7%	328	583	77.6%	335	733	119.3%
System Renewal	1,490	1,706	14.5%	1,513	1,427	-5.7%	1,539	1,644	6.8%
System Service	310	238	-23.3%	314	38	-87.8%	316	29	-90.7%
General Plant	500	653	30.7%	427	555	30.0%	826	549	-33.6%
TOTAL EXPENDITURE	2,622	3,309	26.2%	2,582	2,603	0.8%	3,016	2,956	-2.0%
Capital Contributions	120	334	178.3%	120	207	72.2%	120	372	209.8%
NET CAPITAL EXPENDITURES	2,502	2,975	18.9%	2,462	2,396	-2.7%	2,896	2,584	-10.8%
System O&M	$ 2,104	$ 2,156	2.4%	$ 2,085	$ 2,133	2.3%	$ 2,124	$ 2,269	6.8%

CATEGORY	2018 Plan	2018 Actual	2018 Var	2019 Plan	2019 Actual	2019 Var	2020 Plan	2020 Actual	2020 Var	2021 Plan	2021 Actual	2021 Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	341	1,378	304.1%	348	1,200	245.3%	721	1,086	50.8%	712	1,091	53.2%
System Renewal	1,565	1,565	0.0%	1,592	1,768	11.1%	1,935	1,627	-15.9%	1,866	2,027	8.6%
System Service	318	38	-88.1%	320	30	-90.7%	55	51	-7.5%	55	6	-89.7%
General Plant	445	837	88.0%	415	613	47.8%	973	460	-52.7%	1,040	876	-15.7%
TOTAL EXPENDITURE	2,669	3,818	43.1%	2,675	3,611	35.0%	3,683	3,225	-12.5%	3,673	4,000	8.9%
Capital Contributions	120	585	387.8%	120	444	269.8%	200	466	132.8%	200	481	140.7%
NET CAPITAL EXPENDITURES	2,549	3,233	26.8%	2,555	3,168	24.0%	3,483	2,759	-20.8%	3,473	3,519	1.3%
System O&M	$ 2,171	$ 2,602	19.9%	$ 2,591	$ 2,408	-7.1%	$ 2,678	$ 2,601	-2.9%	$ 2,642	$ 2,445	-7.5%

CATEGORY	2022 Plan	2022 Actual	2022 Var	2023 Plan	2023 Actual	2023 Var	2024 Plan	2024 Actual[2]	2024 Var	Forecast Period (planned) 2025	2026	2027	2028	2029
	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	863	1,013	17.4%	805	1,186	47.4%	1,212	1,212	0.0%	2,399	2,463	2,531	2,601	1,743
System Renewal	2,044	2,222	8.7%	2,469	2,114	-14.4%	2,236	2,236	0.0%	3,101	3,351	3,421	3,505	3,590
System Service	55	34	-38.5%	75	110	46.9%	77	77	0.0%	359	374	384	397	409
General Plant	969	907	-6.4%	1,665	1,927	15.8%	4,193	4,193	0.0%	1,878	1,299	1,262	1,274	1,585
TOTAL EXPENDITURE	3,931	4,175	6.2%	5,014	5,337	6.4%	7,717	7,717	0.0%	7,737	7,487	7,598	7,777	7,327
Capital Contributions	200	343	71.7%	400	447	11.7%	219	219	0.0%	327	332	338	345	352
NET CAPITAL EXPENDITURES	3,731	3,832	2.7%	4,614	4,871	5.6%	7,517	7,517	0.0%	7,410	7,156	7,260	7,432	6,974
System O&M	$ 2,845	$ 2,904	2.1%	$ 3,087	$ 3,049	-1.2%	$ 3,352	$ 3,352	0.0%	$ 3,515	$ 3,620	$ 3,729	$ 3,841	$ 3,956

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

3. System O&M contains the following accounts: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096, 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 5195

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

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. If this is the first application where the applicant is rebasing under MIFRS, contact OEB staff for further guidance on the appropriate fixed asset continuity schedules to complete (i.e. applicable years and accounting standard for each schedule).

2 The "CCA Class" for fixed assets should generally 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 OEB.

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. Amortization of deferred revenue will be removed from the depreciation expense shown on this fixed asset continuity schedule as it should be included as income in Appendix 2-H Other 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.

7 This account includes the amount recorded under finance leases for plant leased from others and used by the utility in its utility operations.

8 The applicant must establish the continuity of historical cost for gross assets and accumulated depreciation by asset class by ensuring that the opening balance in the year agrees to the closing balance in the prior

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table 2-43
Page:	59-60
Date:	2024-04-26

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles	45	2%	45	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles	40	3%	40	3%	No	No
				Steel	30	70	95	1830	Poles	40	3%	40	3%	No	No
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles	60	2%	60	2%	No	No
			Cross Arm	Wood	20	40	55	1830	Poles	40	3%	40	3%	No	No
				Steel	30	70	95	1830	Poles	40	3%	40	3%	No	No
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	60	2%	60	2%	No	No
		OH Services			no guideline			1855	Services	60	2%	60	2%	no guideline	
	9	OH Transformers & Voltage Regulators			30	40	60								
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall - DS		30	45	60	1820	Distribution Station Equipment <50 kV	40	3%	40	3%	No	No
			Overall -TS		30	45	60	1815	Transformer Station Equipment >50 kV	40	3%	40	3%	No	No
			Bushing		10	20	30	1815	Transformer Station Equipment >50 kV	20	5%	20	5%	No	No
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1815	Transformer Station Equipment >50 kV	45	2%	45	2%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60	1815	Transformer Station Equipment >50 kV	50	2%	50	2%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45	1815	Transformer Station Equipment >50 kV	15	7%	15	7%	No	No
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60	1815	Transformer Station Equipment >50 kV	55	2%	55	2%	No	No
	23	Steel Structure			35	50	90	1815	Transformer Station Equipment >50 kV	60	2%	60	2%	No	No
	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (Non-TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30	1845	Underground Conductors and Devices	25	4%	25	4%	No	No
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Underground Conductors and Devices	25	4%	25	4%	No	No

UG	28	Primary TR XLPE Cables Direct Buried		25	30	35								
	29	Primary TR XLPE Cables in Duct		35	40	55	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	30	Secondary PILC Cables		70	75	80								
	31	Secondary Cables Direct Buried		25	35	40								
	32	Secondary Cables in Duct		35	40	60	1855	Services	40	3%	40	3%	No	No
	33	Network Tranformers	Overall	20	35	50								
			Protector	20	35	40								
	34	Pad-Mounted Transformers		25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers		25	35	45	1850	Line Transformers	40	3%	40	3%	No	No
	36	UG Foundation		35	55	70	1850	Line Transformers	40	3%	40	3%	No	No
	37	UG Vaults	Overall	40	60	80	1850	Line Transformers	40	3%	40	3%	No	No
			Roof	20	30	45	1850	Line Transformers	40	3%	40	3%	No	No
	38	UG Vault Switches		20	35	50								
	39	Pad-Mounted Switchgear		20	30	45	1845	Underground Conductors and Devices	30	3%	30	3%	No	No
	40	Ducts		30	50	85	1840	Underground Conduit	50	2%	50	2%	No	No
	41	Concrete Encased Duct Banks		35	55	80	1840	Underground Conduit	50	2%	50	2%	No	No
	42	Cable Chambers		50	60	80	1840	Underground Conduit	50	2%	50	2%	No	No
S	43	Remote SCADA		15	20	30	1980	System Supervisory Equipment	15	7%	15	7%	No	No

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15								
2	Vehicles	Trucks & Buckets	5	15								
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings	Buildings	50	75	1808	Buildings and Fixtures	60	2%	60	2%	No	No
		Buildings	no guideline		1809	Buildings and Fixtures	60	2%	60	2%	no guideline	
		HVAC equipment	no guideline		1908	Buildings and Fixtures	10	10%	10	10%	no guideline	
		Buildings	no guideline		1908	Buildings and Fixtures	60	2%	60	2%	no guideline	
		Parking	25	30	1908	Buildings and Fixtures	30	3%	30	3%	No	No
		Fence	25	60	1908	Buildings and Fixtures	30	3%	30	3%	No	No
		Roof	20	30	1908	Buildings and Fixtures	20	5%	20	5%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leasehold improvements	5	20%	5	20%	Yes	Yes
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	60	2%	60	2%	No	No
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - hardware	5	20%	5	20%	No	No
		Software	2	5	1611	Computer Software	5	20%	5	20%	No	No
		Software - ERP/CIS	no guideline		1611	Computer Software	10	10%	10	10%	no guideline	
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and garage equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measure & testing Equipment	8	13%	8	13%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters	15	7%	15	7%	Yes	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	15	7%	15	7%	Yes	No
	Primary Energy Meters		no guideline		1860	Meters	20	5%	20		no guideline	
11	Wholesale Energy Meters		15	30	1860	Meters	20	5%	20	5%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	40	3%	40	3%	No	No
13	Smart Meters		5	15	1880	Smart meters	10	10%	10	10%	No	No
14	Repeaters - Smart Metering		10	15	1880	Smart meters	10	10%	10	10%	No	No
15	Data Collectors - Smart Metering		15	20	1880	Smart meters	10	10%	10	10%	Yes	No

TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control System

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table 2-44 to 2-54
Page:	61-71
Date:	2024-04-26

Appendix 2-C
Depreciation and Amortization Expense

General: This appendix is to assess the reasonability of the depreciation expense that is included in rate base via. accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1 This should include assets in column A (excel column C) that become fully depreciated.
2 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board,
3 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
4 The applicant must provide an explanation of material variances in its evidence.

Year 2015

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets.	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 2,360,056	$ -	$ 70,200	$ 1,463,321	$ 931,835	17.11	5.85%	**$ 54,474**	$ 54,474	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 370,401	$ -	$ 306,328	$ -	$ 523,565	4.35	22.98%	**$ 120,293**	$ 120,293	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 494,571	$ -	$ -	$ -	$ 494,571	12.55	7.97%	**$ 39,423**	$ 39,423	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$ -	$ 13,935,158	43.52	2.30%	**$ 320,192**	$ 320,192	**$ -**
1820	Distribution Station Equipment <50 kV	$ 254,798	$ -	$ -	$ -	$ 254,798	9.15	10.92%	**$ 27,835**	$ 27,835	**$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 10,264,040	$ -	$ 581,837	$ -	$ 10,554,959	41.44	2.41%	**$ 254,718**	$ 254,718	**$ -**
1835	Overhead Conductors & Devices	$ 6,437,700	$ -	$ 347,558	$ -	$ 6,611,479	48.18	2.08%	**$ 137,222**	$ 137,222	**$ -**
1840	Underground Conduit	$ 3,886,852	$ -	$ 387,924	$ -	$ 4,080,814	41.28	2.42%	**$ 98,861**	$ 98,861	**$ -**
1845	Underground Conductors & Devices	$ 6,112,549	$ -	$ 490,818	$ -	$ 6,357,959	29.43	3.40%	**$ 216,004**	$ 216,004	**$ -**
1850	Line Transformers	$ 5,681,103	$ -	$ 407,840	$ -	$ 5,885,023	30.67	3.26%	**$ 191,869**	$ 191,869	**$ -**
1855	Services (Overhead & Underground)	$ 2,072,988	$ -	$ 193,102	$ -	$ 2,169,539	30.51	3.28%	**$ 71,111**	$ 71,111	**$ -**
1860	Meters	$ 962,973	$ -	$ 26,555	$ 4,001	$ 972,249	14.17	7.06%	**$ 68,593**	$ 68,593	**$ -**
1860	Meters (Smart Meters)	$ 2,738,785	$ -	$ 47,979	$ 2,730	$ 2,760,045	6.66	15.01%	**$ 414,319**	$ 414,319	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 465,827	$ -	$ 141,389	$ -	$ 536,521	15.63	6.40%	**$ 34,330**	$ 34,330	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 85,910	$ -	$ 91,504	$ -	$ 131,662	8.62	11.60%	**$ 15,271**	$ 15,271	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 354,933	$ -	$ 58,144	$ -	$ 384,005	4.11	24.32%	**$ 93,390**	$ 93,390	**-$ 0**
1930	Transportation Equipment	$ 944,582	$ 27,740	$ 40,680	$ -	$ 937,181	7.91	12.65%	**$ 118,545**	$ 118,545	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 159,916	$ -	$ 15,434	$ -	$ 167,633	6.02	16.62%	**$ 27,868**	$ 27,868	**$ -**
1945	Measurement & Testing Equipment	$ 9,659	$ -	$ -	$ -	$ 9,659	3.00	33.33%	**$ 3,220**	$ 3,220	**$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**

1955	Communications Equipment	$ 367	$ -	$ 3,501	$ -	$ 2,117	10.01	9.99%	**$ 212**	$ 212	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 6,315	$ -	$ -	$ -	$ 6,315	5.73	17.45%	**$ 1,102**	$ 1,102	**$ -**
1970	Load Management Controls Customer Premises	$ 43,749	$ -	$ -	$ -	$ 43,749	2.95	33.85%	**$ 14,808**	$ 14,808	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 177,377	$ -	$ 98,649	$ -	$ 226,701	12.87	7.77%	**$ 17,613**	$ 17,613	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.22	2.84%	**-$ 99,367**	-$ 99,367	**$ -**
2440	Deferred Revenue	$ -	$ -	-$ 333,945	$ -	-$ 166,973	28.34	3.53%	**-$ 5,892**	-$ 5,892	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 55,573,235**	**$ 27,740**	**$ 2,975,496**		**$ 54,631,355**	**$ 469**		**$ 2,236,014**	**$ 2,236,014**	**-$ 0**

Year 2016

		Book Values				Service Lives		Depreciation Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets,**	**Variance [4]**
		a	**b**	**c**	**d**	**e = a-b+0.5*c-d**	**f**	**g = 1/f**	**h = e/f**	**i**	**j = i-h**
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 676,729	$ 70,110	$ 232,429	$ -	$ 722,833	4.70	21.27%	**$ 153,732**	$ 153,732	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 494,571	$ 49,355	$ -	$ -	$ 445,216	30.19	3.31%	**$ 14,747**	$ 14,747	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$ -	$ 13,935,158	43.52	2.30%	**$ 320,188**	$ 320,188	**$ -**
1820	Distribution Station Equipment <50 kV	$ 254,798	$ 28,924	$ -	$ -	$ 225,874	16.89	5.92%	**$ 13,373**	$ 13,373	**-$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 10,845,877	$ -	$ 415,993	$ 4,053	$ 11,049,821	41.82	2.39%	**$ 264,194**	$ 264,194	**$ -**
1835	Overhead Conductors & Devices	$ 6,785,258	$ -	$ 280,767	$ -	$ 6,925,642	48.47	2.06%	**$ 142,891**	$ 142,891	**$ -**
1840	Underground Conduit	$ 4,274,776	$ -	$ 126,385	$ -	$ 4,337,968	41.79	2.39%	**$ 103,793**	$ 103,793	**$ 0**
1845	Underground Conductors & Devices	$ 6,603,368	$ -	$ 460,749	$ -	$ 6,833,742	29.82	3.35%	**$ 229,188**	$ 229,188	**$ -**
1850	Line Transformers	$ 6,088,943	$ -	$ 309,192	$ -	$ 6,243,539	31.09	3.22%	**$ 200,832**	$ 200,832	**$ -**
1855	Services (Overhead & Underground)	$ 2,266,090	$ -	$ 315,975	$ -	$ 2,424,078	31.41	3.18%	**$ 77,171**	$ 77,171	**$ -**
1860	Meters	$ 985,526	$ -	$ 25,019	$ -	$ 998,035	14.31	6.99%	**$ 69,754**	$ 69,754	**$ -**
1860	Meters (Smart Meters)	$ 2,784,035	$ -	$ 79,634	$ 6,769	$ 2,817,083	6.70	14.92%	**$ 420,224**	$ 420,224	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 607,216	$ 10,247	$ 146,538	$ -	$ 670,238	16.31	6.13%	**$ 41,099**	$ 41,099	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 177,414	$ 554	$ 6,485	$ -	$ 180,103	9.00	11.11%	**$ 20,003**	$ 20,003	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 413,077	$ 51,227	$ 116,807	$ -	$ 420,254	4.20	23.79%	**$ 99,961**	$ 99,961	**$ -**
1930	Transportation Equipment	$ 957,521	$ -	$ 61,189	$ 30,764	$ 957,352	7.86	12.73%	**$ 121,851**	$ 121,851	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 175,350	$ 41,156	$ 22,344	$ -	$ 145,366	5.31	18.83%	**$ 27,377**	$ 27,377	**$ -**
1945	Measurement & Testing Equipment	$ 9,659	$ 6,439	$ -	$ -	$ 3,220	1.00	100.00%	**$ 3,220**	$ 3,220	**-$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,868	$ -	$ -	$ 367	$ 3,501	9.06	11.03%	**$ 386**	$ 386	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 6,315	$ -	$ -	$ -	$ 6,315	5.73	17.45%	**$ 1,102**	$ 1,102	**$ -**
1970	Load Management Controls Customer Premises	$ 43,749	$ 39,506	$ -	$ -	$ 4,243	1.00	100.00%	**$ 4,243**	$ 4,243	**$ 0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 276,026	$ -	$ 38,213	$ -	$ 295,132	13.31	7.51%	**$ 22,175**	$ 22,175	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.22	2.84%	**-$ 99,367**	-$ 99,367	**$ -**

2440	Deferred Revenue	-$ 333,945	$ -	-$ 206,585	$ -	-$ 437,237	40.52	2.47%	-$ **10,791**	-$ 10,791	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 57,050,939**	**$ 297,519**	**$ 2,431,134**		**$ 56,960,099**	**$ 507**		**$ 2,295,820**	**$ 2,295,820**	**$ 0**

Year 2017

		Book Values				Service Lives		Depreciation Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets,**	**Variance [4]**
		a	**b**	**c**	**d**	**e = a-b+0.5*c-d**	**f**	**g = 1/f**	**h = e/f**	**i**	**j = i-h**
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 839,047	$ 34,097	$ 282,383	$ -	$ 946,142	4.83	20.71%	**$ 195,941**	$ 195,941	**$ 0**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 445,216	$ 5,037	$ -	$ -	$ 440,179	29.85	3.35%	**$ 14,745**	$ 14,745	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ -	$ -	$ 13,935,158	43.52	2.30%	**$ 320,188**	$ 320,188	**$ -**
1820	Distribution Station Equipment <50 kV	$ 225,874	$ -	$ 34,695	$ -	$ 243,222	17.62	5.68%	**$ 13,807**	$ 13,807	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 11,257,817	$ -	$ 461,590	$ -	$ 11,488,612	42.17	2.37%	**$ 272,465**	$ 272,465	**$ -**
1835	Overhead Conductors & Devices	$ 7,066,025	$ -	$ 365,637	$ -	$ 7,248,844	48.75	2.05%	**$ 148,682**	$ 148,682	**$ -**
1840	Underground Conduit	$ 4,401,161	$ -	$ 108,219	$ -	$ 4,455,270	42.02	2.38%	**$ 106,032**	$ 106,032	**$ -**
1845	Underground Conductors & Devices	$ 7,064,116	$ -	$ 431,330	$ -	$ 7,279,781	30.14	3.32%	**$ 241,550**	$ 241,550	**$ -**
1850	Line Transformers	$ 6,398,135	$ -	$ 519,430	$ -	$ 6,657,850	31.53	3.17%	**$ 211,189**	$ 211,189	**$ -**
1855	Services (Overhead & Underground)	$ 2,582,065	$ -	$ 336,699	$ -	$ 2,750,415	32.49	3.08%	**$ 84,656**	$ 84,656	**$ -**
1860	Meters	$ 1,010,545	$ -	$ 79,835	$ -	$ 1,050,463	14.44	6.93%	**$ 72,758**	$ 72,758	**$ -**
1860	Meters (Smart Meters)	$ 2,856,900	$ -	$ 27,989	$ -	$ 2,870,894	6.75	14.81%	**$ 425,267**	$ 425,267	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 743,507	$ 11,442	$ 126,216	$ -	$ 795,173	16.73	5.98%	**$ 47,532**	$ 47,532	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 183,345	$ -	$ 9,962	$ -	$ 188,326	9.04	11.06%	**$ 20,825**	$ 20,825	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 478,657	$ 28,799	$ 93,309	$ -	$ 496,513	4.61	21.68%	**$ 107,632**	$ 107,632	**$ -**
1930	Transportation Equipment	$ 987,947	$ -	$ 7,390	$ -	$ 991,642	8.19	12.20%	**$ 121,024**	$ 121,024	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 156,538	$ 22,197	$ 29,482	$ -	$ 149,082	5.61	17.81%	**$ 26,552**	$ 26,552	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 6,315	$ 3,137	$ -	$ -	$ 3,178	2.88	34.67%	**$ 1,102**	$ 1,102	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 314,239	$ -	$ 41,588	$ -	$ 335,033	13.49	7.41%	**$ 24,829**	$ 24,829	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.22	2.84%	**-$ 99,367**	-$ 99,367	**$ -**
2440	Deferred Revenue	-$ 540,530	$ -	-$ 371,810	$ -	-$ 726,435	59.36	1.68%	**-$ 12,239**	-$ 12,239	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 59,135,138**	**$ 104,709**	**$ 2,583,945**		**$ 59,355,467**	**$ 527**		**$ 2,399,997**	**$ 2,399,997**	**$ 0**

Year 2018

Book Values	Service Lives	Depreciation Expense

Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets.	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 1,087,333	$ 82,898	$ 178,912	$ -	$ 1,093,891	4.80	20.84%	**$ 227,989**	$ 227,989	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 440,179	$ 1,577	$ -	$ -	$ 438,602	32.52	3.07%	**$ 13,486**	$ 13,486	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 13,935,158	$ -	$ 5,300	$ -	$ 13,937,808	43.53	2.30%	**$ 320,188**	$ 320,188	**$ -**
1820	Distribution Station Equipment <50 kV	$ 260,569	$ -	$ 21,739	$ -	$ 271,439	18.70	5.35%	**$ 14,512**	$ 14,512	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 11,719,407	$ -	$ 530,251	$ -	$ 11,984,533	42.63	2.35%	**$ 281,109**	$ 281,109	**$ -**
1835	Overhead Conductors & Devices	$ 7,431,662	$ -	$ 404,796	$ -	$ 7,634,060	49.10	2.04%	**$ 155,467**	$ 155,467	**$ -**
1840	Underground Conduit	$ 4,509,380	$ -	$ 415,526	$ -	$ 4,717,143	41.11	2.43%	**$ 114,756**	$ 114,756	**$ -**
1845	Underground Conductors & Devices	$ 7,495,446	$ 529	$ 736,821	$ -	$ 7,863,327	30.55	3.27%	**$ 257,407**	$ 257,407	**$ -**
1850	Line Transformers	$ 6,917,565	$ -	$ 305,727	$ -	$ 7,070,429	31.92	3.13%	**$ 221,498**	$ 221,498	**$ -**
1855	Services (Overhead & Underground)	$ 2,918,765	$ -	$ 271,629	$ -	$ 3,054,579	33.33	3.00%	**$ 91,652**	$ 91,652	**$ -**
1860	Meters	$ 1,090,380	$ 547	$ 132,780	$ -	$ 1,156,223	14.56	6.87%	**$ 79,433**	$ 79,433	**$ -**
1860	Meters (Smart Meters)	$ 2,884,888	$ 5,024	$ 114,130	$ -	$ 2,936,929	6.79	14.72%	**$ 432,373**	$ 432,373	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 858,281	$ 11,465	$ 183,588	$ -	$ 938,609	16.38	6.10%	**$ 57,297**	$ 57,297	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 193,307	$ 13,630	$ 9,764	$ -	$ 184,559	8.46	11.82%	**$ 21,812**	$ 21,812	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 543,167	$ 189,680	$ 94,549	$ -	$ 400,762	3.96	25.26%	**$ 101,228**	$ 101,228	**$ -**
1930	Transportation Equipment	$ 995,337	$ 63,268	$ 334,227	$ -	$ 1,099,183	8.10	12.34%	**$ 135,635**	$ 135,635	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 163,823	$ 22,404	$ 35,757	$ -	$ 159,297	6.56	15.23%	**$ 24,265**	$ 24,265	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 355,827	$ 1,025	$ 42,534	$ -	$ 376,069	13.60	7.35%	**$ 27,645**	$ 27,645	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 912,339	$ -	-$ 585,308	$ -	-$ 1,204,993	25.11	3.98%	**-$ 47,985**	-$ 47,985	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 61,614,375**	**$ 392,049**	**$ 3,232,721**		**$ 61,871,752**	**$ 504**		**$ 2,484,963**	**$ 2,484,963**	**$ -**

Year 2019

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets.	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 1,183,347	$ 183,294	$ 226,526	$ -	$ 1,113,316	4.62	21.65%	**$ 240,992**	$ 240,992	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ 3,150	$ -	$ 1,575		0.00%	**$ -**	$ -	**$ -**

1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	$ -	$ -	$ -
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	$ **13,171**	$ 13,171	-$ 0
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 13,940,458	$ -	$ 35,855	$ -	$ 13,958,386	43.45	2.30%	$ **321,261**	$ 321,261	$ -
1820	Distribution Station Equipment <50 kV	$ 282,308	$ -	$ 17,481	$ -	$ 291,049	19.40	5.15%	$ **15,003**	$ 15,003	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 12,249,659	$ -	$ 500,051	$ -	$ 12,499,684	42.98	2.33%	$ **290,850**	$ 290,850	$ -
1835	Overhead Conductors & Devices	$ 7,836,458	$ -	$ 431,387	$ -	$ 8,052,152	49.42	2.02%	$ **162,945**	$ 162,945	$ -
1840	Underground Conduit	$ 4,924,906	$ -	$ 140,926	$ -	$ 4,995,369	41.52	2.41%	$ **120,322**	$ 120,322	$ -
1845	Underground Conductors & Devices	$ 8,231,738	$ 1,191	$ 724,236	$ -	$ 8,592,664	30.85	3.24%	$ **278,531**	$ 278,531	$ -
1850	Line Transformers	$ 7,223,292	$ -	$ 415,768	$ -	$ 7,431,177	32.24	3.10%	$ **230,516**	$ 230,516	-$ 0
1855	Services (Overhead & Underground)	$ 3,190,393	$ 27,973	$ 209,405	$ -	$ 3,267,123	33.55	2.98%	$ **97,374**	$ 97,374	-$ 0
1860	Meters	$ 1,222,613	$ 2,977	$ 117,399	$ -	$ 1,278,336	14.76	6.77%	$ **86,579**	$ 86,579	$ -
1860	Meters (Smart Meters)	$ 2,993,994	$ 14,439	$ 375,266	$ -	$ 3,167,187	6.99	14.30%	$ **452,950**	$ 452,950	$ -
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,030,403	$ -	$ 223,823	$ -	$ 1,142,315	16.07	6.22%	$ **71,088**	$ 71,088	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 189,440	$ -	$ 1,274	$ -	$ 190,077	9.68	10.33%	$ **19,637**	$ 19,637	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 448,036	$ 85,226	$ 75,790	$ -	$ 400,705	4.52	22.13%	$ **88,664**	$ 88,664	$ -
1930	Transportation Equipment	$ 1,266,296	$ 106,342	$ 56,425	$ -	$ 1,188,167	8.50	11.76%	$ **139,728**	$ 139,728	$ -
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 177,176	$ -	$ 29,367	$ -	$ 191,859	8.33	12.01%	$ **23,040**	$ 23,040	$ 0
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	$ **350**	$ 350	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	$ **318**	$ 318	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 397,335	$ 234	$ 27,123	$ -	$ 410,663	13.80	7.25%	$ **29,756**	$ 29,756	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	-$ **99,945**	-$ 99,945	$ -
2440	Deferred Revenue	-$ 1,490,314	$ -	-$ 443,731	$ -	-$ 1,712,180	37.29	2.68%	-$ **45,912**	-$ 45,912	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 64,462,381**	**$ 421,675**	**$ 3,167,521**		**$ 64,657,531**	**$ 524**		**$ 2,591,692**	**$ 2,591,692**	**-$ 0**

Year 2020

		Book Values				Service Lives		Depreciation Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets.**	**Variance [4]**
		a	**b**	**c**	**d**	**e = a-b+0.5*c-d**	**f**	**g = 1/f**	**h = e/f**	**i**	**j = i-h**
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	$ **54,473**	$ 54,473	-$ 0
1611	Computer Software (Formally known as Account 1925)	$ 1,226,579	$ 306,328	$ 216,420	$ -	$ 1,028,462	4.35	22.98%	$ **236,325**	$ 236,325	$ -
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	$ -	$ -	$ -
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	$ -	$ -	$ -
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	$ **13,171**	$ 13,171	-$ 0
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 13,976,313	$ -	$ 72,697	$ -	$ 14,012,662	43.18	2.32%	$ **324,551**	$ 324,551	$ -
1820	Distribution Station Equipment <50 kV	$ 299,789	$ 10,170	$ 227,076	$ -	$ 403,157	22.32	4.48%	$ **18,060**	$ 18,060	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 12,749,710	$ -	$ 283,463	$ 39,887	$ 12,851,554	42.98	2.33%	$ **299,041**	$ 299,041	$ -
1835	Overhead Conductors & Devices	$ 8,267,845	$ -	$ 261,099	$ -	$ 8,398,395	49.64	2.01%	$ **169,193**	$ 169,193	$ -
1840	Underground Conduit	$ 5,065,832	$ -	$ 532,871	$ -	$ 5,332,268	41.97	2.38%	$ **127,059**	$ 127,059	$ -

1845	Underground Conductors & Devices	$ 8,954,782	$ 2,087	$ 555,305	$ -	$ 9,230,348	31.17	3.21%	$ 296,124	$ 296,124	$ -
1850	Line Transformers	$ 7,639,061	$ -	$ 305,450	$ -	$ 7,791,786	32.53	3.07%	$ 239,531	$ 239,531	-$ 0
1855	Services (Overhead & Underground)	$ 3,371,826	$ -	$ 229,210	$ -	$ 3,486,431	35.64	2.81%	$ 97,834	$ 97,834	-$ 0
1860	Meters	$ 1,337,035	$ 1,902	$ 132,394	$ -	$ 1,401,330	15.11	6.62%	$ 92,750	$ 92,750	$ -
1860	Meters (Smart Meters)	$ 3,354,820	$ 2,406,014	$ 131,206	$ -	$ 1,014,410	3.46	28.90%	$ 293,196	$ 293,196	$ -
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,254,226	$ -	$ 156,731	$ -	$ 1,332,592	16.00	6.25%	$ 83,263	$ 83,263	-$ 0
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 190,714	$ 4,802	$ -	$ -	$ 185,913	9.62	10.40%	$ 19,332	$ 19,332	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 438,600	$ 58,144	$ 60,194	$ -	$ 410,552	4.67	21.42%	$ 87,925	$ 87,925	$ -
1930	Transportation Equipment	$ 1,216,379	$ 137,828	$ -	$ -	$ 1,078,552	8.77	11.40%	$ 122,917	$ 122,917	$ -
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 206,543	$ 9,837	$ 26,793	$ -	$ 210,103	8.37	11.94%	$ 25,092	$ 25,092	$ -
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	$ 350	$ 350	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	9.99	10.01%	$ 318	$ 318	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 424,224	$ 549	$ 33,569	$ -	$ 440,460	13.88	7.21%	$ 31,740	$ 31,740	$ 0
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	-$ 99,945	-$ 99,945	$ -
2440	Deferred Revenue	-$ 1,934,045	$ -	-$ 465,828	$ -	-$ 2,166,959	37.93	2.64%	-$ 57,127	-$ 57,127	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 67,208,227**	**$ 2,937,660**	**$ 2,758,650**		**$ 64,643,069**	**$ 528**		**$ 2,475,174**	**$ 2,475,174**	**-$ 0**

Year 2021

Account	Description	Book Values: Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Service Lives: Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets.	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	$ 54,473	$ 54,473	-$ 0
1611	Computer Software (Formally known as Account 1925)	$ 1,136,672	$ 232,429	$ 66,063	$ -	$ 937,274	4.45	22.48%	$ 210,698	$ 210,698	$ -
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	$ -	$ -	$ -
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	$ -	$ -	$ -
1808	Buildings	$ 438,602	$ 9,671	$ -	$ -	$ 428,932	32.57	3.07%	$ 13,171	$ 13,171	$ 0
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 14,049,010	$ -	$ 143,417	$ -	$ 14,120,718	42.26	2.37%	$ 334,173	$ 334,173	$ -
1820	Distribution Station Equipment <50 kV	$ 516,695	$ -	$ 1,887	$ -	$ 517,638	26.59	3.76%	$ 19,469	$ 19,469	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 12,993,286	$ 2,590	$ 663,008	$ -	$ 13,322,200	43.32	2.31%	$ 307,556	$ 307,556	$ -
1835	Overhead Conductors & Devices	$ 8,528,945	$ -	$ 318,477	$ -	$ 8,688,183	49.84	2.01%	$ 174,321	$ 174,321	$ -
1840	Underground Conduit	$ 5,598,703	$ -	$ 283,236	$ -	$ 5,740,321	45.18	2.21%	$ 127,059	$ 127,059	$ -
1845	Underground Conductors & Devices	$ 9,508,000	$ 15,012	$ 851,058	$ -	$ 9,918,517	31.43	3.18%	$ 315,583	$ 315,583	$ -
1850	Line Transformers	$ 7,944,510	$ 203,333	$ 407,561	$ -	$ 7,944,958	31.98	3.13%	$ 248,444	$ 248,444	$ -
1855	Services (Overhead & Underground)	$ 3,601,036	$ -	$ 350,012	$ -	$ 3,776,041	36.06	2.77%	$ 104,707	$ 104,707	$ -
1860	Meters	$ 1,467,527	$ 6,795	$ 46,318	$ -	$ 1,483,891	15.29	6.54%	$ 97,070	$ 97,070	$ -
1860	Meters (Smart Meters)	$ 1,080,013	$ -	$ 53,232	$ -	$ 1,106,629	10.40	9.62%	$ 106,440	$ 106,440	$ -
1905	Land	$ -	$ 12,585	$ -	$ -	-$ 12,585		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,410,958	$ -	$ 477,555	$ -	$ 1,649,735	17.06	5.86%	$ 96,716	$ 96,716	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 185,913	$ -	$ 8,348	$ -	$ 190,087	10.14	9.86%	$ 18,751	$ 18,751	$ -

1915	Office Furniture & Equipment (5 years)	$ -	$ 116,806	$ -	$ -	-$ 116,806		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 440,649	$ 26,344	$ 275,021	$ -	$ 551,815	5.31	18.84%	**$ 103,951**	$ 103,951	**$ -**
1930	Transportation Equipment	$ 1,078,552	$ -	$ 16,511	$ -	$ 1,086,807	10.49	9.54%	**$ 103,650**	$ 103,650	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 223,499	$ -	$ 26,796	$ -	$ 236,897	9.22	10.85%	**$ 25,697**	$ 25,697	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	5.00	20.00%	**$ 700**	$ 700	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ 20,459	$ -	$ -	-$ 20,459		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 457,245	$ -	$ 11,881	$ -	$ 463,185	13.96	7.16%	**$ 33,177**	$ 33,177	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,499,578	$ -	-$ 141,936	$ -	-$ 3,570,546	35.73	2.80%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 2,399,873	$ -	-$ 481,457	$ -	-$ 2,640,602	43.55	2.30%	**-$ 60,633**	-$ 60,633	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 66,989,329**	**$ 646,024**	**$ 3,376,986**		**$ 67,064,863**	**$ 548**		**$ 2,335,547**	**$ 2,335,547**	**-$ 0**

Year 2022

		Book Values				Service Lives		Depreciation Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets,**	**Variance [4]**
		a	**b**	**c**	**d**	**e = a-b+0.5*c-d**	**f**	**g = 1/f**	**h = e/f**	**i**	**j = i-h**
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 970,306	$ 282,383	$ 299,790	$ -	$ 837,818	4.82	20.73%	**$ 173,656**	$ 173,656	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	$ -	$ -	$ -
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	$ -	$ -	$ -
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 14,192,427	$ -	$ 86,263	$ -	$ 14,235,558	41.18	2.43%	**$ 345,657**	$ 345,657	**$ -**
1820	Distribution Station Equipment <50 kV	$ 508,911	$ 1,769	$ -	$ -	$ 507,142	26.18	3.82%	**$ 19,370**	$ 19,370	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 13,656,294	$ -	$ 763,001	$ -	$ 14,037,794	44.06	2.27%	**$ 318,606**	$ 318,606	**$ -**
1835	Overhead Conductors & Devices	$ 8,847,421	$ -	$ 392,360	$ -	$ 9,043,602	49.84	2.01%	**$ 181,457**	$ 181,457	**$ -**
1840	Underground Conduit	$ 5,881,939	$ -	$ 66,651	$ -	$ 5,915,265	43.75	2.29%	**$ 135,220**	$ 135,220	**$ -**
1845	Underground Conductors & Devices	$ 10,356,468	$ 12,294	$ 804,724	$ -	$ 10,746,536	31.02	3.22%	**$ 346,462**	$ 346,462	**$ -**
1850	Line Transformers	$ 8,352,072	$ -	$ 374,144	$ -	$ 8,539,144	33.07	3.02%	**$ 258,215**	$ 258,215	**-$ 0**
1855	Services (Overhead & Underground)	$ 3,951,047	$ -	$ 317,708	$ -	$ 4,109,901	36.55	2.74%	**$ 112,455**	$ 112,455	**$ -**
1860	Meters	$ 1,498,833	$ 214,520	$ 207,453	$ -	$ 1,388,040	13.52	7.40%	**$ 102,652**	$ 102,652	**$ -**
1860	Meters (Smart Meters)	$ 929,912	$ 68,716	$ 190,502	$ -	$ 956,447	9.18	10.89%	**$ 104,200**	$ 104,200	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,881,717	$ 27,578	$ 357,228	$ -	$ 2,032,753	16.85	5.94%	**$ 120,660**	$ 120,660	**-$ 0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 181,676	$ 2,545	$ 8,676	$ -	$ 183,469	9.74	10.27%	**$ 18,845**	$ 18,845	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 598,864	$ 93,310	$ 176,461	$ -	$ 593,784	4.64	21.57%	**$ 128,088**	$ 128,088	**$ -**
1930	Transportation Equipment	$ 1,095,062	$ 257,102	$ 68,635	$ -	$ 872,278	9.06	11.03%	**$ 96,226**	$ 96,226	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 223,951	$ 22,851	$ 28,200	$ -	$ 215,200	8.28	12.08%	**$ 25,987**	$ 25,987	**-$ 0**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -

1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	9.99	10.01%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 448,667	$ 30,123	$ 33,563	$ -	$ 435,325	12.89	7.76%	**$ 33,782**	$ 33,782	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,641,514	$ -	$ 141,936	$ -	-$ 3,570,546	35.73	2.80%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 2,881,331	$ -	-$ 343,410	$ -	-$ 3,053,036	39.72	2.52%	**-$ 76,869**	-$ 76,869	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 69,720,292**	**$ 1,013,191**	**$ 3,973,884**		**$ 69,727,107**	**$ 541**		**$ 2,413,037**	**$ 2,413,037**	**-$ 0**

Year 2023

		Book Values				Service Lives		Depreciation Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets.**	**Variance [4]**
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 987,713	-$ 178,912	$ 551,449	$ -	$ 1,442,350	9.16	10.92%	**$ 157,468**	$ 157,468	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 14,278,690	$ -	$ 212,043	$ -	$ 14,384,711	40.15	2.49%	**$ 358,236**	$ 358,236	**$ -**
1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ -	$ 507,142	26.22	3.81%	**$ 19,345**	$ 19,345	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 14,419,295	$ -	$ 617,447	$ -	$ 14,728,018	44.53	2.25%	**$ 330,763**	$ 330,763	**$ -**
1835	Overhead Conductors & Devices	$ 9,239,782	$ -	$ 409,824	$ -	$ 9,444,694	50.10	2.00%	**$ 188,525**	$ 188,525	**$ -**
1840	Underground Conduit	$ 5,948,590	$ -	$ 288,698	$ -	$ 6,092,939	43.92	2.28%	**$ 138,719**	$ 138,719	**$ -**
1845	Underground Conductors & Devices	$ 11,148,898	-$ 47,073	$ 427,299	$ -	$ 11,409,620	32.31	3.10%	**$ 353,138**	$ 353,138	**$ -**
1850	Line Transformers	$ 8,726,215	$ -	$ 553,413	$ -	$ 9,002,922	33.37	3.00%	**$ 269,810**	$ 269,810	**$ -**
1855	Services (Overhead & Underground)	$ 4,268,755	$ -	$ 242,624	$ -	$ 4,390,067	36.96	2.71%	**$ 118,793**	$ 118,793	**$ -**
1860	Meters	$ 1,491,766	-$ 197,415	$ 433,583	$ -	$ 1,905,973	17.56	5.69%	**$ 108,521**	$ 108,521	**$ -**
1860	Meters (Smart Meters)	$ 1,051,698	$ -	$ -	$ -	$ 1,051,698	9.69	10.32%	**$ 108,509**	$ 108,509	**$ 0**
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 2,211,367	-$ 7,732	$ 1,060,506	$ -	$ 2,749,352	17.54	5.70%	**$ 156,767**	$ 156,767	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 187,807	-$ 3,684	$ -	$ -	$ 191,491	10.10	9.91%	**$ 18,968**	$ 18,968	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 682,015	-$ 94,549	$ 290,629	$ -	$ 921,879	5.91	16.92%	**$ 156,011**	$ 156,011	**$ -**
1930	Transportation Equipment	$ 906,595	-$ 108,265	$ 92,935	$ -	$ 1,061,327	12.22	8.18%	**$ 86,852**	$ 86,852	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 229,300	-$ 20,797	$ 36,453	$ -	$ 268,324	9.92	10.08%	**$ 27,038**	$ 27,038	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ -	$ 3,178	10.00	10.00%	**$ 318**	$ 318	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 452,107	-$ 28,656	$ 120,308	$ -	$ 540,917	14.46	6.92%	**$ 37,410**	$ 37,410	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**

2440	Deferred Revenue	-$ 3,224,740	$ -	-$ 446,781	$ -	-$ 3,448,131	44.86	2.23%	-$ 76,869	-$ 76,869	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 72,680,985**	**-$ 687,084**	**$ 4,890,430**		**$ 74,846,348**	**$ 565**		**$ 2,526,371**	**$ 2,526,371**	**$ 0**

Year 2024

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Service Lives: Depreciation Rate Assets	Depreciation Expense: Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 2,579,847	$ -	$ 905,000	$ 3,032,347	19.85	5.04%	**$ 152,761**	$ 152,761	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 14,640,733	$ -	$ 274,600	$ 14,778,033	45.09	2.22%	**$ 327,720**	$ 327,720	**$ -**
1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ 507,142	26.15	3.82%	**$ 19,392**	$ 19,392	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 15,121,742	$ -	$ 75,000	$ 15,159,242	46.11	2.17%	**$ 328,762**	$ 328,762	**$ -**
1835	Overhead Conductors & Devices	$ 11,241,879	$ -	$ 2,000,455	$ 12,242,106	48.04	2.08%	**$ 254,842**	$ 254,842	**$ -**
1840	Underground Conduit	$ 7,132,788	$ -	$ 1,294,850	$ 7,780,213	50.32	1.99%	**$ 154,608**	$ 154,608	**$ -**
1845	Underground Conductors & Devices	$ 11,559,123	$ -	$ 50,000	$ 11,584,123	33.00	3.03%	**$ 351,032**	$ 351,032	**$ -**
1850	Line Transformers	$ 9,694,629	$ -	$ 595,000	$ 9,992,129	35.45	2.82%	**$ 281,864**	$ 281,864	**$ -**
1855	Services (Overhead & Underground)	$ 4,511,379	$ -	$ -	$ 4,511,379	38.88	2.57%	**$ 116,033**	$ 116,033	**-$ 0**
1860	Meters	$ 2,127,934	$ -	$ 1,427,297	$ 2,841,582	20.17	4.96%	**$ 140,891**	$ 140,891	**$ -**
1860	Meters (Smart Meters)	$ 1,051,698	$ -	$ -	$ 1,051,698	10.12	9.88%	**$ 103,932**	$ 103,932	**-$ 0**
1905	Land	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 5,429,141	$ -	$ 505,000	$ 5,681,641	26.20	3.82%	**$ 216,845**	$ 216,845	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 184,123	$ -	$ -	$ 184,123	11.37	8.79%	**$ 16,192**	$ 16,192	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,071,164	$ -	$ 296,636	$ 1,219,482	6.89	14.52%	**$ 177,088**	$ 177,088	**$ -**
1930	Transportation Equipment	$ 1,341,265	$ -	$ 125,000	$ 1,403,765	13.21	7.57%	**$ 106,226**	$ 106,226	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 289,956	$ -	$ 46,200	$ 313,056	10.87	9.20%	**$ 28,796**	$ 28,796	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	10.00	10.00%	**$ 350**	$ 350	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178	20.00	5.00%	**$ 159**	$ 159	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 620,258	$ -	$ 141,500	$ 691,008	17.30	5.78%	**$ 39,932**	$ 39,932	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 3,890,621	$ -	-$ 219,113	-$ 4,000,177	52.04	1.92%	**-$ 76,864**	-$ 76,864	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 84,382,171**	**$ -**	**$ 7,517,425**	**$ 87,173,948**	**$ 627**		**$ 2,708,261**	**$ 2,708,261**	**-$ 0**

Year 2025

Book Values	Service Lives	Depreciation Expense

Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ 966,935	$ -	$ -	$ 966,935	17.75	5.63%	**$ 54,473**	$ 54,473	**-$ 0**
1611	Computer Software (Formally known as Account 1925)	$ 2,579,847	$ -	$ 905,000	$ 3,032,347	12.37	8.08%	**$ 245,042**	$ 245,042	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 3,150	$ -	$ -	$ 3,150		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 1,252,202	$ -	$ -	$ 1,252,202		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 438,602	$ -	$ -	$ 438,602	33.30	3.00%	**$ 13,171**	$ 13,171	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 14,640,733	$ -	$ 274,600	$ 14,778,033	44.30	2.26%	**$ 333,569**	$ 333,569	**$ -**
1820	Distribution Station Equipment <50 kV	$ 507,142	$ -	$ -	$ 507,142	26.15	3.82%	**$ 19,392**	$ 19,392	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 15,121,742	$ -	$ 75,000	$ 15,159,242	45.89	2.18%	**$ 330,325**	$ 330,325	**$ -**
1835	Overhead Conductors & Devices	$ 11,241,879	$ -	$ 2,000,455	$ 12,242,106	39.77	2.51%	**$ 307,830**	$ 307,830	**$ -**
1840	Underground Conduit	$ 7,132,788	$ -	$ 1,294,850	$ 7,780,213	46.93	2.13%	**$ 165,772**	$ 165,772	**$ -**
1845	Underground Conductors & Devices	$ 11,559,123	$ -	$ 50,000	$ 11,584,123	33.03	3.03%	**$ 350,732**	$ 350,732	**-$ 0**
1850	Line Transformers	$ 9,694,629	$ -	$ 595,000	$ 9,992,129	34.02	2.94%	**$ 293,676**	$ 293,676	**$ 0**
1855	Services (Overhead & Underground)	$ 4,511,379	$ -	$ -	$ 4,511,379	39.15	2.55%	**$ 115,234**	$ 115,234	**$ -**
1860	Meters	$ 2,127,934	$ -	$ 1,427,297	$ 2,841,582	12.67	7.89%	**$ 224,226**	$ 224,226	**$ -**
1860	Meters (Smart Meters)	$ 1,051,698	$ -	$ -	$ 1,051,698	10.65	9.39%	**$ 98,781**	$ 98,781	**$ -**
1905	Land	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 5,429,141	$ -	$ 505,000	$ 5,681,641	23.57	4.24%	**$ 241,024**	$ 241,024	**-$ 0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 184,123	$ -	$ -	$ 184,123	20.40	4.90%	**$ 9,026**	$ 9,026	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,071,164	$ -	$ 296,636	$ 1,219,482	5.54	18.05%	**$ 220,106**	$ 220,106	**$ -**
1930	Transportation Equipment	$ 1,341,265	$ -	$ 125,000	$ 1,403,765	13.83	7.23%	**$ 101,501**	$ 101,501	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 289,956	$ -	$ 46,200	$ 313,056	10.28	9.73%	**$ 30,455**	$ 30,455	**$ -**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 3,501	$ -	$ -	$ 3,501	20.00	5.00%	**$ 175**	$ 175	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 3,178	$ -	$ -	$ 3,178		0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 620,258	$ -	$ 141,500	$ 691,008	14.79	6.76%	**$ 46,736**	$ 46,736	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,499,578	$ -	$ -	-$ 3,499,578	35.02	2.86%	**-$ 99,945**	-$ 99,945	**$ -**
2440	Deferred Revenue	-$ 3,890,621	$ -	-$ 325,018	-$ 4,053,130	51.45	1.94%	**-$ 78,773**	-$ 78,773	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 84,382,171**	**$ -**	**$ 7,411,520**	**$ 87,120,996**	**$ 591**		**$ 3,022,529**	**$ 3,022,529**	**-$ 0**

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table 2-59
Page:	86
Date:	2024-04-26

Appendix 2-D
Overhead Expense

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	**2015 Historical Year**	**2016 Historical Year**	**2017 Historical Year**	**2018 Historical Year**	**2019 Historical Year**	**2020 Historical Year**	**2021 Historical Year**	**2022 Historical Year**	**2023 Historical Year**	**2024 Bridge Year**	**2025 Test Year**
Operations Expense	$ 1,221,497	$ 1,254,466	$ 1,240,603	$ 1,479,406	$ 1,162,812	$ 1,359,468	$ 1,154,952	$ 1,375,403	$ 1,567,662	$ 1,771,299	$ 1,902,585
Maintenance Expense	$ 1,689,049	$ 1,608,783	$ 1,784,230	$ 1,930,411	$ 1,829,483	$ 1,775,631	$ 2,058,804	$ 2,255,610	$ 2,229,552	$ 2,405,272	$ 2,653,668
Billing & Collections Expense	$ 1,251,776	$ 1,295,739	$ 1,272,765	$ 1,188,727	$ 1,259,373	$ 1,208,934	$ 1,293,457	$ 1,283,486	$ 1,448,423	$ 1,542,185	$ 1,707,271
Community Relations Expense	$ 11,632	$ 9,900	$ 13,400	$ 9,745	$ 7,413	$ 12,268	$ 1,015	$ 1,115	$ -	$ 9,507	$ 19,427
Administration & General	$ 2,130,943	$ 2,511,500	$ 2,361,487	$ 2,821,357	$ 2,639,221	$ 2,585,385	$ 2,645,657	$ 2,945,305	$ 3,396,030	$ 3,772,182	$ 4,408,728
LEAP	$ 13,000	$ 13,200	$ 13,410	$ 13,510	$ 13,650	$ 13,860	$ 30,060	$ 14,550	$ 15,000	$ 15,630	$ 20,050
Total OM&A Before Capitalization (B)	$ 6,317,897	$ 6,693,588	$ 6,685,895	$ 7,443,156	$ 6,911,952	$ 6,955,547	$ 7,183,945	$ 7,875,468	$ 8,656,666	$ 9,516,074	$ 10,711,729

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	**2015 Historical Year**	**2016 Historical Year**	**2017 Historical Year**	**2018 Historical Year**	**2019 Historical Year**	**2020 Historical Year**	**2021 Historical Year**	**2022 Historical Year**	**2023 Historical Year**	**2024 Bridge Year**	**2025 Test Year**	**Directly Attributable? (Yes/No)**	**Explanation for Any Change in Treatment of Capitalized Overhead**
employee benefits													
costs of site preparation													
initial delivery and handling costs													
costs of testing whether the asset is functioning properly													
professional fees													
Benefit Costs and Labour Burden	$ 797,106	$ 806,296	$ 823,669	$ 895,063	$ 662,220	$ 675,392	$ 899,310	$ 865,124	$ 928,945	$ 1,015,801	$ 1,124,749	Yes	
Transportation and Fleet Costs	$ 166,314	$ 144,291	$ 163,402	$ 160,529	$ 135,630	$ 102,182	$ 139,773	$ 128,736	$ 123,267	$ 131,022	$ 156,719	Yes	
Total Capitalized OM&A (A)	$ 963,420	$ 950,586	$ 987,071	$ 1,055,592	$ 797,850	$ 777,574	$ 1,039,082	$ 993,860	$ 1,052,213	$ 1,146,823	$ 1,281,468		

% of Capitalized OM&A (=A/B)	15%	14%	15%	14%	12%	11%	14%	13%	12%	12%	12%		

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Attachment 2-2
Page:	
Date:	26-Apr-24

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Excluding Loss of Supply and Major Event Days					Including Major Event Days, Excluding Loss of Supply					Including Loss of Supply, Excluding Major Event Days					Including Loss of Supply and Major Event Days				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
SAIDI	1.79	1.27	1.95	0.81	1.09	1.78	1.27	1.95	0.81	1.09	2.22	2.08	2.61	1.33	1.81	2.21	2.08	2.61	1.33	1.81
SAIFI	1.78	1.00	1.63	0.77	0.81	1.78	1.00	1.63	0.77	0.81	2.73	1.50	2.58	1.68	1.90	2.73	1.50	2.58	1.68	1.90

5 Year Historical Average

SAIDI		1.380		1.379		2.010		2.008
SAIFI		1.198		1.198		2.078		2.078

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2019	2020	2021	2022	2023
Low Voltage Connections	90.0%	96.99%	95.31%	97.89%	95.92%	93.26%
High Voltage Connections	90.0%	100.00%	N/A	100.00%	100.00%	N/A
Telephone Accessibility	65.0%	88.45%	98.86%	91.71%	90.42%	98.07%
Appointments Met	90.0%	98.50%	97.69%	98.88%	97.70%	97.70%
Written Response to Enquires	80.0%	100.00%	99.97%	99.98%	99.95%	100.00%
Emergency Urban Response	80.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Emergency Rural Response	80.0%	N/A	100.00%	100.00%	100.00%	100.00%
Telephone Call Abandon Rate	10.0%	0.92%	1.71%	1.98%	0.97%	0.96%
Appointment Scheduling	90.0%	97.92%	97.43%	97.56%	98.05%	96.68%
Rescheduling a Missed Appointment	100.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Reconnection Performance Standard	85.0%	100.00%	100.00%	100.00%	100.00%	100.00%

File Number:	EB-2024-0023
Exhibit:	
Tab:	
Schedule:	Table 2-58
Page:	79
Date:	2024-04-26

Commodity Expense

Step 1: **Commodity Pricing**

Forecasted Commodity Prices

Table 1: Average RPP Supply Cost Summary*

			non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$31.79	$31.79
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$72.86	$72.86
Adjustments ($/MWh)				$6.40
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$111.05**

Step 2: **Commodity Expense**

(volumes for the test year is loss adjusted)

Commodity

Customer		Revenue	Expense		2025 Test Year					
Class Name	UoM	USoA #	USoA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		2,870,942	154,873,125	$ 0.03179	$ 0.11105	$17,289,928
GS < 50	kWh	4010	4705	-		14,706,738	49,319,113	$ 0.03179	$ 0.11105	$5,944,415
GS > 50	kWh	4035	4705	240,708,111		105,812,755	16,707,585	$ 0.03179	$ 0.11105	$12,871,276
Large Use	kWh	4010	4705	29,216,275		-	-	$ 0.03179	$ 0.11105	$928,785
Street Light	kWh	4025	4705	-		2,331,227	95,113	$ 0.03179	$ 0.11105	$84,672
Sentinel Light	kWh	4025	4705	-		-	97,679	$ 0.03179	$ 0.11105	$10,847
Unmetered Scattered Load	kWh	4025	4705	-		504,447	326,877	$ 0.03179	$ 0.11105	$52,336
Wholesale Market Participant	kWh	4025	4705	-		-	-	$ 0.03179	$ 0.11105	$0
	kWh	4025	4705					$ 0.03179	$ 0.11105	$0
	kWh	4025	4705					$ 0.03179	$ 0.11105	$0
	kWh	4025	4705					$ 0.03179	$ 0.11105	$0
TOTAL				**269,924,387**		**126,226,110**	**221,419,491**			**$37,182,259**

Class A - non-RPP Global Adjustment

Customer		Revenue	Expense		2025		Hist. Avg GA/kWh ***	Amount
					kWh Volume			
General Service > 50 to 4999 kW		4035	4707		240,708,111		0.044989740	$10,829,395
Large Use		4010	4707		29,216,275		0.046338161	$1,353,828

		4010	4707							$0
		4010	4707							$0
		4010	4707							$0
				-	269,924,387					**$12,183,224**

Class B - non-RPP Global Adjustment

					2025					
Customer		**Revenue**	**Expense**							Amount
Class Name	UoM	USoA #	USoA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			2,870,942			$ 0.07286	$209,177
GS < 50	kWh	4010	4707			14,706,738			$ 0.07286	$1,071,533
GS > 50	kWh	4035	4707			105,812,755			$ 0.07286	$7,709,517
Large Use	kWh	4010	4707			0			$ 0.07286	$0
Street Light	kWh	4025	4707			2,331,227			$ 0.07286	$169,853
Sentinel Light	kWh	4025	4707			0			$ 0.07286	$0
Unmetered Scattered Load	kWh	4025	4707			504,447			$ 0.07286	$36,754
Wholesale Market Participant	kWh	4025	4707			0			$ 0.07286	$0
	kWh	4025	4707			0			$ 0.07286	$0
	kWh	4025	4707			0			$ 0.07286	$0
	kWh	4025	4707			0			$ 0.07286	$0
Total Volume						**126,226,110**				
TOTAL										**$9,196,834**

*Regulated Price Plan Prices for the Period November 1, 2023 to October 31, 2024, p. 5

** Enter 2024 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

File Number:	EB-2024-0023
Exhibit:	2
Tab:	
Schedule:	Table 2-57
Page:	76-86
Date:	2024-04-26

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

		2025 Test Year	RPP		2025 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	154,873,125		17,198,661	2,870,942		91,267	
GS < 50	kWh	49,319,113		5,476,887	14,706,738		467,527	
GS > 50	kWh	16,707,585		1,855,377	346,520,867		11,015,898	
Large Use	kWh	0		-	29,216,275		928,785	
Street Light	kWh	95,113		10,562	2,331,227		74,110	
Sentinel Light	kWh	97,679		10,847	0		-	
Unmetered Scattered Load	kWh	326,877		36,300	504,447		16,036	
Wholesale Market Participant	kWh	0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
SUB-TOTAL				24,588,634			12,593,624	$ 37,182,259 OK

Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential - Class B	kWh			0			209,177	
GS < 50 - Class B	kWh			0			1,071,533	
GS > 50 - Class B	kWh			0			7,709,517	
Large Use - Class B	kWh			0			-	
Street Light - Class B	kWh			0			169,853	
Sentinel Light - Class B	kWh			0			-	
Unmetered Scattered Load - Class B	kWh			0			36,754	
Wholesale Market Participant - Class B	kWh			0			-	
				0			-	
				0			-	
				0			-	
General Service > 50 to 4999 kW - Class A	kWh			0			10,829,395	
Large Use - Class A	kWh			0			1,353,828	
				0			-	
				0			-	
				0			-	
SUB-TOTAL				0			21,380,058	$ 21,380,058

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	154,873,125	0.0108	1,676,775	2,870,942	0.0108	31,083	
GS < 50	kWh	49,319,113	0.0095	467,909	14,706,738	0.0095	139,528	
GS > 50	kW	49,833	4.3275	215,652	830,714	4.3275	3,594,889	
Large Use	kW	-	4.7913	-	44,439	4.7913	212,925	
Street Light	kW	215	3.0725	661	5,796	3.0725	17,807	
Sentinel Light	kW	264	3.0883	817	-	3.0883	-	
Unmetered Scattered Load	kWh	326,877	0.0095	3,101	504,447	0.0095	4,786	
Wholesale Market Participant	kW	-	4.3275	-	17,350	4.3275	75,080	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				2,364,915			4,076,098	6,441,013

Transmission - Connection								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0063	973,080	2,870,942	0.0063	18,038	
GS < 50	kWh	49,319,113	0.0057	282,694	14,706,738	0.0057	84,298	
GS > 50	kW	49,833	2.5668	127,912	830,714	2.5668	2,132,279	
Large Use	kW	-	2.9351	-	44,439	2.9351	130,433	
Street Light	kW	215	1.8100	389	5,796	1.8100	10,490	
Sentinel Light	kW	264	1.8480	489	-	1.8480	-	
Unmetered Scattered Load	kWh	326,877	0.0057	1,874	504,447	0.0057	2,891	
Wholesale Market Participant	kW	-	2.5668	-	17,350	2.5668	44,533	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				1,386,438			2,422,964	3,809,402

Wholesale Market Service								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0041	634,980	2,870,942	0.0041	11,771	
GS < 50	kWh	49,319,113	0.0041	202,208	14,706,738	0.0041	60,298	
GS > 50	kWh	16,707,585	0.0041	68,501	346,520,867	0.0041	1,420,736	
Large Use	kWh	-	0.0041	-	29,216,275	0.0041	119,787	
Street Light	kWh	95,113	0.0041	390	2,331,227	0.0041	9,558	
Sentinel Light	kWh	97,679	0.0041	400	-	0.0041	-	
Unmetered Scattered Load	kWh	326,877	0.0041	1,340	504,447	0.0041	2,068	
Wholesale Market Participant	kWh	-	0.0041	-	-	0.0041	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				907,820			1,624,217	2,532,037

Class A CBR								

Class per Load Forecast							$	Total
Residential	kWh	-	-	-	-	-	-	
GS < 50	kWh	-	-	-	-	-	-	
GS > 50	kWh	-	-	-	240,708,111	0.0003203	77,102	
Large Use	kWh	-	-	-	29,216,275	0.0003665	10,707	
Street Light	kWh	-	-	-	-	-	-	
Sentinel Light	kWh	-	-	-	-	-	-	
Unmetered Scattered Load	kWh	-	-	-	-	-	-	
Wholesale Market Participant	kWh	-	-	-	-	-	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				-			87,809	87,809
Class B CBR								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0004	61,949	2,870,942	0.0004	1,148	
GS < 50	kWh	49,319,113	0.0004	19,728	14,706,738	0.0004	5,883	
GS > 50	kWh	16,707,585	0.0004	6,683	105,812,755.46	0.0004	42,325	
Large Use	kWh	-	0.0004	-	-	0.0004	-	
Street Light	kWh	95,113	0.0004	38	2,331,227	0.0004	932	
Sentinel Light	kWh	97,679	0.0004	39	-	0.0004	-	
Unmetered Scattered Load	kWh	326,877	0.0004	131	504,447	0.0004	202	
Wholesale Market Participant	kWh	-	0.0004	-	-	0.0004	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				88,568			50,490	139,058
RRRP								
Class per Load Forecast							$	Total
Residential	kWh	154,873,125	0.0014	216,822	2,870,942	0.0014	4,019	
GS < 50	kWh	49,319,113	0.0014	69,047	14,706,738	0.0014	20,589	
GS > 50	kWh	16,707,585	0.0014	23,391	346,520,867	0.0014	485,129	
Large Use	kWh	-	0.0014	-	29,216,275	0.0014	40,903	
Street Light	kWh	95,113	0.0014	133	2,331,227	0.0014	3,264	
Sentinel Light	kWh	97,679	0.0014	137	-	0.0014	-	
Unmetered Scattered Load	kWh	326,877	0.0014	458	504,447	0.0014	706	
Wholesale Market Participant	kWh	-	0.0014	-	-	0.0014	-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				309,987			554,611	864,598
Low Voltage - No TLF adjustment								
Class per Load Forecast							$	Total

Residential	kWh	150,904,341	0.0005	77,376	2,797,371	0.0005	1,434	
GS < 50	kWh	48,055,259	0.0005	22,479	14,329,863	0.0005	6,703	
GS > 50	kW	49,833	0.2041	10,171	830,714	0.2041	169,553	
Large Use	kW	-	0.2334	-	44,439	0.2334	10,372	
Street Light	kW	215	0.1439	31	5,796	0.1439	834	
Sentinel Light	kW	264	0.1469	39	-	0.1469	-	
Unmetered Scattered Load	kWh	318,500	0.0005	149	491,520	0.0005	230	
Wholesale Market Participant	kW	-	0.2041	-	17,350	0.2041	3,541	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				110,245			192,667	302,912

Smart Meter Entity Charge								
Class per Load Forecast							$	Total
Residential		20,167	0.42	101,643	374	0.42	1,885	
GS < 50		1,653	0.42	8,333	493	0.42	2,485	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				109,976			4,370	114,346
SUB- TOTAL				29,866,584			42,986,908	72,853,492
OER CREDIT	19.3%			(5,764,251)			0	(5,764,251)
TOTAL				**24,102,333**			**42,986,908**	**67,089,241**

3.The OER Credit 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

2025 Test Year - Cop		
4705 -Power Purchased	$	37,182,259
4707- Global Adjustment	$	21,380,058
4708-Charges-WMS	$	3,623,502
4714-Charges-NW	$	6,441,013
4716-Charges-CN	$	3,809,402
4750-Charges-LV	$	302,912
4751-IESO SME	$	114,346
Misc A/R or A/P	$	(5,764,251)
TOTAL	**$**	**67,089,241**

-

Attachment 2 - 2

Distribution System Plan

Festival Hydro Inc.

Distribution System Plan

[2024] Cost of Service Application

Historical Period:

2015-2023 (Bridge year 2024)

Forecast Period:

2025-2029

[April 2024]

CONTENTS

5.2 Distribution System Plan 1
5.2.1 Distribution System Plan Overview 1
5.2.1.1 Description of the Utility Company 1
5.2.1.2 Capital Investment Highlights 4
5.2.1.3 Key Changes Since Last DSP Filing 9
5.2.1.4 DSP Objectives 10
5.2.2 Coordinated Planning with Third Parties 11
5.2.2.1 Customers 11
5.2.2.2 Subdivision Developers 15
5.2.2.3 Municipalities 16
5.2.2.4 Transmitter & Other LDC's 17
5.2.2.5 Other LDCs & IESO 18
5.2.2.6 Regional Planning Process 18
5.2.2.7 Telecommunication Entities 22
5.2.2.8 CDM Engagements 23
5.2.2.9 Renewable Energy Generation (REG) 23
5.2.3 Performance Measurement for Continuous Improvement 23
5.2.3.1 Distribution System Plan 23
5.2.3.2 Service Quality and Reliability 27
5.2.3.3 Distributor Specific Reliability Targets 33
5.3 Asset Management Process 34
5.3.1 Planning Process 34
5.3.1.1 Overview 34
5.3.1.2 Important Changes to Asset Management Process since last DSP Filing 36
5.3.1.3 Process 37
5.3.1.4 Data 44
5.3.2 Overview of Assets Managed 48
5.3.2.1 Description of Service Area 48
5.3.2.2 Asset Information 50
5.3.2.3 Transmission or High Voltage Assets 55
5.3.2.4 Host & Embedded Distributors 56
5.3.3 Asset Lifecycle Optimization Policies and Practices 56

5.3.3.1 Asset Replacement and Refurbishment Policy 56
5.3.3.2 Description of Maintenance and Inspection Practices 57
5.3.3.3 Processes and Tools to Forecast, Prioritize & Optimize System Renewal Spending 59
5.3.3.4 Important Changes to Life Optimization Policies and Practices since Last DSP Filing 60
5.3.4 System Capability Assessment for REG & DERs 61
5.3.5 CDM Activities to Address System Needs 61
5.4 Capital Expenditure Plan 62
5.4.1 Capital Expenditure Summary...62
5.4.1.1 Plan vs Actual Variances for the Historical Period 66
5.4.1.2 Forecast Expenditures...74
5.4.1.3 Comparison of Forecast and Historical Expenditures 85
5.4.1.4 Important Modifications to Capital Programs Since Last DSP...................91
5.4.1.5 Forecast Impact of System Investments on System O&M Costs..............92
5.4.1.6 Non-Distribution Activities 93
5.4.2 Justifying Capital Expenditures 93
5.4.2.1 Material Investments 98

LIST OF APPENDICES

Appendix A – Material Investment Narratives

Appendix B – Third-Party Building Assessment Report

Appendix C – FHI Strategic Plan

Appendix D – Customer Engagement Survey Reports

Appendix E – HONI Needs Assessment 2019

Appendix F – IESO Scoping Assessment Outcomes Report 2019

Appendix G – IRRP – South Huron – Perth Sub Region

Appendix H – RIP Great Bruce-Huron 2022

Appendix I – FHI 2022 Reliability Report

Appendix J – Kinectrics 2023 Asset Condition Assessment

Appendix K – FHI Maintenance & Inspection Policy

Appendix L – Trilliant Focus Meter End-of-Life Notice

Appendix M – Seaforth Substation Assessment

Appendix N – AMI 2.0 Evaluation Summary

LIST OF FIGURES

Figure 5.2-1: FHI's Service Areas 2
Figure 5.2-2: South Huron-Perth Sub-Region 19
Figure 5.3-1: Historical and Forecasted Peak Demand by Station 53
Figure 5.3-2: ACA Overview 54
Figure 5.4-1: Overall Expenditures Comparison 86
Figure 5.4-2: Net System Access Expenditures Comparison 87
Figure 5.4-3: Net System Renewal Expenditures Comparison 89
Figure 5.4-4: Net System Service Expenditures Comparison 90
Figure 5.4-5: Net General Plant Expenditures Comparison 91
Figure 5.4-6: Overall Expenditure Trends 98

LIST OF TABLES

Table 5.2-1: FHI's Strategic Priorities.................... 3
Table 5.2-2: Historical and Forecast Capital Expenditures and System O&M 5
Table 5.2-3: Summary of Consultations 22
Table 5.2-4: DSP Performance Measures 24
Table 5.2-5: Historical Service Quality Metrics....................27
Table 5.2-6: Historical Reliability Performance Metrics – All Cause Codes 28
Table 5.2-7: Historical Reliability Performance Metrics – LOS and MED Adjusted 28
Table 5.2-8: Summary of MEDs over the Historical Period....................29
Table 5.2-9: List of MEDs over the Historical Period 29
Table 5.2-10: Number of Outages (2015-2023)....................29
Table 5.2-11: Outage Numbers by Cause Codes – Excluding MEDs....................30
Table 5.2-12: Customers Interrupted Numbers by Cause Codes – Excluding MEDs 32
Table 5.2-13: Customer Hours Interrupted Numbers (rounded) by Cause Codes – Excluding MEDs 32
Table 5.3-1: Changing Trends in Customer Base 48
Table 5.3-2: Peak System Demand Statistics 49
Table 5.3-3: Efficiency of kWh Purchased by FHI 49
Table 5.3-4: Circuit Length by Voltage Level....................50
Table 5.3-5: Nominal Station Capacity 50
Table 5.3-6: Historical and Forecasted Peak Demand by Station 52
Table 5.3-7: Health Index Results Summary....................55
Table 5.3-8: Summary of Inspection and Maintenance Activities....................58
Table 5.4-1: Historical Capital Expenditures and System O&M* 63
Table 5.4-2: Forecast Capital Expenditures and System O&M 65
Table 5.4-3: Variance Explanations - 2015 Planned Versus Actuals 67
Table 5.4-4: Variance Explanations - 2016 Planned Versus Actuals 68
Table 5.4-5: Variance Explanations - 2017 Planned Versus Actuals 69
Table 5.4-6: Variance Explanations - 2018 Planned Versus Actuals 70
Table 5.4-7: Variance Explanations - 2019 Planned Versus Actuals 71
Table 5.4-8: Variance Explanations - 2020 Planned Versus Actuals 72
Table 5.4-9: Variance Explanations - 2021 Planned Versus Actuals 72
Table 5.4-10: Variance Explanations - 2022 Planned Versus Budget....................73
Table 5.4-11: Variance Explanations - 2023 Planned Versus Budget....................73
Table 5.4-12: Forecast Capital Expenditure by OEB Investment Category 74
Table 5.4-13: Forecast Net System Access Expenditures 75
Table 5.4-14: Forecast Net System Renewal Expenditures 79
Table 5.4-15: Forecast Net System Service Expenditures....................82
Table 5.4-16: Forecast Net General Plant Expenditures 83
Table 5.4-17: Forecast System O&M Expenditures....................93
Table 5.4-18: Proposed Capital Investments during Test Year - Projects over Materiality 99
Table 5.4-19: Prioritization Scoring by Project for the Test Year....................107
Table 5.4-20: List of Projects Deferred....................108

LIST OF ACRONYMS

Acronym	Meaning
ACA	Asset Condition Assessment
AHSIP	Accelerated High Speed Internet Program
CAIDI	Customer Average Interruption Duration Index
CDM	Conservation Demand Management
CHI	Customer Hours Interrupted
CI	Customers Interrupted
DER	Distributed Energy Resource
DSP	Distribution System Plan
ESA	Electrical Safety Authority
FHI	Festival Hydro Inc.
GS	General Service
HI	Health Index
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LOS	Loss of Supply
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Day
NWA	Non-Wires Alternative
OEB	Ontario Energy Board
OH	Overhead
REG	Renewable Energy Generation
RIP	Regional Infrastructure Plan
RRFE	Renewed Regulatory Framework for Electricity Distributors
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TRXLPE	Tree Retardant Cross Link Polyethylene
UG	Underground
XLPE	Cross Link Polyethylene

5.2 Distribution System Plan

Festival Hydro Inc. (FHI) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) Chapter 5 – Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications, dated December 15, 2022 (the "Filing Requirements") as part of its 2024 Cost of Service Application (the Application).

The DSP is a stand-alone document filed in support of FHI's Application. The DSP's duration is a minimum of ten years in total, comprising of a historical period and a forecast period. The DSP covers the historical period of 2015 to 2024, with 2024 being the bridge year, and a forecast period of 2025 to 2029, with 2025 being the test year.

The DSP contents are organized into three major sections:

- Section 5.2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement.
- Section 5.3 provides an overview of asset management practices, including an overview of the assets managed and asset lifecycle optimization policies and practices.
- Section 5.4 provides a summary of the capital expenditure plan, including a variance analysis of historical expenditures, an analysis of forecast expenditures, and justification of material projects above the materiality threshold.

The materiality threshold for FHI is $80,000 and detailed descriptions of specific projects/programs exceeding the materiality threshold are provided in Section 5.4.2.1 and Appendix A. Other pertinent information relevant to this DSP is included in the Appendices.

This DSP follows the chapter and section headings in accordance with the Chapter 5 Filing Requirements.

5.2.1 Distribution System Plan Overview

5.2.1.1 Description of the Utility Company

FHI is a licensed electricity distributor. FHI owns, operates, and manages the assets associated with the distribution of electrical power to approximately 23,000 customers in the City of Stratford, Town of St. Marys, and communities of Seaforth, Hensall, Zurich, Brussels and Dashwood pursuant to a distribution license issued by the Ontario Energy Board (the "Board") and charges Board-authorized rates for the distribution service it provides. Each service territory is bounded by Hydro One Networks Inc (HONI).

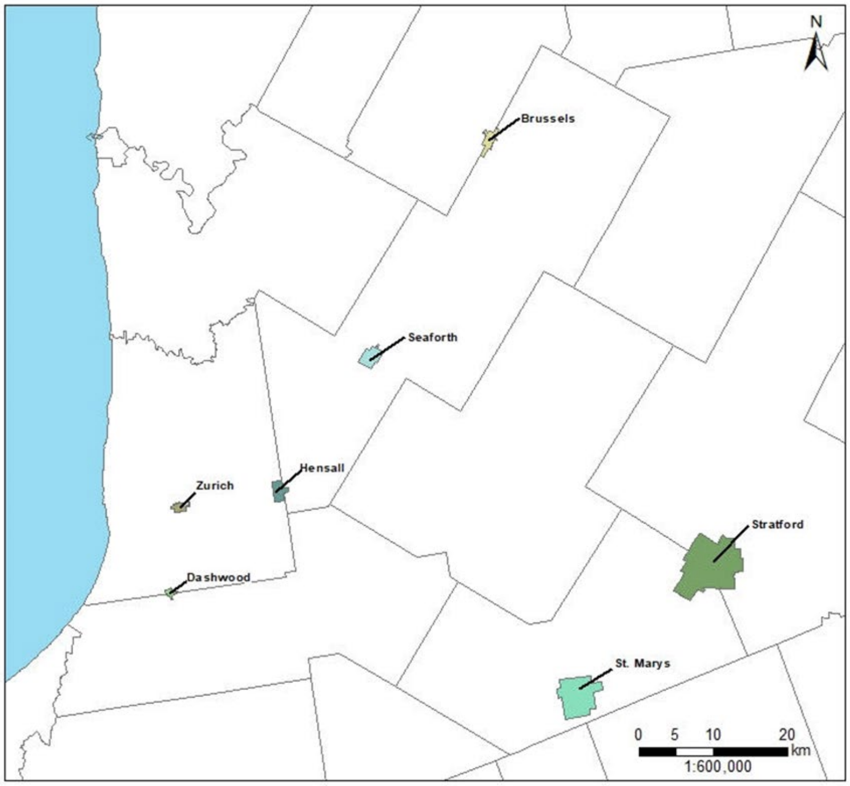


Figure 5.2-1: FHI's Service Areas

FHI is a Registered Market Participant for the purposes of settlement with the Independent Electricity System Operator ("IESO"). However, FHI is considered a partially "embedded" LDC because it received some of its electricity from HONI's low voltage distribution system for electricity supplied to customers in the communities of Brussels, Seaforth, Hensall, Zurich, and Dashwood.

FHI is driven by its corporate vision, mission, and core values. Together, they provide the basis to deliver on targeted strategic goals and performance objectives. FHI's mission, vision, values, and corporate strategic goals are summarized as follows:

Mission

To responsibly provide value to their customers, communities, shareholders, and employees through cost effective distribution of reliable and safe electric power.

Vision

Enable prosperity within their communities through exceptional people, partnership, and performance.

Purpose

Powering lives, empowering communities.

Values

FHI’s core values include People First through Positive Teamwork, Accountability, Honesty, Commitment to Customers, Trust.

Strategic Priorities

The Vision statement is further supported by the commitment to earn this reputation by:

• Being a leader in implementation and utilization of technology to support communication and automation.

• Diversifying into new areas for alternative generation to meet customer demand/expectation.

• Increasing our scope through additional business lines.

• Continuing to meet key performance indicator (KPI) targets and operate as an efficient and effective utility in the province.

• Being recognized as a technology leader and showcase utility in the industry.

As part of the strategic planning process these corporate statements were reviewed and provided guidance for the enhancement of the four key priorities for the business over the next four years.

FHI’s strategic priorities include Financial Stability, Customer Focus, Our People, and Community Support. These priorities are further detailed in the table below:

Table 5.2-1: FHI’s Strategic Priorities

Area of Strategic Focus	Strategic Long-Term Goals	Strategy to Achieve Success
Our People	• To ensure safety of FHI staff is paramount. • To create a sustainable, motivated workforce and enhance productivity. • To be viewed as a great place to work.	• Create an employee retention plan. • Ensure a competitive compensation plan is in place. • Formal succession plan includes high-performing employee (HPE)identification with a corresponding multi-year Development Plan. • Develop an Employee Recognition Program. • Invest in physical facilities upgrade.
Invest in New Operational Technologies	• To reduce costs and improve operational efficiencies. • To improve internal and external communications. • To enhance and improve the customer experience.	• Refresh our Technology Roadmap. • Implementation of a new Customer Information System (CIS). • Invest in digital systems for handling workflows. • Continued enhancement of security to protect confidential information and internal systems and concerns.

Area of Strategic Focus	Strategic Long-Term Goals	Strategy to Achieve Success
Collaborate with Other Local Community Stakeholders	• Enhance long term viability.	• Partner with Invest Stratford and the City to support economic development & investment in our region. • Meet with large industrial customers to understand their business strategies/growth targets. • Build FHI brand & value by getting involved in Community events to show the value of local utility ownership.
Create Scale in the Utilities Space	• Reduce costs and enhance efficiencies. • Ensure financial viability. • Business continuity.	• Continue to partner with other utilities & organizations to create future opportunities. • Seek out shared service opportunities with other utilities. • Consider joining already established industry groups that we are not currently associated with.

5.2.1.2 Capital Investment Highlights

FHI's capital investments over the planning period have been aligned to the 4 categories of system access, system renewal, system service, and general plant outlined in the Filing Requirements. Table 5.2-2 presents FHI's historical actuals and forecast expenditures for both capital and O&M categories.

Table 5.2-2: Historical and Forecast Capital Expenditures and System O&M

**2024 expenditures are all forecast numbers*

Category	Historical ($ '000)										Forecast ($ '000)				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access (Gross)	$ 713	$ 582	$ 733	$ 1,378	$ 1,200	$ 1,086	$ 1,091	$ 1,013	$ 1,186	$ 1,212	$ 2,399	$ 2,463	$ 2,531	$ 2,601	$ 1,743
System Renewal (Gross)	$ 1,706	$ 1,427	$ 1,644	$ 1,565	$ 1,768	$ 1,627	$ 2,027	$ 2,222	$ 2,114	$ 2,236	$ 3,101	$ 3,351	$ 3,421	$ 3,505	$ 3,590
System Service (Gross)	$ 238	$ 38	$ 29	$ 38	$ 30	$ 51	$ 6	$ 34	$ 110	$ 77	$ 359	$ 374	$ 384	$ 397	$ 409
General Plant (Gross)	$ 653	$ 555	$ 549	$ 837	$ 613	$ 460	$ 876	$ 907	$ 1,927	$ 4,193	$ 1,878	$ 1,299	$ 1,262	$ 1,274	$ 1,585
Gross Capital Expenses	$ 3,309	$ 2,603	$ 2,956	$ 3,818	$ 3,611	$ 3,224	$ 4,000	$ 4,175	$ 5,337	$ 7,717	$ 7,737	$ 7,487	$ 7,598	$ 7,777	$ 7,327
Contributed Capital	$ 334	$ 207	$ 372	$ 585	$ 444	$ 466	$ 481	$ 343	$ 447	$ 219	$ 327	$ 332	$ 338	$ 345	$ 352
Net Capital Expenses after Contributions	$ 2,975	$ 2,396	$ 2,584	$ 3,233	$ 3,168	$ 2,759	$ 3,519	$ 3,832	$ 4,890	$ 7,498	$ 7,409	$ 7,155	$ 7,260	$ 7,432	$ 6,975
System O&M	$ 2,137	$ 2,102	$ 2,220	$ 2,564	$ 2,368	$ 2,473	$ 2,357	$ 2,817	$ 2,945	$ 3,249	$ 3,515	$ 3,620	$ 3,729	$ 3,841	$ 3,956

5.2.1.2.1 System Access

FHI's System Access investments are modifications (including the relocation of assets) to the distribution system that FHI is obligated to perform to provide a customer or group of customers with access to electricity services via its distribution system. The proposed investments under this category over the forecast period include costs associated with:

- Connecting residential, commercial, and industrial customers.
- Metering investment to comply with Measurement Canada guidelines.
- Connecting subdivision and townhouse lots.
- Municipal driven projects, and
- Deployment of an AMI 2.0 network, meters, and associated hardware/systems, further described below in section 5.2.1.2.5.

Due to a multitude of factors, FHI is forecasting a need to significantly increase its investment in its metering infrastructure. Examples include condition, age, increasing meter failures, and obsolescence. All other investments within this category will follow a similar pattern to FHI's historical period.

5.2.1.2.2 System Renewal

System Renewal investments are driven by the need to address assets that are at risk of failure and therefore could have a negative impact on reliability. FHI uses the outputs of its ACA as a key input into its planning process, which is described further in section 5.3.1, to inform the type and level of system renewal investments that are required to be carried out. Details on FHI's ACA can be found in section 5.3.2.2.2 and Appendix J.

The following asset classes have been identified for investment programs during the forecast period:

- Overhead Pole-line Replacement Program - This program will address poles that have been identified by the ACA as showing significant deterioration and are in poor or very poor condition. This is a continuation of an annual program FHI has been carrying out historically.
- Underground Renewal Program – This program will address UG XLPE cable that is in poor or very poor condition and should be considered for replacement in the next five years. In addition to replacing these assets, where the existing installation method does not allow for replacement of just the cable without additional civil work, new duct will also be installed to allow for simpler replacement in the future. This follows industry best practices and is expected to prolongsthe life of the new UG cable. Furthermore, this program has been structured following guidance and requirements from the OEB to ensure that in the planning process FHI considers the future capacity needs of the distribution system. For projects identified through this program, FHI will take the opportunity to review the number of customers connected to each pad mount transformer and will use their updated practice to add or rebalance customer connections to each transformer, aiming to provide adequate capacity for future needs over the life of the assets that will be installed. This includes planning for adequate capacity that would allow a 200A service for each connection. This causes certain projects to

now have an enhanced scope of work compared to historical replacement projects in this program.

- Air Insulated Switchgear Replacement Program – This program will address switchgear that through the ACA, have been identified as in need of replacement. These will be replaced with solid dielectric switchgear. This is a continuation of an annual program FHI has been carrying out historically.
- Transformer Station Renewal Program – This program will address replacements of critical equipment due to unexpected failures, recommendations from a recently completed TS assessment report and include assets that are now obsolete, and in some cases unsupported by the original equipment manufacturers (OEM).

5.2.1.2.3 System Service

System service investments are modifications to FHI's distribution system to ensure the distribution system continues to meet FHI operational objectives (e.g., reliability, grid flexibility, and distributed energy resource (DER) integration) while addressing anticipated future customer electricity service requirements.

Over the forecast period FHI will carry out two major programs:

- Distribution Automation Program – This program intends to continue the installation of fault indicators and will begin installing and commissioning reclosers to enhance the capabilities of FHI's Distribution System. Fault indicators will be installed at the demarcation of HONI's distribution system, where FHI is an embedded distributor. This allows FHI to respond efficiently to understand the location of faults in these areas. Reclosers will be added within Stratford to enhance sectionalizing, fault identification, and restoration.
- Voltage Conversion Program - The practice of upgrading the distribution system to a higher operating voltage and decommissioning substations has several known benefits. This program will allow for the retirement of the last two 4.16kV substations in FHI's service territories, and therefore realize benefits, which include:
  - Reduced Operating & Maintenance (O&M) costs associated with maintaining and operating 4kV substations.
  - The significant deferral of capital expenses by replacing and converting this end-of-life infrastructure, the majority of which has been identified as being in poor or very poor condition, so that the substation assets associated with these areas can be removed from service as opposed to replaced.
  - Some reduction of system losses.
  - Reduction in inventory due to removal of the 4.16kV operating voltage.

5.2.1.2.4 General Plant

FHI's general plant investments are critical to its 24/7 operations. The projects include replacing and modifying land and buildings, tools and equipment, fleet vehicles, and software and hardware to be able to continue to support the day-to-day business and operations activities. Below are some of the key projects FHI will carry out in the forecast period:

- Install a new Enterprise Resource Planning (ERP) system.
- Carry out administration and service centre building projects based on condition assessments and yearly inspections. Detailed third-party assessments can be found in Appendix B.
- Replace fleet vehicles based on the fleet condition assessment and needs of the vehicles for FHI's operations.
    - When replacing vehicles hybrid, electric and/or alternative fuel vehicles will be considered.

5.2.1.2.5 AMI 2.0

FHI is undertaking an Advanced Metering Infrastructure 2.0 (AMI 2.0) deployment to replace their legacy AMI 1.0 system. The majority of legacy AMI 1.0 meters were installed in 2010-2011. Since being installed, this legacy system required nearly 11,000 of FHI's approximately 23,000 installed meters to be sent back for repair, with over 700 meters currently installed in the field that require manual reads monthly due to various equipment failures, leading to a low read rate of meters (~94%). This results in increased maintenance costs for FHI to repair and replace these failing meters, as well as the costs to manually read them each month. The residential meters that FHI has historically purchased, which make up approximately 85% of the meter population, are at end-of-life due to component obsolescence, with no cost equivalent solution available for commercial purchase as of October 2023.

The AMI 2.0 program's primary goal is to replace FHI's current and increasingly failing AMI in an economic and operationally efficient manner, thereby maintaining compliance with regulatory metering and billing requirements under the Federal Electricity Gas and Inspection and Weights and Measures Acts, the DSC and billing provisions of the Standard Supply Service Code ("SSSC"). The need to replace AMI 1.0 infrastructure also creates benefits and opportunities as there have been significant advancements in the technology since the AMI 1.0 system was commissioned approximately 15 years ago. AMI 2.0 is a foundational investment in a modern AMI platform to address foreseeable needs over its service life.

This investment ensures that customers will continue to receive the high level of billing accuracy they are accustomed to. It also ensures that customers continue to stay connected to safe, reliable power, while enabling greater access to flexible service options. The modern platform, through improved network communications and security will enhance end-to-end protection of customer data, while also enabling tools to help manage and understand energy usage and bills in the future. It will also reduce manual meter reads, reduce truck rolls for certain types of disconnection/reconnections, and provide customers with a modern AMI platform to meet foreseeable customer needs over the lifetime of the assets.

FHI, utilizing the services of a third-party contractor who has vast experience in this area, launched its competitive RFP process for a new AMI 2.0 system in 2023, selecting a vendor in Q1 2024, with mass meter deployment planned to begin in 2025, lasting through 2029. The estimated capital cost of this program is $7M spread over the years of 2024 to 2029. Vendor responses to the RFP provided the same general solution capabilities, which are described in detail in the AMI 2.0 Material Investment Narrative in Appendix A.

5.2.1.3 Key Changes Since Last DSP Filing

There have been several changes that FHI has either implemented or experienced since its last DSP filing:

- FHI carried out an ACA to inform its investment plans and is based on condition rather than just age.
- A refreshed Strategic Plan has been developed for 2023 that has informed this DSP.
- Enhanced and formalized its project prioritization framework, updating weighting and accounting for risks to projects.
- Implemented a GIS system that allows FHI to visualize and track its assets.
- Began pole-testing in 2017 in addition to visual inspections, which allows FHI to identify the remaining strength of the poles.
- Covid-19 had an impact similar to other utilities with issues of supply chain and labour lead times and costs. This has impacted what work FHI was able to carry out along with the related costs.
- Similar to above, FHI has been impacted by economic and inflationary pressures related to workforce shortages, supply chain issues, and geopolitical conflicts. As an example, the average cost to replace a pole has increased 62% since 2015, and 23% since 2021. Furthermore, it is on average 93% more expensive to replace 100m of underground cable since 2015, and 36% more since 2021.
- Increased observation of frequency and severity of extreme weather events from climate change.
- The positions and number of employees needed to run an LDC business have changed significantly since FHI's building was initially constructed in 1959. The existing space no longer met the needs of the company from a utilization or accessibility perspective to provide the long-term sustainable success of the business.
- For transformers that have an issue identified during inspections, FHI looks to repair/refurbish (e.g. sandblast and reapply paint) rather than always replace, to extend the asset life if it is just the structure/shell that requires repair.
- FHI has identified that the increase in electrification, both building and transportation, will likely have an impact on how FHI carries out its planning and forecasting. Since there is still a lot of uncertainty about the pace of electrification, it will cause uncertainty in its forecast. This means FHI will need to have plans that can be easily and quickly adapted.
- FHI has implemented an Engineering Analysis and Outage Management Software called SmartMAP in December 2023. This enables FHI to perform load flow, short circuit, and system planning studies internally. It also allows FHI to receive outage notifications and details from the AMI network to provide additional insight into outage locations and areas without solely relying on customer calls. It allows FHI to provide customers with a public outage map that they can visit when there are planned and unplanned outages to get updates on the outage and underlying cause. SmartMAP also provides loading data at individual transformer level which

gives FHI an understanding of when these transformers may be getting overloaded so FHI can proactively replace these transformers.

- Regulatory changes and requirements, many of which identified issues and limitations inherent in FHI's current software and software providers, including:
    - Green Button,
    - Bill Presentment,
    - Ultra low overnight rate, Time of Use Net-Metering, tiered billing, and
    - OEB's Cybersecurity Framework.
- FHI has reviewed the recent guidance document from the OEB regarding the need for 200A services to be offered to customers. FHI already provides each new house the infrastructure to accommodate a 200A service, and has incorporated this guidance into their UG Renewal Program.
- Related to the Ontario Connected act, FHI has typically been very good at getting all locates completed on time, significantly above the provincial average, as FHI employ its own staff to complete locates. Recent legislation passed (comes into force May 1, 2024) gives FHI 10 days to complete standard locate requests for large excavation projects. FHI is also exploring options for office clears to further minimize the number of locate requests FHI must send staff out to and if that will result in an overall savings.
- As FHI has observed potential increase in EV's, they have looked at the dataset on EV's from Ministry of Energy and identified areas where they have been installed to see any impact on demand. FHI has also changed residential transformer sizing and number of customers connected to plan for the increased electrification demand at each household.

5.2.1.4 DSP Objectives

FHI's DSP is a stand-alone document that is filed in support of FHI's Cost of Service Application. The DSP was prepared to provide to the OEB and all interested stakeholders:

- An overview of FHI's AM objectives and processes.
- An overview of FHI's managed assets and asset lifecycle optimization practices.
- An overview of FHI's coordinated planning and engagement with third parties.
- A review of FHI's operational performance in the historical period.
- A preview of FHI's planned expenditures for the forecast period.
- A detailed justification of FHI's planned capital expenditures in the Test Year.

This DSP covers a planning horizon of five years starting in the 2025 Test Year. Employing this long-term approach requires FHI to consider future customer needs and any required changes to its distribution system in advance. This approach enhances FHI's ability to plan and respond to evolving customer needs in a timely manner while managing and levelling the impacts of expenditures on consumer rates to maintain the affordability of its service.

FHI's DSP has been prepared to support the four key objectives established in the OEB's *Renewed Regulatory Framework (RRF) for electricity*:

1. **Customer Focus:** Services are provided in a manner that responds to identified customer preferences.
2. **Operational Effectiveness:** Continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives.
3. **Public Policy Responsiveness:** Utilities deliver on obligations mandated by the government (i.e.: in legislation and regulatory requirements imposed further to Ministerial directives to the Board).
4. **Financial Performance:** Financial viability is maintained, and savings from operational effectiveness are sustainable.

To realize these four outcomes, FHI has outlined the following objectives:

- Investment in Distribution Automation.
- AMI 2.0 Deployment.
- Ensuring System Capacity and flexibility to facilitate load growth, DER's, and new customer connections.
- Executing a sustainable, condition-based infrastructure replacement strategy.
- Maintaining a safe and reliable system for workers and the public.
- Improve operational efficiencies using new technologies.
- Continue to incorporate customer feedback and comments into planning and prioritization of projects.

In addition, FHI will also continue to reference its updated mission, vision, and values, focusing on the strategic priorities previously noted and further detailed in FHI's Strategic Plan. (Appendix C)

5.2.2 Coordinated Planning with Third Parties

5.2.2.1 Customers

Purpose of the Consultation

The purpose of FHI engaging with its customers is to share information, to educate them, and to gather their opinions and insights on its services to ensure that their needs, preferences and expected level of service are taken into consideration during planning activities.

Initiation and Participation

FHI commissioned Oraclepoll to conduct an engagement survey of its customers while Brickworks and FHI designed the questionnaire (see Appendix D). The survey was completed online using Computer Assisted Telephone Interviewing (CATI) between the days of May 18th and June 2nd, 2023. This was an open-online self-selection survey where respondents could connect with the survey link to complete their interview. The survey was promoted by Brickworks and FHI through its resources. Participants included residential and small commercial business customers.

Furthermore, FHI commissioned Brickworks Communications to conduct an open-online survey and telephone survey of its customers. The purpose of this survey process was to obtain customer input regarding their satisfaction with the services provided by FHI and on FHI's DSP plans. The survey was conducted from November 22nd to December 11th, 2023.

Brief Description of Consultation

Customer engagement is often done through FHI's website, social media channels and customer engagement events. FHI utilizes surveys to educate, inform, and solicit input from customers regarding both current and future plans. Over the historical period, FHI partnered with Oraclepoll and Brickworks to commission and design the customer satisfaction surveys; with the latest one issued in May/June 2023. Results from these surveys are detailed in FHI's Scorecards and are available on the OEB website[1].

FHI and Brickworks designed the survey to primarily focus on the following seven areas:

- Customer Preference Priorities.
- Power Outages.
- Smart Grid.
- Utility's Assets.
- Tree Trimming.
- New Technologies.
- Communication.

In November and December 2023, FHI conducted its final DSP customer engagement survey to help inform its DSP. Approximately 469 customers completed the survey online, with an additional 400 completing the telephone survey. The focus of this survey was to get final input and feedback on FHI's proposed DSP plans.

FHI and Brickworks designed the survey to primarily focus on the following six areas:

- Automated Tools / Communication Methods.
- Emerging Technologies.
- Legacy Metering Network.
- Tree Trimming.
- Future Renewal Expenditures.
- Rate Impacts.

Consultation Materials

As noted above, FHI partnered with Oraclepoll and Brickworks to conduct five customer satisfaction surveys over the historical period, with the two recent ones being in 2022

[1] Ontario Energy Board. Electricity Utility Scorecards

and 2023. Results from these surveys are included in FHI's scorecards, which are available on the OEB website[2]. In November and December 2023, FHI conducted its final survey related to its DSP. FHI's Customer Survey results are included in Appendix D.

Consultation Outcomes and Impact on this DSP

Ultimately, all feedback FHI received from its engagement with its customers further supports the proposed investment plan within this DSP, as the majority of customers are supportive of the main investments and the impacts/benefits associated with it. Customers also indicated that they were generally supportive of the investment amounts, even with the associated bill impact, which informed FHI's decision on the type and amount of project deferrals that were contemplated and can be found in Section 5.4.2.1.

From the survey completed in May/June 2023 FHI concluded the following from the responses received:

- Customer Preference Priorities: The top priorities identified by customers include providing safe and reliable electricity with fewer outages and focusing on public and employee safety. This is along with other customer preferences such as prioritizing aesthetics over most cost-effective solutions when constructing or replacing assets as well as providing electricity at a low cost at the expense of reliability, green initiatives, innovation, and customer service. The two lowest priorities were investing in innovative solutions and providing excellent customer service.

- Power Outages: With respect to minimizing power outages, 64% said it is important and are willing to pay more to increase investments to keep the power on, paying less than $1 extra per month on their bill. About 27% understand it is important but are not willing to pay any more each month despite their service being impacted. Only 9% claimed that this is not an important issue, while 1% did not know.

- Smart Grid: On the issue of smart grids, a 61% majority said they are important, and would be willing to pay more to increase investments to keep the power on (at less than $1 extra per month on bill). 30% understand their importance but are not willing to pay an additional cost despite understanding that service may be negatively impacted. There were 8% that stated smart grids are not important, while 1% were unsure.

- Utility's Assets: 61% claimed that this issue is important, and they are willing to pay less than $1 on their monthly bill to increase investment in this area. 30% understand their importance but are not willing to pay an additional cost, fully

[2] Ontario Energy Board. Electricity Utility Scorecards

understanding that service will be negatively impacted. 1% are undecided and 7% said this is not important to them.

- Tree Trimming: Tree trimming was deemed important to 57% of customers, and they would be willing to pay less than $1 per month to increase investment in this area. 33% of the respondents felt that while it is important, they are not willing to pay additional money despite the risks. A total of 8% felt the issue was not important and 2% were unsure.

- New Technologies: 54% of customers indicated the importance and displayed willingness to pay more to invest in emerging technologies at less than $1 extra per month. 36% understand the importance of new technologies but are not willing to pay more. A total of 8% felt the issue was not important and 2% were unsure.

- Communication: A total of 58% feel this is important and are willing to pay $1 more a month for more customer service tools, while 32% claim this is important but are not willing to pay more. A total of 8% felt the issue was not important and 2% were unsure.

Following the second DSP customer engagement survey completed in November/December 2023, FHI concluded, based on the online results, with the telephone results being very similar, the following outcomes from the responses received:

- Automated Tools / Communication Methods: FHI noted that it is looking to invest in automated tools and communication methods for customer service as according to a customer engagement survey that was conducted earlier this year. More than half of the customers responded that this is important and that they were willing to pay extra for customer service tools (less than $1 extra per month). 48% of customers indicated they would prefer an increase in customer service enhancements with increased costs. Meanwhile, 34% of the respondents indicate that FHI should continue with planned enhancements but do not need more tools such as an app or website chat features.

- Emerging Technologies: A total of 35% of FHI customers would prefer if FHI invested more money in renewable energy and environmentally friendly options at an additional cost. 29% would like to see FHI invest more money in new technologies at an additional cost. 25% of respondents would like to see FHI investing in both renewables and new technologies at an additional cost. However, 8% would like FHI to continue investing in traditional infrastructure.

- Legacy Metering Network: Included in FHI's plans for 2025, is a multi-year replacement of its legacy metering network and assets which will provide improved and more reliable information to FHI and its customers. One of the solutions that FHI is considering has applications on the meter that the customer could download in the future and gain better insight into electricity use by appliance, as well as potential future uses for electric vehicles and receive information on when the best time to turn on/off major appliances (e.g. Air Conditioner)." A total of 59% of FHI's customers would be interested in this type of application and would likely use it, with a further 33% indicating they might be interested but are unsure if they would use it.

- Tree Trimming: A total of 44% of FHI's customer support the current process of more frequent tree trimming with appropriate clearance to balance reliability, aesthetic and environmental concerns. A further 40% would like trees trimmed more frequently where possible with branches cut back more than today, regardless of aesthetic or environmental concerns, so that fewer power outages occur and there are shorter wait times to restore power after storms, and costs are reduced.

- Future Renewal Expenditures: A total of 60% of respondents felt that the proposed overall level of future system renewal expenditures was just right, 21% too high while 9% indicated too low. A total of 10% were unsure.

- Rate Impacts: A total of 52% of respondents don't like the idea of a rate increase but understand it is necessary, with a further 30% indicating the rate increase is reasonable. A total of 14% felt the rate increase is unreasonable with a further 4% unsure.

In addition, FHI reached out to its top 10 largest power consumers to engage further. FHI managed to organize seven meetings, with all the customers indicating that reliability is more important than cost. In addition, all these customers indicated that any additional demand from FHI in the short term will be on the small scale, and therefore unlikely to introduce additional demands when factoring in future load growth.

5.2.2.2 Subdivision Developers

Purpose of the Consultation

The main goal of consultations with developer groups is to share information and coordinate long-term planning such that the needs of all parties can be considered when planning for resources.

Initiation and Participation

FHI participates in meetings with larger developer groups monthly and initiates individual meetings to discuss specific projects as required. In addition to FHI and the developer groups, other potentially impacted stakeholders such as the Town of St. Mary's, the City of Stratford, Telecoms, and HONI may be involved in these meetings as well. Invitations to participate are determined on a case-by-case basis depending on the scope of the discussions and potential impacts.

Brief Description of Consultation

Meetings with larger developers are based on mutual needs of the developers' requirement for services and FHI's ability to deliver the required power. FHI attends regular Utility Coordination Committee (UCC) and planning meetings with the Town of St. Mary's and the City of Stratford. Both municipal and customer-owned projects are discussed at these meetings. These meetings provide an excellent opportunity for open dialogue with other stakeholders to learn about and discuss their current and upcoming plans and provide insights into what the municipalities, developers and FHI will need to consider should any projects move forward.

FHI is circulated on all planning, consultation, and/or zoning applications from all the municipalities they serve. FHI encourages its customers to notify the distributor early if they believe a project is likely to commence and discuss as many high-level technical details as possible. This provides FHI with the opportunity to notify developers if there are any significant challenges to their projects ahead of time.

Consultation Materials

The outcomes of these consultations are in the form of development information such as plans and associated schedules and budgets.

Consultation Outcomes and Impact on this DSP

Based on these meetings, FHI is able to enhance its forecast System Access type investments, such as road relocation, new service and subdivisions etc. Within the year, FHI uses this information to refine its plan for that year and the next year. For subdivisions, there are seven that are currently expected to be constructed between 2024 and 2025. Six of the programs currently have no signed agreement, but FHI expects three or four of them to be constructed in each year. The specific projects that FHI expects to be constructed in 2025 based on the consultations can be found in Section 5.4.1.2.1.

5.2.2.3 Municipalities

Purpose of the Consultation

FHI regularly interacts with the Town of St. Mary's, the City of Stratford, and the other appropriate municipalities that their 5 outlying communities are based in, to coordinate infrastructure planning within its service territory so that new connections to customers can be connected in a timely manner and projects involving line relocates to facilitate road reconstruction projects can be planned.

Initiation and Participation

FHI meets with the Town of St. Mary's and the City of Stratford monthly, unless there is a specific project underway that requires more frequent coordination. For other municipalities, FHI is circulated on any plans or permit applications on a regular basis and will engage for more detailed dialogue as-needed. For each project identified, FHI typically participates in exploratory meetings, progress meetings, and closing meetings.

Brief Description of Consultation

Coordination with the Town of St. Mary's, the City of Stratford, and the other municipalities requires advanced planning to ensure timing and funding is available to collaborate with these entities for improvements. For municipal road projects, FHI reaches out to applicable municipalities to understand their short-term plans and the potential impacts on FHI's planned work within the same time range. FHI circulates all actual construction projects to gauge the impact the work will have on FHI's infrastructure. Internally, FHI notifies operations on the potential that planned work will need to be scheduled to relocate and/or support infrastructure.

Consultation Materials

The outcomes of these consultations are in the form of construction information such as plans and associated schedules and budgets.

Consultation Outcomes and Impact on this DSP

There is a project in Dashwood on the main highway that FHI will be completing. This project was originally planned in 2020. However, in working with the municipality FHI found that this entire road was to be rebuilt. As a result, FHI deferred the project to this forecast period to coordinate it with the new road reconstruction so that they could ensure that the pole line construction will meet the needs of FHI and the municipality.

5.2.2.4 Transmitter & Other LDC's

Presently, and throughout the forecast period, there are no transmission or distribution capacity constraints to deter new load or connections of Renewable Energy Generation. From the engagements with HONI and other LDC's, FHI has not identified any direct investments.

FHI owns and operates one grid-connected transformer station supplied by HONI 230 kV transmission lines. HONI is FHI's only transmitter and the only other LDC that FHI is an embedded distributor to. FHI consults with HONI to share planning and operational information that will aid in a timely, coordinated, and cost-effective delivery of services for both parties. The value of the information may be immediate and considered in current design, construction or operational decisions or longer term to be used in system planning. These consultations can be initiated by either party and vary in format and timing.

Most of FHI's engagement with HONI will be over operational issues, specifically supply point reliability.

Some examples of recent consultations with HONI are outlined below:

a) On a regular basis, FHI's operations and stations staff and their HONI counterparts communicate and coordinate over daily operations as well as planned and emergency maintenance. These communications can be initiated by either party. These communications have a great impact on O&M and the resulting actions are coordinated such that equipment outage requirements can be reduced. As these are ongoing consultations there are no final deliverables associated with these types of consultations.

b) On an as needed basis, FHI senior engineering and operations staff initiate consultations with more senior HONI staff, mainly over supply point reliability performance. Reliability has been and will continue to be an area of focus over the forecast period. Deliverables from these consultations come in the form of raising HONI's awareness over transmission or distribution supply and reliability performance expectations from FHI.

c) Increasing the ultimate fault level limit at Stratford TS: This request and subsequent approval has removed the previous restrictions that limited Renewable Enabling investments, allowing these projects to once again connect to feeders supplied from the HONI owned Stratford TS.

5.2.2.5 Other LDCs & IESO

Most of FHI's engagement with other LDC's and the IESO is done on an ad-hoc and as needed basis. Outside of these ad-hoc meetings, FHI also engages through other industry forums and groups, such as the USF forum, OEB working groups, EDA Councils, etc. No direct investments have been identified through these engagements.

5.2.2.6 Regional Planning Process

The Regional Planning Process represents a coordinated, transparent, and cost-effective planning of electrical infrastructure at the regional level, which was mandated by the OEB in 2013. To facilitate effective planning, the Province of Ontario is divided into 21 planning regions. As the lead transmitter, HONI conducts a Need Assessment (NA) and develops a Regional Infrastructure Plan (RIP) that involves representatives from the IESO, and LDCs of the planning region.

No direct investments have been identified through these engagements, and consistent with these results, this DSP forecasts no investments from the latest Regional Plans.

FHI is part of the South Heron-Perth planning sub-region which is a part of the Greater Bruce/Huron region (depicted in Figure 5.2-2). This sub-region comprises the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford, Lambton, and Middlesex counties.

The planning region includes the following participants involved in the scoping assessment and regional planning for the South Huron-Perth region:

- IESO.
- Entegrus Powerlines Inc.
- ERTH Power Corporation.
- FHI.
- HONI (Distribution).
- HONI (Transmission).
- Wellington North Power Inc.
- Westario Power Inc.

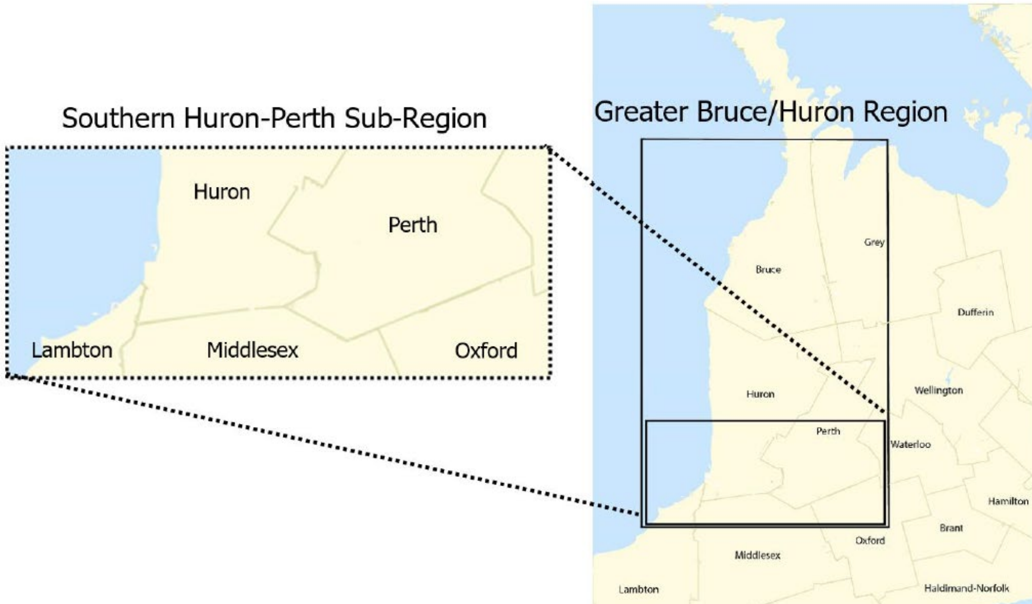


Figure 5.2-2: South Huron-Perth Sub-Region

The first regional planning cycle for the Greater Bruce-Huron region was completed in August 2017 with the publication of the RIP. Needs were identified in the near- to medium-term time frames, and several solutions were recommended to address them.

The second cycle of the regional planning process for the Greater Bruce-Huron region was triggered in April 2019. The current RIP (published in April 2022) is the final phase of the second cycle of the regional planning process for the Greater Bruce-Huron Region which follows the completion of HONI's Needs Assessment (NA) in May 2019. The NA is the first step in the regional planning process. The NA is in accordance with the Regional Planning process – stating the regional planning cycle should be revisited at least every five years. The needs identified in the NA report are inputs to the scoping process to determine the planning process required. IESO's Scoping Assessment Outcome Report and Terms of Reference was released in September 2019. The Scoping Assessment Outcome Report identified needs that were further assessed through the South Huron-Perth Sub-Region IRRP in September 2021.

5.2.2.6.1 Needs Assessment

The first cycle of the Regional Planning process for the region was initiated in spring 2016 and was completed in August 2017. The publication of the RIP provided a description of needs and recommendations of preferred wires plans to address near and mid-term needs at the time. The purpose of the second cycle NA was to identify any new needs for the region as well as recommend a path forward for each need by either developing a preferred plan or identifying which needs require further assessment and/or regional coordination. Inputs considered for the NA included:

- Load forecasts for all supply stations.

- Known capacity and reliability needs, operating issues and/or major assets approaching the End-of-Life (EOL).
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the Greater Bruce-Huron Region.

The report identified several needs in the region that may require further regional coordination and concluded that these needs should be reviewed further under the IESO-led Scoping Assessment process. Key needs identified directly impacting FHI include:

- the need for HONI to address the transmission supply capacity needs for circuit L7S in the Greater Bruce-Huron area; and

Purpose: To identify potential needs in the Greater Bruce-Huron region and to recommend which need may require further assessment and/or regional coordination.

Participants: HONI, IESO, Entegrus, ERTH Power, FHI, Wellington North Power, and Westario Power.

Status: Complete.

Deliverables: NA Report issued by HONI on May 31, 2019 (see Appendix E)

5.2.2.6.2 Scoping Assessment

A Scoping Assessment Outcome Report was developed for the Greater Bruce-Huron region in September 2019. The main outcome of the Scoping Assessment is the identification of the best planning approach for each need identified in the NA. An integrated approach is recommended to address the capacity needs in the Southern Huron Perth sub-region. The Scoping Assessment concluded that individual IRRP is necessary for the South Huron-Perth sub-region. Key needs relating to FHI's service area identified to go through the IRRP process are as follows:

- Explore integrated capacity planning to address both near and medium-term capacity needs (in 2022 and 2027, respectively) on circuit L7S from load growth in the area it supplies by considering non-wires alternatives (NWAs).
- Identify opportunities to optimize EOL investments in the near-term at four transformer stations, i.e., by considering expected service life (ESL) information, local planning, assessing wires and non-wires solutions.

Purpose: To further review the needs identified, in combination with information collected as part of the NA and information on potential solutions, in order to assess and determine the best planning approach for the whole or parts of the region.

Participants: IESO in collaboration with the Greater Bruce-Huron regional participants.

Status: Complete.

Deliverables: Scoping Assessment Outcome Report issued by IESO on September 19, 2019 (see Appendix F)

5.2.2.6.3 Southern Huron-Perth Sub-Region Integrated Regional Resource Plan (IRRP)

This IRRP develops and recommends options to meet the supply needs of the Southern Huron-Perth sub-region in the near, medium, and long term. The plan was prepared by the IESO on behalf of HONI distribution and transmission, Entegrus, and FHI. The objective of the Southern Huron-Perth IRRP is to assess the adequacy of electricity supply to customers in the sub-region supplied by the L7S circuit; explore opportunities to optimize future end-of-life investments; and make recommendations to maintain reliability of supply to the sub-region over the next 20 years.

This IRRP report will consider the following data and assumptions:

- Electricity demand growth data.
- Conservation Demand Management (CDM) and Distributed Generation (DG) data.
- Relevant community plans.
- Existing system capability.
- EOL asset considerations and sustainment plans.

With the increase in customer requests and demand growth expected to increase under the high growth scenario following the loss of circuit D8S, a potential long-term supply capacity need would emerge on circuit L7S in 2035, reaching 11 MW by 2038. Additionally, under outage conditions to D8S following the loss of Seaforth T6, a supply need on circuit L7S would emerge in 2030, reaching 21 MW by 2038. The following three options were considered to address the above supply needs:

- Option 1: Load transfers.
- Option 2: CDM.
- Option 3: L7S circuit upgrade.

FHI has currently not seen the demand growth that requires them to carry out investments related to the above supply considerations.

Purpose: To provide recommendations to address the electricity needs of the sub-region over the next 20 years.

Participants: IESO, HONI Distribution and Transmission, Entegrus and FHI.

Status: Complete.

Deliverables: Integrated Regional Resource Plan – South Huron-Perth Sub-Region (see Appendix G)

5.2.2.6.4 Regional Infrastructure Plan (RIP)

The RIP issued by HONI Transmission in April 2022 represents the final phase of the second cycle of the Greater Bruce-Huron Regional Planning process. The RIP provides a consolidated summary of needs and recommended plans for the region over the previous ten-year planning horizon (2019-2028). Two near and mid-term needs were identified for the Greater Bruce-Huron Region: transmission circuit capacity on L7S and customer delivery point performance review on the 115 kV system. This has no impact on FHI's proposed investments.

Purpose: To develop an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and any additional needs identified based on new and/or updated information.

Participants: IESO, HONI Distribution and Transmission, Entegrus, ERTH Power, FHI, Wellington North Power, and Westario Power.

Status: Complete.

Deliverables: Greater Bruce-Huron Regional Infrastructure Plan (see Appendix H)

5.2.2.7 Telecommunication Entities

FHI regularly engages with the telecommunication companies that operate within its service area. All parties communicate when large scale projects are being carried out that could impact each others equipment and operations.

In relation to this DSP, FHI engaged with these telecommunication companies directly to gather any information on any large investments that were being planned that FHI needed to be aware of and account for in its DSP.

Table 5.2-3: Summary of Consultations

Date of Consultation	Consultation Overview	Participants
July 31, 2023	E-mail	Rogers
July 31, 2023	E-mail	Bell
July 31, 2023	E-mail	Eastlink
July 31, 2023	E-mail	Mitchell Seaforth Cable TV
December 6, 2022/ October 4, 2023	E-mail	Xplore (formerly Xplornet)
July 31, 2023	E-mail	Rhyzome Networks

FHI sent out an email to its contacts at all telecom companies that have existing attachments within its service territory. The email comprised of:

"Hi {insert participant name},

As part of our 2024/2025 budgeting process, we are reaching out to all of the joint use parties attached to our poles to determine if you have any planned upgrades or new construction projects within that time range, that may impact our planned projects or any significant make-ready work on other existing poles.

Please let us know if we need to be aware of anything within our service territory, even if it's in early planning/design stages."

In addition, FHI reached out to Xplore, who was awarded projects in the City of Stratford and Town of St. Mary's based on the Building Broadband Faster Act to understand where they are planning to build and associated timelines, but Xplore did not have the exact specifics at the time of consultation.

Result of Consultations

All responses received indicated that the stakeholders do not have any planned projects in the next two years that would impact FHI and require to be incorporated into its capital budget. FHI received responses that the stakeholders would have to perform customer driven work if required, but with no infrastructure upgrade plans.

Xplore responded on October 4th, 2023, indicating that they will only utilize wireless technology for their projects within FHI's service territory and will not attach to any of the poles. Therefore, FHI does not need to incorporate any costs into its capital plans.

5.2.2.8 CDM Engagements

FHI has not had any CDM-related consultations that have an impact on this DSP.

5.2.2.9 Renewable Energy Generation (REG)

FHI does not anticipate any REG investments over the forecast period.

5.2.2.9.1 IESO Comment Letter

FHI does not anticipate any REG investments over the forecast period, and therefore has not sought a comment letter from the IESO.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

5.2.3.1.1 Objectives for Continuous Improvement Set out in Last DSP Filing

FHI does not have any additional metrics that are not reported through the performance scorecard.

5.2.3.1.2 Performance Scorecard

Table 5.2-4: DSP Performance Measures

Performance Outcome	Measure	Metric	2015	2016	2017	2018	2019	2020	2021	2022	2023	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	99.60%	99.70%	98.66%	99.25%	96.99%	95.31%	97.89%	95.92%	93.26%	90%
		Scheduled Appointments Met on Time	99.80%	100.00%	99.42%	98.93%	98.50%	97.69%	98.88%	97.70%	97.70%	90%
		Telephone Calls Answered on Time	90.10%	87.00%	84.71%	87.59%	88.45%	98.86%	91.71%	90.42%	98.07%	65%
	Customer Satisfaction	First Contact Resolution	99.97%	99.99%	99.97%	99.99%	99.99%	99.93%	100%	99.99%	100.00%	No target
		Billing Accuracy	99.97%	99.97%	99.99%	99.95%	99.99%	99.96%	99.98%	99.97%	99.97%	98%
		Customer Satisfaction Survey	79%	91%	91%	97%	97%	91%	91%	93%	93%	No target
Operational Effectiveness	Safety	Level of Public Awareness	80.00%	80.00%	81.00%	81.00%	81.00%	80.00%	77.00%	77.00%	77.00%	No target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C	C	C	C	C
		Number of General Public Incidents	0	0	0	0	1	0	0	0	0	0
		Rate per 10, 100, 1000 km of line	0	0	0	0	0.383	0	0	0	0	0
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	1.02	1.32	1.69	0.92	1.79	1.27	1.95	0.81	1.09	1.35
		Ave. Number of Times that Power to a Customer is Interrupted	1.21	0.93	1.92	0.73	1.78	1	1.63	0.77	0.81	1.31

	Asset Management	Distribution System Plan Implementation Progress	107.67%	97.20%	94.20%	103.60%	112%	92%	105%	95%	106%	No target
	Cost Control	Efficiency Assessment	4	4	4	4	3	3	3	3	3	No target
		Total Cost per Customer	$639	$645	$612	$658	$650	$629	$614	$674	$759	No target
		Total Cost per km of Line	$50,535	$51,669	$49,303	$53,904	$53,219	$51,767	$50,551	$52,180	$58,652	No target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation CIA Completed on Time	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	N/A	100.00%	No target
		New Micro-embedded Generation Facilities Connected on Time	100.00%	100.00%	100.00%	100.00%	N/A	N/A	100.00%	100.00%	100.00%	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	0.46	0.55	0.5	0.5	0.53	0.54	0.51	0.46	0.5	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	1.26	1.32	1.32	1.19	1.11	1.04	0.99	0.97	0.85	No target
		Regulatory ROE – Deemed (included in rates)	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	No target
		Regulatory ROE - Achieved	14.24%	7.37%	8.43%	8.30%	9.10%	8.89%	9.93%	9.25%	8.62%	No target

A review of FHI’s historical performance above indicates that FHI has largely met or exceeded expectations over the historical period, with the following exceptions:

a) SAIDI & SAIFI in 2017, 2019 and 2021

FHI did not meet its SAIDI and SAIFI performance targets in 2017, 2019 and 2021 primarily due to outages caused by Defective Equipment, Adverse Weather and Foreign Interference. Specifically:

- In 2017, there was an increase in SAIDI and SAIFI due to multiple feeders in Stratford experiencing prolonged interruptions due to Foreign Interference (wildlife and vehicular) and Defective Equipment.
- In 2019 there was an increase in SAIDI and SAIFI largely because of Adverse Weather, Foreign Interference, and an Unknown outage cause on feeders in Stratford.
- In 2021 there was an increase in SAIDI and SAIFI that was mainly due to a severe weather event that affected two large feeders in Stratford and one in St. Mary's. This accounted for majority of the outage minutes in 2021 but was not enough to trigger a Major Event Day.

FHI has historically undertaken the following efforts to address and mitigate reliability issues:

- Installed smart switches and smart fault indicators to assist with locating system faults.
- Continue investing in System Renewal projects that replace depreciated assets.
- Ongoing inspection and maintenance of assets to identify and mitigate potential issues.
- Work with the municipality to provide more aggressive tree trimming and tree removal that caused recurring outages.
- Re-insulating areas of St. Mary's and Stratford to provide greater clearance between live conductor and concrete poles as well as install additional animal guarding.

Additional information on FHI's historical reliability performance as well as information on FHI's ongoing and planned efforts to address reliability over the forecast period are provided in Section's 5.2.3.2.2 and 5.2.3.2.3.

b) Number of General Public Incidents in 2019

FHI did not meet its general public incident performance target in 2019. There was one reportable serious electrical incident in 2019. This was from a meter that catastrophically failed while in service. FHI replaced all meters of this model type in their service territory to remedy the solution and remove the safety risk.

FHI remains strongly committed to both the safety of staff and the general public. FHI regularly provides its customers with electrical safety information via its website and social media. There are several ongoing and planned efforts to maintain system safety. These efforts include:

- Immediate or planned replacement of deteriorated infrastructure as identified by testing and inspection.
- Regular inspection and testing of in-service assets.
- Regular vegetation management to keep trees and branches away from infrastructure.

5.2.3.2 Service Quality and Reliability

5.2.3.2.1 Service Quality Requirements

FHI measures and monitors service quality in accordance with its core value of being responsive to customer needs to ensure continued improvement and achieve a high level of customer satisfaction. FHI tracks and reports on Service Quality Requirements (SQR) in accordance with Chapter 7 of the OEB's DSC. Table 5.2-5 presents FHI's SQR performance for the historical period.

Table 5.2-5: Historical Service Quality Metrics

Service Quality Metric	2015	2016	2017	2018	2019	2020	2021	2022	2023	Minimum Standards
Low Voltage Connections	99.6	99.7	98.66	99.25	96.99	95.31	97.89	95.92	93.26	> 90%
High Voltage Connections	N/A	N/A	100	100	100	N/A	100	100	N/A	> 90%
Telephone accessibility	90.1	87	84.71	87.59	88.45	98.86	91.71	90.42	98.07	> 65%
Appointments met	99.8	100	99.42	98.93	98.5	97.69	98.88	97.7	97.7	> 90%
Written response to enquiries	100	100	100	100	100	99.97	99.98	99.95	100	> 80%
Emergency Urban Response	100	100	100	90.48	100	100	100	100	100	> 80%
Emergency Rural Response	N/A	N/A	N/A	N/A	N/A	100	100	100	100	> 80%
Telephone call abandon rate	1	0.8	1.09	1.08	0.92	1.71	1.98	0.95	0.96	< 10%
Appointment scheduling	97.1	99.5	96.84	97.06	97.92	97.43	97.56	98.05	96.68	> 90%
Rescheduling a Missed Appointment	100	100	100	100	100	100	100	100	100	> 100%
Reconnection Performance Standard	100	99.7	100	100	100	100	100	100	100	> 85%
New Micro-embedded Generation Facilities Connected	100	100	100	100	N/A	N/A	100	100	100	> 90%
Billing Accuracy	99.97	99.97	99.99	99.95	99.99	99.96	99.98	99.97	99.97	> 98%

FHI continuously strives to serve customers with the highest excellence, as is indicated by FHI's historical service quality performance. FHI has met the performance target for each performance metric during each of the past eight years.

5.2.3.2.2 Reliability Requirements

The key metrics FHI tracks to measure reliability are the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). SAIDI, SAIFI and CAIDI are measured under four scenarios:

1. By including all power interruptions.
2. By excluding interruptions due to Loss of Supply.
3. By excluding interruptions due to Major Event Days.

4. By excluding interruptions due to Loss of Supply and Major Event Days.

Loss of Supply (LOS) outages occur due to problems associated with assets owned by another party other than FHI, or the bulk electricity supply system. "Major Events" are defined by OEB as the events beyond the control of the distributor and are unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operation and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system.

Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers. Major Event Days (MED) are calculated using the IEEE Std 1366-2012 methodology. MEDs are confirmed by assessing whether interruption was beyond the control of FHI (i.e., force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

The fixed performance baseline targets for SAIDI and SAIFI over the historical period is based on the average historical performance, excluding LOS and Major Events. In 2015 the target was 1.85 for SAIDI and 1.95 for SAIFI. From 2016 to 2019, it was 1.19 for SAIDI and 1.57 for SAIFI and from 2020 onward it has been 1.35 for SAIDI and 1.31 for SAIFI. No targets are set for CAIDI.

FHI's results are reported annually as part of the OEB Scorecards. FHI's historical performance for SAIDI, SAIFI and CAIDI are shown in the following tables and figures.

Table 5.2-6: Historical Reliability Performance Metrics – All Cause Codes

Metric	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average
SAIDI	1.36	3.94	2.77	4.69	2.22	2.08	2.61	1.33	1.81	2.53
SAIFI	1.36	1.73	2.53	3.12	2.73	1.5	2.58	1.68	1.9	2.13
CAIDI	1	2.28	1.09	1.5	0.81	1.38	1.01	0.79	0.95	1.20

Table 5.2-7: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average
	Loss of Supply Adjusted (including MEDs, Excluding LOS)									
SAIDI	1.02	1.32	2.23	1.83	1.79	1.27	1.95	0.81	1.09	1.48
SAIFI	1.21	0.93	2.11	1.53	1.78	1	1.63	0.77	0.81	1.31
CAIDI	0.85	1.42	1.06	1.19	1	1.26	1.2	1.06	1.34	1.15
	Major Event Days Adjusted (including LOS, excluding MEDs)									
SAIDI	1.36	1.62	2.13	1.69	2.22	2.08	2.61	1.33	1.81	1.87
SAIFI	1.36	1.05	2.31	1.56	2.73	1.5	2.58	1.68	1.9	1.85
CAIDI	1	1.54	0.92	1.09	0.81	1.38	1.01	0.79	0.95	1.05
	Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)									
SAIDI	1.02	1.32	1.69	0.92	1.79	1.27	1.95	0.81	1.09	1.32
SAIFI	1.21	0.93	1.92	0.73	1.78	1	1.63	0.77	0.81	1.20
CAIDI	0.85	1.42	0.88	1.26	1	1.26	1.2	1.06	1.34	1.14

5.2.3.2.3 Outage Details for Years 2015-2023

Table 5.2-8: Summary of MEDs over the Historical Period

Year	# of MEDs	Cause of MEDs
2016	1	Loss of Supply; HONI had to shut off transmission lines into City of Stratford when person climbed onto transmission tower
2017	1	Adverse weather from extreme rain and wind gusts greater than 100km/h caused tree limbs and uprooted trees to fall on overhead power lines.
2018	3	April 15th - Adverse weather due to freezing rain and strong winds which caused tree limbs and uprooted trees to fall on overhead power lines. April 24th - Loss of Supply due to a fault detected at HONI's Stratford TS that caused an outage on the transmission level affecting all customers in Stratford. May 4th - Adverse weather due to strong winds which caused tree limbs to fall on overhead power lines

Table 5.2-9: List of MEDs over the Historical Period

Date	Customer Base Interrupted	Description
June 24th, 2016	14,066	Loss of Supply; HONI had to shut off transmission lines into City of Stratford when person climbed onto transmission tower.
October 15th, 2017	4,551	Adverse weather from extreme rain and wind gusts greater than 100km/h caused tree limbs and uprooted trees to fall on overhead power lines.
April 15th, 2018	5,316	Adverse weather due to freezing rain and strong winds which caused tree limbs and uprooted trees to fall on overhead power lines.
April 24th, 2018	14,770	Loss of Supply due to a fault detected at HONI's Stratford TS that caused an outage on the transmission level affecting all customers in Stratford
May 4th, 2018	10,780	Adverse weather due to strong winds which caused tree limbs to fall on overhead power lines

Table 5.2-10: Number of Outages (2015-2023)

Categorization	2015	2016	2017	2018	2019	2020	2021	2022	2023
All interruptions	184	194	230	177	210	200	197	189	194
All interruptions excluding LOS	176	175	211	161	185	180	178	169	185
All interruption excluding MED and LOS	176	174	208	153	185	180	178	169	185

The root cause of any outage is monitored and analyzed by FHI. Each outage that occurs on FHI's distribution system is recorded and an outage cause code is assigned. There are no targets for the number of outages, but it is monitored for investment planning purposes and to identify specific outage causes that need to be addressed to improve negative trending. Table 5.2-10 presents a summary of total outages that have occurred within FHI's service territory using three different categorizations.

Table 5.2-11 presents the count of outages broken down by cause code for the historical period, excluding MEDs. The number of outages is an indication of outage frequency and allows FHI to better understand the impacts and trends of each outage type. FHI continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 5.2-11*: *Outage Numbers by Cause Codes – Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total Outages	%
0-Unknown/Other	0	6	5	4	8	5	7	2	8	45	3%
1-Scheduled Outage	106	108	144	90	93	105	87	95	95	923	53%
2-Loss of Supply	8	10	17	10	25	20	19	20	9	138	8%
3-Tree Contacts	6	10	5	3	1	10	8	9	10	62	4%
4-Lightning	0	4	0	0	0	3	4	0	2	13	1%
5-Defective Equipment	32	18	19	33	35	23	33	31	22	246	14%
6-Adverse Weather	2	8	2	4	15	3	10	8	5	57	3%
7-Adverse Environment	0	0	1	0	2	0	0	0	0	3	0%
8-Human Element	0	0	2	2	3	1	0	1	1	10	1%
9-Foreign Interference	30	20	30	17	28	30	29	23	42	249	14%
Total	**184**	**184**	**225**	**163**	**210**	**200**	**197**	**189**	**194**	**1746**	**100%**

The total annual number of interruptions, excluding MED's, over the historical period varies from a low of 163 to a high of 225, with the overall trend increasing slightly in the period. This represents an average of 0.45 to 0.62 interruptions per day.

As illustrated in Table 5.2-11 above, the top three contributors to the quantity of outages experienced over the historical period are Scheduled Outages, Defective Equipment and Foreign Interference.

At 53%, Scheduled Outages represents the largest cause for outages on FHI's distribution system over the last eight years. Scheduled Outages are due to the disconnection of service for FHI to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. FHI aims to mitigate the impact of these outages through proactive planning and advanced notice to affected customers.

At 14%, Foreign Interference represents the next largest cause for outages. Foreign Interference includes animal interference, dig-ins, vehicle collisions, vandalism, and/or foreign objects. Some of these contributing factors can be minimized by installing wildlife guards, increasing clearances between conductors and poles, as well as educating the public about electrical overhead and underground electrical hazards, all of which FHI continues to do. However, there are also factors such as vehicle collisions which can happen at random and, depending on the extent and the location of the collision, may result in an increased duration and number of customers affected from the outage. These are typically outside FHI's control.

At 14%, Defective Equipment represents the third largest cause for outages on FHI's distribution system. Defective Equipment outages result from equipment failures due to condition deterioration, ageing effects, manufacturing defects, or imminent failures detected from regular maintenance programs. For applicable asset classes, FHI plans renewal investments to prioritize assets for replacement before experiencing a failure that may cause an outage. This includes replacing deteriorated poles, primary distribution cables, and underground infrastructure. FHI utilizes asset condition data from the recently completed ACA to assist in prioritizing investments in asset classes. Some examples of the programs and projects FHI continues to implement are:

- Air-Insulated Switchgear replacements to address the multiple switchgear failures FHI has observed in the historical years.
- Transformer sandblasting/repainting to extend the life of padmount transformers, by re-enforcing the metal enclosure.
- UG cable testing to provide more quantitative data on cable condition to enhance the information and results from condition assessments.

FHI closely monitors both the Defective Equipment and Foreign interference measures to help gauge the appropriate degree and location of investment required in asset renewal and grid resilience.

Customers Interrupted and Customers Hours Interrupted

The number of Customers Interrupted (CI) is a measure of the extent of outages. Customer Hours Interrupted (CHI) is a measure of outage duration and the number of customers impacted. The tables below provide the historical values and trends for both CI and CHI.

Table 5.2-12: Customers Interrupted Numbers by Cause Codes – Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total CI	%
0-Unknown/Other	0	75	1241	1888	6948	919	4937	1066	1074	18148	5%
1-Scheduled Outage	1859	4125	2824	3015	3405	1559	2973	2028	1651	23439	7%
2-Loss of Supply	3040	2554	8147	17295	20435	10877	20867	20325	24567	128107	36%
3-Tree Contacts	7726	921	4638	33	1	1647	7402	3696	423	26487	7%
4-Lightning	0	4514	0	0	0	68	298	0	1074	5954	2%
5-Defective Equipment	9135	2127	14324	2854	5808	10663	3272	3733	4789	56705	16%
6-Adverse Weather	741	4122	13	861	13585	4415	11504	103	1710	37054	10%
7-Adverse Environment	0	0	15	0	16	0	0	0	0	31	0%
8-Human Element	0	0	2078	3963	75	8	0	21	1765	7910	2%
9-Foreign Interference	5391	3376	15379	2972	8505	2562	5412	6424	5706	55727	15%
Total	**27892**	**21814**	**48659**	**32881**	**58778**	**32718**	**56665**	**37396**	**42759**	**359562**	**100%**

Table 5.2-13: Customer Hours Interrupted Numbers (rounded) by Cause Codes – Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total CHI	%
0-Unknown/Other	0	93	2011	2770	6574	857	3251	464	1326	17346	5%
1-Scheduled Outage	2564	8905	6404	5901	6886	3020	5790	2805	3053	45328	13%
2-Loss of Supply	6583	6293	9258	16106	9242	17683	14610	11486	16281	107542	30%
3-Tree Contacts	7336	1501	2703	34	7	6692	9891	2228	334	30726	8%
4-Lightning	0	483	0	0	0	106	677	0	260	1526	0%
5-Defective Equipment	7179	5251	12347	5123	2978	9605	2312	4155	7662	56612	16%
6-Adverse Weather	1445	9093	8	2012	13080	2918	18670	205	3706	51137	14%
7-Adverse Environment	0	0	90	0	11	0	0	0	0	101	0%
8-Human Element	0	0	2334	1727	4	2	0	23	118	4208	1%
9-Foreign Interference	2551	2033	9771	2039	8903	4338	2209	8168	7996	48008	13%
Total	**27658**	**33652**	**44926**	**35712**	**47685**	**45221**	**57410**	**29534**	**40736**	**362534**	**100%**

When analyzing CI and CHI, Loss of Supply, Defective Equipment, Foreign Interference and Adverse Weather are the top contributing causes, as seen in Table 5.2-12 and Table 5.2-13.

Loss of Supply is a customer interruption due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system and as such are beyond the control of FHI.

Adverse Weather is also beyond the control of FHI. However, FHI continues to design and invest in infrastructure that improves FHI's ability to withstand Adverse Weather events compared to the assets they are replacing (e.g., improvements that can make utility infrastructure more resilient to the weather). FHI also continues to invest in vegetation management programs to reduce the occurrences of tree contacts during weather events.

Defective Equipment and Foreign Interference are addressed and invested in as outlined previously. The top cause code that can be controlled and managed by FHI is Defective Equipment. As previously noted, there are several ongoing and planned efforts to manage the number of controllable outages and continue meeting reliability targets. These efforts include ongoing testing, inspection, and maintenance of assets to identify and mitigate potential problems, in addition to planned capital investment programs to replace assets before experiencing a failure that may cause an outage (e.g., FHI's planned pole, underground cable and switchgear replacement programs).

5.2.3.3 Distributor Specific Reliability Targets

FHI tracks the following additional reliability metrics each year in the Reliability Report:

- Customer Average Interruption Duration Index (CAIDI).
- Momentary Average Interruption Frequency Index (MAIFI).

FHI compares CAIDI to the Ontario average. Additionally, FHI tracks MAIFI every year on a per feeder basis. MAIFI enables FHI to determine if there are certain feeders that may not necessarily have a lot of sustained outages but have momentary outages, i.e., momentaries. FHI aims to have less than 10 momentaries/year on each feeder. Further information on this can be found in the Reliability report (see Appendix I).

FHI uses results from within the reliability report to inform the re-insulating program and determine where to add animal guarding and further scrutinize for tree trimming.

FHI also looks at their Worst Performing Feeders (WPFs) by comparing the number of outage minutes to help identify potential trouble feeders and understand if there is a need to better balance feeders via loading/customers[3], or if there is a need to address the issue using one of FHI's investment plans.

Through its engagement, FHI customers have identified reliability as a top priority, with 69% of customers indicating that FHI proposed investment were adequate and 82% felt the proposed rate increase for this was necessary.

[3] FHI's 2022 customer survey provides details on how customers feel about reliability/response times/outages (see Appendix D).

5.3 ASSET MANAGEMENT PROCESS

5.3.1 PLANNING PROCESS

5.3.1.1 Overview

FHI's Asset Management (AM) process proactively identifies, manages, and mitigates risks within their electricity distribution system, thereby allowing FHI to achieve their mission of responsibly serving their customers and communities through cost effective distribution and generation of reliable and safe electric power.

Integrated within FHI's AM process are AM Objectives that are largely driven by a combination of FHI's corporate mission, vision, values, and strategic goals and relevant legislative and regulatory obligations, including the OEB's RRF Performance Outcomes and requirements outlined in the DSC and the OEB Act. FHI has established the following objectives derived from its AM philosophy to ensure that FHI's customers continue to receive the level of service they expect while maintaining financial accountability to allow for a sustainable investment plan. These objectives are:

- Reliability and Supply of Power
- Health and Safety of workers and public
- Asset History and Performance
- Customer and Community Focus
- Productivity/Efficiency
- Organizational Effectiveness
- Environment and Sustainability

These AM objectives form the high-level philosophy framework for FHI's capital program. They define the content of the programs and the major projects in the capital expenditure plan needed to sustain FHI's electrical distribution system, guiding FHI in making effective capital investment decisions, which inherently make the best use of assets and maximize their value to the company. Used as an initial starting point, these objectives continue to be developed, enhanced, and adjusted as necessary to align with the business environment that the company operates in and help encourage continuous improvement. Each objective has been integrated into FHI's capital investment process to prioritize investments.

FHI's AM process demonstrates its high-level AM direction, principles, and mandatory requirements. The AM process interprets the company's vision, mission, and values and serves as the connection between top-level corporate and strategic goals and objectives through to the bottom-level AM practices.

Decisions involving investment into assets play a major role in determining the optimal performance of distribution system assets. Most of these investments are triggered by one or more of these situations:

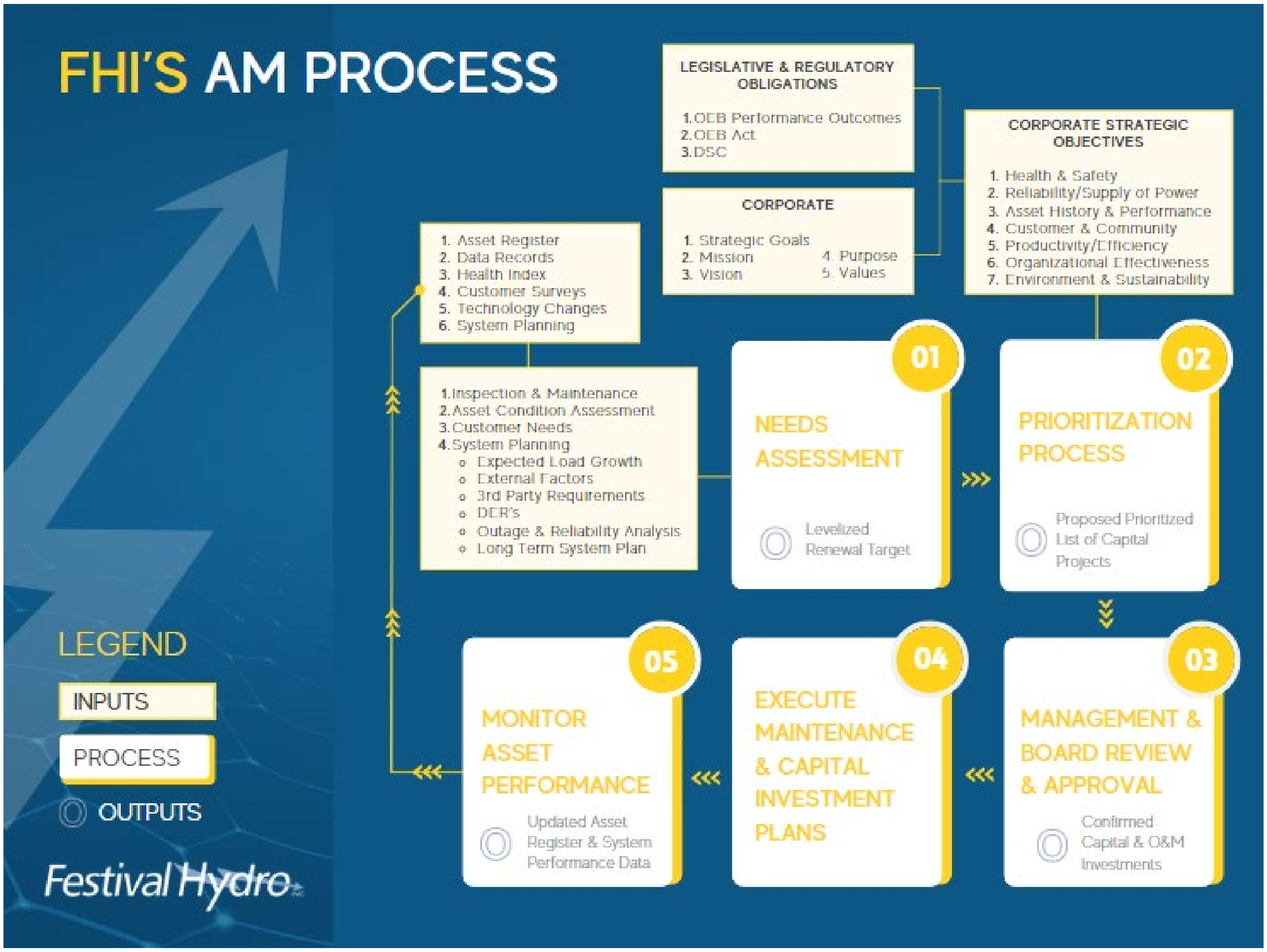
- A performance decline in the areas of supply system reliability, power quality, or safety.

- An increase in operating and maintenance costs associated with aging and deteriorating assets.
- Anticipated demand growth, requiring capacity upgrades.
- Asset or technological obsolescence, lack of support.
- Meeting legislative requirements.
- Asset performance and history, based on testing, inspections, failures, and ACA results.

In any of these cases, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, when system investments are not made on time it raises the risk of performance targets not being achieved and will also result in non-optimal operation. Optimal operation of the distribution system is achieved when right-sized investments in renewal and replacement (capital investments), in asset repair, rehabilitation, and preventative maintenance are planned and implemented based on a just-in-time approach. In summary, the overarching objective of the AM strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

FHI employs a condition-based AM strategy. This strategy determines the likelihood of an asset failure based on its condition. A range of asset health indices is commonly used to quantify conditions. FHI's AM strategy covers the full life cycle of a fixed asset, from the preparation of the asset specification and installation standards to the scope and frequency of preventative maintenance during the asset's service life to the determination of the asset's end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest operating costs.

FHI's AM process is established such that activities are coordinated to ensure assets are optimally achieving the company's corporate and AM objectives. Conceptually, the process includes items such as setting out the criteria for optimizing and prioritizing AM objectives, lifecycle management requirements of the assets, stating the approach and methods by which the assets are managed (including performance, condition, and criticality assessment), the approach to the management of risk, and identifying continuous improvement initiatives. FHI's iterative AM process is regularly updated with the latest sets of data and information to ensure that FHI is initiating capital projects at the right time. As well as using this process to develop its original five-year DSP capital plan, FHI also uses it as part of its annual capital expenditure planning process to update its budget and plan for the following year. Key elements of FHI's AM process used to prepare its capital expenditure plan are identified in the following sections, including objectives, data inputs, preliminary process steps, and outputs.



5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

FHI's last DSP did not feature a condition-based asset assessment to assist in identifying the quantity and location of assets for replacement. It also did not have a project prioritization and weighting criteria to assist in ensuring that the projects being chosen with fixed funds were the highest priority. These have been developed and incorporated into this DSP filing.

Since issuing its 2015 DSP, FHI has had some changes to its overall AM process. FHI has created project prioritization and weightings to rank projects. With several upcoming discretionary projects, this is used to rank these projects to ensure the right investments are being objectively and consistently prioritized.

FHI now has a GIS system with a detailed asset registry. System Renewal projects are now also being informed by FHI's testing data, along with inspection data. FHI has started testing assets (e.g. poles) to determine their condition rather than just relying on age demographics. FHI relies on ACAs to award a qualitative HI score to each asset rather than just relying on age wherever possible. Where data gaps are identified, FHI works to implement new processes to improve data quality and quantity. Using the GIS system, the HI outputs of the ACA are spatially shown, to visually see areas with clusters of assets in poor and very poor condition. This enables FHI to identify potential capital projects.

In addition, FHI has started collecting asset removal data for poles, transformers, switchgear, and underground cables thereby allowing FHI to build their own failure curves in the future and identify prematurely failing assets and the reasons for asset removal.

5.3.1.3 Process

FHI uses input data and information to enable it to determine its operating and capital expenditure plans.

Inputs:

First, FHI identifies the majority of their assets by building an asset register of their main/core assets (e.g., poles, transformers, switchgear, etc.) with pertinent information about the asset (e.g., age, type, location). This information is stored in either the GIS, SCADA, OMS, or excel database. Having a repository of all assets, FHI then looks at other asset-related information such as:

- Maintenance
- Inspection
- Testing
- Loading
- Utilization
- Studies/Reports
- Outages/Outage Causes

ACA: Once these datapoints are put together, FHI then creates a HI, where appropriate, for its assets using a third party to generate an ACA. This takes all the above inputs, specific to each asset and gives a health score specific to that asset. These HI scores create a flag for action, or recommended replacement plan based on the statistical probability of the number of each type of asset that may fail in any given year. The output of the ACA process yields a levelized renewal target (i.e., assets flagged-for-action) for each of the major asset categories identified in the above section. The quantity of assets identified as flagged-for-action is the statistical minimum level of intervention required to maintain the asset base.

The ACA is an essential driver for decisions on maintenance levels, maintenance requirements, and decisions regarding the selection and scope of capital investments. Ultimately, the objective of this assessment is to monitor the physical indicators of asset degradation or malfunction and determine the appropriate level of intervention (e.g., maintain or replace) to ensure the distribution system continues to operate effectively and economically.

Asset needs directly inform the development of System Renewal investment (voltage conversion investments are underpinned by eliminating the capital and operating costs associated with station replacements, along with reductions in system losses). A substantial portion of the System Renewal category will fund the replacement of assets that do not meet the criteria to remain in service across all major distribution asset categories including transmission stations, pole replacements, underground renewal, and air insulated switchgear replacements.

Customer surveys: FHI regularly and proactively connects with their customers through a variety of approaches, including formal surveys, on-going engagement activities, and customer connection requests.

Through its engagement with subdivision developers and the municipalities, FHI is able to identify the required non-discretionary projects that may be need to be carried out in this DSP period, and is updated annually as more information is obtained.

For its discretionary type projects, FHI uses its customer survey with residential and commercial customers to help identify their top priorities, identify specific projects, and help inform the balance of investment with the rate impacts. This allows FHI to produce a prudent, informed and customer approved investment plan.

New Technologies: FHI remains engaged with vendors and industry groups to evaluate new product and service options regularly as well as when considering new asset investments.

System Planning: Consideration is given regarding FHI's expected load growth within its service area which is driven by known projects coming from consultations with the municipality, developers, and customers, as well as looking at historical trends, planning reports from regional planning, OEB guidance and bulletins, and IESO's planning outlook. These inputs assist in the understanding of the impacts that EVs or the electrification of other historically alternatively sourced fuels may have on the distribution system in the future and allows FHI to prepare and incorporate these impacts into their investment plans.

Potential system constraints and/or areas where fortification or upgrades of the distribution system may be needed to accommodate this are then identified. Proactive examples that FHI has taken include:

- Limiting or reducing the number of customers connected to transformers.
- Increasing the number of transformers per customer in underground areas when completing cable replacement projects.
- Placing larger capacity padmount transformers to accommodate expected load growth from electrification to mitigate risk of stranded assets.

Third-party Information: The use of this information is valuable, for example, FHI requested a report from ESA on the number of EV charger installations in their service territory, and regularly receives information by postal code from the Ministry of Transportation on EV registrations. This allowed FHI to understand where they have been installed so they could examine and understand the corresponding load increases that may coincide with this to assist in future planning for sizing transformers and make informed decisions on the number of customers to connect to each transformer.

Outage and Reliability Statistics: This helps FHI determine whether they are seeing any trends or increases in outages on a particular feeder or a particular cause code that warrants further investigation. These statistics also assist in identifying potential feeder reconfiguration or distribution automation investments.

DERs: To understand if FHI has any constraints or issues with being able to connect DERs, and if there are any renewable enabling investments that should be considered or investigated further.

Long-term System Planning: This considers future consolidations or voltage conversions, helping to evaluate any potential stacked benefits to a project. An example of this is renewing depreciated assets and furthering the goal of eliminating old 4kV substations, removing the need to maintain this voltage level and the investments involved in maintaining and upgrading them.

Project Identification:

Depending on the assets, FHI looks at preferred or possible avenues such as refurbishment, replacement, expansion, or finding a way to defer through other various means (e.g., CDM, NWAs).

For assets that can be refurbished or enhanced to extend their life at a lower cost, then that strategy could be implemented. For example, sandblasting and repainting of padmount transformers where the shell is prematurely rusting but the electrical asset is still good. Or putting on larger insulators or changing brackets on concrete poles to try and minimize animal contacts in areas where a higher frequency of this occurrence is observed, but the poles condition does not warrant replacement. This is also done for tree trimming where there is a higher frequency of momentary interruptions or outages from unknown causes.

For assets where it is deemed that replacement is the most effective course of action, capital projects are created. These inputs assist FHI in creating the upcoming year's capital and O&M budget, and help guide the 5-year forecast, which is updated and re-examined each budget cycle.

The projects and programs that FHI selects for its capital budget are ones that best address the safety, efficiency, and reliability of its distribution system, and to complete other projects as needed to allow FHI to carry out its obligation to distribute electricity within its service area as defined by the DSC.

Different investment categories are then budgeted for based on a combination of the above inputs.

System Access: These projects are mainly informed through customer engagements, communications with developers and municipalities and are driven by third party and customer requests. They receive the highest priority in FHI's project prioritization process as they are non-discretionary investments and are budgeted and scheduled to meet the customers' timelines. Examples of such projects include new subdivisions, service upgrades, asset relocations for road work, etc. In addition, this category covers FHI's metering projects to comply with the DSC and Measurement Canada (MC) regulations.

System Renewal: The volume and locations of these projects are primarily driven by the outcome of the ACA which helps FHI compile and develop a set of constructable projects in their future budget. FHI looks at certain asset classes (such as poles and underground cables) that have poor HI scores and are clustered together to create constructable projects. For large assets (such as switchgears), or where smaller assets (such as poles) are deemed to have a very low HI score, but no other assets in the vicinity warrant, it may be a single replacement. Customer input and sustainability of the expected ongoing operation and maintenance of the asset is also considered as part of these projects (e.g., moving from backlot infrastructure to the municipal right of way).

When completing these projects, system planning and future load growth are incorporated into the design and construction of these projects to ensure they will meet the long term needs of the distribution system and FHI customers. For example, larger conductor, larger and/or more distribution transformers, taller poles may all be incorporated into the design as electricity is expected to service more customer demands than historically. Ideally System Renewal investments remain levelized year over year to allow for a consistent and sustainable investment plan.

System Service: These projects are proposed based on several factors. Customer input, technological advancements, outage history (e.g., improve reliability, safety, power quality) and system planning form the main basis for these projects. These projects may also allow for constructability of future projects by creating new primary distribution circuit connections which allow for future operating and restoration flexibility ("ties"), to account for future growth and demand in service area, and to add new functionality to the distribution system (e.g., reclosers or remote fault indicators). These projects are typically discretionary in nature but provide more visibility and flexibility to the distribution system.

General Plant: These projects are identified through various ways. Fleet is identified through ACA, third party inspections, utilization, maintenance history and employee feedback. Building repairs are identified through expert knowledge and reports as well as regular inspections. Information Technology (I.T.) projects are identified through regulatory requirements, software and hardware lifecycles, and expert knowledge. While some of these projects are discretionary, they can have a negative impact on O&M costs as delaying a capital investment can require more upkeep to maintain the existing asset and can also potentially lead to larger reactive costs should an asset fail with no replacement plan.

Project Prioritization:

Once the list of projects has been created, they are then prioritized from highest to lowest. Inputs for the prioritization are guided by FHI's corporate goals and strategic objectives, OEB renewed regulatory framework expectations, customer input, and regulatory requirements.

System Access projects, which are non-discretionary in nature, are typically given top priority, as only work that addresses imminent health and safety issues is given a higher priority. These are identified through customer interactions, information from the municipality, and developers. The timing and cost of these projects are driven by the requesting party and are budgeted and resourced to meet these requirements. Projects driven by regulatory requirements (e.g., mandated by a governing body or regulator) are also given top priority as these are typically mandated to fulfill all regulatory obligations in FHI's distribution license. The only project that is within the System Access category that has been included in the project prioritization, due to it being discretionary, is FHI's proposed AMI 2.0 project.

Once all non-discretionary projects have been identified, the rest of the System Renewal, System Service and General Plant projects are prioritized through a prioritization criterion and maximum weighting as outlined below. The breakdown of the criterion categories and relative weighting for each Corporate Strategic Objective is outlined in Section 5.4.2.1.

CORPORATE STRATEGIC OBJECTIVE WEIGHTINGS	
Health and Safety	25.0%
Reliability/Supply of Power	20.0%
Asset History & Performance	15.0%
Customer & Community	15.0%
Productivity/Efficiency	10.0%
Organizational Effectiveness	10.0%
Environment & Sustainability	5.0%

1. **Health and Safety:** FHI has a legal and moral duty to its workers, customers, and the public to carry out its business and maintain its distribution system in a safe and responsible manner. This is done by having a robust inspection and maintenance plan, identifying and replacing deteriorating assets, and designing and constructing following approved standards and regulations. In addition, it is essential to provide staff with the proper training, equipment, and environment to excel and complete their work. As the technology landscape continues to rapidly evolve and change, FHI must also consider safety from a cybersecurity perspective. This is done by ensuring software systems are kept up to date, secure, and in compliance by completing security assessments, following the OEB's cybersecurity framework, and making timely investments to protect FHI and its customers.

2. **Reliability and Supply of Power:** These two factors are a primary consideration in FHI's management of assets. Adequate electrical supply helps enable the local economy to sustain itself and allows local government and business leaders to attract business to the area in what is a very competitive global economy. Opportunities lost due to inadequate electrical supply not only impact future FHI revenue growth but also community jobs, tax base and secondary development. When selecting a project to complete, FHI ensures that it will meet not only the current requirements of the distribution system but take into account the expected future system growth from new loads such as EVs. This includes items such as transformer capacity sizing, limiting or reducing the number of customer

connections per transformer, and ensuring the proper size of primary and secondary conductor are selected so that assets are appropriately sized for current and future needs. Reports and guidance from documents such as IESO's Annual Planning Outlook, the Load Forecast Guideline for Ontario and USF's transformer sizing for future electrification all assist in this planning. Reliability is a prominent consideration as it is the key measure of how well FHI is fulfilling its mandate to supply electricity to its customers. The importance of electrical supply reliability has been a consistent message that has been received from all customers through FHI's many consultations. Reliability is an important contributor, both for business and for residential customers, to the prosperity of the community. By considering both factors, FHI is able to responsibly serve current and future customers, timing replacements and upgrades in a targeted way that is cost effective and sustainable.

3. **Asset History and Performance** – All physical assets depreciate over time. It is necessary to continually invest in assets to maintain value and integrity. FHI aims to time capital investments in such a way that replacement of depreciated assets occurs before they become unsafe, unreliable, and uneconomical. This area aims to ensure the project, service or product replaces substandard equipment to address concerns with assets based on historical experience and performance.

4. **Customer and Community:** FHI is focused on providing customers with the highest level of service through innovation in infrastructure, financial responsibility, strategic partnerships, and community outreach. There are many inputs that ultimately contribute to the service provided to customers. FHI believes it is important to consider the effect of its combined objectives on customer service to provide better insights and balance to FHI's investment decision making process to provide a sustainable business model. As a locally owned utility, FHI also has a unique opportunity to work in partnership with the municipality and the economic development team to attract new business, investment, and opportunities to the community and it understands the value of having strong relationships with community members and customers. Through enhanced collaboration and relationship building, FHI seeks to better understand the goals and needs of their customers and communities to ensure that their needs are met and that they are participating as a partner in their success.

5. **Productivity and Efficiency:** FHI understands that its own success, and that of its customers, depends upon the affordability of the services it delivers. Maintaining the status quo without looking for new and more effective ways to run the business and serve customers is not acceptable and leads to running an inefficient and unsustainable business. Hence, FHI actively investigates opportunities to improve value and lower the costs of its operations without sacrificing service levels through new technologies or leveraging existing efficiencies. Although cost pressures such as labour and material inputs, regulatory requirements and service levels continue to increase, FHI continues to focus on improvement in this area.

FHI believes it is important to be a leader in implementation and utilization of technology to support communication and automation. Technology is constantly changing and developing at a very fast pace and new technologies are launched continuously that can improve upon efficiencies and processes that the business relies on. FHI seeks to look for technologies that fit the unique needs of its teams, help to reduce reliance on paper, and improve upon customer and employee experiences to create a positive culture that puts people first and focuses on the employment of technology to promote efficiencies.

FHI also considers the more widespread effects that these implementations will have for its customers and considers how they can continue to improve the level of service for their end users which includes considerations for enhanced communications during outages, automation that will decrease the length and number of outages experienced, and systems that allow staff quick access to accurate customer information that can be used to assist with inquiries and better recommend support programs that are available to those in need.

6. **Organizational Effectiveness:** FHI considers organizational effectiveness as a key factor in supporting sustainability, prudent spending, health, safety and environmental improvements, cost-effective use of rates, timeliness of service delivery, O&M execution, and capital investment planning. A culture of innovation has been the driver for strategic business and community growth by offering better ways to manage power, enhance effective use of infrastructure and capital assets, and create increased process efficiencies through automation.

   FHI strives to consistently prove that local utilities can play a key role in facilitating impactful initiatives while ensuring business fiduciary expectations, customer satisfaction, and managing downside risk while providing upside potential. FHI has played a key role in investment attraction and has been sought out as a thought leader willing to participate in projects leading the future of energy management. FHI believes in incorporating the use of technology and leveraging strategic partnerships as enablers to achieve the organizations goals and promote continuous business improvement.

   Just as FHI recognizes the incredible value of relationship building with stakeholders in the communities it serves, it also emphasizes the importance of teamwork and collaboration with peers in the energy industry. By seeking out shared service opportunities, participating in working groups and industry councils, and forging strategic partnerships with other utilities, FHI has the opportunity to learn from others, leverage the power that comes from unity, better control costs, and contribute to setting the standards for industry best practices. This will help to ensure continued responsible and value-driven operation of the organization well into the future.

7. **Environment and Sustainability:** FHI understands that to be seen as a community leader, environmentally conscious decisions must be factored into investment decisions and considered as part of the long-term strategy. This is included in, and considered as part of investment decisions when considering both the future impacts from climate change to build a robust distribution system and considering environmental risk during maintenance and inspections to assist investment decisions.

Each year projects are reassessed/reprioritized for that specific year's budget, as there may be new trends or needs that have developed over the previous year that would cause a re-prioritization in projects. For example, if air insulated switchgears were seeing an increase in failures, replacement of remaining units may be prioritized higher, while deprioritizing a different investment.

Once all projects have been identified and prioritized, it is reviewed by Senior Management at FHI to ensure it is within the budget envelope and meets the expected corporate objectives. Once approved by Senior Management, it goes to FHI's Board for final approval. Revisions are made as necessary throughout this process. Once approved by the Board, the plans and projects identified in the capital and operating budgets are executed by various departments and contractors. Regularly scheduled meetings are held with all stakeholders to review the progress of the budget from a dollar spent and from a project completion perspective. Issues or risks to the budget are identified and mitigation or alternatives are discussed.

On a quarterly basis, the Board is updated with capital progress and forecasts of capital spend and project completion where appropriate as well as highlighting risks and corresponding mitigations to the plan. Installation, inspection, testing, maintenance, and outage data is gathered throughout the year to ensure that FHI's asset registry is kept updated and so that asset performance is continually monitored and can be factored into the next year's budget cycle.

5.3.1.4 Data

FHI uses several datasets and inputs to assess the status of its assets and to assist in determining the capital and operational investments to be made. FHI uses their ACAs, customer engagement and survey results, inspection and maintenance results, its AM Objectives and evaluates how those can be linked with the OEB's Performance Outcomes and any other external factors. Some of the key elements are explained below.

Key data inputs which are utilized as part of FHI's AM process include asset information, outage data records, asset utilization and loading, customer engagement and survey results, and information on innovative technologies being implemented in the industry. Much of this information is stored within an asset register which is kept updated with current information. The section below summarizes the components of FHI's asset register that is available and used for planning purposes.

<u>Inspection and Maintenance</u>

FHI regularly undertakes maintenance and inspection practices to maintain customer reliability and power requirements in the system. Inspection, maintenance, and operational data are collected and stored which is used to support FHI's operating and capital expenditure plans. Completion of the inspection and maintenance programs is not only a matter of compliance but, the results from the inspection and maintenance programs also allow for a continual update of the asset database. FHI's maintenance and inspection programs allow for assets to be inspected and assessed for any necessary actions that need to be taken promptly in a proactive approach. FHI's inspection and maintenance programs are audited annually as required by Ontario Regulation 22/04. Further information on FHI's maintenance and inspection practices can be found in Section 5.3.3.2.

Third Party Reports

For assets that FHI does not have the in-house expertise to evaluate, qualified and independent third parties are used to assess, inspect, and provide recommendations. Examples of these would be for the buildings that FHI owns to monitor the condition of the building systems/structure and develop an investment plan based on the results, as well as certain I.T. assets and cybersecurity assessments.

Asset Condition Assessment

An ACA was completed in 2023, based on data up to December 31, 2022, for FHI's station, distribution, and fleet assets, which uses conditions to identify those assets most likely to fail. The ACA involves the interpretation of condition and performance data of key assets to assess the overall condition of the asset and identify assets that have the highest likelihood of failure. The ACA is a key supporting tool for developing an optimized lifecycle plan for asset sustainability. The results of the ACA were incorporated into a formalized capital plan and have resulted in the revision of project prioritization within the service area for the forecast period. Further information on FHI's ACA can be found in section 5.3.2.2.2 and Appendix J.

System Performance Analysis

FHI places a high level of importance on ensuring distribution system reliability meets the expectations of its customers. FHI strives to continually improve its processes for collecting, measuring, analyzing, and using outage information within its AM process to effectively manage distribution system reliability in its service area. Outage causes are tracked and analyzed by outage cause codes. This allows FHI to identify trends in causes of outages and allows for this information to feed into its prioritization and evaluation process when developing its capital investment plans. Outages on a per feeder basis are also tracked to allow FHI to identify Worst Performing Feeders (WPFs) and determine if any current or new programs can assist in improving the reliability to these customers. The analysis is used to inform the development of O&M programs and capital expenditure plans for each year.

System Loading and Capacity

Load forecasting and capital growth planning continue to be the underlying basis for the near and longer-term capital requirements for new or enhanced capacity. The loading and capacity information help to identify system needs and constraints. The information is collected on system peak loading at many points in the system and the data is analyzed to measure the risk of system overloading and to mitigate any concerns. Given the current and forecasted load growth over the five-year planning horizon (detailed further in section 5.3.2.2.1), major upgrades and system expansions are not planned to be needed over the forecast period.

Financial Metrics

FHI utilizes financial metrics on a per unit basis for certain asset categories based on actual historical replacement costs to estimate future capital costs for projects of similar size and scope. These metrics are updated annually to ensure that the estimating process continues to be effective and is based on the best available data each year.

Customer Needs and Preferences

FHI focuses on providing reliable, cost effective, and safe electricity to its customers. As part of the investment planning process, FHI conducts customer surveys to understand customer needs, preferences, and expectations. These also address requirements for new customer connections and/or modification to existing customer connections, allowing them to be incorporated early in the AM process. Additional information on FHI's customer engagement process and findings are included in section 5.2.2.1 of this DSP. Customer survey results are also included in Appendix D.

External Factors

External drivers may sometimes influence FHI's decision-making in determining the optimal plans for their system. These may include:

- Political: Governments have their directions and strategies that FHI must be aware of and adhere to.
- Economic: Economic growth and decline within FHI's service area as well as the shift of more business operations within residential units.
- Social: Changes in the environment that illustrate customer needs.
- Technological: Innovation and development within the electrical/utility sector which includes automation, technology awareness, electric vehicle (EV) penetration, DER's, battery energy storage systems (BESS), and new services.
- Environmental: Ecological and environmental aspects that can affect FHI's operations or demand which include renewable resources, weather or climate changes, and utility responsibility initiatives.
- Regulatory/Legal: Legal allowances and/or changing requirements from the OEB as well as additional legal operations such as health and safety requirements, labour laws, and consumer protection laws.

FHI continues to remain cognizant of these external drivers when developing its capital and maintenance plans.

Third-Party Infrastructure Requirements

FHI has an obligation, as per the DSC, to address investments in third-party infrastructure. Any requirements by the municipalities or other third parties to develop or modify the system are considered which also includes government programs, such as the AHSIP, which aims to connect every region in Ontario to reliable, high-speed internet by the end of 2025.

Corporate Objectives

Another input into the AM process is FHI's corporate mission, vision, core values, and strategic goals and objectives, which are described previously in section 5.2.1.1.

OEB Performance Objectives

FHI's AM process is also informed by the following four key objectives established in the OEB's RRF for Electricity:

1. Customer Focus: Services are provided in a manner that responds to identified customer preferences.

2. Operational Effectiveness: Continuous improvement in productivity and cost performance is achieved and utilities deliver on system reliability and quality objectives.

3. Public Policy Responsiveness: Utilities deliver on obligations mandated by the government (e.g.: in legislation and regulatory requirements imposed further to Ministerial directives to the OEB).

4. Financial Performance: Financial viability is maintained and savings from operational effectiveness are sustainable.

AM Objectives

FHI's AM objectives, as outlined previously in section 5.3.1.1, are another key input into FHI's AM process. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain FHI's electrical distribution system. The objectives guide FHI to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in and help to encourage the process of continuous improvement. The AM objectives have been integrated into FHI's capital investment process to prioritize investments for several years including the test year.

Technological Innovation

As part of its commitment to continuous improvement, FHI monitors the state of technological advancements made within the utility sector. Projects and equipment involving system automation, EV uptake, battery storage and other NWA's are monitored, and where appropriate, considered as part of FHI's planning process. Where it is financially responsible to do so, these technologies may be incorporated into the renewal and upgrade projects to meet the current and future needs of customers, improve operational effectiveness, as well, support the integration of renewables and smart grid technologies.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of Service Area

5.3.2.1.1 Overview of Service Area

FHI has a service area of 43.42 km^2, which includes the City of Stratford, Town of St. Marys, and communities of Seaforth, Hensall, Zurich, Brussels and Dashwood. The service area is all considered urban.

FHI's service area is within the temperate climate region of Southern Ontario. Throughout the year, the temperature typically varies from -10^{o}C during the winter to 25^{o}C in the summer. Both overhead (OH) and underground (UG) distribution systems are employed in FHI's service territory. Currently, FHI owns 587.4 km of primary conductors' length, of which 393 km is OH primary conductor and 194.4 km is UG primary cable.

FHI is seeing moderate growth within its service area, with a need to invest in its systems to ensure it can maintain reliability and safety.

5.3.2.1.2 Customers Served

Table 5.3-1 below illustrates a moderate increasing trend in FHI's total customer base over the historical period, divided into residential, general service less than 50 kW, general service greater or equal to 50 kW, large users, sentinel and street lighting. Over the historical period, FHI's customer base has grown by an average of 1.4% annually. FHI expects a similar trend over the forecast period.

Table 5.3-1: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Large User	Sentinel Lighting Connections	Street Lighting Connections
2023	20,203	2,134	212	1	36	6,356
2022	19,889	2,115	206	2	36	6,393
2021	19,598	2,097	212	2	35	6,355
2020	19,343	2,092	218	2	37	6,431
2019	19,082	2,075	224	2	36	6,536
2018	19,063	2,090	215	2	40	6,589
2017	18,799	2,088	220	2	42	6,567
2016	18,534	2,072	218	2	43	6,599
2015	18,279	2,061	215	2	44	6,530

5.3.2.1.3 System Demand & Efficiency

Table 5.3-2 shows the annual season and average peak demand in kW for FHI's distribution system. FHI experiences a system peak during the summer months.

Typically, the peak demand has remained fairly static over the historical years, reflecting the fact that FHI has observed fairly modest customer growth.

Table 5.3-2: Peak System Demand Statistics

Annual Year	Winter Peak with Embedded Generation (kW)	Summer Peak with Embedded Generation (kW)	Average Peak (kW)	Winter Peak without Embedded Generation (kW)	Summer Peak without Embedded Generation (kW)	Average Peak (kW)
2023	94,472.00	110,318.00	94,985.00	94,597.00	112,424.00	96,648.00
2022	93,384.00	107,738.00	100,561.00	93,411.00	108,662.00	101,036.50
2021	96,904.00	106,448.00	101,676.00	97,799.00	108,576.00	103,187.50
2020	94,353.00	116,734.00	105,543.50	95,812.00	118,829.00	107,320.50
2019	99,067.00	103,142.00	101,104.50	101,309.00	106,254.00	103,781.50
2018	96,254.00	108,689.00	102,471.50	96,254.00	111,693.00	103,973.50
2017	93,753.00	104,450.00	99,101.50	93,753.00	105,557.00	99,655.00
2016	93,467.00	107,476.00	100,471.50	93,467.00	108,369.00	100,918.00
2015	96,322.00	104,538.00	100,430.00	96,419.00	105,104.00	100,761.50

Table 5.3-3 indicates the efficiency of the kilowatt-hour purchased by FHI and delivered. Historical losses as a percentage of purchased energy have been at or below 3% demonstrating that FHI has been minimizing any system losses over the historical period.

Table 5.3-3: Efficiency of kWh Purchased by FHI

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2023	603,576,249	622,407,594	3%
2022	614,762,964	624,627,795	2%
2021	596,820,094	610,737,932	2%
2020	585,259,047	604,483,597	3%
2019	611,186,477	626,711,582	2%
2018	613,192,612	633,220,675	3%
2017	592,768,367	607,172,998	2%
2016	607,564,604	624,543,695	3%
2015	605,549,950	624,159,352	3%

5.3.2.1.4 Summary of System Configuration

As of December 2023, FHI owns 587.4 km of primary conductors, of which 393 km is OH primary conductor and 194.4 km is UG primary cable. FHI operates using primary voltage levels of 2.4/4.16kV, 4.8/8.32kV, 8.0/13.8kV and 16.0/27.6kV for its distribution feeders.

The number of circuits at each voltage level as well as the associated conductor length are summarized in Table 5.3-4.

Table 5.3-4: Circuit Length by Voltage Level

Voltage Level	Underground Cable Length	Overhead Conductor Length (km)	Total Conductor Length (km)
2.4/4.16kV	3.4	32.3	35.7
4.8/8.32kV	0.9	22	22.9
8/13.8kV	39.5	80.6	120.1
16/27.6kV	150.6	258.1	408.7
Total	**194.4**	**393**	**587.4**

FHI owns two DS in the community of Seaforth and one TS in the City of Stratford. Table 5.3-5 lists the rated nominal capacity of each station, in MVA.

Table 5.3-5: Nominal Station Capacity

Substation	Output Voltage (kV)	Nominal Capacity (MVA)
Chalk St DS	4.16kV	6.67
Welsh St DS	4.16kV	6.67
Wright MTS#1	27.6kV	62 (LTR)
Total Nominal Capacity (MVA)		**75.34**

FHI also has 5 dedicated 27.6kV feeds from HONI owned Stratford TS (68M2, 68M3, 68M4, 68M5, 68M8) and 4 dedicated 13.8 kV feeds from HONI owned St. Marys TS (9M1, 9M2, 9M3, 9M4).

FHI is also an embedded distributor to HONI in the following areas in its service territory:

- Hensall (fed from Seaforth TS 61M5 at 27.6kV)
- Brussels (fed from Brussels DS Feeder 3 at 8.32kV)
- Seaforth (Fed from Seaforth TS 61M3 at 27.6KV)
- Zurich (fed from Grand Bend East DS F1 at 27.6kV)
- Dashwood (fed from Grand Bend East DS F1 at 27.6kV)

5.3.2.2 Asset Information

5.3.2.2.1 Asset Capacity & Utilization

Table 5.3-6 and Figure 5.3-1 represent the forecasted peak electrical demand for FHI's service territory. The last regional planning that FHI participated in were completed in 2022. For those planning exercises, FHI relied on their traditional load forecasting processes. This included looking at historical loading and increasing by a percentage in the future to accommodate for future load growth from new connections.

To accommodate for the expected increase in electrification of transportation, a slightly less conservative load forecast has been used for this submission. This is based on the IESO's 2022 Annual Planning Outlook that expects 17% year over year growth in the transportation sector and to examine the risk of FHI running into near term constraints due to potential EV adoption rates. At this moment, FHI has not seen a material impact to their distribution system from electric vehicles. However, using data released from the government that outlines the number of EV vehicles purchased by the first three characters of a postal code, FHI has seen the number of EV's registered in their service area increase over 80% since the start of 2022 with over 150 new registrations in FHI's two largest communities alone. With this increase in mind, and to account for their expected increased adoptions and the governments mandate of 60% of vehicles sold being zero emissions by 2030 and 100% by 2035 an additional 0.5% to 1% increase in peak demand has been forecasted over the regional planning estimates which equates to between 0.6MW to 1.2MW. Currently, at locations with EV's installed, FHI typically sees a demand increase of 7-10kW for 2-4 hours when EV's are charging.

With the uncertainty of charging patterns for customers, using 8kW as an average load increase, and with EV sales expected to continue increasing, this estimate accounts for EV's that could potentially be charging during peak times.

Even with this increase in forecast, there is significant additional capacity on all feeders and stations. No feeder or station constraints are expected over the forecast period and asset utilization is not a material investment driver for FHI in this DSP.

Table 5.3-6: Historical and Forecasted Peak Demand by Station

			Historical				Forecast					
Station	Assigned Capacity (MW)	Additional Available Capacity (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Stratford TS*	52.5	39.1	56.2	51.8	51.9	52.8	53.7	54.2	54.8	55.6	56.4	57.3
Wright MTS#1**	62		35.8	31.3	35.2	34.9	35.7	36.0	36.4	36.9	37.5	38.0
St. Marys TS*	17.5	24.7	19	18.4	17.6	18.6	18.6	18.8	19.0	19.2	19.5	19.8
Seaforth 61M3*	2.91	13.8	3.8	3.7	3.7	3.8	3.8	3.8	3.8	3.9	3.9	4.0
Seaforth 61M5*	3.42	11.1	4.5	4.9	4	4.4	4.6	4.7	4.7	4.8	4.9	5.0
Grand Bend East DS F1*	.893	11.3	1.36	1.21	1.5	1.25	1.3	1.3	1.3	1.4	1.4	1.4
Grand Bend DS F1*	.375	.95	0.6	0.575	0.573	0.553	0.6	0.6	0.6	0.6	0.6	0.6
Brussels DS F3*	1.3	.921	1.7	1.8	1.8	1.5	1.7	1.7	1.8	1.8	1.8	1.8

NOTE:

* - This is capacity that has been assigned to FHI by HONI based on definitions in Transmission System Code or Distribution System Code as applicable.

There is available capacity as described in Additional Available Capacity row for each of these locations. However, they are not inherently dedicated to FHI, and would be assigned on an as needed basis.

** - This is based on the Summer LTR of one transformer at Wright MTS#1

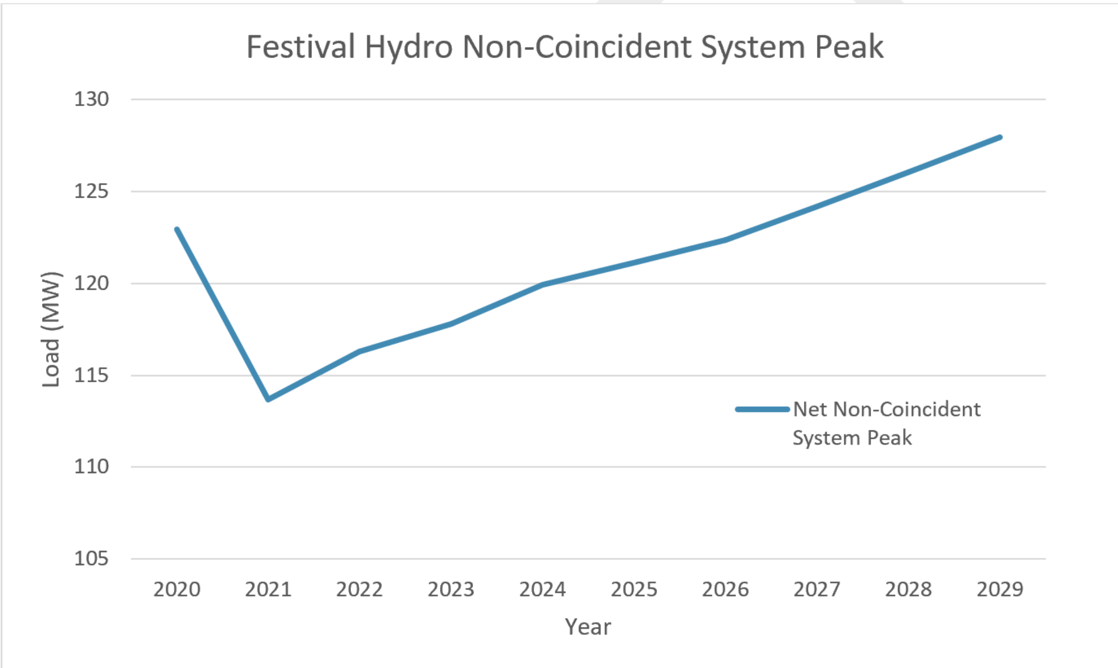


Figure 5.3-1: Historical and Forecasted Peak Demand by Station

FHI will continue to actively monitor actual demand vs. forecast and update forecasted loads to ensure that adequate capacity remains available on the distribution system in the short and medium term so that if any large capacity investments are required, adequate time is available to assess all potential options (e.g. traditional, CDM, non-wires alternatives).

5.3.2.2.2 Asset Condition and Demographics

The ACA study was carried out by engaging Kinectrics Inc. (Kinectrics) in 2023 for FHI to establish the health and condition of its distribution assets in-service.

Figure 5.3-2 presents a summary of the asset health index results from the ACA.

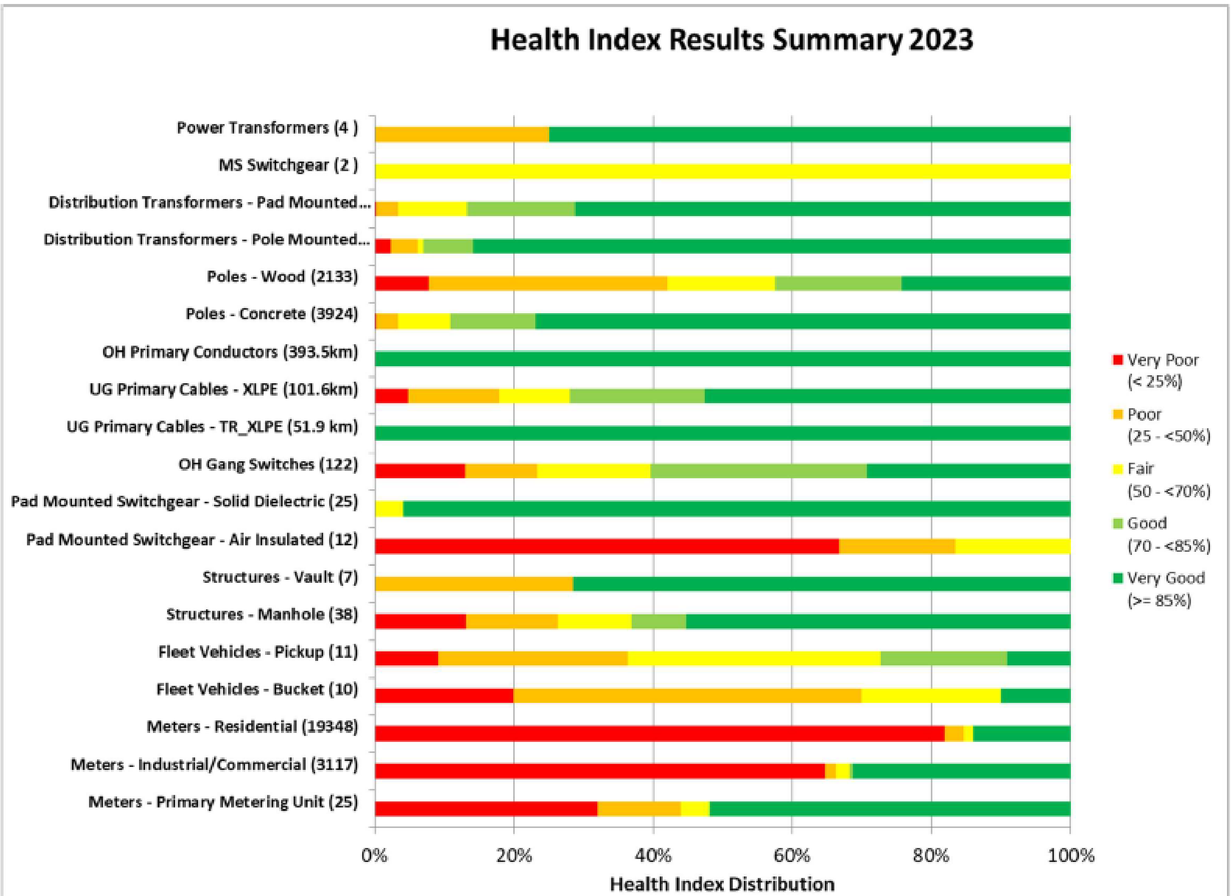


Figure 5.3-2: ACA Overview

As the figure above indicates, 9 of the 19 sub-categories have more than 70% of their units classified as "good" or "very good" and with an average Health Index score of greater than 70%. The asset categories that have all the units in "very good" condition are OH Primary Conductors and UG Primary Cables (TR-XLPE). With respect to the asset categories of concern, Poles (Wood), Pad Mounted Switchgear (Air insulated), Structures (all types), Fleet Vehicles (all types), and Meters (all types) have more than 25% of units classified as "poor" or "very poor" condition.

Table 5.3-7 presents the numerical Health Index (HI) summary for each asset class. The distribution of Health Indices is based on the total population count of a given asset class. For each asset class, the following details are listed: population, sample size, average HI, HI distribution, and average age.

Table 5.3-7: Health Index Results Summary

Asset Category	Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
				Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Power Transformers	4	4	84%	0	1	0	0	3	29
MS Switchgear	2	2	68%	0	0	2	0	0	39
Distribution Transformers - Pad Mounted	1017	985	88%	1	33	96	154	701	19
Distribution Transformers - Pole Mounted	989	921	90%	21	36	8	65	791	21
Poles - Wood	2133	2093	60%	162	718	324	380	509	36
Poles - Concrete	3924	3774	88%	8	121	280	463	2902	20
OH Primary Conductors	393.5	125.5	100%	0.0	0.0	0.0	0.0	125.5	13
UG Primary Cables - XLPE	101.6	101.6	76%	4.9	13.2	10.4	19.8	53.4	24
UG Primary Cables - TR_XLPE	51.9	51.9	100%	0.0	0.0	0.0	0.0	51.9	6
OH Gang Switches	122	116	66%	15	12	19	36	34	22
Pad Mounted Switchgear - Solid Dielectric	25	25	97%	0	0	1	0	24	6
Pad Mounted Switchgear - Air Insulated	12	12	21%	8	2	2	0	0	33
Structures - Vault	7	7	75%	0	2	0	0	5	58
Structures - Manhole	38	38	71%	5	5	4	3	21	51
Fleet Vehicles - Pickup	11	11	56%	1	3	4	2	1	8
Fleet Vehicles - Bucket	10	10	41%	2	5	2	0	1	17
Meters - Residential	19348	19320	33%	15817	530	278	0	2695	12
Meters - Industrial/Commercial	3117	3097	47%	2005	46	61	17	968	10
Meters - Primary Metering Unit	25	25	61%	8	3	1	0	13	9

0% 100%

The ACA report is found in Appendix J which contains detailed results for each asset class including demographics.

5.3.2.2.3 Asset Risks

As previously noted in section 5.3.1 FHI's AM strategy covers the full life cycle of a fixed asset, from the preparation of the asset specification and installation standards to the scope and frequency of preventative maintenance during the asset's service life and finally to the determination of the assets end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest operating costs.

Asset risks (probability of failure x consequence of failure) are considered as part of FHI's prioritization process and are ultimately used to determine the prioritized list of capital projects and programs over the forecast period. Additional information on this process can be found in section 5.3.1.3.

5.3.2.3 Transmission or High Voltage Assets

FHI Hydro owns the following high voltage assets:

- 230/27.6kV Transmission Station MTS#1 (Stratford)

These assets have been deemed as distribution assets and FHI does not intend to change their status to transmission assets.

5.3.2.4 Host & Embedded Distributors

FHI is not a host distributor to any other LDC. FHI is partially embedded into the HONI sub-transmission system.

For the communities of Hensall, Seaforth, Zurich, Brussels and Dashwood, FHI is within their distribution system and the total assigned capacity to FHI is 8.9MW.

In the Town of St. Mary's, FHI has four breaker positions right at the HONI owned St. Mary's Transformer Station (at 13.8kV). At this T.S., HONI has some of their own breaker positions and the total assigned capacity to FHI is 17.5MW[4] .

In the City of Stratford, FHI has five breaker positions right at the HONI owned Stratford Transformer Station (at 27.6kV). At this T.S., HONI has some of their own breaker positions and the total assigned capacity to FHI is 52.5MW[4].

In the City of Stratford, FHI has its own transmission connected station from 230kV down to 27.6kV. The nameplate capacity of the transformers at this station is 42MW per transformer and the total capacity is 62MW, which is the 10-day summer LTR of one transformer.

5.3.3 Asset Lifecycle Optimization Policies and Practices

5.3.3.1 Asset Replacement and Refurbishment Policy

FHI considers a wide range of factors when deciding whether to refurbish or replace distribution assets, including but not limited to public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition, future capacity requirements, and life expectancy. All these factors are considered when determining the prudency of any asset replacement or refurbishment.

System Renewal spending is optimized and prioritized based on the ACA and AM process. It is scheduled to align with budget envelopes through long-term planning and project prioritization. Long-term planning helps to smooth rate impacts, while project prioritization helps to limit rate impacts while ensuring the safety, functionality, and longevity of all FHI's assets and facilities. Per FHI's Maintenance and Inspection Policy (see Appendix K), the following station and distribution assets are covered:

- Load break switches.
- Substations and transformer stations.
- Smart switches and reclosers.
- Vaults and manholes.
- Padmount transformers.
- Switchgears.
- Poles.
- Aerial transformers.
- Switching and protective devices.

[4] This number was calculated based on TSC definition of available capacity using highest 3-month average peak from the past 5 years.

- Conductors and cables.
- Hardware and other attachments.

Where appropriate, while following industry standards, removed and repaired assets that are still in good working order are retained as spares. When upgrading or replacing its assets, FHI reviews any future capacity requirements, to ensure that assets will meet future requirements and do not need to be prematurely replaced.

5.3.3.2 Description of Maintenance and Inspection Practices

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. The purpose of FHI's Maintenance and Inspection Policy is to establish guidelines and procedures for conducting regular maintenance, inspections, and testing to ensure the safety, functionality, and longevity of all assets and facilities. All maintenance activities will adhere to applicable legislation, manufacturers' recommendations, and recognized utility best practices. FHI has undertaken a comprehensive overview of various asset classes, developed or updated the appropriate procedure, determined an inspection frequency, and placed the necessary resources in place to inspect, replace and maintain complete records of work.

Table 5.3-8: Summary of Inspection and Maintenance Activities

System	Asset	Practice	Frequency[5]
Overhead distribution assets	Load Break Switches	Visual Inspection	Yearly
		Maintenance	Ten-year cycle
	Reclosers	Visual Inspection	Yearly
		Maintenance	Ten-year cycle
	Wood Poles	Visual Inspections	Yearly
		Detailed inspection/testing	Five-year cycle
	Concrete Poles	Visual Inspections	Yearly
		Detailed inspection/testing	Ten-year cycle
	Aerial Transformers	Visual Inspections	Yearly
	Aerial Transformers	Infrared	Yearly
	Switching/Protective Devices	Visual Inspections	Yearly
	Switching/Protective Devices	Infrared	Yearly
	Conductors	Visual Inspections	Yearly
	Conductors	Tree Trimming	Three-year cycle[6]
	Hardware and attachments	Visual Inspection	Yearly
Underground distribution assets	Vaults and Manholes	Visual inspection, Infrared and Maintenance	Quarterly
	Padmount Transformers and Switchgears	Visual inspection, Infrared and Maintenance	Yearly
	Cables	Visual Inspections and Cable Testing	Yearly
Station assets	Substation equipment	Visual Inspections	Monthly
		Maintenance	Five-year cycle
		Oil Sampling (Dissolved Gas Analysis (DGA), furan analysis, oxidation inhibitor, Polychlorinated Biphenyl (PCB))	Yearly
	Transformer Station	Visual Inspections	Monthly
		Maintenance	Four-year cycle
		Oil Sampling (Dissolved Gas Analysis (DGA), furan analysis, oxidation inhibitor, Polychlorinated Biphenyl (PCB))	Yearly
		Infrared	Four-year cycle

FHI's Engineering, Operations, and Stations teams have primary responsibility for overseeing maintenance and inspection activities. FHI's Maintenance and Inspection

[5] Note, whilst the frequency may vary, a portion of all asset classes is visually inspected each year. It is the cycle for covering all assets that vary- yearly, three-year, four-year, five year, ten-year.

[6] Tree trimming cycles generally occur every three years in most communities, while the City of Stratford and typically the Town of St. Mary's adheres to an annual trimming schedule.

policy is reviewed periodically to ensure its continued relevance and effectiveness. The following aspects are assessed for updates:

- List of items being inspected.
- List of items being maintained.
- Frequency of inspection cycles, and
- Compliance with new regulations or standards.

Regular reviews and updates will help ensure the policy remains in line with industry standards, regulatory requirements, and best practices. Detailed information on FHI's Maintenance and Inspection procedures for station and distribution assets can be found in Appendix K.

5.3.3.3 Processes and Tools to Forecast, Prioritize & Optimize System Renewal Spending

The inputs and processes for forecasting, prioritizing, and optimizing System Renewal spending are summarized in the following sub-sections. Additional information can be found in section 5.3.1 of this DSP.

5.3.3.3.1 Forecasting

System Renewal projects are discretionary. The project needs for a particular period are supported by a multitude of factors, depending on the information available for each asset type. This could include a combination of asset inspection, individual asset performance, and condition information.

An ACA study was carried out by Kinectrics to establish the health and condition of distribution and substation assets in service. By considering all relevant information related to the assets' operating condition, the condition of all infrastructure assets was assessed and expressed on a normalized index in the form of a health index (HI). The HI was related to the probability of failure values for each project, using a weighted average approach, as described in detail in Appendix J, and each asset was assigned a health indicator expressed as "very good," "good," "fair," "poor," and "very poor." The resulting information from the ACA study, which included a flag-for action plan developed by Kinectrics was used as a key input to help forecast the renewal needs of FHI's assets over the forecast period.

5.3.3.3.2 Prioritization & Optimization

As described in section 5.3.1.3, System Renewal projects are prioritized through a prioritization criterion and weighting, considering: health & safety, reliability/supply of power, asset performance, customer feedback, productivity/efficiency, organizational effectiveness, and environment & sustainability.

The prioritized System Renewal investments are paced for implementation based on the funding available for asset renewal and by considering the resources required for project implementation for the type of work involved.

The continued performance of assets is also managed through FHI's capital investments and maintenance programs. FHI's inspection, maintenance, and testing practices support asset life-cycle risk management by rectifying deficiencies to extend the lives of the assets and identifying the assets in the very worst condition for replacement. Information obtained through asset databases, condition assessments, maintenance and inspection records, and outage records is a critical input into prioritizing and optimizing which projects will bring the best value.

5.3.3.3.3 Strategies for Operating within Budget Envelopes

The proposed System Renewal projects over the forecast period were identified to maintain system reliability and were paced for implementation based on the funding available for asset renewal and by considering the resources required for project implementation for the type of work involved. Using FHI's AM process, assets have been prioritized for renewal or rehabilitation during the next five years.

However, since FHI's AM process is continually being updated with new information, FHI completes investment planning on an annual basis to help inform any necessary budget adjustments for the following year. FHI understands that circumstances may change, and if needed, budgets can be re-prioritized depending on customer and system needs. For example, due to the non-discretionary nature of System Access projects, these projects will take priority if there are competing demands with System Renewal projects. Completing investment planning on an annual basis allows FHI to use the best available information to effectively plan for and manage the highest priority projects and programs over the forecast period while remaining within the approved budget envelopes.

5.3.3.3.4 Risks of Proceeding / Not Proceeding

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process and is ultimately used to determine the prioritized list of capital projects and programs over the forecast period. It is at this stage of the process that FHI considers the risks associated with proceeding versus not proceeding with an individual capital expenditure and decides whether the capital expenditure is required during the forecast period or if it can be deferred.

Assets with high-priority scores are monitored closely and plans are included in the project scope to alternatively maintain, refurbish, or replace the assets to reduce the risk. It is noteworthy that some assets carry an inherently higher risk than others. For example, power transformers at stations have a higher nominal risk level than pole mount transformers. Assets with low HI and higher consequence risk are given a priority for replacement, while assets with low HI but lower consequence risk are given a lower priority for replacement. The top projects in each category are identified in the prioritization process and scrutinized using further investigation and expert opinion to eliminate data inconsistencies and determine appropriate scopes of work.

5.3.3.4 Important Changes to Life Optimization Policies and Practices since Last DSP Filing

FHI has made one main change in this area since its last DSP filing:

Preventative Maintenance Program: FHI has revised and refreshed their preventative maintenance programs since the last DSP filing. This includes:

- completing regular load break maintenance, rather than just inspection.

- completing sandblasting and painting of padmount transformers to extend the life of the transformer shell.
- pole testing being completed.
- underground cable condition assessment and testing, and
- transformer station maintenance on a four-year cycle for the entire station.

5.3.4 System Capability Assessment for REG & DERs

FHI has no forecast costs to accommodate and connect REG facilities, and does not currently have, nor forecasts to have any restricted feeders in their distribution system.

5.3.5 CDM Activities to Address System Needs

CDM activities are aimed at reducing electricity consumption to manage system costs, reduce peak demand and improve affordability for customers.

CDM activity under the provincial 2021-2024 CDM Framework is centralized under the IESO. This has reduced the role of LDC's like FHI in the delivery of CDM. FHI confirms that no costs for dedicated CDM staff to support IESO programs funded under the 2021-2024 CDM Framework are included in this application and that FHI will continue to rely on the IESO CDM programs for this area.

FHI continues to work with its customers in encouraging or supporting energy efficiency, energy generation or storage in their development projects as the belief is that CDM will be integral to the planning process for both temporary solutions (e.g., to manage load growth while infrastructure is being developed) and permanent solutions (e.g., shift demand to eliminate overloads). FHI also continues to support private sector initiatives in this regard by facilitating connections.

FHI considers the impact of conservation programs on the system and in particular its impact to mitigate load growth and consequent distribution system improvements. Conservation programs have historically had a positive impact in mitigating distribution improvements attributed to load growth. At this time, FHI has no plans to seek a partnership with the IESO's Local Initiatives Program, nor any rate-based CDM activities to address system needs.

Beyond this, FHI will monitor the availability of new CDM programs and activities that can be offered to customers.

5.4 CAPITAL EXPENDITURE PLAN

This section summarizes FHI's capital expenditure plan, which has been developed to meet FHI's strategic corporate objectives. The capital expenditure plan was developed based on the planning and AM processes previously described in Section 5.3.

5.4.1 CAPITAL EXPENDITURE SUMMARY

The capital expenditure summary provides a snapshot of FHI's capital and System O&M expenditures over the 2015– 2029 DSP period. For summary purposes, the entire costs of individual projects have been allocated to one of the four OEB investment categories based on the primary driver for the investment:

1. System Access.
2. System Renewal.
3. System Service.
4. General Plant.

The breakdown of OEB-approved amounts from FHI's last DSP versus actuals over the historical period by investment category, is provided in Table 5.4-1 and the forecast costs broken down by investment category are provided in Table 5.4-2. Additional details can also be found in the Chapter 2 Appendices 2-AA and 2-AB. For clarity, due to the circumstances that FHI has deferred their Cost of Service application by a number of years, for the variance analysis, the 'Plan' costs displayed are the OEB DSP approved amounts for 2015-2019, and for 2020-2024 these are the costs approved by FHI's board.

Table 5.4-1: Historical Capital Expenditures and System O&M*

Category	Historical														
	2015			2016			2017			2018			2019		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access															
Gross Capital Spend	322	713	122%	328	582	78%	335	733	119%	341	1,378	304%	348	1,200	245%
Capital Contributions	120	334	178%	120	207	72%	120	372	210%	120	585	388%	120	444	270%
Net Capital Expenditures	202	379	88%	208	376	81%	215	362	69%	221	793	259%	228	756	232%
System Renewal															
Gross Capital Spend	1490	1706	14%	1513	1427	-6%	1539	1644	7%	1565	1565	0%	1592	1768	11%
Capital Contributions															
Net Capital Expenditures	1490	1706	14%	1513	1427	-6%	1539	1644	7%	1565	1565	0%	1592	1768	11%
System Service															
Gross Capital Spend	310	238	-23%	314	38	-88%	316	29	-91%	318	38	-88%	320	30	-91%
Capital Contributions															
Net Capital Expenditures	310	238	-23%	314	38	-88%	316	29	-91%	318	38	-88%	320	30	-91%
General Plant															
Gross Capital Spend	500	653	31%	427	555	30%	826	549	-34%	445	837	88%	415	613	48%
Capital Contributions															
Net Capital Expenditures	500	653	31%	427	555	30%	826	549	-34%	445	837	88%	415	613	48%
Total Expenditure, Gross	**2622**	**3309**	**26%**	**2582**	**2603**	**1%**	**3016**	**2956**	**-2%**	**2669**	**3818**	**43%**	**2675**	**3611**	**35%**
Total Capital Contribution	**120**	**334**	**178 %**	**120**	**207**	**72%**	**120**	**372**	**210%**	**120**	**585**	**388%**	**120**	**444**	**270%**
Total Expenditure, Net	**2502**	**2975**	**19%**	**2462**	**2396**	**-3%**	**2896**	**2584**	**-11%**	**2549**	**3233**	**27%**	**2555**	**3167**	**24%**
System O&M	2104	2137	2%	2085	2102	1%	2124	2219	5%	2171	2564	18%	2591	2368	-9%

This table is being continued on the next page to accommodate information for the remaining historical years.

Category	Historical												Bridge Year		
	2020			2021			2022			2023			2024		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access															
Gross Capital Spend	$721	$1,086	51%	$712	$1,091	53%	$863	$1,013	17%	$805	$1186	47%	$1212		
Capital Contributions	$200	$466	133%	$200	$481	141 %	$200	$343	72%	$400	$447	12%	$219		
Net Capital Expenditures	$521	$620	19%	$512	$610	19%	$663	$670	1%	$405	$740	83%	$993		
System Renewal															
Gross Capital Spend	1935	1627	-16%	1866	2027	9%	2044	2222	9%	2469	2114	-14%	2236		
Capital Contributions															
Net Capital Expenditures	1935	1627	-16%	1866	2027	9%	2044	2222	9%	2469	2114	-14%	2236		
System Service															
Gross Capital Spend	55	51	-7%	55	6	-90%	55	34	-38%	75	110	47%	77		
Capital Contributions															
Net Capital Expenditures	55	51	-7%	55	6	-90%	55	34	-38%	75	110	47%	77		
General Plant															
Gross Capital Spend	973	460	-53%	1040	876	-16%	969	907	-6%	1665	1927	16%	4193		
Capital Contributions															
Net Capital Expenditures	973	460	-53%	1040	876	-16%	969	907	-6%	1665	1927	16%	4193		
Total Expenditure, Gross	**3683**	**3224**	**-12%**	**3673**	**4000**	**9%**	**3931**	**4175**	**6%**	**5014**	**5337**	**6%**	**7717**	**$0.00**	**-100%**
Total Capital Contribution	**200**	**466**	**133%**	**200**	**481**	**141 %**	**200**	**343**	**72%**	**400**	**447**	**12%**	**219**	**$0.00**	**-100%**
Total Expenditure, Net	**3483**	**2758**	**-21%**	**3473**	**3519**	**1%**	**3731**	**3832**	**3%**	**4614**	**4890**	**6%**	**7498**	**$0.00**	**-100%**
System O&M	2678	2472	-8%	2642	2357	-11%	2845	2817	-1%	3087	2945	-5%	3249		

Table 5.4-2: Forecast Capital Expenditures and System O&M

Category	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
	$ '000	**$ '000**	**$ '000**	**$ '000**	**$ '000**
System Access					
Gross Capital Spend	2399	2463	2531	2601	1743
Capital Contributions	327	332	338	345	352
Net Capital Expenditures	2072	2132	2193	2256	1391
System Renewal					
Gross Capital Spend	3101	3351	3421	3505	3590
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	3101	3351	3421	3505	3590
System Service					
Gross Capital Spend	359	374	384	397	409
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	359	374	384	397	409
General Plant					
Gross Capital Spend	1878	1299	1262	1274	1585
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	1878	1299	1262	1274	1585
Total Expenditure, Gross	**7737**	**7487**	**7598**	**7777**	**7327**
Total Capital Contribution	**327**	**332**	**338**	**345**	**352**
Total Expenditure, Net	**7409**	**7155**	**7260**	**7432**	**6975**
System O&M	3515	3620	3729	3841	3956

5.4.1.1 Plan vs Actual Variances for the Historical Period

Assessing and understanding the variances is an important step for FHI to promote continuous improvements in its estimation and budgeting process. Excluding projects identified as mandatory, FHI creates each project budget based on preliminary designs and historical costs for planning its programs annually. Once detailed designs are complete and ready to be issued for construction, the project estimate is revised, if necessary, to reflect any changes in the design. The revised estimate is used to track against the actual costs, which are reviewed monthly.

Customer demand projects are budgeted using averages from previous years, as well as any known projects based on consultations. These projects are mostly unplanned and tracked in real-time to balance the total annual budget with other discretionary projects (i.e., FHI may take action to reduce system renewal projects to ensure the total annual actual expenditures remain in line with the total annual proposed budget). Likewise, if the actual budget of System Access projects is less than the forecasted budget, FHI may plan to allocate the budget to other project categories where appropriate to maintain consistent annual expenditures and address other critical investments.

The breakdowns below are provided by each category for each year. Variances that exceed $80,000 (the materiality threshold) are explained and are in reference to Table 5.4-1.

Table 5.4-3: Variance Explanations - 2015 Planned Versus Actuals

Category	2015 Plan.	2015 Act.	2015 Var.	Variance Explanation
	$ '000			
System Access, Net	202	379	177	In last DSP metering and all transformer purchases were budgeted under SR. However, FHI has made a change and now tracks actuals for all meter costs in the System Access category, as they are to facilitate customer connections, or meet regulatory requirements for reverification. Actuals for transformer purchases that were for customer connections have also been moved into System Access.
System Renewal, Net	1,490	1,706	216	In last DSP FHI had switchgear replacement and Re-insulating costs allocated to System Service. However, as these projects are more System Renewal related, the actuals were allocated to System Renewal.
System Service, Net	310	238	-72	N/A
General Plant, Net	500	653	153	FHI increased spending of building renovations and refurbishments within its buildings to accommodate additional staff and remedy existing issues. Furthermore, some IT projects ended up costing more than originally planned primarily due to creation and setup of a website through London Hydro and corresponding integration costs with FHI's CIS provider. There was also unexcepted costs to a contractor for domain and email server upgrade due to an unplanned staffing change.
Total Expenditure, Net	2,502	2,975	473	See explanations above, and in Capital Contributions.
Capital Contributions	120	334	214	FHI experienced significantly more customer driven work than originally budgeted over the entire historical period, which lead to significantly more capital contributions as well. This was mainly a combination of subdivision and service work.
Total Expenditure, Gross	2,622	3,309	687	See explanations above.
System O&M	2,104	2,137	33	N/A

Table 5.4-4: Variance Explanations - 2016 Planned Versus Actuals

Category	2016 Plan. ($ '000)	2016 Act. ($ '000)	2016 Var. ($ '000)	Variance Explanation
System Access, Net	208	376	168	In last DSP metering and all transformer purchases were budgeted under SR. However, FHI has made a change and now tracks actuals for all meter costs in the System Access category, as they are to facilitate customer connections, or meet regulatory requirements for reverification. Actuals for transformer purchases that were for customer connections have also been moved into System Access.
System Renewal, Net	1,513	1,427	-86	FHI deferred a planned overhead project from 2016 to 2017 which resulted in an overall decrease in the System Renewal costs.
System Service, Net	314	38	-276	In last DSP FHI had switchgear replacement and Re-insulating costs allocated to System Service. However, as these projects are more System Renewal related, the actuals were allocated to System Renewal. This resulted in a decrease in System Service costs for 2016.
General Plant, Net	427	555	128	FHI required additional investment to update its IT system to introduce new functionality, and implement new locator software. Additionally, FHI had to invest in a new travel restraint system to comply with TSSA codes to allow tradespeople to work in its roof of its buildings, as well as unplanned HVAC work.
Total Expenditure, Net	2,462	2,396	-66	N/A
Capital Contributions	120	207	87	FHI experienced significantly more customer driven work than originally budgeted over the entire historical period, which lead to significantly more capital contributions as well. This was mainly a combination of subdivision and service work.
Total Expenditure, Gross	2,582	2,603	21	N/A
System O&M	2,085	2,102	17	N/A

Table 5.4-5: Variance Explanations - 2017 Planned Versus Actuals

Category	2017 Plan. ($ '000)	2017 Act. ($ '000)	2017 Var. ($ '000)	Variance Explanations
System Access, Net	215	362	147	In last DSP metering and all transformer purchases for customer driven projects were budgeted under SR. However, FHI has made a change and now tracks actuals for all meter costs in the System Access category, as they are to facilitate customer connections, or meet regulatory requirements for reverification. Actuals for transformer purchases that were for customer connections have also been moved into System Access.
System Renewal, Net	1539	1644	105	FHI increased its transformer purchases due to large underground rebuild projects requiring higher than typical transformer replacements.
System Service, Net	316	29	-287	In last DSP FHI had switchgear replacement and Re-insulating costs allocated to System Service. However, as these projects are more System Renewal related, the actuals were allocated to System Renewal.
General Plant, Net	826	549	-277	FHI purchased placed an order for a Bucket truck in 2017, however the delivery date quoted was 2018, and therefore the cost was deferred to 2018.
Total Expenditure, Net	2896	2584	-312	Overall net cost was underspent due to larger capital contributions than originally forecast, as well as a reduction in System Renewal and General Plant costs
Capital Contributions	120	372	252	FHI experienced significantly more customer driven work than originally budgeted over the entire historical period, which lead to significantly more capital contributions as well. This was mainly a combination of subdivision and service work. This year also had large generation projects that contributed to the amount.
Total Expenditure, Gross	3016	2956	-60	N/A
System O&M	2124	2220	96	Increases were mainly due to an overlap in metering staff for succession planning for an upcoming retirement.

Table 5.4-6: Variance Explanations - 2018 Planned Versus Actuals

Category	2018 Plan. ($ '000)	2018 Act. ($ '000)	2018 Var. ($ '000)	Variance Explanations
System Access, Net	221	793	572	Actuals for transformer purchases that were for customer connections were moved from System Renewal to System Access. Metering was also higher than normal as 3 wholesale primary metering unit upgrades were required to be compliant with IESO regulations.
System Renewal, Net	1,565	1,565	0	N/A
System Service, Net	318	38	-280	In last DSP FHI had switchgear replacement and Re-insulating costs allocated to System Service. However, as these projects are more System Renewal related, the actuals were allocated to System Renewal.
General Plant, Net	445	837	392	FHI placed an order for a Bucket truck in 2017, however the delivery date quoted was 2018, and therefore the cost was deferred to 2018.
Total Expenditure, Net	2,549	3,232	683	Overall net costs were higher than forecast due to System Access and General Plant cost increases.
Capital Contributions	120	585	465	FHI experienced significantly more customer driven work than originally budgeted over the entire historical period, which lead to significantly more capital contributions as well. This was mainly a combination of subdivision and service work. This year also had large generation projects that contributed to the amount.
Total Expenditure, Gross	2,669	3,818	1,149	Overall gross costs were higher than forecast due to System Access and General Plant cost increases.
System O&M	2,171	2,564	393	Increases in costs due to insurance claim, maintenance due to inspection results, new staffing position created. Maintenance labour in both overhead and underground also increased.

Table 5.4-7: Variance Explanations - 2019 Planned Versus Actuals

Category	2019 Plan. ($ '000)	2019 Act. ($ '000)	2019 Var. ($ '000)	Variance Explanations
System Access, Net	228	756	528	Actuals for transformer purchases that were for customer connections were moved from System Renewal to System Access Metering was higher than average because this was our first year of smart meter reverifications required. Extra meters were purchased to replace those needed to be pulled for reverification.
System Renewal, Net	1,592	1,768	176	In last DSP FHI had switchgear replacement and Re-insulating costs allocated to System Service. However, as these projects are more System Renewal related, the actuals were allocated to System Renewal. In 2019, 5 dead front switchgears were replaced/removed instead of 3 in original plan. This was in response to increased failures and outages being seen on air insulated switchgears to quicken the removal off all from the distribution system.
System Service, Net	320	30	-290	In last DSP FHI had switchgear replacement and Re-insulating costs allocated to System Service. However, as these projects are more System Renewal related, the actuals were allocated to System Renewal.
General Plant, Net	415	613	198	An extra vehicle was purchased for a new locator that was brought on for the delivery of the fiber to the home program. Increased spend was incurred for OEB Cybersecurity projects which were not part of the DSP planned spend in 2019.
Total Expenditure, Net	2,555	3,168	613	Increase in overall spend was due to increases in System Access, System Renewal and General Plant
Capital Contributions	120	444	324	FHI experienced significantly more customer driven work than originally budgeted over the entire historical period, which lead to significantly more capital contributions as well. This was mainly a combination of subdivision and service work. This year also had large generation projects that contributed to the amount.
Total Expenditure, Gross	2,675	3,611	936	See explanations above.
System O&M	2,591	2,368	-223	Costs from 2018 were recovered from insurance claim noted above. Additionally, there were two staff vacancies for part of year.

Table 5.4-8: Variance Explanations - 2020 Planned Versus Actuals

Category	2020 Plan. ($ '000)	2020 Act. ($ '000)	2020 Var. ($ '000)	Variance Explanations
System Access, Net	521	620	99	Actuals for transformer purchases that were for customer connections were moved from System Renewal to System Access
System Renewal, Net	1,935	1,627	-308	Due to Covid-19, some projects were deferred.
System Service, Net	55	51	-4	N/A
General Plant, Net	973	460	-513	Due to Covid-19, some projects were deferred.
Total Expenditure, Net	3,483	2,759	-724	Due to Covid-19, some projects were deferred.
Capital Contributions	200	466	266	Increases in System Access projects led to increase in capital contributions
Total Expenditure, Gross	3,683	3,224	-459	Due to Covid-19, some projects were deferred.
System O&M	2,678	2,473	-205	Due to Covid-19, some programs and expenses were deferred or not needed.

Table 5.4-9: Variance Explanations - 2021 Planned Versus Actuals

Category	2021 Plan. ($ '000)	2021 Act. ($ '000)	2021 Var. ($ '000)	Variance Explanations
System Access, Net	512	610	98	Actuals for transformer purchases that were for customer connections were moved from System Renewal to System Access
System Renewal, Net	1,866	2,027	161	Some System Renewal Projects deferred from 2020, due to Covid, were carried out in 2021.
System Service, Net	55	6	-49	N/A
General Plant, Net	1,040	876	-164	Due to the impacts of Covid on lead times for new vehicles, a new vehicle delivery and subsequent payment was deferred.
Total Expenditure, Net	3,473	3,519	46	N/A
Capital Contributions	200	481	281	Coming out of COVID there was a significant amount of subdivision work due to economic conditions. This led to an increase in capital contributions for this type of work.
Total Expenditure, Gross	3,673	4,000	327	See explanation above
System O&M	2,642	2,357	-286	Staff vacancies for the majority of the year in two areas were mainly responsible for shortfall in O&M costs.

Table 5.4-10: Variance Explanations - 2022 Planned Versus Budget

Category	2022			Variance Explanations
	Plan.	Act.	Var.	
	$ '000			
System Access, Net	663	669	6	N/A
System Renewal, Net	2,044	2,222	178	In 2022 there were two overhead unbudgeted carry over projects. One planned underground job experienced cost overrun due to material cost increase for the project, which had a significant impact on the total cost of the project.
System Service, Net	55	34	-21	N/A
General Plant, Net	969	907	-62	N/A
Total Expenditure, Net	3,731	3,832	101	See explanation above.
Capital Contributions	200	343	143	Many subdivisions were started in 2021, but houses were not yet built. Significant amount of new service connections in these subdivisions were required in 2022.
Total Expenditure, Gross	3,931	4,175	244	See explanation above.
System O&M	2,845	2,817	-28	N/A

Table 5.4-11: Variance Explanations - 2023 Planned Versus Budget

Category	2023			Variance Explanations
	Plan.	Act.	Var.	
	$ '000			
System Access, Net	405	740	335	Actuals for transformers for customer connections were moved from System Renewal to System Access. Shipment for MIST meters that was supposed to come in 2022, was delivered in 2023. One additional subdivision was completed compared to budget.
System Renewal, Net	2,469	2,114	-355	Customer driven transformer purchases were moved to System Access, switchgear that were purchased and slated for delivery in 2023 were delayed due to manufacturing lead times and will be delivered in 2024 instead.
System Service, Net	75	110	35	N/A
General Plant, Net	1,665	1,927	262	CIS software replacement project incurred additional capital costs in 2023, which was the result of pulling some of the project work and costs forward from 2024. Building renovation had scope changes during construction based on site conditions and consultation with contractor. Some design costs for final two phases of renovation were pulled into 2023 to receive required permits and design drawings to meet construction timeline.

Total Expenditure, Net	5,014	5,337	323	See explanations above
Capital Contributions	400	447	47	N/A
Total Expenditure, Gross	4,614	4,890	276	See explanations above
System O&M	3,087	2,945	-142	Staff vacancies in three areas for portions of the year were mainly responsible for the shortfall in O&M costs.

As 2024 is still ongoing, no variance analysis for 2024 has been carried out.

5.4.1.2 Forecast Expenditures

The following table summarizes FHI's planned capital expenditures, by investment category, over the forecast period.

Table 5.4-12: Forecast Capital Expenditure by OEB Investment Category

Category	Forecast					Total	Percent of Total (Gross)
	2025	2026	2027	2028	2029		
	$ '000						
System Access	2,399	2,463	2,531	2,601	1,743	11,737	31%
System Renewal	3,101	3,351	3,421	3,505	3,590	16,968	45%
System Service	359	374	384	397	409	1,923	5%
General Plant	1,878	1,299	1,262	1,274	1,585	7,298	19%
Capital Contributions	327	332	338	345	352	1,694	N/A
Total Expenditure, Gross	**7,737**	**7,487**	**7,598**	**7,777**	**7,327**	**37,926**	**N/A**
Total Expenditure, Net	**7,409**	**7,155**	**7,260**	**7,432**	**6,975**	**36,231**	**N/A**

System Renewal is the largest planned capital expenditure over the 2025-2029 forecast period representing 45% of overall gross spending, which is followed by System Access investments at 31%, then General Plant at 19% and System Service at 5%.

The following subsections describe the planned capital expenditures in each investment category in more detail.

5.4.1.2.1 System Access

Typically, the expenditures within the System Access category are largely driven by customer service requests for new connections and/or service upgrades, and mandated service obligations. The timing of these investments is driven by the needs of external parties and are considered mandatory. Over the forecast period, FHI also plans to invest in an AMI 2.0 network to replace the existing AMI infrastructure. This will be one of FHI's largest investments. The timing of this investment is driven by the age and performance history of the existing AMI infrastructure, as well as the enhancements that have been made in what LDC's and customers can receive from an AMI 2.0 solution. Further detail on the AMI 2.0 project is captured in its corresponding material investment narrative in Appendix A. A summary of the investments in System Access are captured in the following table.

Table 5.4-13: Forecast Net System Access Expenditures

Category	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000						
New Services	375	378	371	383	386	1,893	19%
New Subdivisions	407	312	335	338	351	1,743	17%
Other Recoverable Work	189	110	113	117	120	649	6%
AMI 2.0	1,316	1,540	1,585	1,631	702	6,774	67%
Metering	112	123	127	132	184	678	7%
Capital Contributions	-327	-332	-338	-345	-352	-1,694	-17%
Total Expenditure, Net	**2,072**	**2,132**	**2,193**	**2,256**	**1,390**	**10,043**	**100%**

System Access is the second largest planned capital expenditure over the 2025–2029 forecast period representing 31% of overall gross spending. Other than the AMI 2.0 redeployment costs, the proposed expenditure level is estimated based on the historic spending levels and specific information available from developers, customers and other third parties about planned projects at the time of preparation of this DSP.

AMI 2.0 (67%)

AMI 2.0 accounts for the largest portion of the system access expenditures over the forecast period. The Advanced Metering Infrastructure 2.0 program (AMI 2.0) is a multi-year investment to replace Festival's legacy AMI 1.0 that was installed and commissioned in 2010 and 2011. The anticipated service life of the AMI 1.0 meters was initially thought to be approximately 10 years according to the Kinectrics study completed for the OEB, with a maximum useful life of 15 years. The life of this asset class is being impacted by issues FHI is currently seeing in its field devices. Due to various hardware component issues, FHI's current read rate is approximately 94% and steadily declining. Although FHI actively replaces hundreds of meters that require manual reads each year, there are still several hundred meters that need to be read manually each month, with the number of failures continuing to increase each year. A new AMI system will allow FHI to replace its current aging and failing infrastructure, as well as take advantage of modern AMI capabilities to pursue both operational and customer facing benefits in the years to come.

The AMI 2.0 project consists of replacing both the software and hardware components of FHI's existing AMI system. This investment is expected to maintain billing accuracy, optimize network communications, reduce manual meter reads, provide faster response times to disconnection/reconnection requests, provide more accurate outage information, and provide customers with a modern AMI platform to meet foreseeable customer needs over the lifetime of the assets. FHI's AMI is critical to ensure reliable billing for its approximately 23,000 customers, and to maintain regulatory compliance. The AMI 2.0 program spans the pre-test, test, and post-test periods and is organized in three sequential phases: Pre-Deployment RFP (2023); Planning, Head End System, and Pilot (2024-2025); and Mass Meter Deployment (2025-2029). The program will employ the newest generation of equipment to meet current needs and provide a platform to address foreseeable future needs over the investment's service life.

FHI forecasts capital expenditures of approximately $6.8M for this investment in the 2025-2029 period. The AMI 1.0 system comprises approximately 23,000 meters, of which approximately 19,100 (or 85%) are between 11-15 years old and will soon reach or have already reached the end of their expected 15-year service life and have been identified as being in poor or very poor condition by the ACA. The physical deterioration of meter components and meter failures pose impacts and critical risks to FHI affecting various elements of its business including:

- Reduced billing reliability and resulting customer dissatisfaction from estimated billing and billing corrections.
- Increasing costs associated with reactive individual meter replacements as a result of failed meters.
- Higher labour costs for unplanned individual failed meter replacement relative to mass meter replacement.
- Higher contractor costs for manually reading non-communicating meters monthly.
- Replacement of failed meters with obsolete technology and the associated lost opportunities for future benefits that address foreseeable needs, and
- Regulatory noncompliance.

Since FHI installed the AMI 1.0 system, it has had to return approximately 11,000 meters for various issues. The main issue being that the connector in the communications board was built with a defect causing the large number of non-communicating meters. FHI also has approximately 1,600 additional meters that could be returned for a return material authorization (RMA) that are either still in the field and being manually read each month or have been replaced to keep the number of meters reads each month to a manageable level.

With each shipment of meters returned, the percentage of meters that are unable to be repaired and are subsequently retired from service is increasing. Between 2018-2020 approximately 8-10% of meters returned were too costly to repair or unrepairable and were subsequently retired from service. This has increased to approximately 23-25% of meters returned from 2021-2023.

The meters that FHI has historically purchased have been deemed end of life by the manufacturer due to parts obsolescence, and at the time of writing this DSP the manufacturers recommended replacement meter does not have MC certification, putting FHI in an uncertain situation for future procurement and availability of meters to serve their customers.

The new AMI system also provides numerous benefits to both the utility and the customer. With edge computing, there are applications that allow customers to better understand consumption patterns and load disaggregation. FHI can also leverage this information to better understand load characteristics of consumers, proactively monitor transformers and their loading, understand EV/DER patterns, and complete remote disconnects. It can also improve power quality and monitoring so that when there are issues, FHI can use these meters to obtain data for root cause analysis rather than having to install a separate piece of equipment to obtain similar data. The new system provides flexibility with multi-tenancy, allowing FHI the potential to partner with others for shared services within the headend system for cost saving opportunities.

After completion of the project, it is expected to put downward pressure on O&M costs in the following areas:

- Significantly less manual meter reads each month. Currently FHI performs over 700 manual reads a month, with the expectation, once AMI 2.0 is fully deployed that this would decrease substantially with a more reliable communication module.
- The AMI 2.0 solution also includes a 100% coverage model to be able to read all meters with the proposed installation.
- Less truck rolls for certain disconnects/reconnects as it can be remotely done.
- Less collectors for AMI data, meaning reduced monthly costs for backhauling meter data.
- Significantly reduced meter reverifications as none are needed in first 10 years of the meter being installed.
- Significantly reduced RMA’s and associated costs to replace meters which are non-communicating or have other defective components.

New Services (19%)

New Services represents the next largest driver within this category. This involves fulfilling customer requests for new services or upgrade of existing services. Since the projected growth in FHI’s service territory over the forecast period remains stable compared to historical numbers, services are projected to be levelized over the forecast period growing in accordance with inflation.

New Subdivisions (17%)

Subdivision costs in this category involve designing and constructing the civil and electrical infrastructure to accommodate these connections. FHI is aware of a few subdivision developments, expected to begin in 2025.

- **Thames West Phase 2**, a subdivision development with an anticipated build-out of 45 homes.

- **520/525 Orr**, a subdivision development with an anticipated build-out of 192 homes.
- **Thames Crest Phase 2B**, a subdivision development with an anticipated build-out of 63 homes.

Given the undeveloped subdivision land left that FHI expects to service, subdivision costs are expected to remain at a levelized state over the rest of the forecast period.

Metering (7%)

At 7%, the metering category is related to the supply, installation and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for customers connected to FHI's distribution system. The investment in this forecast period is lower than historical due to the AMI 2.0 deployment above. The only costs associated with metering in the forecast period will be for the purchase of metering and related metering instrument transformers required for new/upgraded customer connections in legacy AMI 1.0 areas, those required for reverifications, and the removal and replacement of legacy oil filled primary metering units.

Other Recoverable Work (6%)

At 6%, Other Recoverable work is the smallest investment area within this category. These projects involve road authority works where OH and/or UG lines are relocated to accommodate road widening projects driven by municipalities. It also involves any recoverable expansions or extensions to the distribution system that may be needed for customer driven requests. Over the forecast period this is based on historical averages other than where specific projects are known at the time of creating this DSP. Currently FHI is aware of one known project that will proceed in the forecast period:

- **Highway 83 Road Relocation- Dashwood Community**. This will require the replacement and relocation of 17 wood poles and is scheduled to take place in 2025.

Since the level of investment required under this investment category for the preceding areas (New Services, Subdivision, Other Recoverable work) is largely dependent on third-party requests, the level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of requests received.

5.4.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. As outlined in Section 5.3.1, a key input into determining its system renewal projects is the ACA results. These results are a key starting point for FHI to use to determine which investments are required over the DSP period. Where an HI has been created, the asset information is automatically fed into the planning process.

Typically, any asset(s) that are identified as poor or very poor are inevitably considered for investment. However, this does not mean that FHI takes all assets in these categories and puts them straight into its investment plan. As outlined earlier, various other factors are taken into consideration as well, along with an aim at levelized and sustainable investments in these areas. Investments in System Renewal are captured in the following table.

Table 5.4-14: Forecast Net System Renewal Expenditures

Category	2025	2026	2027	2028	2029	Total	Percent of Total
	$ '000						
Animal Mitigation	75	75	75	75	75	375	2%
Overhead Pole-line Replacement	848	1082	1059	1055	1110	5154	31%
Transformer Station Renewal	275	273	279	289	298	1414	8%
Unplanned Small Replacements	349	356	363	370	378	1816	11%
System Re-establishment	122	90	111	113	115	551	3%
Underground Renewal	1188	1231	1534	1602	1614	7169	42%
Switchgear Replacement	244	244	0	-	-	488	3%
Total Expenditure, Net	**3101**	**3351**	**3421**	**3504**	**3590**	**16967**	**100%**

System Renewal is the largest planned capital expenditure over the 2025–2029 forecast period representing 45% of overall spending. The level of investment required over the forecast period was determined using FHI's AM process, which is described in detail in Section 5.3.1, and the ACA was used to assist in prioritizing investments in asset classes. Major programs within the System Renewal category include the renewal and replacement of deteriorated assets at the end of their service life and identified as being in poor or very poor condition, including poles, transformers, underground cable, transformer station assets, and switchgear. Unplanned System Renewal projects are also budgeted each year to allow for replacement of electrical infrastructure damaged by inclement weather, vehicle accidents or those identified through inspections or testing as needing immediate replacement.

Overall, the observed increase in System Renewal spending over the forecast period is driven by two major factors. One is the increased cost pressures that the industry has witnessed. Since 2021, it is roughly 24% more expensive to replace a pole, and 36% more expensive to install a section of underground cable. This puts an increased cost in this category to just maintain the replacement levels that FHI has historically completed. As FHI's labour and trucking costs have only increased by 8% since 2021, the majority of these cost increases are driven by materials, of which FHI has little control over. The second factor is the corporate objective to maintain or slightly improve the reliability of the distribution system. The amount of investment planned over the forecast period, eliminates the remaining live front switchgear, which FHI has seen asset failures with historically. It also maintains the overall demographics and asset mix of both poles and underground cable in FHI's distribution system, allowing for a sustainable investment plan.

Additionally, as noted in Section 5.2.2.1, customers identified "providing electricity that is "reliable" and "safe" with fewer outages, and focusing on public and employee safety as their top priorities. In subsequent surveys, approximately 70% of customers agreed that the proposed level of spending for System Renewal expenditures was appropriate.

The proposed level of System Renewal investment over the forecast period will allow FHI to prioritize assets for replacement, allowing FHI to manage the system's health and performance more effectively in order to continue delivering the level and quality of service that customers have come to expect.

The system renewal programs are summarized below:

Underground Renewal Program (42%)

This investment category includes the replacement of primary underground cable, padmount transformers and associated equipment that are past their typical useful life and have been deemed in need of replacement due to being in poor or very poor condition and having a high risk of failure as identified through the ACA. This program also has many other benefits as it installs ducting where needed, increases transformation where appropriate to ensure adequate transformation for expected future system needs, provides looped feeds where practical and replaces XLPE cable with TRXPLE to provide an enhanced quality of conductor with a longer expected life.

Overhead Pole-line Replacement Program (31%)

This investment category includes the replacement of pole lines and associated equipment that have been tested or deemed in need of replacement due to having a high risk of failure. ACA results are used to help inform which poles may need replacing in the forecast period. Pole size, conductor size, framing, and transformer size are all optimized as well when completing these projects to ensure future system needs are accounted for. In instances where the associated hardware (conductor, insulators, transformers) is suitable for re-use, FHI strives to do so.

Unplanned and Small Capital Replacements (11%)

This investment category includes unplanned capital jobs that arise due to asset failure, customer complaints or compliance issues. This program also deals with single pole replacements due to asset condition, where a larger rebuild is not warranted, as well as storm damage and repairs that are capital in nature including pole, transformer, conductor and switch replacements.

Transformer Station Renewal Program (8%)

This investment category includes replacement of transformer station assets based on asset history and performance, ACA results and other independent study results and recommendations. Examples include station battery and charger renewals, as well as replacement or purchase of spare protection and control assets that are obsolete or no longer supported, or critical assets with a history of failure.

System Re-establishment (3%)

This investment category is for the installation of new pole lines or underground conductor to facilitate rebuilds in areas with depreciated infrastructure, but where ties do not currently exist to practically replace these assets without requiring multiple customer interruptions or significant temporary installations, or where rebuilds of the existing assets are not feasible. When new ties are created, this category also offers the benefit of increasing the operational flexibility of FHI's distribution system. On average this is the addition of one three-phase pole line, or one three-phase underground circuit to areas where only radial installations currently exist. When complete, this category will also allow for additional switching points for load transfers, or during outage events to reduce restoration time.

Switchgear Replacement Program (3%):

This investment category includes completing the replacement of live front, air insulated distribution system switchgears based on asset failure history, results from the annual visual inspection, infrared program, and ACA results.

Animal Mitigation (2%):

This investment category is to install animal guarding, as well as replace insulators and steel brackets with larger insulators and fiber glass brackets in areas with concrete poles where animal contacts have been regularly seen as well as any areas noted during annual OH inspections.

5.4.1.2.3 System Service

System Service investments are modifications to FHI's distribution system to ensure the distribution system continues to meet FHI's operational objectives (system efficiency, DER integration, grid flexibility, etc.) while addressing anticipated future customer electricity service requirements. Investments in system service are captured in the following table.

Table 5.4-15: Forecast Net System Service Expenditures

Category	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ ‘000						
Distribution Automation	142	150	156	162	169	779	41%
4kV Voltage Conversion	217	224	228	235	240	1,144	59%
Total Expenditure, Net	**359**	**374**	**384**	**397**	**409**	**1,923**	**100%**

System service investments represent 5% of FHI’s overall budgeted net capital expenditures over the forecast period. These programs are summarized below:

4kV Voltage Conversion (59%):

This investment category is for the upgrade of FHI’s last 4kV community to 27.6kV, which will allow FHI to remove from service their final two 4kV substations, eliminating the need to rebuild these substations, both have which have assets that are past or at their typical useful life, and that have been identified as being in poor condition. This category includes replacement of approximately 900m of distribution system assets (poles or underground cable) yearly, the majority of which the ACA has identified as being in poor or very poor condition. These assets will be rebuilt to 27.6kV standards and with dual voltage transformers to accommodate the future voltage conversion without needing to replace or strand these assets. In 2019, during a substation condition assessment, FHI received a third-party estimate of $1.6M to rebuild each substation (Appendix M). Accounting for actual inflation since 2019 and using the Bank of Canada’s 2% target inflation rate in forecast years, FHI completed a net present value calculation. This put the total cost to finish converting the community at $1.77M, while the cost to rebuild both stations was $3.32M (in 2028 and 2033) using the 2019 estimate. This made voltage conversion the lowest cost option and it will allow FHI to decommission two older municipal substations, removing the need to invest in complete station upgrades of all electrical equipment at both sites. It is likely that the NPV would favour even more heavily towards voltage conversion, if the significant increase in the cost of material, labour and construction of a new substation is taken into account.

Distribution Automation (41%):

This investment category is for the addition of remote fault indicators, reclosers/smart switches and the equipment and time necessary to design, configure and install them in FHI’s distribution system. This includes the addition of, on average, one set of remote fault indicators and one recloser per year. The fault indicators will be placed at the demarcation boundaries where FHI is an embedded distributor to better determine, during outage events, if the issue is in FHI’s service area or upstream, or in strategic locations within FHI’s service area. Reclosers will be placed between normal open points between feeders and at strategic points within feeders to better sectionalize customers during outage and switching events. These modernization initiatives are being done to improve reliability, restoration times, load transfer capabilities and limit truck rolls.

5.4.1.2.4 General Plant

Expenditures in the General Plant category are driven by the need to modify, replace, or add to assets that are not part of the distribution system but support FHI's 24/7 operations. The items within this category are important and contribute to the safe and reliable operation of a distribution system. If General Plant investments are ignored or deprioritized this could lead to future operational risks or increased investments in future years. FHI's planned capital investments in General Plant are captured in the table below.

Table 5.4-16: Forecast Net General Plant Expenditures

Category	2025	2026	2027	2028	2029	Total ($ '000)	Percent of Total
Fleet	125	575	220	478	598	1,996	27%
ERP System	875	0	0	0	0	875	12%
Building & Equipment	505	315	535	269	440	2,064	28%
IT Software	30	72	92	95	99	388	5%
IT Hardware	297	289	367	381	397	1,731	24%
Tools	46	47	49	50	51	243	3%
Total Expenditure, Net	**1,878**	**1,298**	**1,263**	**1,273**	**1,585**	**7,297**	**100%**

General plant investments represent 19% of FHI's overall budgeted net capital expenditures over the forecast period.

The proposed expenditure level is based on the outputs of the ACA, projects required due to technological obsolescence or lack of vendor support, the risk of not being in regulatory compliance, as well as recommendations from third party assessments and reports.

The budget is allocated amongst the following six programs:

<u>Buildings and Equipment (28%)</u>

This category comprises of general investments and improvements to building and equipment at FHI's offices. Project identification is based on asset failures as well as a third party building condition assessment that was completed. Subsequent inspections and reports are also completed to ensure building assets are replaced at the appropriate time. This program includes the replacement of the administrative building roof in 2025 and a portion of the service center building roof in 2026, which was identified as a need in the latest building condition assessment completed in 2019 and further reinforced by subsequent inspections of the roof in 2023.

Fleet (27%)

This investment category includes investments in FHI's passenger vehicles, and bucket trucks. FHI plans to alternate the replacement years of passenger vehicles and trailers with bucket trucks to smooth spending as much as possible. However, given the current state of FHI's fleet based on the ACA results, investment in new vehicles is needed each year. These include new single buckets, RBD's, trucks/vans, and forklift.

IT Hardware (24%)

Investments in this category include general upgrade and replacement of end of life hardware assets, as well as physical hardware to enable cybersecurity enhancements. This includes updates to both the IT and OT networks.

ERP (12%)

Investments in this category are specifically for FHI's upgrade and replacement of their existing ERP system. This system is functionally outdated and support from the vendor is no longer adequate. Upgrading to this new platform is expected to occur over 2024 and 2025. Additional information can be found in the corresponding material investment narrative in Appendix A.

IT Software (5%)

Investments in this category include general upgrade and replacement of end of life software assets, other business process efficiencies and adding modules to existing software solutions.

Tools, Shop and Garage Equipment (3%)

This category includes investments in various tools and small equipment necessary to carry out the 24/7 operations and maintenance activities of the Engineering, Operations, and Stores departments.

Green Button Update

With the issuance of Ontario Regulation 633/21 under the Electricity Act, 1998 (Green Button Regulation), the OEB requires distributors (electricity and natural gas) to make available energy usage and account information identified in the North American Energy Standards Board (NAESB) Energy Service Provider Interface (ESPI) standard that the distributor currently collects and make available to customers in the normal course of the distributor's operation. Energy usage information must be provided for an interval of one hour or less and at least 24 months of usage data must be available (unless the customer has not held an account with the distributor for that long).

Green Button is part of the Ontario government's commitment to give consumers more choice when it comes to their energy use and will enable easy, quick, and secure access to their consumption data through smartphone or computer applications so they can find customized tips to reduce energy use or switch electricity price plans to save money. FHI has met all the requirements of this program and is Green Button Certified by the Green Button Alliance and met the regulatory requirement of November 1, 2023.

5.4.1.2.5 Investments with Project Lifecycle Greater than One Year
For capital projects spanning multiple years, costs remain under construction work-in-progress (WIP) until the capital project is in service. Therefore, capitalization will only occur at the end of the project once it is in service. One example of a multi-year capital project proposed over the forecast period includes the new ERP system project. In this case, although the project costs span multiple years, costs will remain under WIP throughout the execution of the project and will only be capitalized once in service.

5.4.1.3 Comparison of Forecast and Historical Expenditures
A comparison of FHI's capital expenditures in the DSP's forecast period as compared to the historical period is provided in the following subsections.

5.4.1.3.1 Overall Capital Expenditures
The overall net capital expenditure trends over the 2015 to 2029 period are shown in Figure 5.4-1. The average overall capital expenditures forecast is approximately 95% higher than the historical plus bridge-year average. This is largely a result of the AMI 2.0 deployment, increased spend related to fleet replacements, and increased System Renewal and System Service investments to maintain the overall condition and reliability of FHI's system.

When comparing overall net expenditures over the historical and forecast periods, it is important to compare expenditures on a like-for-like basis as much as possible. Comparing from 2021 to 2024, the average overall capital expenditures forecast drops to a 47% increase. This better compares the forecast costs of labour and materials with what has been seen in the recent historical period as materials in many cases have increased by at least 40% since 2021, with labour and contractor costs also increasing. The AMI 2.0 deployment is not considered a part of FHI's normal capital expenditures. When it is removed, this drops further to an 19% increase.

As detailed in subsequent sections, excluding the AMI 2.0 deployment, the overall increase is driven by three main factors:

- The increase in System Service spending to modernize the distribution system, as well as begin the process of converting FHI's last 4kV community.
- The need for increased investment in System Renewal to maintain and upgrade equipment to ensure a safe and reliable electricity supply, as well as the significant increase in per unit replacement costs.
- An increase in General Plant to maintain and upgrade FHI's fleet, IT, and buildings.

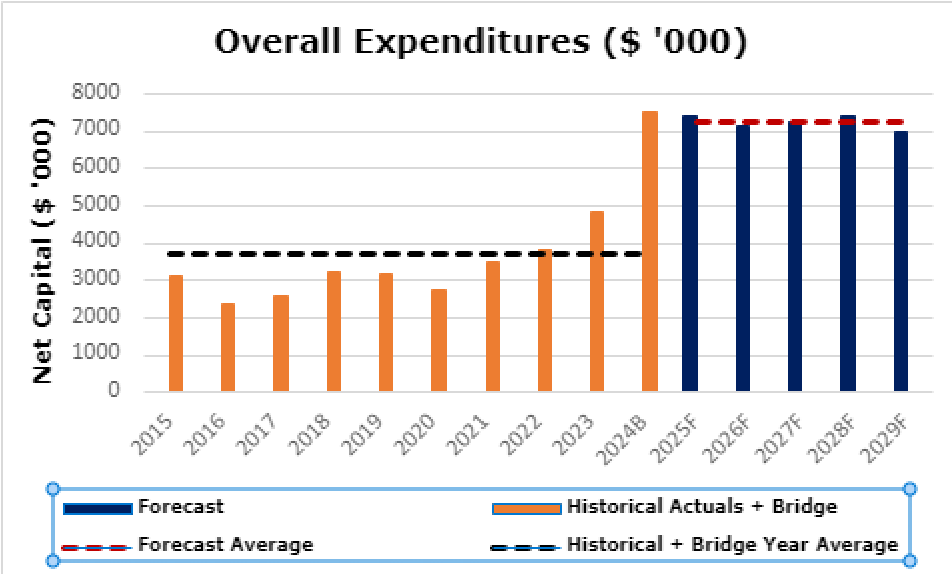


Figure 5.4-1: Overall Expenditures Comparison

5.4.1.3.2 System Access

As shown in Figure 5.4-2, FHI's System Access forecast average is 219% greater than the historical plus bridge year average. However, when removing the costs for the AMI 2.0 deployment project, this changes to a 15% increase.

While difficult to accurately predict spend in this category, the forecast is inline with trends FHI is seeing coming out of the COVID-19 pandemic for customer requests, new developments, and other recoverable work such as road relocations.

FHI has had two extensive Fiber to the home projects in their largest communities and does not expect to be impacted by Accelerated High-Speed Internet Program (AHSIP) projects in any of the communities it services. It is also expected that subdivision and customer requests will remain steady, but not reach the heights that they did during the pandemic. There is also a lack of clarity on road authority works projects past the test year as these projects are difficult to forecast multiple years out and may change as they are dependent on external drivers. FHI will re-prioritize, and shift investments as needed should these projects materialize.

The AMI 2.0 deployment is expected to be completed over the forecast period, finishing in 2029. This will allow all communities to realize the benefits of this new system and improve the reliability of the metering network for FHI. This is not expected to be an ongoing investment past the forecast period and metering costs in the future will reflect new and upgraded services, as well as investments required for regulatory requirements.

The historical System Access trend is variable year over year due to the unpredictability of customer connection service requests, externally initiated subdivision and relocation projects, as well as third-party delays, deferrals, cancellations, and/or the introduction of new or additional works.

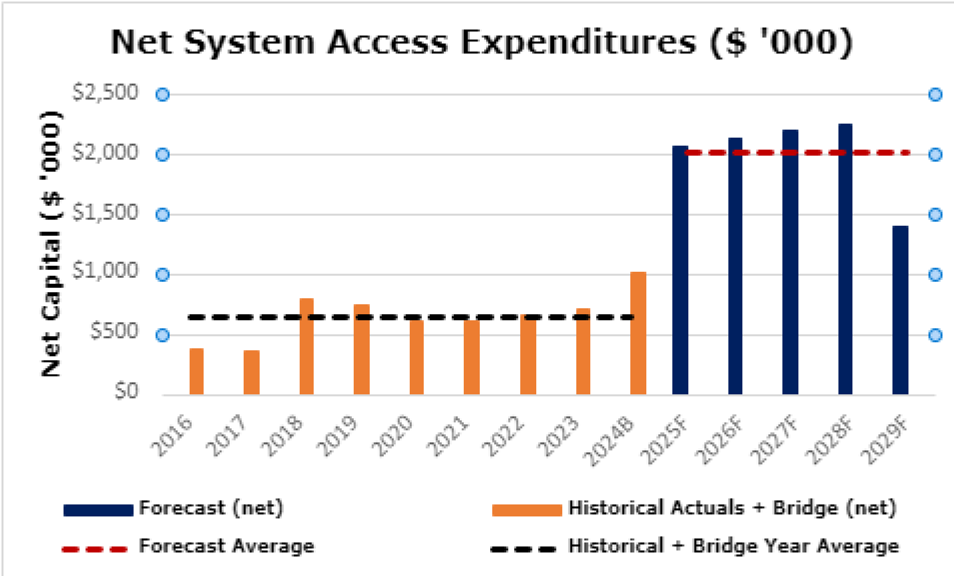


Figure 5.4-2: Net System Access Expenditures Comparison

5.4.1.3.3 System Renewal

System Renewal expenditures are impacted by planned capital investments and the objective to address any condition-based maintenance activities within the asset base to meet customer expectations in regard to performance and reliability. As shown in Figure 5.4-3, the forecast average for System Renewal is 85% higher than the historical plus bridge year average. However, when comparing with 2021-2024 average, that number drops to 57%. Costs for material and labour have increased significantly since 2021, making this a better comparator of historical spend.

Examples of this include:

- The cost for pad mount transformers has increased by an average of 50% on the most common units ordered by FHI due to the significant cost increase of core materials and labour to try and retain workforce. This cost impacts almost all rebuild projects, as typically each distribution transformer in a rebuild area is of a similar condition as all other infrastructure and requires replacement; If replacements have been made that means newer transformers are in these areas, FHI strives to re-use them rather than replace.
- The price of wood poles has increased by 53% since 2021 and the price of concrete poles has increased by 47%. The cost for FHI to replace a pole is approximately 23% higher as a result.

- Common wire and cable costs, manufactured out of copper and aluminum have increased by as much as 81% since 2021. The cost for FHI to replace a section of U/G cable is approximately 36% higher as a result.

While these are specific examples of cost increases, these have been experienced across all materials and contracted services (e.g., hydro vac) that FHI requires to complete these projects.

The level of forecast System Renewal spending is reflective of the ongoing efforts needed in asset renewal to balance the need to keep pace with recommendations identified in the ACA, while staying in step with customer's top priorities of maintaining affordable cost of electricity and maintaining and upgrading equipment to ensure a safe and reliable electricity supply. Historically, this is an area that FHI has under invested in compared to ACA recommendations. The proposed investments in the forecast period reflect an investment strategy that is sustainable going forward to prevent a large spike in spend being needed in the future when a significant number of assets reach poor and very poor condition, leading to increased reactive spending, poorer reliability, and increased safety risks. This includes replacing approximately 15 more concrete poles each year compared to historical, and approximately 1.5-2.5km more underground cable each year, along with associated equipment and hardware where appropriate.

Furthermore, projects for underground renewal have been structured following guidance and requirements from the OEB to ensure that in the planning process FHI is considering the future capacity needs of the distribution system. For projects identified through this program, FHI will take the opportunity to review the number of customers connected to each pad mount transformer and will use the updated practice to add or rebalance customer connections to each transformer in an aim to provide adequate capacity for future needs over the life of the assets that will be installed. This includes, planning for adequate capacity that would allow a 200A service for each connection. This causes certain projects to now have an enhanced scope of work compared to historical replacement projects in this program.

Despite the pressures seen from increasing costs, the forecasted System Renewal spending is expected to remain relatively stable with only small year-over year increases to accommodate the proactive and reactive System Renewal investments needed to meet the customer's expected performance and reliability, while also accounting for inflation. Historically, the year-over-year variations observed over the historical period are relatively minor, with an increase in spend seen beginning in 2021, mainly due to higher costs to purchase and construct jobs, as well as beginning to increase the amount of underground cable replaced each year.

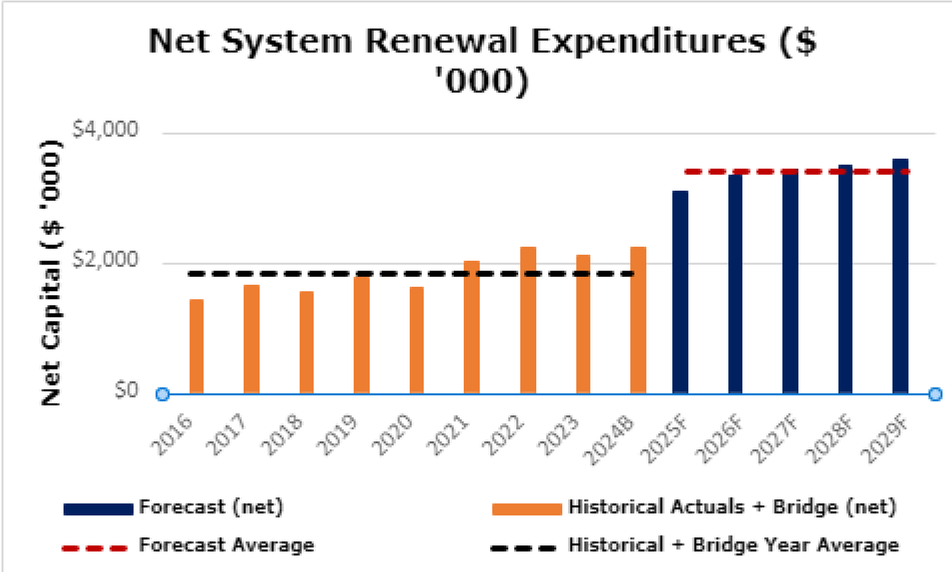


Figure 5.4-3: Net System Renewal Expenditures Comparison

5.4.1.3.4 System Service

The forecast average for System Service is 492% greater than the historical plus bridge year average, as shown in Figure 5.4-4. However, in dollars, that is $320,000, given the minimal investment that occurred in this category over the historical period.

The observed increase in spending is primarily driven by two factors.

- 4kV voltage conversion program. This is a new program that FHI is introducing to convert their last 4kV community to 27.6kV. This will eliminate the need to stock inventory for this voltage class, improve the efficiency of the distribution system, and will eliminate the need to maintain, and replace the two 4kV substations that currently service this community. The forecast period includes the replacement of 900m of conductor a year for this initiative. This is a multi-year project, which will allow FHI to retire the substations before they are expected to need to be replaced or upgraded, which in 2019 was estimated at a high level at $1.6M per substation (Appendix M). This program provides a lower cost option to the substation upgrade, and not only reduces significant capital costs, but it also reduces system O&M costs associated with the two stations. The majority of assets that will be replaced in this program have also been identified as being in poor or very poor condition by the ACA, providing a secondary benefit.

- The second is the continued addition of distribution automation to FHI's distribution system. This proposed investment will add one recloser and one set of remote fault indicators to the distribution system each year to enhance the grid modernization of FHI's system. Only one recloser has been added to the distribution system over the historical period, and only 3 sets of remote fault indicators. The limited spending observed over the historical period are mainly driven by lack of employee resources to dedicate to this work. However, in 2022 a position was hired with a portion of their job being grid modernization and resiliency. This role will be responsible for implementing these projects.

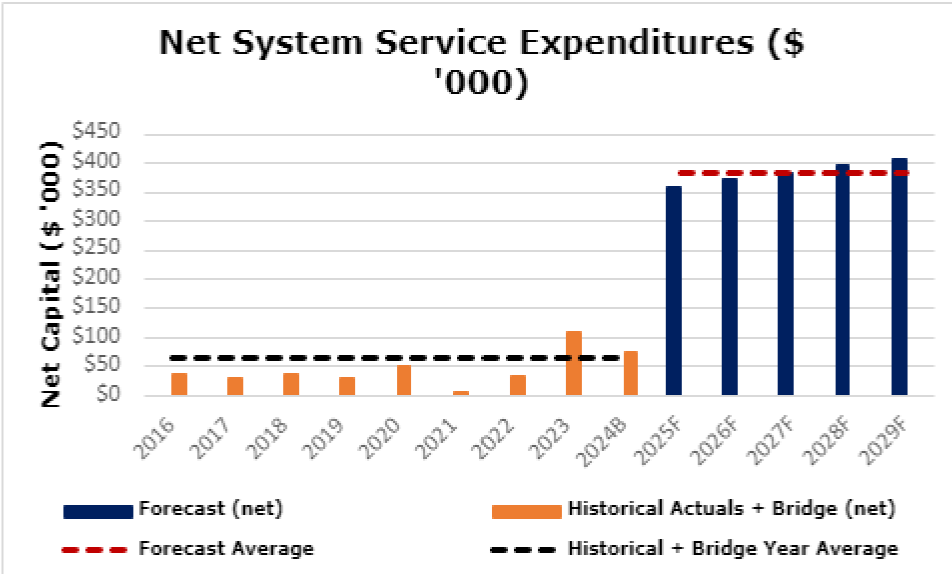


Figure 5.4-4: Net System Service Expenditures Comparison

5.4.1.3.5 General Plant

FHI uses input from various sources, such as its ACA, third party reports, and vendor end of life notices, to address critical issues needed within the General Plant program, including existing facilities, fleet, and IT assets. As shown in Figure 5.4-5, the forecast average is 26% greater than the historical plus bridge year average.

The forecast period focuses on investments in maintaining the state of FHI's buildings and replacing end of life components, improving the state of FHI's aging fleet, and electrifying it where appropriate, as well as replacing end of life hardware and software components in IT.

2024 and 2025 has a large spend to finish installing an ERP system, with 2026, 2028 and 2029 replacing one large fleet vehicle each year (RBD in 2026 and 2029 and bucket truck in 2028). Building spend is expected to fluctuate year over year, increasing in years where large fleet vehicles are not purchased, and decreasing in years when they are, in an effort to keep overall spend in this category more levelized. The facility spend is to address items identified as end of life or nearing end of life when building condition assessments were conducted, such as the roof.

Historically, year over year variations were fairly minor. However, beginning in 2021, FHI began to renovate its existing administration building which was built in 1959. This was done after an independent report identified it as the most economic choice compared to constructing a new building and was completed between 2021-2024. No further renovations are expected in the forecast years.

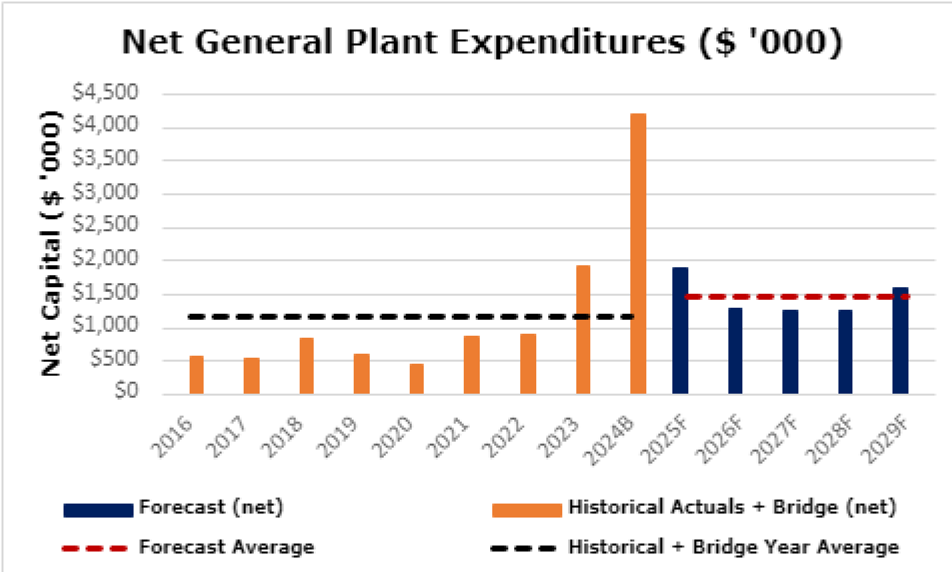


Figure 5.4-5: Net General Plant Expenditures Comparison

5.4.1.4 Important Modifications to Capital Programs Since Last DSP

The following programs have been introduced or modified since FHI's last DSP in 2015. Further detail is provided in Appendix A – Material Investment Narratives.

AMI 2.0 – Given the age and performance of FHI's existing AMI system. FHI is planning over the forecast years to replace the existing metering infrastructure with an AMI 2.0 deployment. After the forecast period, it is expected that costs will return to previous spending for new customer connections and regulatory requirements.

TS Renewal – In the previous DSP, the TS had just recently been built, so no investments were contemplated. However, certain assets have failed and require replacement strategies, or are now reaching end of life and/or becoming obsolete and need attention to maintain one of FHI's most critical assets.

Underground Renewal – FHI plans to replace more primary cable than it has historically, as well as replace cable that is not in duct or in duct that is unsuitable for re-use, where historically projects replaced cable already in suitable duct work. As part of this program, FHI will also take this opportunity to ensure transformation is added where appropriate to provide adequate capacity for the future anticipated demands from new loads (e.g. EV's). Historically, the vast majority of replacements were done using existing duct that was suitable for re-use. When civil work is needed for these projects, that can add between 20-80% more cost to the project depending on the amount of work required. FHI is also planning to complete more cable testing over forecast period to better inform health of existing cables.

Distribution Automation – In FHI's previous DSP, no new reclosers or smart switches were being added to FHI's distribution system. In the forecast period FHI plans to add one recloser a year to its system to provide more flexibility to the distribution system as well as better segmentation and sectionalization when faults occur.

System Re-establishment – In FHI's previous DSP, no money was specifically budgeted for these types of projects, as rebuilds occurred in areas that already had multiple points of supply. However, FHI has many areas with assets that have been identified as being in poor or very poor condition on radial lines where no viable redundancy exists and when rebuilds need to take place the only upgrade option that currently exists is to have multiple long outages or complete significant temporary installations. To address this, FHI plans to complete one project each year in advance of these rebuilds that add redundancy to these areas to mitigate these risks and issues to allow for the replacement of these depreciated assets to take place.

4kV Voltage Conversion – In FHI's previous DSP, no budget was specifically set aside for converting the last community with 4kV. However, the age and condition of the last two substations indicates that a decision needs to be made in the near future to upgrade the stations or convert the community. As a result of a study completed in 2019, outlining the costs of upgrading the stations, FHI has decided the more prudent investment is to convert the community to 27.6kV. In the forecast period FHI plans to replace infrastructure, the majority of which is in poor or very poor condition, in this community above and beyond normal replacement targets to move this community to 27.6kV, prior to the need for large capital investments that would be needed to upgrade the existing distribution stations.

Capital Contributions – In FHI's previous DSP, $120,000 was allocated yearly for capital contributions. In 2020, this number was changed to $200,000 allocated yearly, but no detailed analysis or forecasting was completed to arrive at a more accurate number. However, this methodology has been updated for this DSP to help produce a more robust and accurate number. The capital contribution amount was budgeted based on historical trending, growth predictions, consultations with municipalities and developers, and expected rebates for subdivision assets over the 5-year connection horizon. Due to the fact that capital contributions are driven by third party projects, this number can be difficult to forecast. However, FHI expects that this updated methodology will provide less variance over the forecast period that has been seen historically.

5.4.1.5 Forecast Impact of System Investments on System O&M Costs

Although FHI's forecast capital investments are not expected to reduce system O&M costs, they are expected to prevent System O&M costs from growing over time above regular inflation. Efficiencies achieved in some areas, such as the need for less costs in meter reading with a new AMI system, or disposal of substations, are expected to offset growing O&M needs in other areas as assets continue to age and more regular testing and inspections are required, such as underground cable testing. Based on the ACA findings, and to respect customer preferences to maintain costs and service levels, the forecast level of capital investment has been carefully set with a goal of maintaining system O&M expenditure requirements as well.

Table 5.4-17: Forecast System O&M Expenditures

Category	Forecast ($ '000)				
	2025	2026	2027	2028	2029
System O&M	3515	3620	3729	3841	3956

5.4.1.6 Non-Distribution Activities

FHI has not included any expenditures for non-distribution activities in its budget.

5.4.2 Justifying Capital Expenditures

FHI's overall capital plan consists of many converging inputs that drive and influence the direction of the capital expenditures. FHI's objective with regards to capital expenditures is to meet all regulated requirements while managing the assets in a manner that ensures the costs charged to its customers are prioritized and spent effectively.

The AM process is the foundation for the DSP and the capital expenditure plan which helps align each to FHI's overall corporate objectives. By following a strategic approach to the capital expenditure planning process FHI achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and future customers. During the development of the capital expenditure plan, a number of objectives and planning processes are observed which ensures the plan aligns with the AM objectives and therefore with the overall strategic goals of the corporation (see section 5.3.1). FHI's planning inputs that have shaped the DSP and capital expenditure plan include the following:

1. Provide the proper allocation of investments to meet Health and Safety obligations, ensuring the manner in which work is executed positively impacts the general public, customers and FHI staff.

2. Ensure proper allocation of investments to meet regulatory and customer obligation of system access projects (e.g., system relocations, residential and general services connections).

3. Ensure an adequate supply of power for existing and future demand needs.

4. Ensure adequate level of investment in the renewal of distribution system assets to maintain a safe and reliable system as determined through the continued ACAs.

5. Actively seek improvements in productivity and efficiencies that positively affect reliability and constraints on the system.

6. Review overall expenditures and determine impacts to financials and adjust spending as required.

The assumptions made during the planning process stem from input from various sources such as:

- Growth forecasts.
- Inspection and maintenance.
- Co-ordination with customers and third parties.
- Impact of regulatory initiatives.
- Historic system reliability.
- Asset condition forecasts, and
- Impact of CDM, REG, DER, and EV connections.

The degree to which each of these assumptions affects the overall capital plan varies along with the timing required to execute them. FHI strives for continuous improvement and as a result regularly reviews and revises the above planning assumptions to ensure they accurately reflect reality. As part of the capital expenditure planning process, FHI has determined several assumptions need to be made to support the development of the capital expenditure plan. Key assumptions include:

- The use of historical trends in categories related to System Access to forecast capital expenditures.
- The validity of information from developers, municipalities and other third parties with respect to future requirements of the distributions system to service new projects.
- The use of historical growth, CDM, DER and EV adoption rates as well as information from government and IESO reports for potential future growth or adoption of electrification to assist in the forecasting future contributions to the demand of the distribution system, and
- Third-party condition assessment reports that have helped inform System Renewal and General Plant investments.

FHI’s asset management goal is to identify and prioritize assets for replacement in an optimal manner through the guiding principles of the AM objectives, in such a way as to both; minimize risks to FHI’s vision and core values and maximize long term investment benefits. Each of the AM objectives described in section 5.3.1.1 are considered by utilizing them as weighted criteria to assist in the selection and prioritization of projects in the capital expenditure planning process.

Customer Value

Delivering value to customers and other stakeholders is of critical importance to FHI, as highlighted in FHI’s mission statement and values:

- FHI’s mission statement is “To responsibly provide value to our customers, communities, shareholders, and employees through cost effective distribution of reliable and safe electric power.”
- FHI’s Values are: “People first through positive teamwork, accountability, honesty, commitment to customers, and trust”.

Meeting customers' needs and expectations is one of FHI's AM objectives. These key inputs and objectives drive FHI's planning and AM processes, and customer feedback is a key input considered when developing capital plans.

By prioritizing System Access projects, including new customer connections, service requests, new subdivisions, municipality driven projects, and joint use projects, as mandatory, FHI ensures that customer needs and requests are being met.

The scope of capital investments planned in the System Renewal category has also been determined with the objective of optimizing the pacing of investments to strike a balance between affordable rate increases for customers while still investing in key areas to maintain the safety and reliability of the distribution system from deteriorating below an acceptable level.

This is also in alignment with the results of the customer survey where approximately 70% of customers believed this amount of spend was appropriate to maintain the conditions of the distribution system.

The proposed System Service investments deliver value to customers by accommodating future load growth or DER projects and improving grid operation performance and flexibility.

FHI plans to automate more of its network over the forecast period, which will also enable FHI to expand the use FLISR in its service territory. A fundamental concept of a self healing network. These investments are targeted at reducing the size and duration of outages and improve response times, which is consistent with their customer's desire for a reliable electricity supply and to invest money in new technologies, even if it means there is an additional cost.

FHI's General Plant investments are also selected and prioritized such that they can continue to operate safely, efficiently and support other work. Recent and planned IT-related upgrades include the implementation of an OMS, as well as replacement of CIS and ERP systems. These upgrades will allow FHI to make faster decisions to troubleshoot and respond to outages, provide more information and communication options to customers, improve operational efficiencies by automating processes that were previously completed manually, and ensure continued regulatory compliance.

In order to align FHI's overall capital budget envelope with customer expectations, FHI has prioritized and optimized its proposed capital investments such that the most critical projects and programs have been budgeted over the forecast, while a number of lower priorities, less critical scoped projects and programs have been either deferred, reduced, or eliminated from the budget envelope.

Technological Changes and Innovation

With the emergence of changing policies, net zero targets, increasing prioritization of electrification, innovative technologies, and customer expectations, the distribution grid is quickly evolving from a system-centric, top-down, one-way power flow system to a customer centric, bi-directional power flow system. Customers now have the capability to generate their own electricity via DERs, and as a result, distribution system planning and operations are becoming increasingly complex, and maintaining grid integrity is becoming more challenging. Practices which have historically been acceptable for the traditional grid need to evolve, and an improved and more modernized grid is required to accommodate this evolution.

As identified in FHI's Strategic Plan, innovation is part of FHI's commitment to continuous improvement. FHI monitors the state of technological advancements made within the utility sector. System automation, EV uptake, battery storage and other NWAs are considered as part of FHI's planning process. Where it is financially responsible to do so, these technologies may be incorporated into the renewal and upgrade projects to meet the current and future needs of customers, improve operational effectiveness, as well, support the integration of renewables and smart grid technologies.

Examples of technological improvements and innovation either recently implemented or planned over the forecast period are noted below:

- **AMI 2.0** - FHI plans to replace it's legacy AMI 1.0 installation with an AMI 2.0 redeployment. This will provide FHI with more reliable communications for billing, as the infrastructure will provide for current and future needs over its expected service life. This investment will also provide access to information that is not currently available with AMI 1.0 infrastructure, such as enhanced power quality monitoring and grid edge computing for distributed intelligence, opportunities to better support the integration of renewables and EV's, as well as give customers and FHI better access to energy data and consumption patterns.

- **Distribution Automation -** FHI plans to automate more of its network over the forecast period, which will also enable FHI to expand it's self healing network, allowing the distribution system to automatically re-route power without manual intervention. This is a fundamental concept of a self-healing network, which helps to reduce the size and duration of outages.

- **Voltage Conversion** – FHI is planning to undertake a voltage conversion project in their final 4kV community, continuing beyond the forecast period with completion by 2033. This project is expected to bring benefits in several ways. The removal of the final two stations, which are at or approaching their end of life and allow FHI to avoid the need to invest significant capital to replace and upgrade the transformers and switchgear at both stations. Also, these remaining circuits once transferred over from 4kV to 27.6kV, will better position FHI to accommodate larger customer demand and DER's as these feeders have an enhanced capacity. Finally, there will inherently be a reduction in electrical losses by retiring two 4kV stations and the move to higher voltage.

- **Outage Management System** – FHI began its implementation of an Outage Management System during the historical period with the goal of providing more visibility into events happening on the distribution grid that will proactively and autonomously engage with customers. This project required the integration of several data sources (e.g., customer information systems, AMI, geographic information systems, SCADA) to allow for full implementation of the objectives. This project also provided FHI with better engineering analysis capabilities, an example of which is, providing distribution transformer loading. This has allowed for transformers to be proactively changed that may be undersized. This software also allows FHI to complete system studies, fault analysis and load forecasting.

The above noted investments have and will continue to help prepare FHI for the future role of LDC's in providing a high level of service and reliability customers.

Consideration of Traditional Planning Needs

At a system level, load growth is not anticipated to drive investment during the forecast period as there are no constraints that would prevent the connection of anticipated load or generation customers.

As previously explained in Section 5.3.1, traditional planning needs, including load growth, asset condition, and reliability are key inputs considered as part of FHI's AM processes.

FHI undertakes load studies to identify areas that may require investments to accommodate required capacity. Load growth and supply of power is a direct input into FHI's planning for System Access and System Service type projects. It is also considered when rebuilds are completed in an effort to ensure that existing areas will be able to meet the existing and forecasted future demand needs for customers. Load growth is also a key input into the regional planning process which helps to identify future requirements (both wires and non-wires) to accommodate load growth.

Asset condition and reliability data are key inputs considered by FHI when identifying, selecting, and prioritizing System Renewal expenditures. It is through the ACA and reliability studies that FHI can identify the portion of the system that has reached (or soon will) a point that requires renewal, and where in the system those assets pose the greatest risk to reliability and/or public safety. Asset quantities that are flagged for action directly influence the level of investment proposed over the forecast period and FHI has put forth renewal levels that will yield sustained investment levels on a go forward basis as opposed to variable investment levels (i.e., to manage large demographics of assets in poor condition).

Affordability is front of mind for many customers as rate increases are considered. FHI's challenge is to seek balance between cost, risk and performance and while approximately half the customers responded that they did not like the idea of a rate increase, they understand it is necessary. Therefore, in preparing this DSP, FHI has focused on prioritizing the investments into renewal of the most critical infrastructure components to achieve the balance required between keeping the power supply reliability from degrading while maintaining the electricity distribution rates at affordable levels.

Overall Capital Expenditures

Over the forecast period FHI's capital expenditures are designed to continue to meet FHI's corporate goals including safe, reliable, and affordable power. The proposed level of spending is also aimed at maintaining or slightly improving asset related performance in order to achieve the four performance outcomes established by the OEB, while also adhering to FHI's established AM Objectives set out in Section 5.3.1.1.

As detailed in Section 5.4.1.3, the overall increase relative to historical is driven by an increase in System Access for an AMI 2.0 redeployment, increased investments in System Renewal to maintain and upgrade equipment to ensure a safe and reliable electricity supply, increase in System Service to support distribution automation and voltage conversion programs, and an increase in General Plant to maintain and upgrade FHI's fleet, IT, and buildings. There is also an overall increase due to much higher than inflationary costs being seen in labour, contractors, and materials.

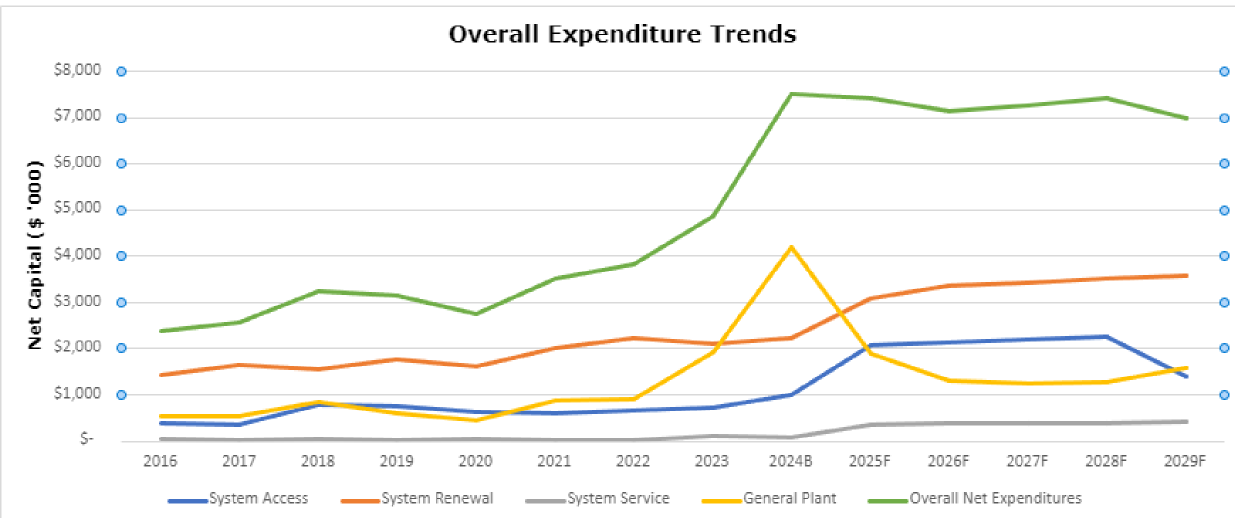


Figure 5.4-6: Overall Expenditure Trends

5.4.2.1 Material Investments

For this Application, FHI's materiality threshold is $80,000. Using the prioritization process previously detailed in Section 5.3.1, FHI has ranked and prioritized its material investments planned in the Test Year (2025). Table 5.4-18 presents the prioritized list of material projects and programs that have been budgeted in 2025 with their associated prioritization scores. The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 5.4-19.

For each of these projects/programs, a detailed write-up, highlighting the drivers, justification, and analysis, is provided in Appendix A – Material Investment Narratives.

Table 5.4-18: Proposed Capital Investments during Test Year - Projects over Materiality

Category	Project Description	Priority Rank	2025 Planned Expenditure ($ '000)
System Access	New Services	N/A	375
	New Subdivisions	N/A	407
	Metering	N/A	112
	Misc. Recoverable Work	N/A	189
System Renewal	Unplanned Small Replacements	1	349
	Switchgear Replacement	2	244
	Underground Renewal	3	1188
	Overhead Pole-line Replacement	4	848
	Transformer Station Renewal	5	275
System Access	AMI 2.0	6	1316
System Service	4kV Voltage Conversion	7	217
General Plant	ERP Replacement	8	875
	IT Hardware	9	297
System Renewal	System Re-establishment	10	122
General Plant	Fleet	11	125
	Building and Equipment	12	505
System Service	Distribution Automation	13	142
Total Expenditure on Material Projects During Test Year			7,586
Total Expenditure on Capital During Test Year (All Investment Categories)			7,737

As detailed in section 5.3.1.3, once all the projects have been identified, FHI performs its prioritization process. Inputs for the prioritization are guided by FHI's corporate goals and strategic objectives, OEB renewed regulatory framework expectations, customer input, regulatory requirements.

Other than work that poses imminent safety risks, System Access projects, which are non-discretionary in nature, are given top priority. These are identified through customer interactions, information from the municipality, and developers. The timing and cost of these projects are driven by the requesting party and are budgeted and resourced to meet these requirements. Projects driven by regulatory requirements (e.g., mandated by a governing body or regulator) are also given top priority as these are typically mandated to fulfill all regulatory obligations in FHI's distribution license.

Once all non-discretionary projects have been identified, the rest of the System Renewal, System Service and General Plant projects are prioritized through a prioritization criterion. The breakdown of the criterion categories and relative weighting for each Corporate Strategic Objective is outlined below:

Health & Safety

Health and Safety	Risk	Prioritization Weighting
Staff: Multiple lost time injuries and/or fatality Public: Known hazard with history of issues, possibly life threatening Security: Critical impact Security Incident	4	25.0%
Staff: At least one lost time injury, MOL investigation Public: Known hazard with no history of issues, possibly life threatening Security: High Impact security incident	3	18.8%
Staff: Injury requiring first aid Public: Public safety concern, not life threatening Security: Medium Impact security incident	2	12.5%
Staff: Minor injury, no first aid needed Public: Potential for injury to public, not life threatening Security: Low Impact security incident	1	6.3%
No impact on health and safety	0	0.0%

Security incident thresholds are as defined in Festival Hydro's Cyber Security Incident Response Plan

Reliability/Supply of Power

Reliability/Supply of Power	Risk	Prioritization Weighting
Sustained interruption of at least one TS distribution feeder and provides for additional system capacity	5	20.0%
Sustained interruption of > 3 MW (greater than half a typical TS distribution feeder) of load and provides for additional system capacity	4	16.0%
Sustained interruption of one MS or embedded distribution feeder and provides for additional system capacity	3	12.0%
Sustained interruption of > 3 MW (greater than half a typical TS distribution feeder) of load	2	8.0%
Sustained interruption of < 3 MW of load or provides for additional system capacity	1	4.0%

Asset History and Performance

Asset History and Performance	Risk	Prioritization Weighting
Distribution System: Asset history has shown impact at a station level or widespread in distribution system General Plant: Asset history shows recurring and significant maintenance expenses impacting availability of assets, vendor support of products has ended	4	15.0%
Distribution System: Asset history shows regular failures (yearly) or >50% of asset class in poor or worse condition General Plant: Asset history shows recurring and increasing maintenance expenses, not yet impacting availability, vendor no longer making enhancements to product, support in maintenance mode.	3	11.3%
Distribution System: Asset history shows intermittent failures (<1 each year) or >50% of asset class in fair or worse condition General Plant: Asset history beginning to show increase in maintenance expenses, vendor support and enhancements of product is nearing end of life	2	7.5%
Distribution System: Asset history shows minimal failures, <50% of assets in fair or worse condition General Plant: Asset history shows minimal maintenance expenses, vendor support and enhancements of product ongoing.	1	3.8%
No impact from Asset History or Performance	0	0.0%

Customer & Community

Customer & Community	Risk	Prioritization Weighting
Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 70% of customers	4	15.0%
Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 60% of customers	3	11.3%
Delivers on one of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 50% of customers	2	7.5%
Delivers on any of the top 4 priorities of customers (safe/reliable power, low rates, aesthetics over cost, innovation) and is supported by over 50% of customers	1	3.8%
Does not address any customer or community needs/preferences	0	0.0%

Productivity/Efficiency

Productivity/Efficiency	Risk	Prioritization Weighting
Aligns with 4	4	10.0%
Aligns with 3	3	7.5%
Aligns with 2	2	5.0%
Aligns with 1	1	2.5%
No impact on productivity or efficiency	0	0.0%

Note: The criteria for this category are as follows:
Investment reduces Operating Expenses
Investment coordinates with or allows other projects to proceed
Investment reduces employee time spent on tasks
Investment decreases liability or increases with inaction.

Organizational Effectiveness

Organizational Effectiveness	Risk	Prioritization Weighting
Aligns with 4	4	10.0%
Aligns with 3	3	7.5%
Aligns with 2	2	5.0%
Aligns with 1	1	2.5%
No impact on organizational effectiveness	0	0.0%

Note: The criteria for this category are as follows:
Investment improves employee response and improves customer experience/access to information
Investment permits shared service or cost sharing opportunities
Investment provides sustainable business operations
Investment supports innovation

Environmental & Sustainability

Environment & Sustainability	Risk	Prioritization Weighting
Addresses any four environmental issues noted	4	5.0%
Addresses any three environmental issues noted	3	3.8%
Addresses any two environmental issues noted	2	2.5%
Addresses any one environmental issue noted	1	1.3%
Does not address any environmental risks	0	0.0%

Note: Environmental issues are as noted:
Addresses Climate Change
Risk of Oil Spills/clean up
Reducing green house gas emissions
Removes hazardous or environmentally damaging equipment
Ministry of Environment involvement

The following table list the material projects for the test year and the relative scoring and prioritisation ranking for the discretionary projects FHI is proposing.

Table 5.4-19: Prioritization Scoring by Project for the Test Year

Project	Health and Safety	Reliability / Supply of Power	Asset History and Performance	Customer and Community	Productivity / Efficiency	Organizational Effectiveness	Environmental	Total
Unplanned Small Replacement	25	8	11.3	11.3	5	5	5	**70.6**
Switchgear	25	8	11.3	11.3	7.5	5	1.3	**69.4**
Underground Renewal	12.5	16	11.3	11.3	7.5	5	3.8	**67.4**
Overhead Pole-line Replacement	12.5	16	11.3	11.3	7.5	5	1.3	**64.9**
Transformer Station Renewal	12.5	20	15	7.5	2.5	5	1.3	**63.8**
AMI 2.0	6.3	4	15	15	10	10	1.3	**61.6**
Voltage Conversion	12.5	12	7.5	11.3	7.5	5	5	**60.8**
ERP	18.8	4	15	7.5	7.5	7.5	0	**60.3**
IT Hardware	18.8	12	3.8	7.5	7.5	7.5	0	**57.1**
System Re-establishment	12.5	12	11.3	7.5	5	5	1.3	**54.6**
Fleet	12.5	4	15	7.5	7.5	5	2.5	**54**
Building	12.5	4	11.3	7.5	7.5	5	2.5	**50.3**
Distribution Automation	6.3	8	3.8	7.5	7.5	7.5	1.3	**41.9**

Project Deferrals/Alterations

In order to align FHI's budget envelopes with customer expectations, decisions were made to defer, alter pacing, or eliminate a number of scoped projects and program budgets over the forecast period. This includes reduced pacing of underground cable replacements, and deferring/reducing investments to animal mitigation, fleet and FHI's building and equipment. It also includes altering the pacing and cost of the AMI 2.0 deployment to complete the bulk of it by 2028, with a smaller deployment in 2029 to finish the project.

FHI has been prudent in its overall forecast plan balancing the priorities of customers as identified from the customer survey to try and address the fact that while the majority of customers understand the need for a rate increase and believe it is reasonable, they still don't like the idea of it. As a result, FHI has taken an approach to reduce or defer some capital projects. Table 5.4-20 lists the projects and programs budgets which have been reduced or deferred.

Table 5.4-20: List of Projects Deferred

Project/Program Name	Deferred Cost & Timing ($ '000)					Total ($ '000)
	2025	2026	2027	2028	2029	
	$ '000	$ '000	$ '000	$ '000	$ '000	
Underground Renewal	281	244	277	282	289	1,373
Animal Mitigation	10	10	13	15	18	66
Fleet	-	155	-	-72	152	235
Buildings	-	180	-	236	75	491
System Re-establishment	-	39	20	21	21	101
AMI 2.0	-114	-292	-299	-307	614	-398
Total Annual Deferrals	**177**	**336**	**11**	**175**	**1,169**	**1,868**

Appendix A

Material Investment Narratives

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM ACCESS

PROJECT: METERING

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

FHI owns and operates approximately 23,000 revenue meters installed on customers' premises which measure the power consumption and demand of connected load for the purpose of billing. All existing residential and general service customers were equipped with smart meters in 2010/2011 following the government legislated program.

The Metering program includes the supply, installation, and replacement of FHI's metering assets, in compliance with Measurement Canada standards.

Since these investments are required by the DSC and Measurement Canada standards, they are considered non-discretionary. The customer connection requests are fulfilled consistent with FHI's Conditions of Service. The projects are designed to meet customer requirements. Through the implementation of this program, FHI can continue to accurately and correctly measure and bill customers for the electricity that they use and satisfy the OEB "Billing Accuracy" requirement to have 98% billing accuracy.

The activities falling within the scope of this program includes:

- Installation of residential and commercial meters, along with applicable instrument transformers at new service locations; Historically this has been between 200-300 new customers each year.
- Replacement of failed and obsolete metering for residential and commercial services; multi-residential metered customers. FHI also plans to complete the conversion of one 40+ year old GS>50 primary metering installation each year to replace obsolete oil filled instrument transformers for which no direct replacement exists today and to remove the environmental risk of the oil filled transformers.
- Required works to maintain compliance with applicable regulations and standards (e.g. Measurement Canada).

FHI's AMI 2.0 investment project alters the spending in this category for the forecast years in the following way:

- New residential customers meter costs will be purchased under the AMI 2.0 project instead. Any new residential customers in areas that have not been converted to the new AMI 2.0 platform will use suitable meters from already converted areas.
- Commercial and industrial customers in AMI 2.0 areas will receive new meters under the AMI 2.0 program, new customers in areas that have not been converted will continue to receive meters and associated instrument transformers under this program.

Based on historical spending, in 2025, and through the forecast period, FHI is projecting that this category will see the following installations:

- 25 new commercial and industrial customers;
- Replacement of 1 oil filled primary meter customer;
- Instrument transformers and other required hardware and labour for each site.

These customers will all be installed in a way that they will be able to be migrated to AMI 2.0 once the system is configured.

2. TIMING

i. Start Date: January 2025

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: There are several factors that could impact the project schedule including:

- Customer timing of request.
- Material procurement delays.
- Unexpected nature of when meters may fail and in what manner.

Meter replacement projects are undertaken by FHI, but timing of replacement is closely coordinated and driven by customer timing to coordinate the outage.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	230	493	207	97	362	314	200	112	123	127	132	184
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	230	493	207	97	362	314	200	112	123	127	132	184

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Metering services are ongoing annual expenditures. Historical costs are reflected in Section A3 above. In historical years, FHI has purchased meters to be used for new meter installs, to replace defective meters, and for meter reverification programs in accordance with Measurement Canada. The table below indicates the quantity of meters purchased each year.

Table 1: Historic Meter Purchases

	2018	2019	2020	2021	2022	2023
# of residential meters purchased	239	590	260	300	1400	250
# of Industrial/Commercial meters purchased	0	353	28	0	0	90

2019 saw an increase in costs and meter purchases due to a large number of installed meters that required reverification.

2022 saw an increase in costs as FHI was given an end-of-life notice for the residential meters that had historically been purchased (Appendix L), with no other Measurement Canada approved alternative available for purchase. Thus, FHI made the decision to purchase enough meters for multiple years to ensure sufficient quantities for future customer connections, while assessing alternative options.

Forecast costs are lower than historical due to the AMI 2.0 program described in Materiality Narrative: AMI 2.0. Most new residential and industrial/commercial meters will be purchased under this program, lowering the spend in this category temporarily. New customers in areas not yet converted to the new AMI 2.0 network, required instrument transformers and meter hardware and replacement of defective meters/metering equipment will make up the spend of this category in the forecast years.

6. INVESTMENT PRIORITY

This investment program is classified as a high priority since it is a non-discretionary program. Mandatory projects are completed as required by FHI. Projects in this program are driven by customer requests, Measurement Canada regulations, and failed/obsolete metering that must be replaced to remain in regulatory compliance. When requests are initiated under this program, they are balanced with other mandatory system access projects but will take priority over other system undertakings and plans.

7. ALTERNATIVE ANALYSIS

This investment is non-discretionary. Failure to perform the work to install, repair, replace and/or reseal meters would be in violation of the DSC and Measurement Canada Guidelines, and has the potential to negatively impact the reliable source of billing and settlement data.

Given the end-of-life notice FHI received in 2022 (Appendix L) for their typical meters, the number of meter hardware issues that have required repair and the overall age of the existing metering infrastructure, FHI began exploring alternatives to their current AMI system to understand what advances had been made since the initial deployment in 2010 and to attempt to resolve the increasing unreliability of the existing metering network. Further details can be found in Material Investment Narrative: AMI 2.0

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: Properly working smart meters with remote communications facilitate the following efficiencies:

- Significant reduction in manual meter reading;
- Integrates meter alarm messages with Outage Management Systems to assist in identifying outage areas quickly and accurately;
- Improve load monitoring capabilities for distribution transformers and assist in identifying transformers that may be improperly sized.

Customer Value: Renewing meters and associated equipment that are failed ensures that customer meters continue to function properly and capture accurate electricity usage. The data from the meters also allows customers to monitor their historical consumption using web services.

Reliability: Individual meters themselves have little impact on reliability, however replacing failed meters and completing reverification of meters ensures that billing and settlement data is reliable and can get back to billing systems. These meters also feed outage and restoration information into FHI's Outage Management System to assist in identifying outage locations.

Safety: Projects under this program are typically not intended to address existing safety concerns; however, all meter installations are installed using applicable safety standards.

2. INVESTMENT NEED

Projects in this program are driven by third party requests, as is the investment prioritization under this program. These are mandatory projects and are non-discretionary in nature.

i. Main Driver: Mandated Service Obligations - The main driver for this program is regulatory obligations as defined in the DSC and by Measurement Canada. FHI is obligated to install and maintain meters at all customer connection points. By replacing failed meters, and those that are expired and need reverification, FHI ensures that it complies with those obligations.

ii. Secondary Drivers: Failure risk – By addressing any expired or defective meters/metering equipment, this reduces the risk of failed metering installations in the field and ensures the continued delivery of reliable and accurate bills.

iii. Information Used to Justify the Investment: New meter installations are mandatory investments that arise from customer requests. FHI also collects and tracks data on existing meters as required to ensure that meters are sampled and reverified on the defined schedule from Measurement Canada. The forecast numbers have been developed based on historical purchases for the instrument transformers needed for new services. There are also some costs for new meter purchases for commercial and industrial meters for those that will not be within the AMI 2.0 deployment area in 2025. No costs for residential meters are included in this category, as it is expected that a portion of ones removed as part of AMI 2.0 will be re-purposed for new residential customers and meters needed for reverification in other communities.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI plans and executes its metering program to accommodate failed meters and comply with regulations. All new meters installed comply with the latest standards and regulations, and all metering services are carried out in accordance with FHI's standards and practices.

ii. Cost-Benefit Analysis:
Normally, no cost-benefit analysis would be done for new connections, as there are minimal options, metering wise to connect a new customer.

However, FHI examined the current state and age of their existing metering infrastructure, the increased operating costs of the meter network, the number of repairs that had been required to existing installed meters, the lack of purchasing options from their current meter vendor and decided to explore an AMI 2.0 deployment through a competitive RFP process, beginning in 2023. More details can be found in Material Investment Narrative: AMI 2.0.

iii. Historical Investments & Outcomes Observed: The historical costs and number of meters purchased are detailed in section A3 and A5 of this document. Through its metering program, FHI has been able to continue to meet customer requirements, comply with relevant regulatory requirements and accurately and correctly measure and bill customers for their electricity usage.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM ACCESS

PROJECT: OTHER CAPITAL RECOVERABLE

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program is comprised of customer driven work for additions or changes to FHI's distribution system. The majority of the work in this program is driven by:

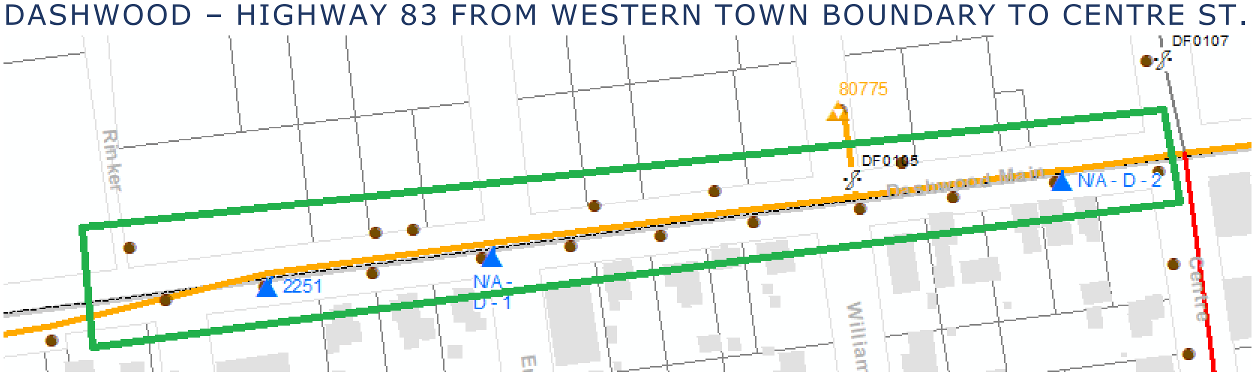
- Municipalities due to road relocations under the Public Service Works on Highways Act,
- Expansions and extensions of the distribution system from customer requests,
- Third party requested relocations of distribution system equipment for various reasons.

FHI works closely with municipalities and customers to ensure their needs and timelines are met for their project.

Typical project scopes may include installation or replacement of poles and anchors and related infrastructure as required. While the main drivers and scope of work behind these projects fluctuates on a yearly basis, the program is expected to remain relatively stable over the forecast years. There are typically 2 or 3 small projects that involve the replacement or relocation of single assets, and then one large project that makes up the majority of the spend for the category.

In 2025 the main project is a road relocation as described below:

DASHWOOD – HIGHWAY 83 FROM WESTERN TOWN BOUNDARY TO CENTRE ST.



The scope of this project is the replacement of 17 poles and overhead primary conductor on Highway 83 from the western boundary of Dashwood to Centre St. This project is being done in coordination with the Township for a road reconstruction project and is a two-part project, with the first phase being completed in 2024. The project spans approximately 400 meters. While the main purpose of this project is to relocate for the new roadway, this project also provides the additional benefit of replacing numerous poles that are over 50 years old and have been identified by the ACA as being in poor or very poor condition.

Capital contributions for these projects are collected in accordance with the DSC, the provisions of FHI's Conditions of Service and any other applicable legislation (e.g. Public Service Works on Highways Act).

2. TIMING

i. **Start Date:** The scope, timing, and schedule of the projects in this program are driven by customers and municipalities. Through regular meetings and communications with these key stakeholders FHI stays aware of the timetable for the various projects throughout the year.

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: There are several factors that could impact the project schedule including:

- Customer delays/timing of request.
- Customer availability of funds.
- Material procurement delays.
- Securing of easements if/when required.

FHI closely coordinates with customers to mitigate as many factors as possible.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	178	164	88	284	17	26	142	189	110	113	117	120
Contributions	108	157	85	147	39	10	32	47	49	51	53	55
Capital (Net)	70	7	3	137	-22	16	110	142	61	62	64	65

4. ECONOMIC EVALUATION

Economic Evaluations are completed in accordance with the Distribution System Code and any servicing agreements for each new expansion or extension project in the FHI service territory to collect capital contributions, as well as to rebate customers over the connection horizon period. FHI works with customers to complete these economic evaluations and collect and rebate as appropriate. Road relocation projects are calculated using the cost sharing methodology outlined in the Public Service Works on Highways Act R.S.O. 1990, c. P.49. The Highway 83 project detailed in Section A1 will use the cost sharing methodology for Public Service Works on Highways Act for affected infrastructure.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

The quantity and scope of requests varies year-to-year, however FHI forecasts based on the best available data considering communication and timing of projects from customers and municipalities as well as historical averages.

6. INVESTMENT PRIORITY

This investment program is classified as a high priority since it is a non-discretionary program. Mandatory projects are completed as required by FHI, and when competing mandatory projects are undertaken FHI ensures alignment to its project prioritization processes.

Projects in this program are driven by customer and municipality requests. This investment program is classed as a high priority since it is a non-discretionary program, which is essential to maintain regulatory compliance and customer satisfaction. When requests are initiated under this program, they are balanced with other mandatory system access projects but will take priority over other system undertakings and plans.

7. ALTERNATIVE ANALYSIS

Relocation projects typically require existing assets to be replaced with new ones in a different location, and the assets being replaced are not necessarily assets that are in poor condition. As a result, FHI works with municipalities to minimize stranded assets, as well as coordinate rebuild projects with their timing to maximize efficiencies. FHI provides input to the road authority with options based on the road design and works to find the optimal solution for both parties.

For expansions or extensions of the distribution system, these projects are customer driven. The design and methodology for these projects are standardized through FHI's practices and standards. Through understanding the customers scope of work, options are discussed to fulfill their needs, such as current and future demand, if there is a preference for overhead or underground, and then a design with applicable costs are finalized with the customer.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: All new installations are designed and constructed as per FHI's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner. FHI also works with municipalities when planning rebuilds to understand upcoming projects that may impact FHI infrastructure and coordinate the timing of projects where possible. FHI will also consider the condition of assets in the near vicinity of these projects and will, where appropriate, expand the scope of the work to replace them at the same time to gain efficiencies in time and cost.

Customer Value: FHI makes best efforts to connect customers within regulated timelines to provide the best value to customers while providing them a cost-effective and timely solution for their situation. Additionally, FHI can offset project costs with contributions received, reducing overall impact to customer rates.

Reliability: Projects installed under this program are not intended for reliability improvements; however, when replacing older assets with new, and constructing in accordance with FHI's current standards and specifications, this inherently lends itself to more reliable performance reducing the risk of outages.

Safety: Projects under this program are typically not intended to address existing safety concerns within the distribution system; however, because they are designed and constructed in accordance with FHI's latest standards and specifications, which meet or exceed all applicable industry standards, they inherently provide a level of both public and operational personnel safety.

2. INVESTMENT NEED

Projects in this program are driven by third party requests, as is the investment prioritization under this program. These are mandatory projects and are non-discretionary in nature.

i. Main Driver: Mandated Service Obligations - These projects are mandatory. Scope and timelines are based on requirements put forth by the municipalities, customers and/or obligations set forth for connecting customers in the DSC.

ii. Secondary Drivers: N/A

iii. Information Used to Justify the Investment: This program, which consists of customer-initiated projects, is non-discretionary. Where available FHI uses information from municipalities and customers to form the investment amount, as is the case in 2025, in the absence of detailed information, historical averages are used.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI ensures that the connection of new customers or relocation of existing infrastructure allows for a flexible and resilient distribution system that also supports future growth. This includes sizing of equipment to meet both the current and projected needs of the customer and the distribution system and any future loads it may impact. Additionally, careful selection of equipment placement in a location that is accessible and easy to maintain, alignment with long term system needs, including securing of easements, as well as overall coordination with municipalities and third parties optimizes design and construction costs for all.

ii. Cost-Benefit Analysis: All new installations are designed and constructed as per FHI's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner. FHI collects costs in accordance with the DSC, the Public Service Works on Highways Act, and any other applicable codes or regulations.

iii. Historical Investments & Outcomes Observed: As these projects are externally driven, FHI routinely accommodates new projects within its service territory. These investments have enabled access to the distribution system, which in turn has allowed continued growth and development within FHI's service areas.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM ACCESS

PROJECT: NEW SERVICES

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program addressed FHI's new services projects which are non-discretionary projects as set out in the DSC. Customer initiated requests for new/upgraded services are budgeted based on historical expenditure trends, growth predictions and consultations with customers and developers. The quantity of service projects varies annually and includes the design and installations of new/upgraded residential and commercial services. This includes upgrades in residential panel service sizes from 100A to 200A for new loads such as EV's. New connections and service upgrades are planned using standardized designs that meet the requirements of O.Reg 22/04. FHI's contribution level is determined using the methodology set forth in the DSC and the Conditions of Service.

A forecast of the number of new/upgraded services is provided below, based on historical levels, and using information from developers where available.

	2025	2026	2027	2028	2029
# of New Lots connected for subdivisions	138	154	120	137	140
# of service layouts complete for new/upgraded services	190	190	190	190	190

2. TIMING

i. Start Date: January 2025

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: There are several factors that could impact the project schedule including:

- Customer delays/timing of request.
- Customer availability of funds.
- Material procurement delays.

FHI coordinates with customers to mitigate as many factors as possible.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	419	454	336	478	410	371	300	375	378	371	383	386
Contributions	244	206	130	239	198	158	91	131	146	148	150	151
Capital (Net)	175	248	206	239	212	213	209	244	232	223	233	235

4. ECONOMIC EVALUATION

Economic Evaluations are generally not applicable for new services where the bulk of the infrastructure is connection assets. However, at times where modifications to the distribution system are necessary they are completed in accordance with the DSC and are in either the Subdivisions or Other Recoverable Work programs.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3. The below table outlines the number of new subdivision lots and number of service layouts completed each year with the associated expenditures.

	2018	2019	2020	2021	2022	2023
# of New Lots connected for subdivisions	129	67	81	156	125	46
# of service layouts complete for new/upgraded services	114	133	184	200	204	201

The quantity and scope of requests made by customers varies year-to-year, however FHI forecasts based on the best available data considering potential growth and development and based on developers expected construction timing.

6. INVESTMENT PRIORITY

This investment program is classed as a high priority since it is a non-discretionary program.

Mandatory projects are completed as required by FHI, and when competing mandatory projects are undertaken FHI ensures alignment to its project prioritization processes.

Projects in this program are driven by customer and developer requests, as is the investment prioritization. This investment program is classed as a high priority since it is a non-discretionary program driven by customers and third-party requests, which is essential to maintain regulatory compliance and customer satisfaction. When requests are initiated under this program, they are balanced with other mandatory system access projects but will take priority over other system undertakings and plans.

7. ALTERNATIVE ANALYSIS

Alternatives are considered on an individual basis for each connection request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. In most cases, residential services are fulfilled where secondary infrastructure already exists making connections straightforward and analysis of alternatives unnecessary. However, in some cases (e.g., rear-lot infrastructure), several aspects must be considered when performing the connection. For instance, the size and location of the lot may require installing additional infrastructure to service the customer, also under consideration is the location of nearby underground infrastructure that may make alternatives cost prohibitive.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: All new installations are designed and constructed as per FHI's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner.

Customer Value: FHI makes best efforts to connect customers within regulated timelines to provide the best value to customers while providing them a cost-effective and timely solution for their situation. Service upgrades to enable the electrification of vehicles and heating/cooling are also completed, empowering customers to benefit from the energy transition taking place.

Reliability: Projects installed under this program are not intended for reliability improvements; however, all new construction is in accordance with FHI's current standards and specifications, which lend themselves to more reliable performance. Construction is coordinated and performed with minimal interruption to existing customers.

Safety: Projects under this program are typically not intended to address existing safety concerns with the distribution system; however, because they are designed and constructed in accordance with FHI's latest standards and specifications, which meet or exceed all applicable industry standards, they inherently provide a level of both public and operational personnel safety.

2. INVESTMENT NEED

Projects in this program are driven by third party requests, as is the investment prioritization under this program. These are mandatory projects and are non-discretionary in nature.

i. Main Driver: Mandated Service Obligations - These projects are mandatory. Scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.

ii. Secondary Drivers: N/A

iii. Information Used to Justify the Investment: This program, which consists of customer-initiated projects, is non-discretionary as outline in the DSC. Where available, FHI uses information from developers and customers to form the investment amount, as is the case for subdivision lots in some of the forecast years, in the absence of detailed information, historical averages are used.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI ensures that the connection of new customers allows for a flexible and resilient distribution system that also supports future growth. This includes sizing of equipment to meet both the current and projected needs of the load and any future loads it may impact, careful selection of equipment placement in a location that is accessible and easy to maintain, alignment with long term system needs including securing of easements as well as overall coordination with municipalities and third parties that optimizes design and construction costs for all.

ii. Cost-Benefit Analysis: All new installations are designed and constructed as per FHI's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner. FHI collects connection costs in accordance with the DSC and the Conditions of Service.

iii. Historical Investments & Outcomes Observed: As these projects are externally driven, FHI routinely accommodates new projects within its service territory. These investments have enabled unrestricted access to the distribution system, which in turn has allowed continued growth and development within FHI's service areas.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM ACCESS

PROJECT: NEW SUBDIVISIONS

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

FHI distributes electricity to residential, commercial, and industrial customers through overhead and underground infrastructure. These projects, which are nondiscretionary (under the Distribution System Code) consist of numerous projects which are required for expansion and connection from FHI's distribution system to new residential subdivisions / developments.

To accommodate these requests, some existing asset upgrades are required, including, but not limited to pole replacements, overhead switch replacements/coordination, pad mounted switch replacements. All requests are reviewed against the DSC and current Conditions of Service to determine FHI's contribution level.

Projects in this program are primarily driven by developer requests as is the investment prioritization under this program. Projects constructed and connected under this program are designed in accordance with FHI's Conditions of Service, design standards, and material specifications. Where applicable, capital contributions towards the cost of these projects are collected by FHI in accordance with the DSC and the provisions of its Conditions of Service.

Based on current subdivision plans and estimated timing from developers, FHI expects to construct infrastructure that would add approximately 300 homes to its customer base. While these areas are subject to change based on developer needs and requirements, currently, it is planned that these areas are:

- **Thames West Phase 2** - a subdivision development with an anticipated build-out of 45 homes.
- **520/525 Orr** - a subdivision development with an anticipated build-out of 192 homes.
- **Thames Crest Phase 2B** - a subdivision development with an anticipated build-out of 63 homes.

2. TIMING

i. Start Date: The scope, timing, and schedule of the projects in this program are driven by the developers and their consultants. Through regular meetings and communications with these key stakeholders FHI stays aware of the timetable for the various projects throughout the year.

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: There are several factors that could impact the project schedule including:
   - Developer delays.
   - Developer availability of funds.
   - Inclement weather conditions.
   - Material procurement delays.

FHI coordinates with developers to mitigate as many factors as possible, including ordering long lead time materials earlier in the process than normal to provide extra delivery time.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	551	89	456	232	223	379	370	407	312	335	338	351
Contributions	226	81	251	95	106	254	96	149	137	139	142	146
Capital (Net)	325	8	205	137	117	125	274	262	175	196	196	205

4. ECONOMIC EVALUATION

Economic Evaluations are completed in accordance with the DSC and Subdivision Agreements for each new subdivision expansion project in the FHI service territory to collect capital contributions, as well as to rebate customers over the connection horizon period. FHI works with developers to complete these economic evaluations and collect and rebate as appropriate.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

Estimates for capital contribution for the various projects listed under this program are developed from historical information of previous similar projects as well as known information about the upcoming developments themselves.

The civil portion of these developer-driven projects are supplied and installed by the developer's contractor, while all electrical infrastructure is typically competed by FHI resources. As per FHI's Subdivision Agreement, the developer's consultant, is required to provide a capitalization of assets to FHI.

FHI gathers all required capital contribution at the beginning of the project, and then will rebate money back over the 5 year horizon after energization of the subdivision, or when the last lot is connected, whatever comes first. Historical costs and net capital contributions fluctuate depending on number of new subdivisions constructed, as well as the amount of rebates owed from previous year connections.

For the forecast year costs, FHI used the average cost of subdivisions/lot for the infrastructure, where detailed designs and estimates had not been completed. Then multiplied that by the number of lots expected in these developments in years where this information is known and used the historical average in years where unknown. For capital contributions, in the absence of detailed estimates, historical averages were used. The below table shows the average cost/lot going back to 2018.

	2018	2019	2020	2021	2022	2023
Average cost/lot	$1737	$1204	$1409	$2044	$2925	$1904

6. INVESTMENT PRIORITY

This investment program is classed as a high priority since it is a non-discretionary program. Mandatory projects are completed as required by FHI, and when competing mandatory projects are undertaken FHI ensures alignment to its project prioritization processes.

Projects in this program are driven by customer and developer requests, as is the investment prioritization. Assets are transferred as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreement. This investment program is classed as a high priority since it is a non-discretionary program driven by customers and third-party requests, which is essential to maintain regulatory compliance and customer satisfaction. When subdivision requests are initiated under this program, they are balanced with other mandatory system access projects but will take priority over other system undertakings and plans.

7. ALTERNATIVE ANALYSIS

Subdivisions are typically designed by developers' consultants with review and input by FHI. The schedule of each project under this program is determined entirely by the land developers. Civil Construction is performed by the developers' contractors with electrical construction completed by FHI. The funding/ownership is as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreements. As these are driven by third party requests, alternative analysis is not typically examined as these projects and scopes are driven by developers and their consultants.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: All new installations are designed and constructed as per FHI's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions.

Customer Value: These projects add new customers to FHI's customer base, this helps existing customers by spreading costs to a larger customer base.

Reliability: Projects installed under this program are not intended for reliability improvements; however, all new construction is in accordance with FHI's current standards and specifications, which lend themselves to more reliable performance reducing the frequency of outages. Construction is coordinated and performed with minimal interruption to existing customers.

Safety: Projects under this program are not intended to address existing safety concerns with the distribution system; however, because they are designed and constructed in accordance with FHI's standards and specifications, which meet all applicable industry standards, they inherently provide a level of both public and operational personnel safety.

2. INVESTMENT NEED

Projects in this program are driven by third party requests, as is the investment prioritization under this program. These are mandatory projects and are non-discretionary in nature.

i. Main Driver: Mandated Service Obligations - These projects are mandatory. Scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.

ii. Secondary Drivers: N/A

iii. Information Used to Justify the Investment: This program, which consists of customer-initiated projects, is non-discretionary. Where available FHI uses information from developers to form the investment amount, in the absence of detailed information, historical averages are used along with available developable land.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI ensures that the connection of new customers allows for a flexible and resilient distribution system that also supports future growth. This includes considerations such as primary loops (installed or provisioned for future), sizing of equipment to meet both the current and projected needs of the load and any future loads it may impact, careful selection of equipment placement in a location that is accessible and easy to maintain, alignment with long term system needs including securing of easements as well as overall coordination with municipalities and third parties to optimize design and construction costs for all.

ii. Cost-Benefit Analysis: All new installations are designed and constructed as per FHI's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions. FHI collects contributed capital as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreement. All assets installed under this project are fully owned by FHI.

iii. Historical Investments & Outcomes Observed: As these projects are externally driven, FHI routinely accommodates new subdivision projects within its service territory. These investments have enabled access to the distribution system, which in turn has allowed continued growth and development within FHI's service areas.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM ACCESS

PROJECT: AMI 2.0

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program outlines FHI’s investments related to its upgrade of its Advanced Metering Infrastructure (AMI) from AMI 1.0 to AMI 2.0.

The AMI utilized by FHI for revenue metering encompasses various pieces of hardware and software such as smart meters, repeaters, collectors, Head End System (HES), and related software and firmware. Together, these components function to reliably acquire remote meter readings, facilitating accurate customer billing in compliance with the provisions outlined in the OEB’s Standard Supply Service Code (SSSC) and the requirements of Measurement Canada. Additionally, AMI offers opportunities to enhance customer service and reduce costs through features like outage detection, provision of customer usage information, tamper detection, and remote disconnect/reconnect capabilities.

FHI initiated the deployment of its initial AMI 1.0 system back in 2010, utilizing Trilliant’s software and hardware as the vendor, following the directives of the Province of Ontario. The AMI 1.0 system comprises approximately 23,000 smart meters interconnected through a mesh network. These meters transmit data to the HES via meters, repeaters, and collectors, with data subsequently relayed back to FHI over cellular or ethernet networks.

As FHI's AMI 1.0 system approaches its 15-year service life in 2025[1] challenges have arisen. The system has experienced significant issues, prompting the return of approximately 11,000 meters due to various issues, primarily stemming from defects in the communications board connectors. Additionally, around 1,600 more meters meet the criteria for return material authorization (RMA), either remaining in the field and manually read each month, or replaced to maintain manageable meter read levels and awaiting inspection to see if they are repairable. The rate of meters deemed irreparable upon return has also escalated over the years, from 8-10% between 2018-2020 to approximately 23-25% from 2021-2023.

Compounding these challenges, FHI received notice in April 2022 that their residential meters, constituting approximately 85% of their meter population, reached end-of-life status due to parts obsolescence (Appendix L). When this end-of-life notice was received, there were no Measurement Canada certified meters that FHI could purchase from Trilliant as an alternative. As well, all their commercial and industrial meters also no longer had Measurement Canada certification. Given this high level of risk, FHI decided to seek alternative meter options for both residential and commercial customers, while concurrently procuring a substantial quantity of meters through a last time buy to ensure adequate stock into 2025 for new connections and attempt to maintain sustainable manual read levels while exploring future steps.

As the AMI system ages, the frequency of meter failures, particularly communication loss, has surpassed standard operating levels, with meters exhibiting signs of deterioration. Left unchecked, these high failure rates pose significant risks to FHI's operations, including non-compliance with regulatory standards under the federal Electricity Gas and Inspection and Weights and Measures Acts, and the OEB’s DSC and billing provisions of the SSSC, customer dissatisfaction due to billing inaccuracies, uneconomical reactive meter replacements, and operational disruptions stemming from technological obsolescence.

---

[1] Hydro One EB 2021-0110 DSP Section 3.3 Attachment 4, Correspondence from Stephen Lupo, Senior VP Trilliant on Meter Expected Service Life (November 29, 2019).

The need to replace AMI 1.0 infrastructure also creates benefits and opportunities as there have been significant advancements in the technology since the AMI 1.0 system was commissioned close to 15 years ago. AMI 2.0 is a foundational investment in a modern AMI platform to address foreseeable needs over its service life.

AMI 2.0 SOLUTION OVERVIEW

FHI launched its competitive RFP process for a new AMI 2.0 system in Q1 2023, finishing in December 2023. Vendor responses to the RFP provided the same general solution capabilities as described below:

- The AMI 2.0 solution will include equivalent core functionality to that of the AMI 1.0 system (i.e., automated meter reading at time-based intervals, “last gasp” notification to support outage management/restoration, etc.) and functionality associated with a modern AMI platform. The system’s capabilities will be in alignment with functions that comparable utilities are seeking in their next generation AMI systems. More specifically, the AMI 2.0 solution will include the following characteristics and features:
    - Employ a communication network utilizing the 900 MHz frequency band (as opposed to the 2.4 GHz band utilized by AMI 1.0). The 900 MHz band has the advantage of improved range even with obstructions (e.g., foliage, hills, buildings, etc.). This advantage is significant as it results in a reduction in the amount of equipment required for a healthy mesh network and is expected to provide close to 100% coverage of customers that can be reached by the network;
    - The proposed meters are built off an established metering platform and will undergo a thorough and robust factory acceptance testing, system acceptance testing and validation before deployment, which will reduce the risk of having issues with the meters. Additionally, FHI intends to enter into meter failure warranty terms with the vendor to ensure that should a similar issue occur, to limit the liability of FHI;
    - The solution will be based on Wi-SUN Alliance standards-based hardware and software enabling interoperability. These standards, combined with the network’s ability to perform over-the-air firmware upgrades to support future standards, will enable FHI to avoid stranded assets and keep the platform current for the life of the system; and
    - Employ enhanced security to protect data against cyber and other security threats.

AMI 2.0 will also have the ability to address the needs of customers in the future and over the course of the system’s expected service life, including customers’ potential future use of DER’s, connectivity and use of mobile devices, Electric Vehicle integrations, and load disaggregation. The AMI 2.0 platform will allow FHI to accommodate the expected customer needs over the life of the investment as follows:

- meters incorporate embedded computing power, additional measurement capability, and more granular levels of sensing capability and storage. This supports the integration of DERs and provides visibility across the network to end points, providing availability, status, condition, and the potential ability for control capabilities needed to maintain and understand the status of the distribution system;
- meters are equipped with standards-based wi-fi communications which can integrate with customer smart devices and mobile phones to allow customers to understand and reduce or shift demand securely and conveniently;
- all residential meters will be equipped with a 200 amp disconnect switch with “over the air” control capability resulting in reduced truck rolls, quicker customer reconnections, and reduced bad debt costs. Over the past 5 years, FHI has averaged over 350

disconnect/reconnects each year that currently require a contractor to physically visit the site, costing FHI between $6,000-$7,000 each year;
- the secure communication network has higher bandwidth and can support exponentially higher volumes of information from meters and other devices, such as sensors, providing the potential to converge metering and distribution automation networks to reduce duplication and costs;
- the AMI 2.0 platform supports an environment for the creation of Applications (similar to consumer smart device “apps”) to improve customer service, enable more convenient energy management, and to better manage grid operations;
- based on apps being already developed, or in development, AMI 2.0 functionality provides the potential for customers to detect existing and new customer loads (e.g., individual appliances, electric vehicles, etc.) and present information to better manage usage;
- Meters have the capability to identify faulty customer equipment (e.g., meter base installations) to improve customer safety and distribution system operations;
- The AMI 2.0 platform provides the capability for meter locational awareness where meters are aware of their connection to the distribution grid as well as their connected neighbouring meters. This information can be used to ensure the accuracy of the distribution utility connectivity model (the location and connection of assets across the distribution system) and improve the operation of the system;
- The AMI 2.0 system will provide FHI with the option of multi-tenancy hosting on the HES. This provides FHI with the option of seeking cost sharing opportunities with neighboring municipalities to potentially host their smart meters, utilizing the existing AMI network; and
- The AMI 2.0 program will allow FHI to implement these functions over the life of the system provided the functions are prudent and address identified customer needs or reasonable system improvements. These functions would not be possible with the existing AMI 1.0 or equivalent system.

As an outcome of this investment, the AMI 2.0 program will:
- Maintain reliable operation of metering infrastructure by replacing the failing AMI 1.0 system that has reached the end of its service life;
- Reduction in higher than normal meter failures;
- Replace AMI 1.0 in an economic and operationally efficient manner through mass deployment, as opposed to reactive, single meter replacements;
- Maintain compliance with regulatory metering and billing requirements;
- Maintain billing accuracy and minimize the potential of estimated billing and bill corrections;
- Improve customer service through providing faster response times for some types of disconnection/reconnection requests and enabling customer facing applications to better understand and manage their energy consumption;
- Improve operational effectiveness and efficiency (e.g., reduction in field visits for manual meter reading and disconnection/reconnection requests, reduction in network management and data backhaul costs, reduction in IT HES costs, provision of new data sets for operational decision-making, etc.); and
- Provide a modern AMI platform to meet foreseeable customer and operational needs over the system’s service life.

The AMI 2.0 program is a multi-year investment organized over three sequential phases: Pre-Deployment request for proposal (RFP); Planning, HES, and Pilot; and Mass Deployment.

PHASE 1: PRE-DEPLOYMENT RFP (2023)

The Pre-Deployment RFP phase of the program was initiated in the Pre-Filing Period and focused on the competitive procurement of a new AMI 2.0 system.
Initiating the RFP process in 2023 was necessary due to the lead times required to execute the program, to address the risk of accelerating AMI 1.0 meter failures and to mitigate the risk that FHI

was facing with no Measurement Canada certified meters available from their incumbent AMI vendor, Trilliant.

AMI 2.0 RFP

The AMI 2.0 RFP, released in 2023, followed FHI's processes to ensure quality, fairness, and due diligence when engaging third party suppliers. The material goods and services proposed to be procured in the AMI 2.0 investment included the AMI 2.0 hardware and software (meters, collectors, repeaters, and HES) and vendor professional services. To optimize the procurement process and leverage best practices that other LDC's had developed through a similar process, FHI worked with a 3rd party contractor who had completed similar RFP's, to assist in the development, administration, and management. Under this process, administrative aspects of the RFP and technical requirements were developed and written jointly but the evaluation and selection of a preferred vendor were conducted independently by FHI's evaluation team.

The team looked at many different factors when evaluating each of the vendors submissions, such as:

- Ability of the vendor to meet the RFP's requirements.
- The vendors fit with FHI and alignment with long term strategy and goals.
- The Technical Requirements of the solution (e.g. head end system, network, hardware, meter features, security, etc.), and
- Pricing

Each factor was given a weighting by FHI's evaluation team to determine the preferred vendor, details are included in Appendix N.

In Q1 of 2024, FHI received Board approval to enter a contract with the preferred AMI 2.0 vendor (for meters, network equipment, HES, software licences, and professional services).

PHASE 2: PLANNING, HEAD END SYSTEM IMPLEMENTATION AND PILOT (2024-2025)

The Planning, HES, and Pilot phase of the program is to be implemented in 2024-2025.
It involves significant program planning; testing and certification of AMI 2.0 meters and network devices; the design, installation, and integration of the HES; and the procurement of a small number of meters and network equipment to conduct an end-to-end pilot of the solution.

Planning

Upon the selection of the AMI 2.0 vendor and contract signing, operational preparedness planning will occur involving finalizing product specifications, project team creation, new product testing and certification, hardware logistics, pilot scoping, network design finalization and site surveys, and deployment strategy and planning.

Head End System (HES)

The HES is the back-office software system where all of the meter and network information is sent and managed before being distributed to other internal IT systems (e.g. Customer Information System), as well as to the IESO's Meter Data Management Repository (MDM/R). This stage of the program involves implementing a structured approach to designing, building, integrating, and testing the HES.

AMI 2.0 Pilot

The AMI 2.0 pilot stage, involving 300-400 meters and a small amount of network equipment, will be planned in 2024 and implemented in Q4 2024 or Q1 2025 upon HES “go live”. The pilot will allow FHI to:

- Gain operational experience with AMI 2.0 in advance of mass deployment;
- Develop the processes required to cost-effectively scale up to mass deployment; and
- Identify best practices in minimizing customer impacts associated with transitioning from AMI 1.0 to AMI 2.0.

PHASE 3: MASS DEPLOYMENT PLANNING AND IMPLEMENTATION (2025-2029)

The mass deployment of network equipment and meters is a multipart activity involving pre-installation planning, network installation activities, field deployment, and customer communications.

Planning

During the planning stage, facilities are prepared for AMI meter processing, network communication device locations are verified, and plans are developed for mass meter deployment. The workforce and contractors are trained, and meters are gone through system acceptance testing to ensure they meet performance requirements.

Network Installation

AMI communications network installation involves verifying the location of Repeaters and Collectors in the field. As part of the RFP process, FHI provided the GPS coordinates of all meters in their network, as well as GPS coordinates of all poles where repeaters and collectors could be mounted. A network design was completed as part of the RFP process to determine the number of repeaters and collectors required for 100% network coverage. This stage will involve field verification of these locations, and deployment, which occurs ahead of meter deployments and involves iterations of validating vendor-selected locations for network equipment.

Mass Deployment

Once a network verification is finalized for each geographic area, network devices are installed. Once network hardware is installed, scheduling occurs with resources to mass replace meters. Figure 1 below outlines the Meter Deployment Plan by year.

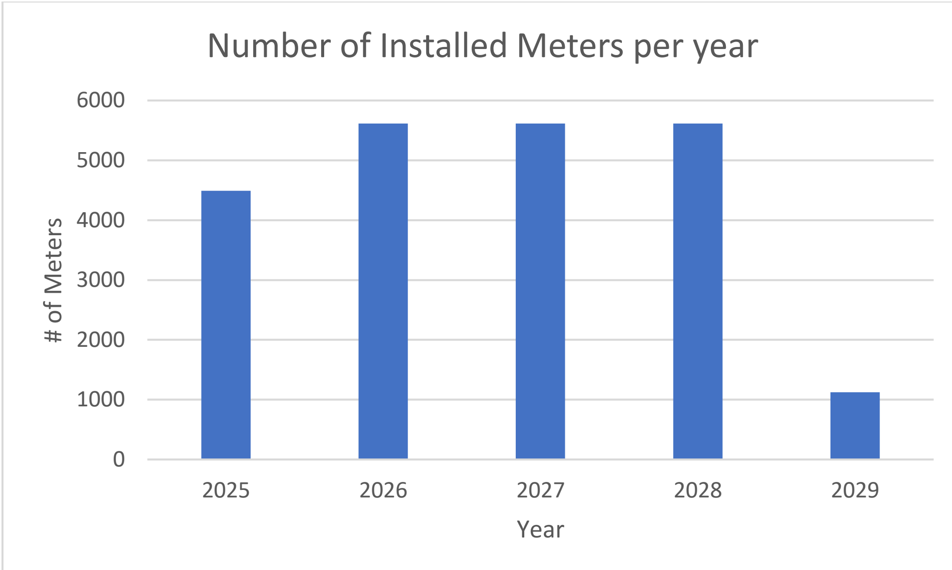


Figure 1: Yearly Meter Deployment Plan

The plan involves the mass replacement of approximately 4,500 meters in 2025 (providing a ramp up period to accommodate the incorporation of lessons learned from the pilot); the sustained mass deployment of approximately 5,600 meters per year from 2026 through 2028; and ramping down to completion in 2029 with the installation of approximately 1,100 meters.

The meter installation process involves informing the customer of a short power interruption of under 5 minutes typically, removing the AMI 1.0 meter, replacing it with a new AMI 2.0 meter, and registering the new meter for the customer premise. Tests of meter communication are performed as part of commissioning, with a monitoring process to identify meters that may not associate with the communication network, and in such cases, steps are taken to determine the cause of the non-communicating meter and rectify the issue.

As part of the competitive RFP process, FHI received pricing from each vendor outlining the capital and operating costs to install and then maintain their proposed AMI 2.0 system. This cost was a contributing factor that was used to evaluate each proposal when deciding on the selected vendor. All costs were made as consistent as possible between vendors to allow for a proper evaluation and scoring.

2. TIMING

i. **Start Date:** 2023

ii. **In-Service Date:** 2023- 2029

iii. **Key factors that may affect timing:** The main factors that could impact the project schedule include:

- Missed meter readings and associated estimated bills/bill corrections during the transition from AMI 1.0 to AMI 2.0 as a result of inadequate network design, the need for multiple re-visits for meter changes, and potential AMI 2.0 technological issues.
    - This risk will be mitigated by defining clear system acceptance tests which will include verification of the network design with field visits, as well as a pilot and test bench phase of the project that ensures communication from meters to the head end system, to the Meter Data

Management Repository (MDM/R) for billing are working as expected and allow for accurate and timely billing.

- Potential for increased costs due to program delays associated with poor network design, operational issues, and incorrect planning assumptions.
  - This risk will be mitigated by verifying network connectivity, planning the deployment of meters, and ensuring the pilot and system acceptance tests are completed and verified prior to mass deployment.
- Potential resource constraints
  - This risk will be mitigated by completing labour forecasting early to identify staffing requirements for the project well in advance.
- Reduced support from AMI 1.0 vendor for legacy network equipment.
  - This risk has been mitigated by forecasting the needs of new AMI 1.0 hardware and aligning purchasing quantities with identified needs.
  - This risk has also been mitigated with FHI's plan to keep sufficient spare AMI 1.0 equipment that is removed from the field in converted AMI 2.0 areas that are suitable for re-use for any unexpected failures.
- There is a residual risk of premature meter component failures as is the case with any electronic equipment.
  - This risk is mitigated by negotiating a warranty period with the new vendor for all hardware and equipment.
- Availability of the vendor to manufacture and deliver AMI equipment in a timely manner, and the availability of qualified resources to perform the volume of replacements required.
  - This risk is mitigated through FHI's due diligence in the RFP process and identifying the deployment timeline as part of the statement of work to understand future supply needs and timings.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Capital (Gross)	0	0	0	0	0	96	200	1316	1540	1585	1631	702
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	96	200	1316	1540	1585	1631	702

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs and their explanations have been provided in Section A3. This program only started in 2023.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 6 out of 13.
This investment is being completed to ensure that FHI stays in regulatory compliance for billing customers from an accuracy and timeliness perspective.
This planned investment is needed to address the deteriorating state of FHI's current AMI 1.0 system, address the numerous technological advancements that have occurred since AMI 1.0 was originally deployed, and eliminate the risk of vendor uncertainty for commercially available meters for purchase for all customers classes.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Potential for injury, not life threatening, or low impact security incident.

Newer AMI infrastructure comes with cybersecurity enhancements that are not present in AMI 1.0 installations given the technological improvements in the past 15 years. Newer AMI meters also have enhanced capabilities to detect potential safety issues and alert FHI to address them in a timely manner.

Reliability/Supply of Power - Sustained interruption of < 3 MW of load or provides for additional system capacity.

Asset History and Performance - Asset history has shown an impact at a station level or has caused widespread issues in the distribution system.

This asset class has experienced multiple defects through approximately half of the meter population, requires manual meter reading throughout FHI's entire service area and has approximately 80% of it's population identified as being in very poor condition through the ACA.

Customer and Community - Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 70% of customers.

This program is designed to deliver on improved reliability of this asset class to the benefit of FHI customers and was supported by over 70% of customers who believed that this new investment, with apps that could be used to manage and understand their electricity consumption are of interest to them.

Productivity/Efficiency - Aligns with 4 (Investment reduces operating expenses, investment increases liability with inaction, investment reduces employee time spent on tasks, Investment coordinates with or allows other projects to proceed).

By addressing these assets in very poor condition, FHI reduces operating expenses by no longer needing to manually read or change out failed meters, which reduces employee time spent on tasks, decrease the chances of no longer being compliant with billing and metering regulations, and coordinates with other projects by providing enhanced information to other systems such as FHI's Outage Management System.

Organizational Effectiveness – Aligns with 4 (Investment improves employee response and improves customer experience, investment provides sustainable business operations, Investment permits shared service or cost sharing opportunities, Investment supports innovation).

This program gives customers and FHI more information about demand behind the meter and provides infrastructure that is expected to meet FHI and customer needs into the future. It also supports innovation given the grid edge capabilities of the meter, and by selecting a vendor who is capable of multi-tenancy allows FHI to explore potential shared service opportunities.

Environmental Impact – Addresses one environmental issue (climate change).

By completing this program climate change is addressed as the new infrastructure will be built to the newest standards which are meant to address the increasing number of weather events being seen from climate change.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing –** This option would involve continuing to individually replace failed AMI 1.0 meters with functioning AMI 1.0 meters on a reactive basis.

This option has been assessed on a range of factors:

- Approximately 19,100 AMI 1.0 meters (85% of the meter population) are between 11-15 years old and will begin to reach the end of their 15-year service life in 2025. As outlined in Hydro One's evidence from EB-2021-0110 on their AMI 2.0 system, this service life has been attested by the vendor and supported by numerous studies including the OEB commissioned Asset Depreciation Study prepared by Kinectrics Inc.[2] and the Auditor General[3].
- The AMI 1.0 system is becoming technologically obsolete, with adverse operational consequences and costs associated with short-notice product de-listings, reduced support for older technology and unavailability of parts;
- The only residential AMI 1.0 meter Trilliant currently has available (which did not gain Measurement Canada certification when the AMI 2.0 RFP process was started and occurred in May 2023) that is compatible with Trilliant's existing AMI infrastructure is more expensive than the AMI 2.0 meter prices that were received as part of the AMI 2.0 RFP.
- AMI 1.0 meter failures are trending upward, with the percentage of meter failures of those being sent for RMA increasing from 8-10% of meters from 2018-2020 up to 23-25% from 2021-2023.
- The risk of individual AMI 1.0 meter failures negatively impacting local mesh networks resulting in decreased billing reliability among otherwise reliable meters;
- Individually replacing meters on a reactive basis is costly and inefficient relative to mass replacement;
- Increasing AMI 1.0 meter failures result in the increasing risk of customer dissatisfaction because of billing estimates and corrections;
- Increasing levels of regulatory compliance risk including:
    - Risk of non-compliance with achieving Distribution System billing reliability requirements;
    - Risk of non-compliance with Measurement Canada good repair and maintenance provisions under the Electricity Gas and Inspection and Weights and Measures Acts; and
    - Risk of sample testing meters exceeding their 15-year service life not passing their re-verification and potentially needing to replace thousands of meters with obsolete technology.

---

[2] Kinectrics Incorporated, Asset Depreciation Study for the Ontario Energy Board, Report No K-418033-RA-001-R0000, July 8, 2010

[3] Auditor General of Ontario, 2014 Annual Report of the Auditor General of Ontario, 2014, pg. 391

This option would result in lost opportunities for operational and customer service benefits associated with a modern AMI 2.0 platform and the inability to respond to foreseeable emerging needs.

Taken together, the above factors make it evident that the status quo of replacing failed AMI 1.0 meters on a reactive basis beyond their expected 15-year service life is not viable, not economically prudent, poses significant regulatory and customer service risk, and limits FHI's ability to plan for and address foreseeable customer needs.

b. **Mass Replacement of AMI 1.0 with Competitively Procured AMI System with the same Functionality -** This option would involve mass replacing the AMI 1.0 system with a competitively procured AMI system with the same functionality as currently installed. This alternative addresses the inefficiencies of reactive individual meter replacements through mass deployment and mitigates regulatory and customer service risks associated with unreliable meter communication. However, this alternative does not include the significant improvements and technological advancements that have occurred in AMI over the last 15 years discussed above (e.g., cost effective remote disconnect/reconnect functionality, improved 900 MHz frequency communications to reach more customers, less network equipment to operate and maintain, etc.), nor would it have the capabilities to address future foreseeable needs over the system's service life (e.g., additional meter computing power and measurement capability, more granular levels of sensing capability and storage, greater network band-width, customer and utility applications, etc.). This alternative, in essence, would involve installing a new AMI system that is technologically obsolete at the time it is placed into service, and therefore is not considered appropriate.

c. **Mass Replacement of AMI 1.0 with Competitively Procured AMI 2.0 System with Enhanced Functionality (Preferred Option) -** This option involves mass replacing the AMI 1.0 system with a competitively procured AMI 2.0 system with modern functionality aligned with the capabilities comparable utilities are seeking in their next generation AMI systems. This alternative addresses the inefficiencies of individual reactive meter replacements through mass replacement, mitigates regulatory and customer service risks associated with unreliable meter communication, provides customers with up-to-date AMI capabilities, and provides a platform to address future foreseeable needs and realize benefits over the service life of the investment. Additionally, once fully deployed in 2029, customers will begin to realize the quantified and unquantified benefits of a modern AMI system including annual OM&A savings from reduced manual meter reading (through improvements in network reach and reduction in non-communicating meters due to defective equipment); reduced network costs (through the reduction in monthly network costs associated with less network equipment); reduced IT management costs (associated with moving the HES to a hosted environment instead of being on premise, and increased support level from vendor); reduced field visits (associated with remote disconnect/reconnect capability on all meters), and eliminating the need to maintain two Head End Systems. Plans to enable additional capabilities providing higher and new levels of customer service, improved distribution operations, and increased sustainability (e.g., Load Disaggregation Information Services for Customers, Meter Locational Awareness, Grid Edge Applications etc.) will be explored and executed using prudent processes including stages for proofs of concept, pilots, business case refinements, and requisite approvals.

8. INNOVATIVE NATURE OF THE PROJECT

There are numerous innovative aspects of this project. These include:

Two-Way Communication: Traditional AMI systems primarily focused on collecting data from meters. AMI 2.0 involves enhancements to the system that facilitate two-way communication, allowing not only data collection but also commands and updates to be sent to meters remotely. This facilitates real-time interaction with the grid and enables potential functionalities like demand response, load management and remote disconnect/reconnects.

Edge Computing and Analytics: Integrating edge computing capabilities within meters or data collection points can enable real-time data processing and analysis. By analyzing data closer to its source, FHI and their customers can extract valuable insights promptly, facilitating quicker decision-making.

Integration with IoT Devices: AMI 2.0 allows for the possibility of integrating with a broader range of Internet of Things (IoT) devices beyond traditional meters. This includes sensors for monitoring environmental factors, smart appliances, or DER's like solar panels and electric vehicle chargers. Such integration provides a more comprehensive view of the grid and enables more precise control and optimization.

Cybersecurity Enhancements: With the increasing digitization and connectivity of grid infrastructure, cybersecurity becomes paramount. AMI 2.0 incorporates advanced cybersecurity measures to safeguard data integrity, privacy, and grid stability against cyber threats.

Grid Modernization Initiatives: As the distribution system continues to diversify, AMI 2.0 could be part of broader grid modernization efforts that involve upgrading infrastructure, implementing smart grid technologies, and integrating DER's. These initiatives aim to enhance grid resilience, flexibility, and sustainability to meet evolving energy demands and environmental goals.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: This investment contributes to FHI's operational effectiveness goals by:

- Maintaining reliable operation of metering infrastructure by replacing equipment that has reached the end of its service life;
- Reducing resource requirements for manual meter reading as the quoted solution is meant to cover 100% of FHI's service territory and should not require manual reads other than those in difficult to read locations (e.g. indoor electrical rooms);
- Increasing efficiency and safety through reduced field visits for manual meter reading and disconnection/reconnection requests; Based on historical averages, it is expected that between 400-500 disconnects/reconnects will be able to be done remotely each year;
- Moving to a hosted environment for the HES will require less IT resources to upkeep the networking and hardware for an AMI system, as well as keeping software up to date.
- Maintains operational efficiencies already existing through AMI 1.0; and
- Provides for future new data sets to improve system visibility, enhance control, and support analytics for more informed and timely planning and operational decision making.
-

Customer Value: This investment contributes to FHI's customer service goals by:

- Maintaining billing accuracy and minimizing estimated billing and bill corrections;
- Providing an expected increase in the number of customer tools available to better manage and understand their electricity use and bills;
- Providing faster response times to some types of disconnection/reconnection requests;
- Providing enhanced end-to-end data protection employing the most modern advancements in security architecture;
- Providing a modern AMI platform to meet foreseeable future customer needs, including access to applications that customers could use to better understand and optimize their electricity usage. This was further justified by over 90% of customers indicating interest in having an application available to them providing this type of insight.

Reliability: The completion of this project is expected to address reliability in the following ways:

- Reduction of failure risk associated with the aging assets being replaced;
- Installing an AMI communication network with devices that are expected to provide near 100% communication, allowing FHI to reliably produce accurate bills on time;
- Installing assets with enhanced cybersecurity, providing a more reliable network for communications with greater privacy and security;
- Provide outage notifications for use with FHI's Outage Management System to assist in outage identification, helping to minimize outage durations.

Safety: While this investment is not meant to specifically address safety concerns, installing devices that have greater cybersecurity capabilities, do increase the safety of the metering network and associated data and customer information that is stored and shared over it.

2. INVESTMENT NEED

FHI employs different strategies for revenue meters depending on the stage in the asset's lifecycle. Shortly after AMI installation and a period of time as the system stabilized, the AMI system was expected to enter a period of consistent performance ("normal service life"). In this stage, a cost-effective, low customer impact, run to failure approach was planned to be employed where individual failed meters are replaced with functioning meters like-for-like. However, since FHI deployed their AMI 1.0 system, there has not been a sustained period of stabilization. Due to issues with a defective communication module in their meters, FHI has had to RMA approximately 11,000 meters for replacement of this module. This means that well before any intervention should have been expected for meter issues, FHI has been manually reading meters which do not communicate and replacing hundreds to thousands of meters every year for premature failures. While many of these meters have historically been able to be put back into service in an attempt to use the asset over their full service life, digital components of the meter do begin to deteriorate due to age and environmental conditions, and individual meter failures are beginning to increase across the service territory. This timing has also coincided with the lack of available alternative options for meters that would leverage the existing AMI network. As a result, the need for more efficient mass meter replacement needed to be assessed. This assessment is based on a combination of factors including manufacturer service life information, risk mitigation for regulatory compliance, and failure trends. All of these inputs, discussed below, allow for the best correlation between age of device, risk of failure, and future costs.

AMI 1.0 METER SERVICE LIFE

In EB-2017-0049, the OEB directed Hydro One to explore with the manufacturer its basis for the estimated service life of smart meters. This information, documented in correspondence, was obtained from the vendor (Trilliant), which is the same vendor that FHI uses. In this correspondence, Trilliant attested that it designs its products to operate for a minimum period of 15 years. Independent laboratory analysis commissioned by Trilliant of its SecureMesh radio, the key meter component that enables it to reliably communicate, supports a minimum expected service life of 15-years. However, Trilliant does not guarantee a minimum 15-year meter service life and states that actual meter performance may differ materially from minimum service life. It recommends a conservative approach to replacing metering equipment with a meter replacement cycle that supports up to and including the 15th year of service to balance maximum service life and security of service. The OEB commissioned Asset Depreciation Study prepared by Kinectrics Inc., also found that the appropriate useful life for smart meters was in the range of 5-15 years, for repeaters 10-15 years, and for collectors 15-20 years. Further, the Ontario Auditor General, in its report on Ontario's smart meter initiative, also found the useful life for a typical first generation smart meter was at most 15 years.

CONDITION OF ASSETS

Similar to other types of computing and telecommunications equipment, the need for replacing AMI systems is driven by two interrelated factors: 1) physical condition; and 2) Technological Obsolescence.

PHYSICAL CONDITION

Meter age and meter failures are key indicators of the health of the revenue meter population. Figure 2 and 3 below provides the age of meters for residential and commercial meters. Approximately 85% of the meter population are between 11-15 years old and will begin to reach the end of their 15-year service life in 2025.

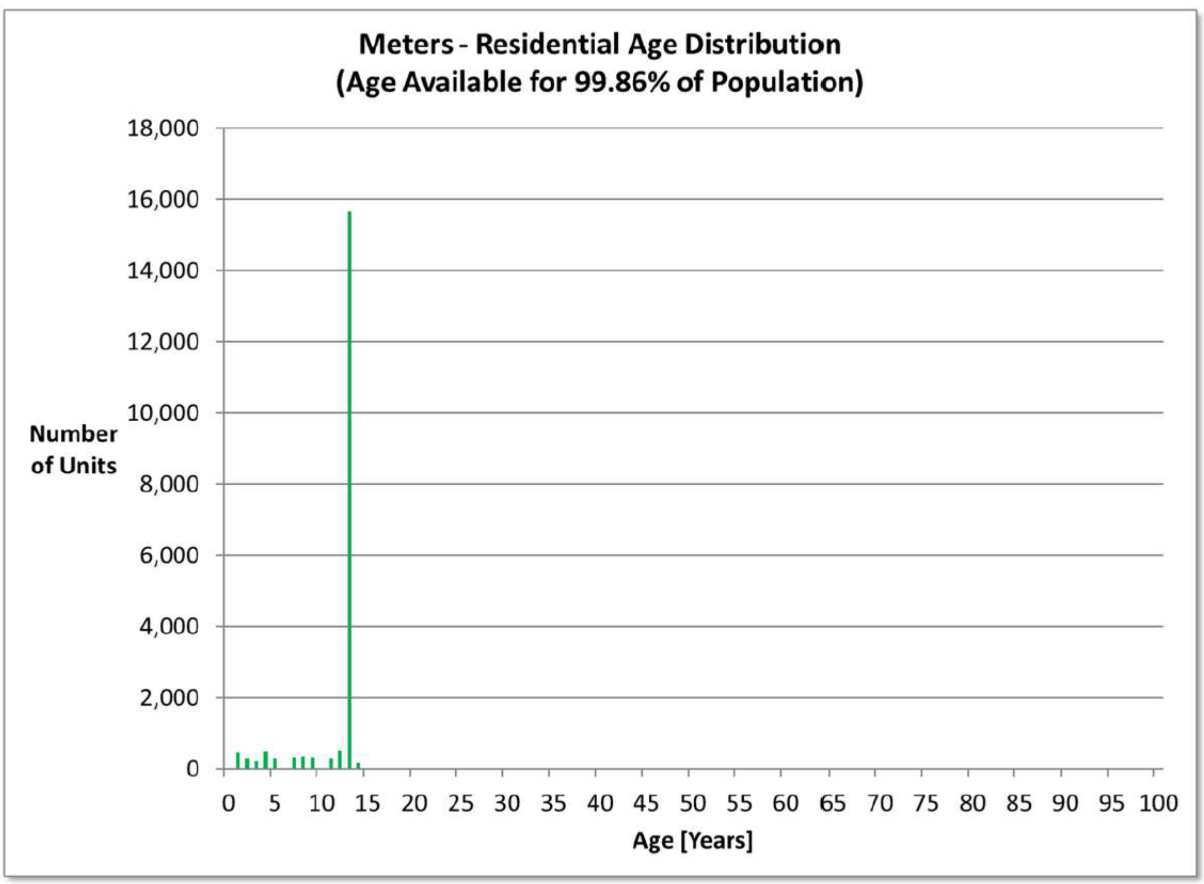


Figure 2. Age of Residential Meters

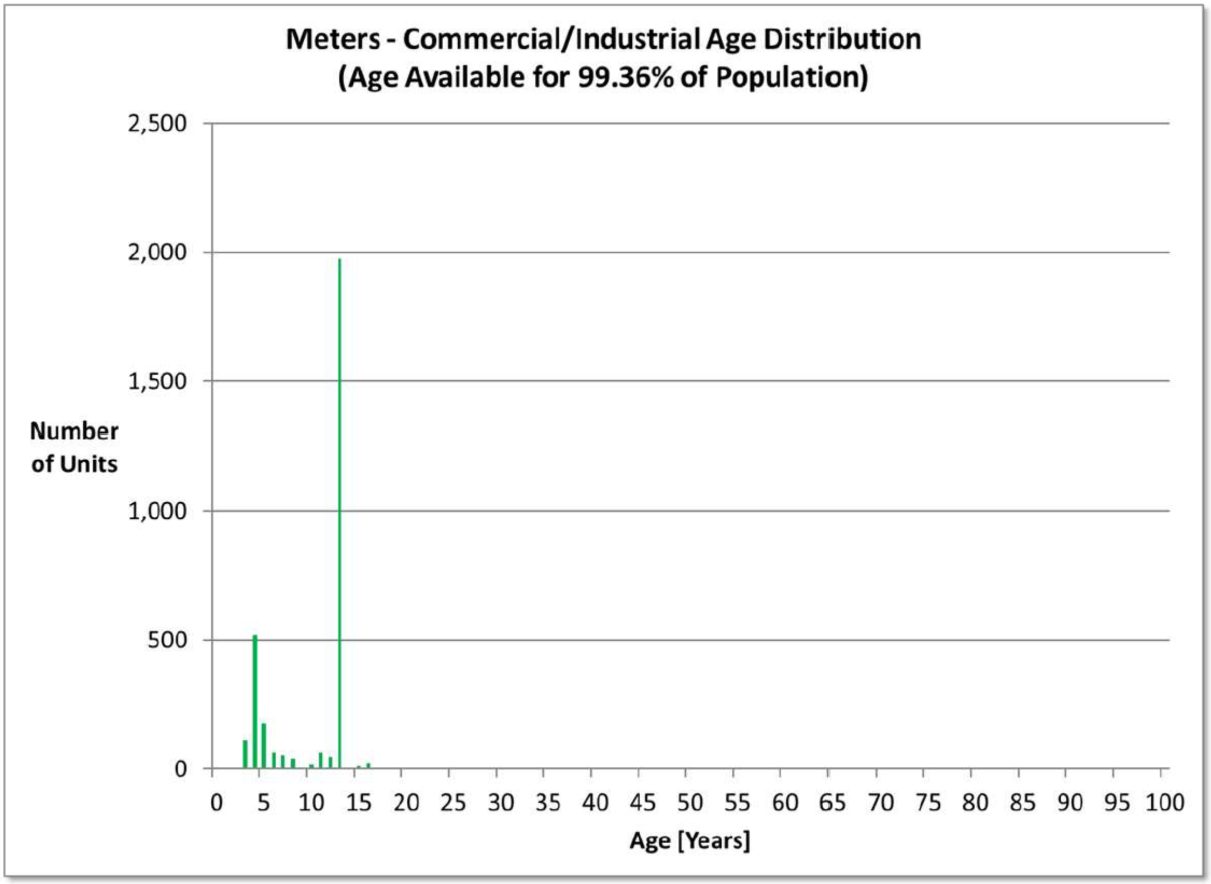


Figure 3. Age of Commercial/Industrial Meters

Figure 4 presents the percentage of meter failures for the period 2015-2023. This is based on the number of meters removed from the field for no longer communicating on the AMI network to the HES, sent to Trilliant for an RMA and deemed unrepairable or too costly to repair.

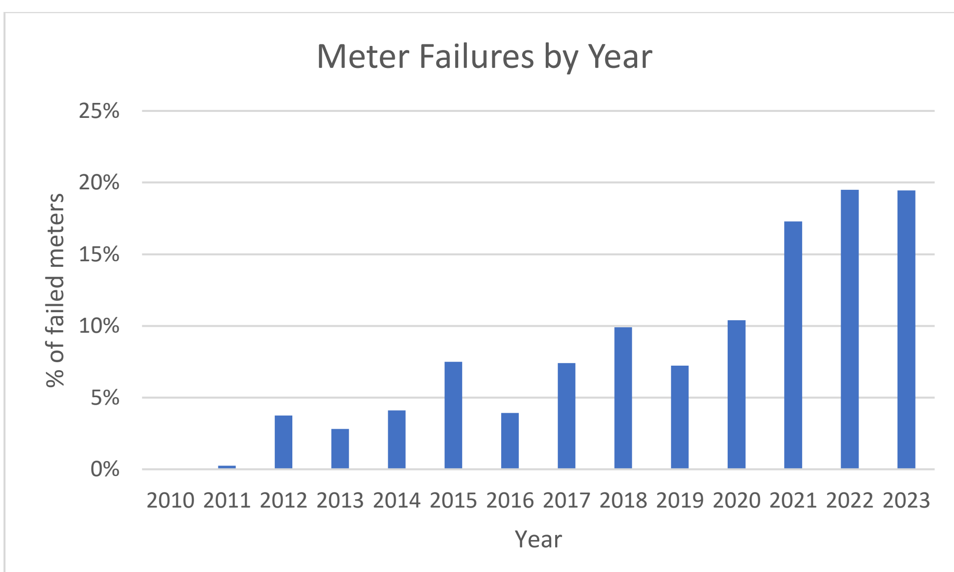


Figure 4. Percentage of meter failures identified through RMAs by year.

This information and condition is further substantiated by Kinectrics ACA, which indicated that approximately 18,000 meters were in very poor condition and require replacement in the next 5 years.

TECHNOLOGICAL OBSOLESCENCE

Unlike traditional electromechanical meters, AMI systems are complex and subject to both physical (discussed above) and technological obsolescence factors. The Ontario Auditor General, in its report on Ontario's smart meter initiative, found a 15-year service life estimate for meters is likely overly optimistic given technological obsolescence considerations. AMI systems, in general, are subject to significant technological changes and are similar to other types of information technology requiring significant upgrades or more frequent replacement as the technology matures. However, unlike other forms of information technology, it is not viable to physically update installed meters given the significant volume of devices, their geographic distribution across the service territory, and their sealed nature. In this regard, FHI is experiencing multiple conditions of technological obsolescence with its AMI 1.0 system, which in turn lead to operational challenges and costs including:

- Short notice product de-listings and the related effort to identify, test and approve replacement products;
- Reduced vendor support for older technology and unavailability of original parts;
- Lost opportunities for benefits and efficiencies associated with advancements in AMI technology since 2010 including improved network reliability and coverage, additional features, and AMI platform enhancements (e.g. enhanced meter memory and increased network capacity) to address foreseeable future needs (e.g., increased adoption of DER's such as distributed generation, battery storage, and electric vehicles).

REGULATORY COMPLIANCE CONSIDERATIONS

ELECTRICITY GAS AND INSPECTION AND WEIGHTS AND MEASURES ACTS

The Electricity and Gas Inspection Act requires all meters be verified through a sampling program at specified intervals in order to ensure a customer's electricity usage is metered accurately. Once a meter seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended through compliance sample testing or be replaced. Approximately 19,000 meters, or 84% of the total meter population will have their seals expire between 2025 and 2029 and require compliance sample testing (involving testing a smaller sample group as per Measurement Canada specifications). As a result, in the absence of intervention, sample testing will need to occur on 84% of the meter population that will have reached or exceeded the end of their service life. This poses a risk of potentially needing to replace thousands of meters with obsolete AMI 1.0 technology should a sample fail.

The Electricity Gas and Inspection Act also requires meters be kept in a condition of "good repair" and the Weights and Measures Act and related regulations require devices be maintained in proper operating condition. In this regard and as discussed above, the meter population has begun to show conditions of disrepair including LCD display failures. As meters age beyond their designed service life and deteriorate due to age and environmental conditions, there is an increasing risk of non-compliance with good repair provisions of the Electricity Gas and Inspection and Weights and Measures Acts, and related regulations.

ONTARIO STANDARD SUPPLY SERVICE CODE AND DISTRIBUTION SYSTEM CODE
The Standard Supply Service Code, together with the Distribution System Code, set out the obligations FHI must meet in regard to billing customers. In this regard, FHI is obligated to bill its customers based on their rate plans and must issue customers no more than 2 estimated bills every 12 months and issue an accurate bill 98% of the time on a yearly basis. The DSC defines an accurate bill as a bill that contains correct customer information, correct meter readings, and correct rates. A bill is considered inaccurate if: a) the bill has been issued to the customer and subsequently cancelled due to a billing error; or b) there has been a billing adjustment in a subsequent bill as a result of a previous billing error. Billing accuracy, as defined above, is a function of the general performance of the AMI network overall, the number of individual meter failures (and the impact of those individual meter failures on neighbouring meters due to the nature of the mesh network), and the related ability to replace meters and/or perform unscheduled manual meter reading in time to avoid an estimated bill. As meter failures continue to increase as discussed above, and the associated volume of field work in replacing individual meters and unscheduled manual meter reading continues to increase, the risk of inaccurate bills and non-compliance with DSC billing reliability standards will also increase without significant intervention. In the 2019-2023 period, field work associated with meter reading increased from $3,900 to $37,900.

i. Main Driver: Failure Risk and Functional Obsolescence – FHI is seeing an increasing percentage of meters no longer being repairable, causing more reactive meter replacements and manual meter reads. Given the age of the AMI 1.0 infrastructure and technologies used as part of this deployment, FHI is observing that vendors no longer support or can build certain meters, and the capabilities of AMI 2.0 meters are significantly more advanced than those deployed in AMI 1.0.

ii. Secondary Drivers: Mandated Service Obligations – As outlined above FHI is looking to minimize the risk of no longer being in regulatory compliance for billing customers and being able to provide meters in a cost-effective manner to maintain this compliance. FHI also encountered an additional risk as an end-of-life notice was received from their vendor for residential meters, with no certified alternative available for purchase, further jeopardizing FHI's ability to maintain compliance.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of this program.

Given vendor attestations, observed meter failure trends, the condition of assets (physical and technological), and regulatory considerations, FHI considers it prudent to plan based on a 15 year service life for its AMI 1.0 meters. FHI also had the additional challenge of being faced with no Measurement Canada approved meters for their existing AMI 1.0 network, with no guarantee of when alternatives would be available. All of these combined to pose critical risks to FHI, which affect various elements of the business, including:

- Reduced billing reliability from individual failed meters resulting in compliance risk and customer dissatisfaction from estimated bills and bill corrections;
- Weakened local mesh communication networks potentially impacting billing reliability of functioning meters;
- Increasing field work and associated costs as a result of unplanned individual meter replacements and unscheduled manual meter reading;
- Higher labour costs for individual meter replacements relative to mass meter replacements;
- Higher unit meter costs as a result of lower volume purchases relative to bulk purchases associated with mass meter replacements;
- Replacement of failed meters with obsolete technology;

- Lost opportunities for operational and customer service benefits associated with up-to-date technology and being in a position to respond to foreseeable emerging trends over the new system's service life; and
- Non-compliance with the Federal Electricity Gas and Inspection and Weights and Measures Acts, and the Distribution System Code.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI completed RMA's and replacements on meters that prematurely failed in an attempt to get their full estimated service life as the most cost-effective way to maintain their AMI 1.0 system. However, given the increasing failures, meter availability uncertainty from the incumbent vendor, and overall age and condition of the system FHI entered into a competitive RFP process for an AMI 2.0 deployment. This is consistent with what many other utilities are doing, and FHI utilized a similar RFP process and evaluation that others have used to ensure a fair and thorough process was used to select the vendor that would best meet FHI's, and their customers, current and future needs.

ii. Cost-Benefit Analysis: As mentioned in Section A1, FHI received pricing from all vendors for their submission. This included the vendors full costs needed to fully deploy and then operate the AMI network over the expected life of the system. A detailed analysis (including a Net Present Value calculation) of each vendors costs over the expected life of the system was then completed. This was factored and weighted into the final selection of the AMI 2.0 vendor to ensure this significant investment would meet the expected needs of FHI over its service life, and that FHI was selecting a solution at a suitable and competitive price (Appendix N).

iii. Historical Investments & Outcomes Observed: Over the historical period, FHI has seen it's operating costs to maintain their AMI 1.0 system continue to increase. These increases are mainly from: RMA's of non communicating meters, manual meter reads, and reactive replacements. FHI's resources are constrained by the amount of manual meter reads being done each month to maintain regulatory compliance, and if the trend continues to increase, puts FHI at risk of falling out of compliance or needing to bring on additional resources for this task.

iv. Substantially Exceeding Materiality Threshold: Given the overall project costs, FHI has included significantly more information within the materiality narrative to justify and explain the need for investment, and the meticulous process undertaken to ensure a solution that was financially responsible and would also serve the needs of customers and FHI over its service life was chosen.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Please refer to Section A8.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM RENEWAL

PROJECT: OVERHEAD POLE-LINE REPLACEMENT

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program outlines FHI overhead capital pole line rebuild projects. These projects address the replacement of sections of pole lines where the majority of these assets have been identified by the ACA as being in poor or very poor condition. Where appropriate, other pole line equipment within these projects that has been identified as end of life, will also be replaced. Examples of these include:

- Aerial transformer
- Insulators
- Cross arms
- Conductor
- Switches, etc.

Where these assets have been determined to be suitable for re-use, they will be kept as spares, or placed back into service as part of the project.

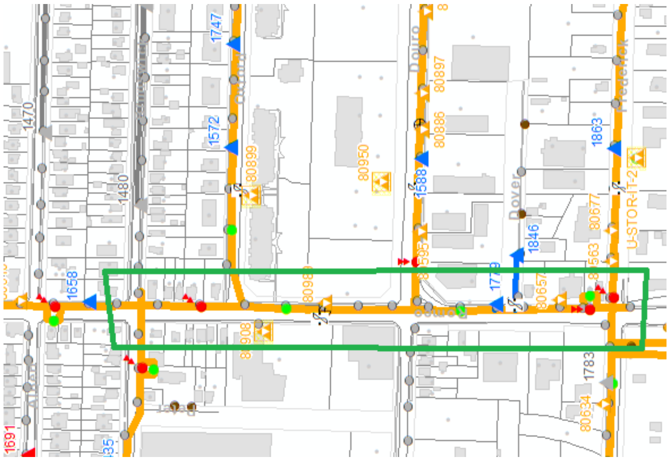
FHI has approximately 6,000 wood and concrete poles that comprise this category. As part of the ACA, Kinectrics identified that 890 wood poles and 129 concrete poles (17% of all poles) were in poor or very poor condition.

Identification of poles as part of this program is a multi-step process beginning with the field inspection and testing data collected as part of the asset management process. The data collected as part of this effort informs the ACA, and this data is then imported into GIS to be viewed spatially. Poles in close vicinity to each other with similarly poor health indices are then grouped together to create a capital pole line rebuild project where feasible. Each project scope includes the design, construction and installation of new poles framed to conform to O. Reg. 22/04 compliant standards. Through this project, FHI plans to improve the level of safety and reliability associated with newer standards and materials.

As part of this program FHI plans to replace on average 60-75 poles per year.

For the 2025 test year the following projects have been selected and will result in the replacement of 59 poles:

ROMEO ST. S – FREDERICK ST TO BRUNSWICK ST.



The scope of this project is the replacement of 20 poles on Romeo St. S. from Frederick St to Brunswick St. The project spans approximately 450 meters. The majority of poles are over 50 years old and have been identified by the ACA as being in poor or very poor condition.

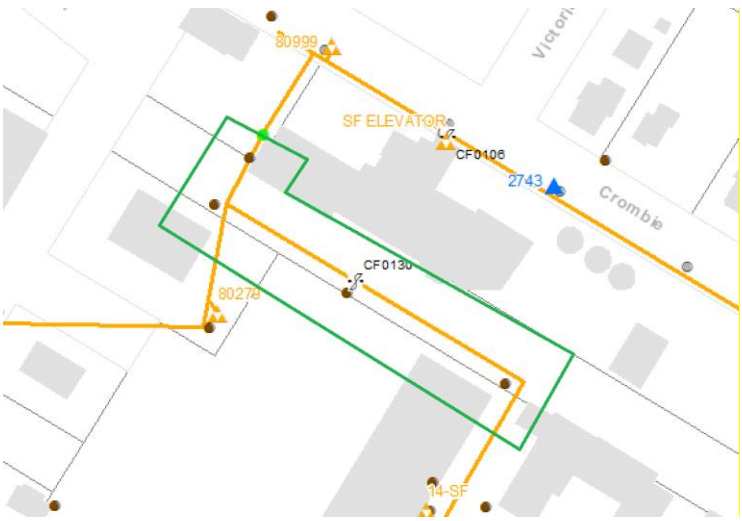
LOUISE ST – BRYDGES ST. TO BLAKE ST.

The scope of this project is the replacement of 5 poles on Louise St. from Brydges St. to Blake St. The project spans approximately 125 meters. The majority of poles are over 50 years old and have been identified by the ACA as being in poor condition.

NELSON ST. – WALNUT ST. TO ASH ST.

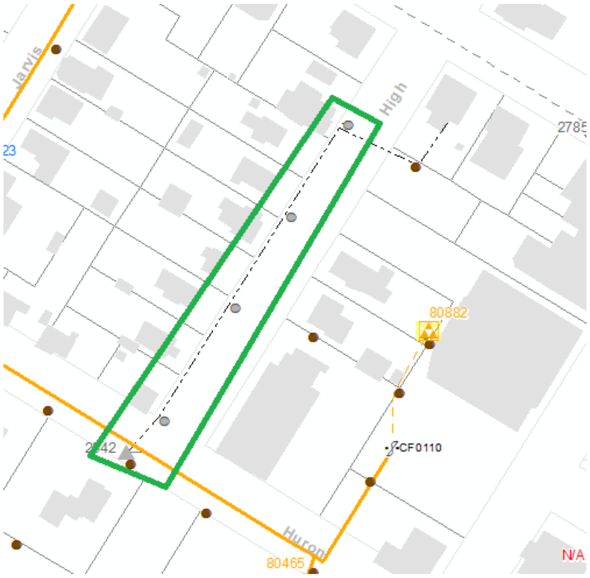
The scope of this project is the replacement of 11 poles on Nelson St. from Walnut St. to Ash St. The project spans approximately 280 meters. The majority of poles are over 45 years old and have been identified by the ACA as being in poor or very poor condition.

RAILWAY CROSSING – MAIN ST AND CROMBIE ST.



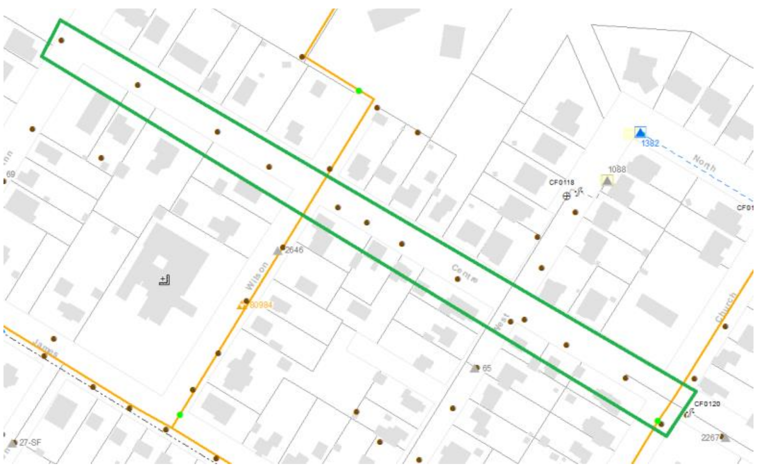
The scope of this project is the replacement of 4 poles along the railway corridor between Main St. and Crombie St. The project spans approximately 120 meters. The majority of poles are over 40 years old and have been identified by the ACA as being in fair or poor condition.

HIGH ST. – HURON ST TO MARKET ST.



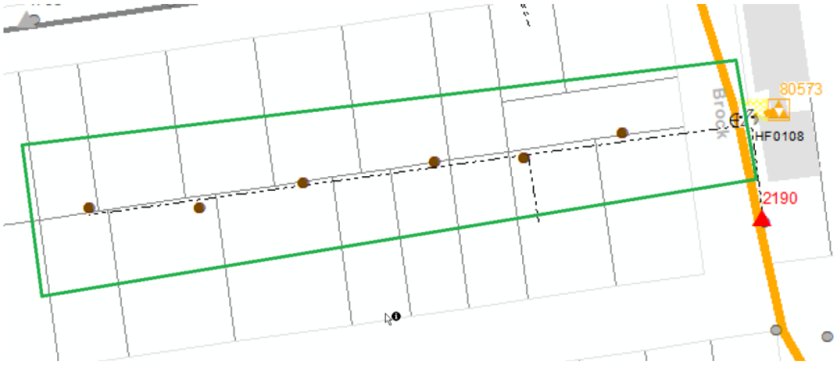
The scope of this project is the replacement of 4 poles on High St. The project spans approximately 130 meters. The majority of poles are over 50 years old and have been identified by the ACA as being in poor condition.

CENTRE ST. – ANN ST TO CHURCH ST.



The scope of this project is the replacement of 8 poles on High St. The project spans approximately 380 meters. The majority of poles are over 70 years old and have been identified by the ACA as being in very poor condition.

REAR LOT – BROCK ST TO ELIZABETH ST.



The scope of this project is the replacement of 6 poles in back yards. The project spans approximately 200 meters. All poles are over 50 years old and have been identified by the ACA as being in poor condition.

2. TIMING

i. Start Date: January 2025

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: The main factors that could impact the project schedule include:

- Unplanned projects from higher priority work (e.g. road relocations), resulting in resource constraints.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Capital (Gross)	654	624	327	443	673	874	637	848	1082	1059	1055	1110
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	654	624	327	443	673	874	637	848	1082	1059	1055	1110

2020 and 2021 saw a decrease in capital expenditures compared to other historical years, with the main contributing factor being COVID and the impacts it had on planned work over the two years.

2025 and onward sees an increase in capital expenditures compared to historical. The main driver for this increase is the results of the ACA which identified the need for FHI to increase the volume of asset renewal in this area based on the flagged for action plan. The replacements in this category, along with those in the Small capital replacements program and voltage conversion, are set at an annual replacement that targets the minimum volume of asset renewal Kinectrics identified in their ACA.

2026 sees an increase in costs over 2025, and an increase in pole replacements (15). This coincides with a forecasted decrease in spending in System Access categories, in particular one large road reconstruction project that involved the replacement of 17 poles, many of which were also in poor condition. Should another non-discretionary project or program require higher than forecasted funds in future years, similar deferrals in System Renewal investments are considered to determine suitability to smooth overall capital spend.

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

	2018	2019	2020	2021	2022	2023
# of Poles Replaced	51	49	30	42	54	62

Over the historical period, FHI has completed many projects of a similar scope. Metrics for these projects have been captured and based on this data, each project receives a detailed estimate annually. FHI updates these metrics annually based on that year's costs for labour and materials. Forecast costs also include inflation, supply chain and material cost increases. It should be noted that FHI, like other utilities, has experienced a significant increase in material costs since 2021. This has and will continue to have an impact on future costs.

To provide further context, since 2021 the approximate cost to replace a pole has increased by 24%. Since 2021, FHI's labour and trucking has only increased by 8%, meaning the majority of the cost increase for these replacements are attributable to material cost increases, of which FHI has little control over.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 4 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending.

Proactively identifying and replacing poles, the majority of which are in poor and very poor condition and therefore statistically the most likely to fail, minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages and safety risks. The planned pole investments are needed to address the volume of deteriorated poles on FHI's distribution system and comply with external codes/standards.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Public safety concern, not life threatening.

With overhead programs, because there are many exposed pieces of infrastructure, it can have a higher impact on customer and employee safety. The assets that are targeted in this program are proactively replaced and make up a portion of the actionable assets identified through the ACA.

Reliability/Supply of Power - Sustained interruption of > 3 MW (greater than half a typical TS distribution feeder) of load and provides for additional system capacity.

Asset History and Performance - Asset history shows regular failures (>1 each year) or >50% of asset class in poor or worse condition.

The majority of assets being replaced under this program fall within this condition rating as identified through the ACA.

Customer and Community - Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates) and is supported by over 60% of customers.

This program is designed to deliver on replacing depreciated assets that could negatively impact reliability to the benefit of FHI customers and was supported by over 60% of customers who believed the proposed level of investment was at the proper level. It is also targeted at solving potential safety risks from failing equipment.

Productivity/Efficiency - Aligns with 3 (Investment reduces operating expenses, investment increases liability with inaction, investment reduces employee time spent on tasks).

By addressing assets in poor and very poor condition, FHI reduces the potential for injury to staff and the public, and reduces time spent reactively replacing and maintaining these assets, which in turn reduces costs.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses one environmental issue (climate change).

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:
a. **Do Nothing** – this results in reactive replacement of poles which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered appropriate.

b. **Remove overhead line and rebuild underground** - while this would improve the aesthetics, and potentially improve reliability by removing outages that generally occur more frequently on overhead systems (tree contact, wildlife), underground construction results in significant cost increases compared to overhead. For this reason, this alternative is not considered.

c. **Replace Like for Like to New Standards (preferred option)** - This is the preferred approach when inspection and ACA data indicates that a group of poles needs replacing. All poles, and where appropriate, associated hardware and equipment, are replaced with the latest standard design. The proactive replacement of poles in poor and very poor condition aims at ensuring that the number of unplanned outages remains minimal by avoiding asset failures, so that customers have access to reliable electricity.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: The infrastructure will be upgraded to current FHI specifications and USF design standards which are intended to improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. Additionally, when these assets are replaced, FHI examines the associated assets (transformer, switch, etc.) and when also identified as end of life, replaces them as well, rather than return at a later date.

Customer Value: The planned, proactive replacements that are enabled as a result of this project is less costly than reactive replacements. It also reduces the number of in service assets at a higher potential for a risk of failure and the safety hazards that are associated with this risk.

Reliability: The completion of this project is expected to maintain current reliability in the following ways:
a) reduction of failure risk associated with the aging assets being replaced;
b) Installation to new standards, which can include fiberglass brackets, larger insulators, animal guarding, to reduce wildlife related outages;
c) The proactive scheduling of asset replacement reduces the outage duration; and
d) Assets installed using current standards are better able to withstand adverse weather conditions.

Safety: A number of these projects involve replacing assets deemed to be in poor and very poor condition, which means, statistically they have some of the highest likelihood of failure in FHI's distribution system. Therefore, replacing them eliminates a potential safety hazard. Typically, newer installations also involve the installation of equipment that provide greater clearances between conductors and between conductors and the pole, this improves worker safety when working on these assets. All new assets are installed to meet the latest FHI specifications.

2. INVESTMENT NEED

i. Main Driver: Failure Risk – The main driver is to minimize the failure risk associated with poor and very poor conditioned poles as identified in the ACA.

ii. Secondary Drivers: Safety – Proactively replacing deteriorated poles reduces the risk of poles and/or live conductors falling to the ground and creating hazardous conditions for the community.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of this program. Recent ACA results identified 839 (13.9%) of poles to be in poor condition and 170 (2.8%) of poles to be in very poor condition. By identifying and proactively replacing poles nearing their end of life and in deteriorated condition, FHI mitigates the risk of outages and provides a safer electrical distribution system.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI utilizes Utility Standards Forum design standards. These standards are based on CSA C22.3 No 1 Overhead Systems Heavy Weather Loading design standards and CSA C22.3 No 7 Underground Systems.

Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. FHI design and construction practices follow Ontario Regulation 22/04 in its design, construction, and material selection to ensure a safe and reliable system.

FHI also conducts annual inspection and testing programs, evaluates the results, and utilizes this information to help identify areas requiring replacement along with the results of their ACA. Replacing deteriorated assets with those that meet today's standards improves safety, maintains reliability, and increases resilience.

ii. Cost-Benefit Analysis: Each project created under this category is reviewed on a case-by-case basis to identify potential options. This may include, replacing with fewer poles to reduce costs, finding an alternative running line to reduce capital and operating expenses, etc. Typically, there are no practical alternatives to pole replacement projects.

iii. Historical Investments & Outcomes Observed: FHI tracks the average historical costs to form the basis for developing the budget for the forecast period. Using ACA recommendations, previous pole testing data, and historical quantities of deteriorated poles identified in the field, FHI attempts to accurately predict the quantity of poles that will require replacement. Historical costs can be found in section A3 and A5 of this document. Through active pole replacement initiatives, FHI has been able to maintain safe and reliable electricity supply.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM RENEWAL

PROJECT: UNPLANNED SMALL REPLACEMENTS

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

The majority of the investments in this program cover the costs of small unplanned projects and reactive replacements over the year for assets that are found to be in poor condition or pose a potential risk to safety and/or reliability.

Examples of work completed in this program are:

- Replacement of wood and concrete poles;
- Replacement of overhead switches; and
- Replacement of aerial or padmount transformers.

The selected assets are either identified as being in poor or very poor condition through the ACA or have prematurely degraded beyond what could be expected of assets of similar age. The assets replaced in this project are identified through ACA results, field inspections and testing, information submitted from customers or internal staff, are small in scope, at several different locations, and are for the most part, unforeseen. These assets are scheduled for replacement within the year and the scope varies widely depending on several factors, such as location, installation complexity and when the issue is identified or type of failure that has occurred.

Similar to historical investments, this category involves the replacement of 12-18 poles, and 10-12 padmount transformers per year, and uses USF standards for construction conforming to O. Reg. 22/04. As these are typically unplanned replacements, the quantity may vary annually based on findings each year. Where appropriate, FHI will incorporate these replacements into a larger program, however these assets are generally replaced when identified.

2. TIMING

i. Start Date: January 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The main factors that could impact the project schedule include:
   - As most of these projects are unplanned, the timing at which the assets need replaced can be random. However, once identified these assets are a high priority for replacement as they pose a risk to safety and reliability.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Period						Bridge Year	Future Costs ($ `000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	247	222	382	506	325	379	349	349	356	363	370	378
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	247	222	382	506	325	379	349	349	356	363	370	378

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

Over the historical period, FHI has completed many projects of a similar scope. The 2021 increase above typical expenditures was largely driven by two underground projects where FHI installed underground road crossings. This was done in coordination with a road rebuild being undertaken by the municipalities and FHI took advantage of this opportunity to install new road crossings as part of the scope of work to be used in a future rebuild. 2021 also saw an increased number of poles replaced over historical, some of which was to compensate for 2020 when COVID caused work interruptions.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 1 out of 13. The timing of these projects is affected by the urgency of resolving the potential risk of failure. When assets are identified as needing immediate replacement they are completed right away, others are scheduled for replacement throughout the year. Not completing this program will result in the perpetuation of reliability issues.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Known hazard with history of issues, possibly life threatening.

Assets that are replaced as part of this program have failed to meet the criteria to remain in service either through test results, because of inspections, or because they are being reactively replaced. These assets must be addressed quickly, prior to them progressing to catastrophic failure in the very near term which would have the potential to cause significant injury.

Reliability/Supply of Power - Sustained interruption of > 3 MW (greater than half a typical TS distribution feeder).

Asset History and Performance - Asset history shows regular failures (yearly) or >50% of asset class in poor or worse condition. Assets replaced under this program meet both of the above thresholds.

Customer and Community - Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates) and is supported by over 60% of customers.

This program is designed to deliver meeting reliability indices to the benefit of FHI customers and was supported by over 60% of customers who believed the proposed level of investment was at the proper level. It is also targeted at solving potential safety risks from failing equipment.

Productivity/Efficiency - Aligns with 2 (Investment reduces operating expenses, investment increases liability with inaction).

By addressing assets in very poor condition, FHI reduces the potential for injury to staff and the public, and reduces time spent reactively replacing and maintaining these assets, which in turn reduces costs.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses four environmental issues (climate change, oil spills, environmentally damaging equipment, Ministry of Environment involvement).

By completing this program climate change is addressed as the new infrastructure will be built to the newest standards which are meant to address the increasing number of weather events being seen from climate change, removing transformers that contain significant amounts of oil prior to leaking eliminates the hazard this equipment could cause and subsequent ministry involvement.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing** – This results in running all assets to failure and the subsequent reactive replacement. This could result in long outages for those customers affected, and potentially after business hours, resulting in a higher cost for replacement. Additionally, the assets in this program have been identified due to their condition and pose a potential risk to public safety and/or customer reliability. The selected assets cannot be ignored. For these reasons, this option was not seen as appropriate.

b. **Like for Like replacement to newest standards (preferred option)** – This option provides the least impact to the customer, the land, and the utility. It is also the most cost-effective and efficient option, and for those reasons is the best alternative when the asset needs to be replaced.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: The infrastructure will be upgraded to current FHI specifications and USF design standards which are intended to improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. Additionally, when an individual asset (e.g. pole) is replaced, FHI may replace the associated assets that are deemed to be at or near end of life as well (transformer, switch, etc.) rather than return at a later date.

Customer Value: The proactive replacements that are enabled as a result of this project as planned is less costly than reactive replacements. It also reduces the number of in service assets at a higher potential for a risk of failure and the safety hazards that are associated with this risk.

Reliability: The completion of this project is expected to have a positive effect on reliability in the following ways:

a) Reduction of failure risk associated with the aging assets being replaced;

b) Installation to new standards can include fiberglass brackets, larger insulators, animal guarding, to reduce wildlife related outages; and

c) The proactive scheduling of asset replacement reduces the outage duration.

Safety: A number of these projects involve assets that pose an imminent failure risk, and therefore, the work almost always involves eliminating a soon to be safety hazard.

2. INVESTMENT NEED

i. Main Driver: Safety - Safety to the public and workers to proactively replace assets before a failure occurs in the system is a driving investment factor. Although the system has protections through fusing, reclosers, relays, and breakers, the initial failure can still pose a safety hazard.

ii. Secondary Drivers: Failure Risk – A secondary driver for this project is aimed at addressing failure risk. Projects replaced in this program have a statistically high probability of failure and these investments facilitate the replacement of these assets, while still continuing to provide a reliable supply of power to customers that would otherwise have been negatively affected.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of this program. The majority of the assets that this program will facilitate the replacement of are in poor condition or worse as identified by the ACA. This investment provides a safe and reliable distribution system and helps maintain FHI's reliability levels.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI conducts annual inspection and testing programs, evaluates the results, and prioritizes the replacement of assets. Replacing deteriorated assets with those that meet today's standards improves safety, maintains reliability, and increases resilience. All replacements are constructed in accordance with USF and/or FHI standards and meet all CSA construction standards and O.Reg 22/04 safety standards.

ii. Cost-Benefit Analysis: The majority of these projects are done like-for-like and no formal cost benefit analysis is completed as this is the most practical solution for assets replaced under this program, and there is a safety risk with delaying their replacement. When projects like the duct road crossings are completed, similar to 2021, FHI considers the long term need in the area, the current condition of assets, and the future costs and practicality of construction to determine the appropriate investment timeframe.

iii. Historical Investments & Outcomes Observed: FHI tracks the average historical costs to form the basis for developing the budget for the forecast period. However, as these are a mix of planned and unplanned replacements, the cost can vary due a variety of factors such as location (backlot infrastructure requiring special machinery), complexity (multi-circuit poles), timing of replacement, and time of year (snowbanks and/or frozen ground). For these reasons it is difficult to create a precise forecast. These replacements have minimal impact to other FHI programs; however reliability has been maintained, enabling FHI to reduce safety hazards to both the public and to staff.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM RENEWAL

PROJECT: SWITCHGEAR REPLACEMENT

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program involves the replacement of poor and very poor condition pad-mounted switchgear.

Distribution system switchgear are essential for connecting, controlling, protecting, and managing electrical distribution networks. They are capable of isolating faults in the distribution system, and can enhance network reliability by sectionalizing outages when they occur. They also are used as switching points to connect local distribution circuits to the main feeder cable systems, and to provide feeder ties that connect multiple circuits together. A single switchgear can impact hundreds of downstream customers.

FHI has 37 switchgears in its system. As part of this program, FHI plans to finish replacing all the air-insulated switchgear with solid di-electric switchgear, as the majority of them have been identified as being in very poor condition.

The reported useful life of pad-mounted switchgear is 20-45 years with a typical useful life of 30 years; and all FHI's remaining air insulated switchgear have exceeded 25 years, with 10 of the 12 identified as being in poor or very poor condition, through the asset condition assessment. FHI has experienced multiple equipment failures from these units over the historical period, decreasing the reliability of its distribution system.

FHI replaces all the air-insulated switchgear units in the system that are with solid dielectric switchgear units. Investments in switchgear replacements will mitigate safety and reliability risks associated with failure of these assets. FHI plans to replace two switchgear per year, until 2026, when the program will be complete. Switchgears are selected and prioritized based on the ACA results, as well as inspection results.

2. TIMING

i. Start Date: April 2025
ii. In-Service Date: 2025-2026
iii. Key factors that may affect timing: The main factors that could impact the project schedule include:
- Material procurement delays.
- Unplanned or higher priority work arises, resulting in resource constraints.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ `000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	173	361	224	297	112	42	206	244	244	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	173	361	224	297	112	42	206	244	244	0	0	0

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

FHI has historically replaced 2-3 air insulated switchgears per year over the historic period, as well as removing one that was not replaced with a switchgear based on the long term system plan and the needs in that area.

2023 spend was lower than typical due to manufacturing delays of the units.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 2 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. The asset management objectives listed below, along with the history of failures seen with this equipment drive the investment priority. Not completing this program will result in the perpetuation of reliability issues with this equipment. The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Known hazard with history of issues and failures.

FHI has had to complete numerous repairs to switchgear as infrared results indicate several hotspots within the units, and since 2015 FHI has had 27 outages as a result of switchgear failures.

Reliability/Supply of Power - Sustained interruption of > 3 MW (greater than half a typical TS distribution feeder) of load.

Asset History and Performance - Asset history shows regular failures (yearly) or >50% of asset class in poor or worse condition. This asset meets both thresholds above.

Customer and Community - Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates) and is supported by over 60% of customers.

This program is designed to deliver on improving the reliability of these assets to the benefit of FHI customers and was supported by over 60% of customers who believed the proposed level of investment was at the proper level. It is also targeted at solving potential safety risks from failing equipment.

Productivity/Efficiency - Aligns with 3 (Investment reduces operating expenses, investment increases liability with inaction, investment reduces employee time spent on tasks).

By addressing assets in very poor condition, FHI reduces the potential for injury to staff and the public, and reduces time spent reactively replacing and maintaining these assets, which in turn reduces costs.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses one environmental issue (climate change).

By completing this program climate change is addressed as the new infrastructure will be built to the newest standards which are meant to address the increasing number of weather events being seen from climate change.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing –** FHI could run the switchgear assets to failure. However, this means prolonged and sustained outages when the assets fail and represents a reduction in reliability and safety for the public and for workers. For these reasons, this option was not seen as appropriate.

b. **Replace like for like** – FHI could replace with the same type of switchgear (air insulated switchgear), rather than updating to solid dielectric. However, this presents drawbacks as the air insulated switchgear are generally more susceptible to environmental factors and contamination, provide less safety as the energized equipment is not encapsulated or enclosed in anything, and typically has more corrosion by being exposed to the air and moisture. It is also now industry accepted standard that all new switchgear installed should be solid di-electric. For these reasons, this option was not seen as appropriate.

c. **Replace with solid di-electric switchgear (preferred option)** – FHI could replace the air-insulated switchgear that are in poor and very poor condition with the latest standard solid di-electric switchgear. This ensures that the new assets installed are in-line with the latest standard, and poor and very poor condition assets are replaced mitigating risk of failure. For these reasons this is the preferred option.

d. **Decrease Pace** - FHI could decrease the pace of investments, prolonging the program. While this would allow for spending in other areas, it increases the risk of equipment failing and reduced reliability. Also, the majority of assets being replaced in this program have also been identified as being in poor or very poor condition, and FHI has already seen numerous failures from this type of equipment. For these reasons, this option was not seen as appropriate.

e. **Removal of the asset (done where appropriate)** - this option is considered for some switchgears based on location and long-term system plan but is not an option for most replacements.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: The infrastructure will be upgraded to current FHI specifications and USF design standards which are intended to improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. Additionally, as there are no exposed apparatus, this type of switchgears are less prone to issues from environmental factors and the accompanying maintenance.

Customer Value: The proactive replacement strategy of the project as planned is less costly than reactive replacements, it also reduces outage length. This strategy also improves communication to customers as the outage is known in advance so that customers can plan alternative arrangements, and FHI can consider customers affected to ensure, as much as is practical, the timing of the replacement has the least impact to them.

Reliability: This project is part of the long-term replacement program. This will reduce incidences of failures due to flashover, improve reliability of the assets, decrease outage time during un-planned replacements and reduce maintenance/repair costs of these assets.

Safety: Switchgear failures pose safety risk to staff and the public. The switchgear may fail when staff are working on the unit or when the public is in close proximity to the unit. When the switchgear unit fails, there may be flashover or rupture of the enclosure, which may result in injury.

2. INVESTMENT NEED

i. Main Driver: Failure Risk - The main driver for this project is aimed at addressing failure risk. This project addresses assets at end of service life and at risk of failure, as identified through annual inspections and the ACA results, creating defective equipment outages.

ii. Secondary Drivers: Safety - At its core, FHI exists to provide safe, reliable electricity supply to its customers in a cost-effective manner. This project removes an asset class that has experienced failures in the past, with a safer alternative.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of the switchgear replacement program. The majority of the assets that will be replaced as part of the program are in poor condition or worse as identified by the ACA, and FHI has seen numerous equipment failures historically from these assets that have contributed to prolonged outages and a decrease in reliability. By replacing assets in poor condition, this investment prevents the power supply reliability from degrading below FHI's targets. The planned replacement is essential in maintaining a reliable distribution system for customers.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. FHI designs and construction facilitates the potential future incorporation of grid modernization equipment and renewable energy generation, and follows Ontario Regulation 22/04 in its design, construction, and material selection to ensure a safe and reliable system. The current industry standard for switchgear is to install solid dielectric as this is a safer alternative for both the public and staff.

ii. Cost-Benefit Analysis: FHI looks at each location to determine the cost of the switchgear replacement with the benefit it will provide. If the long term system plan does not require the need for switchgear in this location, even if one currently exists, the unit is removed from service without replacement, ensuring that the dollars spent in this program are maximized to still remove all air insulated switchgear from service, but not requiring the investment cost that comes with each solid dielectric switchgear.

iii. Historical Investments & Outcomes Observed: FHI has completed several switchgear replacements over the historic period. As a result, the cost for this program can be accurately budgeted based on historical costs and the expected future costs of the units. The proactive replacement is a less costly alternative than reactive as resources and materials can be planned in advance and done during regular business hours. This project helps provide a reliable and safe distribution system for the public and for workers.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM RENEWAL

PROJECT: SYSTEM RE-ESTABLISHMENT

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

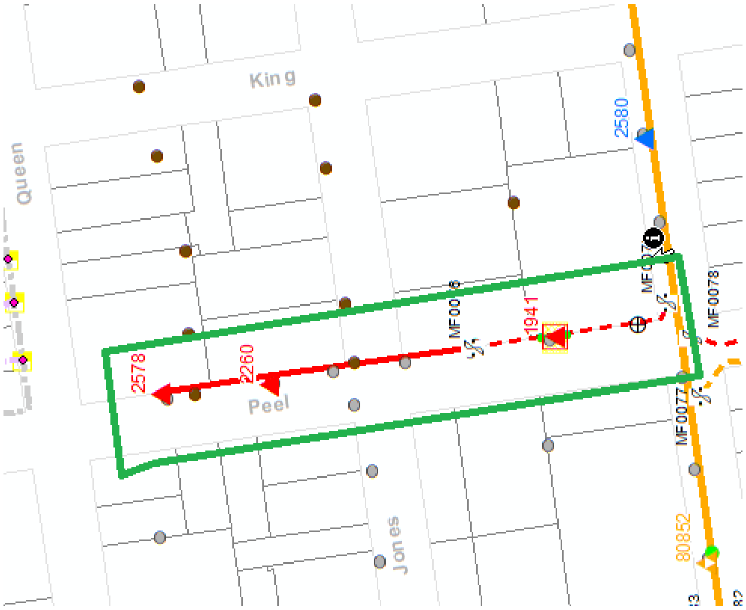
This project category represents investments required to make improvements to feeders in the existing electrical distribution system where the capability of providing redundant supplies of power is constrained. This is a new program that FHI has identified for the forecast period. Typically, these are three phase radial circuits which are in poor condition as identified through the ACA and inspections and require replacement. The existing installations are also typically constructed in a manner such that if an asset is damaged or fails, replacement would be very difficult (e.g. bridge or river crossings).

Projects in this category involve the addition of overhead and/or underground infrastructure to provide the ability to replace assets that normally supply power in these areas and are in poor condition. The trigger for these investments is due to typical replacement of the existing infrastructure without these projects would cause multiple prolonged outages to residential and/or commercial customers and are in areas that should an asset be damaged, or fail, replacement time would be extensive. The project scope includes design, construction and installation of new poles and new underground cables, with associated civil work, designed to conform to O. Reg. 22/04 compliant standards as well as new wire, insulators, and equipment. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability.

As a secondary benefit, these investments provide upgraded or additional circuit ties to facilitate load transfer capabilities. The improvements are also intended to reduce customer restoration times during outages, ease congestion points on the distribution system during abnormal configurations and increase the opportunities to remove equipment from service for maintenance, or replacement, without interrupting the supply of power to customers. These projects may also allow for more operational flexibility for the connection of DER's as the distribution system continues to move to a two-way power flow.

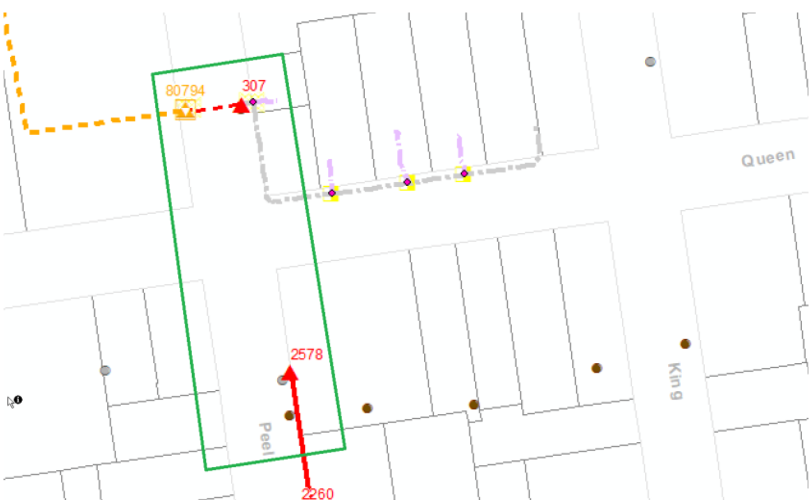
Specifically, in 2025, the projects outlined below are to allow for the replacement of infrastructure that currently is fed through a bridge in the town of St. Mary's. Due to its existing construction, this project cannot be re-built like-for-like, and the assets have been identified as being in poor condition through the ACA, statistically putting them at an increased risk of failure. These projects will ensure a continuous, reliable supply of power, while a replacement plan for the existing infrastructure is developed and executed.

PEEL ST. S – QUEEN ST. TO ELGIN ST.



The scope of this project is a replacement of 2 poles along Peel St. in St. Mary's between Queen St. and Elgin St as well as upgrading the pole line from 1-phase to 3-phase. The project spans approximately 100 meters. This new three phase line is being built to provide a tie to businesses in St. Mary's downtown core that currently have no backup feed. Existing conductor and transformers will be re-used, as well as poles that are suitable for three phase circuits. The two poles being replaced have been identified by the asset condition assessment as being in poor condition and are not suitable for a three phase circuit.

PEEL ST AND QUEEN ST E.



The scope of the project includes the addition of approximately 100 meters of three phase underground primary conductors and the associated civil work to install ducts. This new three phase tie is being built in conjunction with the overhead 1-phase to 3-phase upgrade on Peel St. and will provide a tie to many of the businesses in St. Mary's downtown core that currently have no backup feed.

Upon completion of these projects, the replacement of underground XLPE conductor that is approaching 40 years of age and has been identified by the ACA as being in poor condition and is not in a sufficient civil structure to be re-used can be scheduled for replacement. Currently this conductor feeds residential and commercial customers in the downtown area of St. Mary's on a radial feed.

In each of the remaining forecast years, one project of a similar scope will be completed, providing an additional three phase tie in an area that does not currently exist, to facilitate the replacement of end of life assets.

2. TIMING

i. Start Date: March 2025

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: The main factors that could impact the project schedule include:

- Material procurement delays.
- Unplanned or higher priority work arises, resulting in resource constraints.
- Civil construction issues installing ducts.

FHI aims to mitigate these risks by ordering material well in advance of construction dates and is familiar with multiple methods of civil construction and contractors who can complete these, should complications arise.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						**Bridge Year**	**Future Costs ($ '000)**				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Capital (Gross)	0	0	0	0	0	0	0	122	90	111	113	115
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	0	122	90	111	113	115

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

This is a new program, and no comparable historical costs are available.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 10 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. The asset management objectives listed below drive the investment priority. Not completing this program will result in the perpetuation of reliability issues. The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Non-life threatening injury, but public safety concern.

The assets targeted for replacement as part of this program have been identified as being in poor condition and statistically have the highest likelihood of failure, however as underground infrastructure fails it is less likely to have a severe impact on customers and staff.

Reliability/Supply of Power - Sustained interruption of one MS or embedded distribution feeder and provides for additional system capacity.

Asset History and Performance - Asset history shows intermittent failures (<1 each year) or >50% of asset class in poor or worse condition.

Customer and Community - Delivers on two of the top 3 priorities of customers (safe/reliable power, aesthetics over cost) and is supported by over 50% of customers.

This program is designed to address reliability to the benefit of Festival Hydro customers and was supported by over 50% of customers who believed the proposed level of investment was at the proper level.

Productivity/Efficiency - Aligns with 2 (Investment increases liability with inaction, investment allows other projects to proceed).

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations)

Environmental Impact – Addresses one environmental issue (climate change).

By completing this program climate change is addressed as the new infrastructure will be built to the newest standards which are meant to address the increasing number of weather events being seen from climate change and provides alternate supply and switching points in outage events.

Further information about FHI’s planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing** – FHI could allow these areas to remain being radially supplied and not install infrastructure to re-establish a redundant power supply to these areas. However, this means prolonged and sustained outages when the assets fail, or when the replacement of the assets is undertaken, as many of them are in poor or very poor condition. This represents a reduction in reliability and safety for the public and for workers. For these reasons, this option was not seen as appropriate.

b. **Non-wires alternatives** – FHI could install localized non-wires alternatives (such as a DER) to facilitate the replacement of the poor condition assets, while keeping downstream customers power on, preventing the prolonged outages that would otherwise have been required during the replacement. However, a location to place the DER would need to be found in each specific area, studies completed to ensure proper protections are in place and determine the impact to the distribution system, and there would be significant time and effort to procure, install and commission the device. The type of DER that could be used would also be restricted as it would need to be one that could provide sustained, reliable power, which would rule out many renewable sources. This limits what the DER could do once construction is completed, as many regulations for injecting DER’s into the grid require a renewable component. Also, the main driver for these projects is not to relieve capacity constraints and FHI is not forecasting capacity constraints anywhere within their distribution system in the next five years. For these reasons, this option was not seen as appropriate.

c. **Renew and expand existing lines (preferred option)** - this option consists of renewing or expanding line sections between desired interconnection points and installing additional wires. This option is primarily considered for line sections that are in poor condition and the additional circuitry is required to facilitate rebuilds in this area, with the additional benefit of providing additional switching points in the distribution system in the long term. This option allows for replacements to proceed without causing multiple prolonged and sustained outages to customers, and faster restoration times in areas that otherwise would have been radially fed. For these reasons, this is the preferred option.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: The infrastructure will be upgraded to current FHI specifications and USF design standards which are intended to address reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. The new switching point this creates will also increase operational flexibility for day to day switching and increase flexibility in scheduling maintenance work and replacement work.

Customer Value: The proactive replacement strategy that is enabled as a result of this project as planned is less costly than reactive replacements. It also provides redundant supply to this area, so that when outages, replacements or equipment maintenance occurs, outage duration is significantly reduced or eliminated for customers.

Reliability: The completion of this project is expected to have a positive effect on reliability for the localized areas these projects address. It will result in significantly reducing the risk of prolonged outages for these areas. On a system level, these projects will have some positive effect over time due to:

a) improved interconnection capabilities for day-to-day use; and

b) reduction of failure risk associated with the aging assets being replaced.

Safety: This project facilitates the replacement of end-of-life assets, which carry an inherent failure risk. Also, by providing redundant supply to areas, staff can ensure they are working as safely as possible by de-energizing electrical infrastructure during rebuilds or maintenance, and removing any need to try and balance the need of an outage for safety against the impact the outage causes to downstream customers.

2. INVESTMENT NEED

i. Main Driver: Failure Risk - The main driver for this project is aimed at addressing failure risk. This project facilitates the replacement of assets that are at or near their end of life and at risk of failing, while still continuing to provide a reliable supply of power to customers that would otherwise have been negatively affected, via numerous prolonged outages, during the replacement.

ii. Secondary Drivers: System Operational Objectives (Reliability, System Efficiency, Safety) - At its core, FHI exists to provide safe, reliable electricity supply to its customers in a cost effective manner. This project allows FHI to continue providing reliable supply to its customers while still replacing electrical assets that are nearing the end of life.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of this program. The majority of the assets that this program will facilitate the replacement of, are in poor condition or worse as identified by the ACA. By replacing assets in poor condition, this investment prevents the power supply reliability from degrading below FHI's targets.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. FHI designs and construction facilitates the potential future incorporation of grid modernization equipment and renewable energy generation, and follows Ontario Regulation 22/04 in its design, construction, and material selection to ensure a safe and reliable system.

ii. Cost-Benefit Analysis: FHI looks at each location to determine the need for a redundant supply. Many factors are considered, such as constructability and construction methods that could be employed in the replacement of the assets to reduce the outage impacts to downstream customers. Based on the outcome of this, a decision is made on how to proceed.

iii. Historical Investments & Outcomes Observed: This is a new program, with no historical costs. This project will help provide a more reliable and safer distribution system for the public and for workers and improves switching points within the distribution system for operational flexibility.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM RENEWAL

PROJECT: TRANSFORMER STATION RENEWAL

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program includes the replacement of transformer station assets based on asset history and failure, third party condition assessments and report recommendations, station battery and charger renewals, as well as replacement or purchase, including spares, of protection and control assets that are obsolete or no longer supported.

FHI owns one transmission connected station, connected to Hydro One's 230kV transmission system, and distributes power to thousands of customers in the City of Stratford at 27.6kV. This station contains equipment such as power transformers, primary metering units, switchgear and protection and control assets. This station is critical in ensuring FHI can supply safe and reliable electricity to its customers, as, under some loading conditions, it is not possible to supply power to all customers in the City of Stratford without it, many of which are key industries, such as manufacturing plants, schools, and hospitals. FHI undertakes regular inspections, maintenance and testing of its assets on its stations to ensure proper working order. FHI conducts third party assessments of the station to identify and recommend potential gaps in processes, spare equipment on hand and investment plans. In addition, FHI subscribes to and receives notices from vendors on alerts or issues for assets contained within the stations. Because of the criticality of this asset, and the large consequence of failure of singular pieces of equipment, FHI aims to proactively replace most assets within the station.

Over the forecast period, investments in this category are based on recommendations from the third-party assessment report, items that have been identified as end of life or no longer supported and assets with a history of failure or maintenance issues.

The below table summarizes the recommendations of the third-party assessment report, the rationale behind the recommendation and planned investment year.

Report Recommendation	Rationale	Planned Investment Year
Battery Bank 'A'	Replace based on years in service and test Results	Replaced in 2022 based on test results of battery bank not being sufficient to provide power to critical DC systems, such as protection relays
Spare Ethernet Switches	Four in service, used for network communications within station. Have spare on site so if one fails, can upload saved backup to it, provide full networking capabilities back to station quickly	2023
Spare Fibre Optic Cables	Spare in case of failure	2023
Spare Fuses	Spare in case of failure	2023
T2 Protection Relays	Relay Firmware was obsolete, premature failures reported on power supplies.	2023
T2 SCADA RTU	These RTU's are no longer manufactured and are obsolete.	2024

	No Canadian support, lack of overall support.	
Battery Bank 'B'	Replace based on years in service and test Results	2025
Spare Voltage Regulation Relays	Two in service, used to regulate voltage on power transformers, have spare on site so if one fails, can install new one, wire and test, put transformer back into service quickly	2026
Spare Optical Isolation Cards	Spare in case of failure	2026
T1 SCADA RTU	These RTU's are no longer manufactured and are obsolete. No Canadian support, lack of overall support.	2027
3354 Station RTU	No Longer Manufactured, cannot purchase spare or like-for-like replacement. Upgrade to SEL 3555	2027
Spare SLE 487 Relay	Two in service, used for power transformer protection, have spare on site so if one fails, can quickly program test, and replace to provide full protection of critical asset	2028
Spare NSD570 Relay	Two in service, used to send trip signals to transmitter to isolate transmission line under fault events. Have spare on site so if one fails, can quickly program, test and replace to provide full protection of critical asset	2028
Replace AC Inverter System	Inverter does not function, provides backup power to station lighting, receptacles, certain telecommunication and networking equipment	2029
Network Monitoring	Monitor network health, ensure devices are acting properly, notify of any communication failures	2025-2029 (pieces are completed each year as assets are replaced)

Investments above and beyond the reports recommendations are only undertaken for equipment failures requiring replacement, products that may be unexpectedly unsupported or end-of-life by vendors, or issues identified through the ongoing inspections, maintenance and testing of the station. Adjustments to pacing of other investments would be made to accommodate this.

In 2025 specifically, FHI plans to:

- Purchase two 230kV primary metering units with combined instrument transformers.

- Retrofit and replace an entire three phase line up of wholesale instrument transformers at the station.
- Purchase one on-line oil monitor for a power transformer to replace the failed monitor currently installed. This monitor provides a continuous on-line monitoring of the oil in the power transformer to detect for an abnormal rise in the concentration of certain gases in the transformer oil tank which likely indicate internal issues and allow for more timely intervention to avoid failure.
- Replace the 'B' DC battery bank.

The key driver for the primary metering replacement project was a catastrophic failure of a 230kV primary metering instrument transformer unit that occurred in 2023. FHI was able to replace this unit with an on-site spare, however that has left FHI susceptible to any subsequent failures without any spares. This failure caused the station power transformer to be offline until a replacement could be installed. While this transformer was offline, the other transmission circuit that provides power to this station tripped off, causing an outage of the entire station and thousands of customers, highlighting the importance of this piece of equipment and the need to invest in this equipment, as a subsequent failure would cause a similar risk event.

When FHI inquired about purchasing another replacement it was determined that like-for-like replacements of these units no longer exist. As a result, in 2024, FHI purchased a near like-for-like replacement and utilized the services of their high voltage contractor to engineer a retrofit for the existing infrastructure to be able to utilize this new unit, if required. This once again gave FHI a spare unit that could be used in case of emergency. However, a long term plan was developed to replace an entire bus of metering units proactively to give FHI three spare units, and also proactively complete the retrofit to minimize the outage length for changing out the metering units. FHI has six in-service metering units on site and will have three spare units on site once this project is completed.

The Transformer Station's DC systems are critical infrastructure that provide uninterruptible power to all the protection and control systems at Festival MTS#1. DC Battery Bank 'A' was replaced in 2022/2023 following a cell failure and overall decline in the energy capacity of the bank. Capacity testing of the 'B' battery bank in early 2024 indicated that its capacity was at the threshold for replacement. Due to the redundancy in the DC systems and the 2024 capacity testing results, it was determined that Battery Bank 'B' could remain in service during 2024 but would need to be replaced in 2025 to ensure the continued reliable operation of the station's DC infrastructure.

2. TIMING

i. Start Date: January 2025

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: The main factors that could impact the project schedule include:

- Material procurement delays.
- Unplanned or higher priority work arises, resulting in resource constraints.
- Contractor scheduling and availability.
- Coordinating and scheduling outage with transmitter.

These risks will be mitigated by purchasing needed equipment well in advance of project start. Communicating preferred dates to transmitter and contractor early in the process to ensure availability of outage window and of contractor resources.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	5	36	73	138	86	212	150	275	273	279	289	298
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	5	36	73	138	86	212	150	275	273	279	289	298

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

Because this station was commissioned in 2013, until very recently, significant investments and specific projects for updating or replacing assets were not needed. From 2020 onward, projects to replace and upgrade station assets have slowly continued to increase, most notably, with the replacement of numerous protection relays across 2020/2021 and 2022/2023. To forecast the future costs, FHI has used a combination of historical costs from similar projects as well as quotations from third parties.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 5 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. The asset management objectives listed below, along with the criticality of this asset drive the investment need. Not completing this program will result in potential outages at a station level. The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Potential injury requiring first aid or public safety concern. FHI has had one critical piece of equipment catastrophically fail and plans to replace these assets in this forecast period to mitigate this risk in the future. While the stations are unmanned and the asset is not within reach of personnel, should a failure occur while someone is in the vicinity, there is a risk of injury.

Reliability/Supply of Power - Sustained interruption of at least one TS distribution feeder.

Asset History and Performance - Asset history has shown impact at a station level or widespread impact to the distribution system.

In 2023, the failure of a single asset within the station caused the built-in station redundancy to be lost. Another failure of the same asset would have the same impact.

Customer and Community - Delivers on one of the top 3 priorities of customers (safe/reliable power) and is supported by over 50% of customers. This program is designed to address reliability to the benefit of FHI customers and was supported by over 50% of customers who believed the proposed level of investment was at the proper level.

Productivity/Efficiency - Aligns with 1 (investment increases liability with inaction).

Given that FHI has already had one catastrophic failure of this asset, not addressing the risk increases the chances of it happening in the future.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses one environmental issue (oil spill). By completing this program, oil filled metering units are removed from service and replaced with di-electric ones.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing** – FHI could do nothing and run the assets in their transformer station to failure, or leave assets which have already experienced unexpected, catastrophic failures in service. However, the assets involved in this station not only provide power to thousands of customers in the City of Stratford, but when they fail, have the potential to damage adjacent pieces of equipment, affect the transmission system, and are typically assets that are custom ordered and have long lead times, leading to prolonged outages. For this reason, this option was not seen as appropriate.

b. **Proactive Replacement/Purchase of Spares (preferred option) –** FHI identifies assets which are becoming unreliable, are nearing end of life, or have a history of failure and subsequently makes a decision of when the proper intervention time is to replace the asset. This is based on the criticality of the asset, lead time to replace, and asset performance and history. As an outcome, FHI will either purchase and proactively replace the asset, or purchase a spare, so that if a failure should occur, there is a suitable alternative already on hand to minimize any downtime. FHI decided that most prudent course of action was to proceed with this alternative, at the pace outlined in this DSP.

c. **Increase pace of investment –** FHI could increase the pace of investment in this category based on the criticality of this asset. In service items could be replaced even earlier in their lifecycle to further minimize the risk of assets failing or not functioning properly. However, based on the current investment strategy to ensure adequate spares of critical equipment are on site, the inherent redundancy of the way the station is built, and the maintenance and inspection cycle FHI uses to monitor this station, it is believed that the current proposed investment is appropriate and does not need to be increased. For these reasons, this option was not chosen.

d. **Decrease pace of investment –** FHI could decrease the pace of investment in this category. However, after witnessing the impact that the failure of one piece of equipment can have to the station, and FHI customers, which include manufacturing industries, schools and hospitals, this option is not seen as appropriate to mitigate the risk of not having adequate spare equipment, or proper replacement timelines of assets which could negatively impact duration of outages at a station level.

8. INNOVATIVE NATURE OF THE PROJECT

While not a main driver of projects in 2025, when replacing assets such as protection relays, there may be technological enhancements that can be incorporated into the project, which is looked at on a project by project basis.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. By having an online oil monitor, FHI can be alerted to developing internal transformer issues quicker and respond proactively rather than reactively. Additionally, having adequate spare equipment enables quicker restoration for unexpected failures of critical equipment.

Customer Value: The proactive replacement strategy of the project as planned is less costly than reactive replacements, it also reduces outage length and provides customers access to reliable electricity.

Reliability: These projects are primarily meant to ensure that current reliability levels at the station are maintained and removes the significant risk of another primary metering unit unexpectedly failing in the same manner.

Safety: While stations are built in a way to not allow access to the general public, failures of equipment pose a safety risk to staff, should the failure occur while staff are on site. By removing equipment with a failure history, this helps to improve staff safety.

2. INVESTMENT NEED

i. Main Driver: Failure Risk- The main driver for this project is aimed at addressing failure risk. This project replaces a group of assets that have recently had a catastrophic failure, contributing to a prolonged outage impacting thousands of customers.

ii. Secondary Drivers: Organizational Effectiveness & Efficiency - The effect of these investments is an improvement in organizational effectiveness with the information received from on-line oil monitoring. It will provide better situational awareness for the power transformers, one of the most critical assets in the station, and provides insight into the real time condition of the asset.

iii. Information Used to Justify the Investment: FHI experienced the catastrophic failure of one of their oil filled primary metering instrument transformer units in 2023. In speaking with other LDC's and contacts within the industry, this type of failure had occurred in other locations with similarly aged assets. This prompted FHI to specify and order a spare quickly and develop a replacement plan of the remaining units.

Investing in condition based, continuous on-line monitoring of its grid connected power transformers, allows for more timely and less costly intervention if asset health unexpectedly deteriorates. It also allows FHI to trend the monitors readings over time to understand how the asset is aging. FHI also references the third party assessment report to identify equipment that should have spares on hand, be more closely monitored, or considered for replacement.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: Replacing assets that have a history of unexpected failures is necessary to ensure safety for personnel who could be working in the vicinity of these units. It also maintains the reliability of one of the most critical parts of a distribution system, given the number of customers that can be impacted by the failure of a single piece of equipment.
Through the use of on-line monitoring of power transformers, this helps mitigate the risk of unexpected failure of one of a stations most critical assets. It also allows for condition based replacement to optimize the assets life based on observed data.

ii. Cost-Benefit Analysis:
FHI looked at the cost of replacing these assets, and selected units with the expectation they will remain in service for their entire intended life. The new units that house the metering equipment and associated components are made of a di-electric insulating material rather than oil and FHI is not aware of any unexpected failures for this type of unit. Furthermore, when these units fail, they cause a transmission line outage because of where they are located in regards to protection equipment. Should another unit fail, it would potentially impact all other customers fed from the transmission line. Many of which are large commercial and industrial customers, as well as customers of other LDC's. It would also place these stations in the same scenario as 2023, where there is now a single point of failure that could cause a widespread outage with a subsequent trip on the other circuit, causing a total station outage, impacting thousands of customers, as occurred in 2023.

iii. Historical Investments & Outcomes Observed: FHI has completed the replacement of different station assets over the historic period. FHI has found the proactive replacement is a less costly alternative than reactive as resources and materials can be planned in advance and done during regular business hours. These projects are intended to maintain the safety and reliability of the distribution system.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

See Section A8.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM RENEWAL

PROJECT: UNDERGROUND RENEWAL

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program targets investments to address UG assets within FHI's system that are in poor or very poor condition. This typically involves the replacement of:

- Underground conductor.
- Associated termination equipment (elbows, arrestors, etc.).
- Padmount transformers that have been identified as end of life.
- Padmount foundations when transformer locations change, or where none exist.
- New duct where the underground cable is currently direct buried, or in duct that is structurally inadequate.

Where assets have been determined to be suitable for re-use, they will be placed back into service as part of the project.

FHI has approximately 101.6km of XLPE cable across its system. As part of the ACA, Kinectrics identified 18.1km (18%) of the cable was in poor or very poor condition. There is also a further 26km of cable that is past it's typical useful life.

Identification of cables that require replacement is a multi-step process beginning with the data collected as part of the asset management process. The data collected as part of this effort informs the asset condition assessment which is then imported into GIS to be viewed spatially. Cables in close vicinity to each other with similarly poor health indices are then grouped together to create a capital rebuild project where feasible. Each project scope includes the design, construction and installation of new cables that conforms to O. Reg. 22/04 compliant standards.

This program also targets areas where current installation methods do not allow for easy replacement of cable (direct buried, or structurally inadequate pipe) to install new ductwork that makes future cable replacement easier, and provides mechanical protection to the cables, as is current industry standard practice. It will also add provisioning for additional loops in residential areas where this was not contemplated when originally constructed to bring these areas to current installation standards.

Finally, with the expected electrification of many items and appliances that use an alternate fuel source (heat pumps, EV's, etc.), following advice in the OEB's recent bulletin and the requirements to ensure that in the planning process FHI is considering the future capacity needs of the distribution system[4]. FHI will use this opportunity to review the number of customers connected to each pad mount transformer and will use their updated practice to add or rebalance customer connections to each transformer in an aim to provide adequate capacity for future needs over the life of the assets that will be installed. This includes, planning for adequate capacity that would allow a 200A service for each connection. This causes certain projects to now have an enhanced scope of work compared to historical replacement projects in this program. In 2025, FHI has two projects that are impacted by this, which add approximately 7% and 15% to those specific projects.

Through this program, FHI plans to maintain the level of safety and reliability associated with newer standards and materials. As part of this program FHI plans to replace 4.4km-5.5km of XLPE cable per year with TRXLPE cable, which is expected to have a longer operating life and is the current industry standard for new underground cable installations. This approach was developed to lower the risk to FHI as the timing of asset failure is never certain, but a large population of the assets in this program

[4] OEB staff Bulletin "Residential Customer Connections & Service Upgrades" August 24, 2023
https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-Residential-Customer-Connections-20230824.pdf

are nearing or past their typical useful life and have been identified as being in poor or very poor condition, and even a small sudden increase in failure rates could cause significant issues for FHI.

For the 2025 test year the following projects have been selected and will result in the replacement of 4.4km of cable:

STRATFORD – BARRON ST. TOWNHOMES

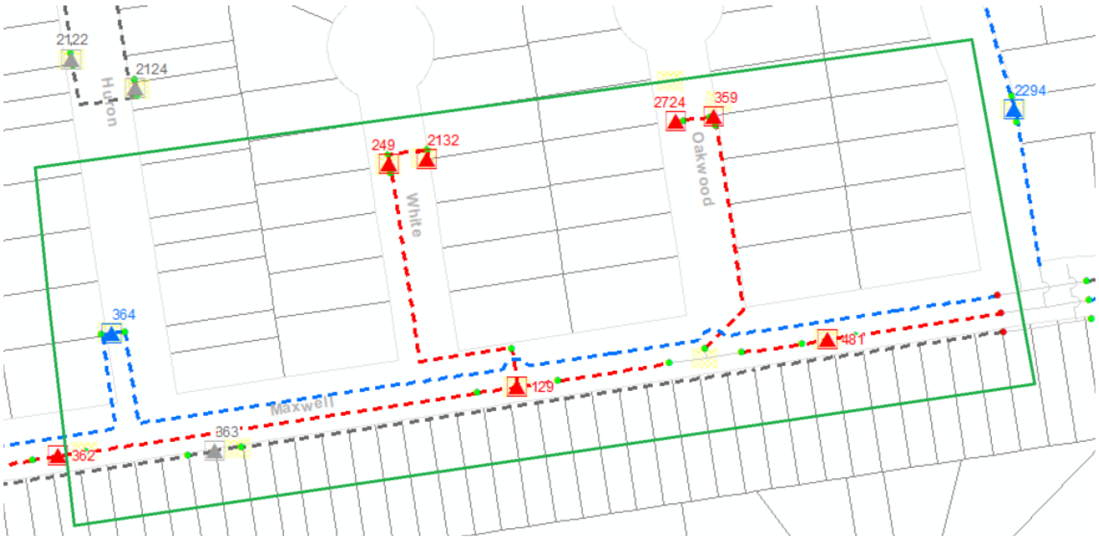
The scope of the project includes the replacement of approximately 420m of single-phase radial underground primary conductors and transformers that service residential customers on Barron St. in Stratford. The underground cable has been identified by the ACA as being in poor condition. This project will also include the installation of extra ducts to allow for future looping of conductors to mitigate prolonged outages due to equipment issues or maintenance.

STRATFORD – 60 ERIE ST. TO 100 ERIE ST.

The scope of the project includes the replacement of approximately 270m of underground primary conductor that services a commercial area on Erie St. in Stratford and facilitates the removal of an air insulated switchgear that is over 40 years old and identified by the ACA as being in very poor condition.

The underground cable is over 30 years old and has also been identified by the ACA as being in poor condition.

ST. MARYS – MAXWELL ST FROM DUNSFORD CR TO OAKWOOD CRT

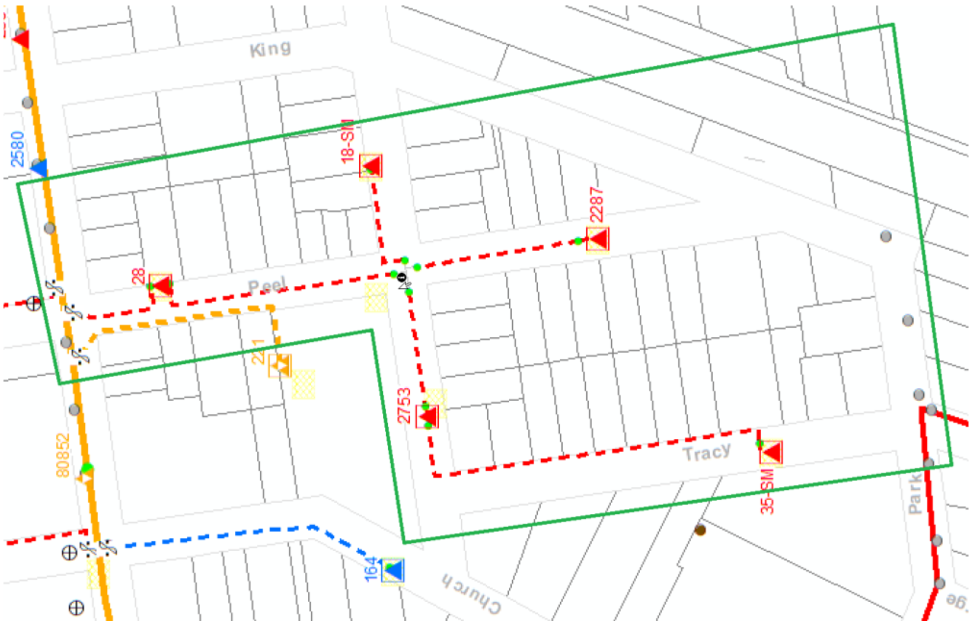


The scope of the project includes the replacement of approximately 1.4km of single phase underground primary conductors and transformers that service residential customers on Maxwell St., White Crt. and Oakwood Crt. in St. Marys. This project will add ducts to enable the looping of underground cables on White Crt. and Oakwood Crt. to provide redundancy in this area for outage and maintenance purposes. Furthermore, and outside of the traditional scope of work for underground renewal programs, while there are adequate locations for transformers, this project will also see increased transformer sizes, as well as customer balancing between transformers as part of FHI's planning initiative to prepare for increased demands from residential electrification. This adds approximately 7% to the overall cost of the project. The underground cable has been identified by the ACA as being in poor condition. This is year two of a multi-year project on Maxwell St to update the entire subdivision.

ST. MARYS – INGERSOLL ST SWITCHGEAR CABLE REPLACEMENT

The scope of the project includes the replacement of approximately 275m of three phase underground primary conductors as well as the associated civil work to install ducts that feed a switchgear on Ingersoll St. This is being done in parallel with the switchgear replacement as the current cables do not have enough length to be re-used and are approximately 25 years old, making replacement the preferred option, with the added benefit of the new cables being in duct that can be re-used in the future.

ST. MARYS – PEEL ST S – ELGIN ST TO PARK ST



The scope of the project includes the replacement of approximately 800 metres of single phase underground primary conductors and transformers as well as the associated civil work to install ducts, that service residential customers on Peel St. and Tracy St in St. Mary's. This area is also radial, and a new loop will be established as part of this project at Tracy and Park St. to provide redundant feeds to the area. Furthermore, and outside of the traditional scope of work for underground renewal programs, this project will have two additional transformers added in this area, as well as increased transformer sizes at the existing transformer locations. This is being done as part of FHI's planning initiative to prepare for increased demands from residential electrification. This adds approximately 15% to the overall cost of the project. The underground cable has been identified by the ACA as being in poor condition.

2. TIMING

i. **Start Date:** January 2025

ii. **In-Service Date:** 2025-2029

iii. **Key factors that may affect timing:** The main factors that could impact the project schedule include:

- Unplanned projects from higher priority work (e.g. road relocations), resulting in resource constraints.
- Material and contractor availability.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Capital (Gross)	426	422	365	441	708	542	809	1188	1231	1534	1602	1614
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	426	422	365	441	708	542	809	1188	1231	1534	1602	1614

2025 and onward sees an increase in capital expenditures compared to historical. The main driver for this increase is the results of the ACA which identified the need for FHI to increase the volume of asset renewal in this area based on the flagged for action plan.

2027 sees an increase in costs over 2025, and an increase in the amount of U/G cable to be replaced (approximately 1km). This coincides with the forecasted decrease in spending in the switchgear renewal category as it is expected that program will be finished in 2026. Using FHI's prioritization process, investments to replace the remaining air insulated switchgear was a more critical project, and Underground Renewal spending was accordingly reduced until that program was finished to levelized spending.

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

	2018	2019	2020	2021	2022	2023
Km of cable replaced	3.5	2.3	2.9	2.5	5.5	1.3

Prior to 2022 FHI had been replacing approximately 2.8km of cable each year. This increased in 2022, however it was for cable replacement of projects all in existing suitable ductwork, requiring almost no civil work to be completed as part of the replacements.

2023 saw a smaller amount of primary underground cable replaced, as much of it was replaced with secondary underground cable instead from nearby overhead infrastructure to remove the duplication of primary infrastructure in close proximity to each other.

Over the historical period, FHI has completed many underground cable replacement projects of a similar scope. Metrics for these projects have been captured and based on this data, each project receives a detailed estimate annually. FHI updates these metrics annually based on that year's costs for labour and materials. It should be noted that FHI, like other utilities, has experienced a significant increase in material costs since 2021. This has and will continue to have an impact on future costs.

To provide further context, since 2021 the approximate cost to replace a segment of underground cable has increased by 36%. Since 2021, FHI's labour and trucking has only increased by 8%, meaning the majority of the cost increase for these replacement costs are attributable to material cost increases, of which FHI has little control over.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 3 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. Proactively identifying and replacing underground cable, the majority of which are in poor and very poor condition and therefore statistically the most likely to fail, minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages and safety risks. Reactive underground replacement time and cost can also vary significantly based on location, time of year, and civil infrastructure. The planned underground cable investments are needed to address the volume of deteriorated cables on FHI's distribution system.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Public safety concern, not life threatening.

The assets targeted for replacement as part of this program have been identified as being in poor condition and statistically have the highest likelihood of failure.

Reliability/Supply of Power - Sustained interruption of > 3 MW (greater than half a typical TS distribution feeder) of load and provides for additional system capacity.

Asset History and Performance - Asset history shows regular failures (>1 each year) or >50% of asset class in poor or worse condition.

The majority of assets being replaced under this program fall within this condition rating as identified through the ACA.

Customer and Community - Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates) and is supported by over 60% of customers.

This program is designed to deliver on replacing depreciated assets that could negatively impact reliability to the benefit of FHI customers and was supported by over 60% of customers who believed the proposed level of investment was at the proper level. It is also targeted at solving potential safety risks from failing equipment.

Productivity/Efficiency - Aligns with 3 (Investment reduces operating expenses, investment increases liability with inaction, investment reduces employee time spent on tasks).

By addressing assets in very poor condition, FHI reduces the potential for injury to staff and the public, and reduces time spent reactively replacing and maintaining these assets, which in turn reduces costs.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses three environmental issues (climate change, reduces risk of oil spills, ministry of environment involvement).

By completing this program climate change is addressed as the new infrastructure will be built to the newest standards which are meant to address the increasing number of weather events being seen from climate change, removing transformers that contain significant amounts of oil prior to leaking eliminates the hazard this equipment could cause and subsequent ministry involvement.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing –** this results in reactive replacement of cable which would result in potential long outages for those customers affected, and outside of regular business hours, resulting in a higher cost for replacement. Also, transformers of the same age and condition are also replaced at the same time, which replaces infrastructure that lowers the risk of environmental concerns due to oil leaks, for these reasons this alternative is not considered appropriate.

b. **Remove underground line and rebuild overhead –** In many locations this is not viable as there are no locations to place overhead systems, it would be in an area with many mature trees and require significant tree trimming and/or removal, or it violates conditions in subdivision agreements which require the burial of hydro services.
For these reasons, this alternative is not considered appropriate.

c. **Cable Rejuvenation –** In locations that are planned under this project this is not viable for the following reasons.

- The conductors planned to be replaced do not have adequate cable length to be able to re-terminate;
- Areas that are fed radially would require multiple outages to inject each cable as isolating each section will cause an outage to all downstream customers;
- FHI plans to replace XLPE cables well past their typical useful life and with a very low health index with TRXLPE, this provides an installation of new infrastructure with a proven track record of longer life;
- FHI needs to install additional transformer locations to prepare for the increasing demand for residential electrification, which would not be able to be serviced using existing cables.

For these reasons, this alternative is not considered appropriate at this time.

d. **Replace Like for Like to New Standards (preferred option) -** This is the preferred approach when inspection and ACA data indicates that a group of cables needs replacing. All cables, and where appropriate, associated civil and electrical hardware and equipment, are replaced with the latest standard design. The proactive replacement of cables in poor and very poor condition aims at ensuring that the number of unplanned outages remains minimal by avoiding asset failures, so that customers have access to reliable electricity.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: The infrastructure will be upgraded to current FHI specifications and USF design standards which are intended address reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. Additionally, when these assets are replaced, FHI typically replaces the associated assets as well (transformer, etc.) if they are at end of life, rather than return at a later date.

Customer Value: The proactive replacements that are enabled as a result of this project as planned is less costly than reactive replacements. It also reduces the number of in service assets at a higher potential for a risk of failure and the safety hazards that are associated with this risk.

Reliability: The completion of this project is expected to address reliability in the following ways:

a) reduction of failure risk associated with the poor and very poor condition being replaced;

b) Installation to new standards which includes improved civil infrastructure, and cable that is expected to have a longer life than the asset it is replacing. e.g., cables installed in ductwork as per industry standards;

c) The proactive scheduling of asset replacement minimizes the outage duration; and

d) Assets installed using current standards are better able to withstand adverse weather conditions.

Safety: A number of these projects involve replacing assets deemed to be in poor and very poor condition and therefore statistically have some of the highest likelihood of failure in FHI's distribution system. Therefore, replacing them eliminates a potential soon to be safety hazard.

2. INVESTMENT NEED

i. Main Driver: Failure Risk – The main driver is to minimize the failure risk associated with poor and very poor conditioned cables as identified in the ACA. Many of these projects are also in targeted areas that should an asset fail, replacement would be difficult and there is inadequate civil infrastructure to quickly replace the failed cable.

ii. Secondary Drivers: Reliability – Not replacing assets in poor and very poor condition is expected to have a negative impact to the reliability of the system. This presents a risk to the utility and the customer that a series of assets will fail and result in an outage that negatively affects reliability and customer satisfaction.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of this program. Recent ACA results identified 13.2km (13%) of Underground XLPE cable to be in poor condition and 4.9km (4.8%) of Underground XLPE cable to be in very poor condition, with portions of these cables feeding customers radially, with no redundant power supply to them, as well as portions that are direct buried or in a structurally inadequate duct for re-use. By identifying and proactively replacing underground cables nearing their end of life and in deteriorated condition, and upgrading the infrastructure and servicing to current standards, FHI mitigates the risk of outages and provides a safe and sustainable electrical distribution system.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI utilizes Utility Standards Forum design standards. These standards are based on CSA C22.3 No 1 Overhead Systems Heavy Weather Loading design standards and CSA C22.3 No 7 Underground Systems. Newer construction standards and materials, which includes installing cables in duct, and using TRXLPE cable, provide for more weather resilient assets to help maintain safety and reliability. FHI design and construction practices follow Ontario Regulation 22/04 in its design, construction, and material selection to ensure a safe and reliable system. FHI also conducts annual inspection and maintenance programs, evaluates the results, and utilizes this information to help identify areas requiring replacement along with the results of their ACA. Replacing deteriorated assets with those that meet today's standards improves safety, maintains reliability, and increases resilience.

ii. Cost-Benefit Analysis:
Each project created under this category is reviewed on a case-by-case basis to identify available options. This may include, reducing the number of phases, and therefore the amount of cable required, optimizing the number of customers fed from transformers, etc. Typically, there are no practical alternatives to underground cable replacement projects.

iii. Historical Investments & Outcomes Observed: FHI tracks the average historical costs to form the basis for developing the budget for the forecast period. Using ACA recommendations, previous testing, inspection, and repair data, FHI attempts to accurately predict the quantity of underground cable that will require replacement. Historical costs can be found in section A3 and A5 of this document. Through active underground cable replacement initiatives, FHI has been able to maintain safe and reliable electricity supply.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM SERVICE

PROJECT: DISTRIBUTION AUTOMATION

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program outlines FHI's proposed investments related to its distribution automation activities. While FHI's service area is only 43.42km^2, given its non-contiguous nature between the 7 different communities it serves, there can be a large travel distance between communities and FHI's main operations centre. Crew call out and response times vary depending on the time of day, current work location and possibly the need to patrol entire feeders/areas prior to power restoration.

This program's purpose is aimed at:

- reducing the number of customers affected by outages;
- automatically re-routing power when outages occur;
- providing improved outage information to customers; and
- identifying or locating outages quicker.

To realize this FHI plans to invest in the following distribution automation technologies:

- Design, installation, and commissioning of one remotely controllable recloser each year over the forecast period to provide sectionalizing or remote switching capabilities.
- Design, installation, and commissioning of one set of remote fault indicators each year over the forecast period. The installations will be used where FHI is an embedded distributor to Hydro One at the demarcation point to understand outage location, or in strategic locations within St. Mary's and Stratford.
- Replacement of discontinued S&C SpeedNet radios used on the existing distribution automation infrastructure.

Reclosers will be placed within the existing distribution system to provide sectionalizing capabilities within the same feeder or remote switching capabilities between different feeders.
The recloser locations will target feeders that currently have none and have been identified as a top 5 worst performing feeder in recent reliability reports as shown below.

In the forecast period this would include sectionalizers on the 8051M1 and 68M5, along with remote switching capabilities between feeders on the 8051M1, 68M3 and 68M5.

Feeder	% of Customer Base in 2022	2018	2019	2020	2021	2022	Total	% of Outage Minutes
68M3	20.4%	143,001	922,089	285,557	969,396	14,763	2,334,806	30.78%
68M5	19.7%	749,759	485,094	208,967	353,715	42,575	1,840,110	24.26%
9M4	3.8%	535,066	6,042	314,234	581	74,827	930,750	11.15%
8051M1	15.4%	105,158	291,569	16,467	86,288	402,454	901,936	11.89%
9M3	6.1%	26,220	35	150	514,724	37,962	579,091	7.63%

Once reclosers have been installed that can work in tandem with one another, a self healing logic will be used between them. The benefit of this is, when an outage happens, power can automatically be restored to customers who are not within the zone of where the outage cause is, minimizing the length of interruption that they see.

Using the historical outage data from 2018-2023, but assuming the system was theoretically operating with fully automated sectionalizers and remote switches between feeders that are planned to be installed over the forecast period, an estimate of what FHI my have seen with regards to outage event reductions are shown in the table below.

Feeder	Estimated Reduction in Outage Minutes (2018-2023)	Estimated Average Yearly Reduction in Outage Minutes	Estimated Reduction in Customers Impacted (2018-2023)	Estimated Average Yearly Reduction in Customers Impacted
68M5	457272	76212	10440	1740
68M3	709968	118328	15278	2546
8051M1	306519	50187	9344	1557
Total	1473759	314727	35062	5843

This could have lead to a roughly 7.5% decrease in total outage minutes over the historical period, and 12% less customers impacted across all outage categories (including loss of supply and major event days), showing the potential positive impact on reliability these investments can have on the distribution system and to FHI customers.

Going forward, while FHI expects to see benefits in reliability from these investments, there are other factors that can also affect the reliability that are outside FHI control (e.g. extreme weather events, location of each outage) and as such, while the above example illustrates historical reliability improvements in these areas, accurately forecasting their impact is difficult.

Remote fault indicators will be placed at ownership demarcation points where FHI is an embedded distributor to Hydro One. This will provide a remote indication during outage events of whether the fault is in FHI or Hydro One territory, which allows for more efficient use of FHI resources as it will give an indication of when crews need to be dispatched to these areas, many of which are far from the main operation center, typically requiring between 2-3 hours of time to drive to and from the operations center, along with patrol the feeder for signs of outage cause.

2. TIMING

i. Start Date: January 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: There are two main factors that could impact the project schedule including:
- Material procurement delays.
- Unexpected communication issues for these devices to the SCADA system for monitoring, control, and self healing.

To mitigate these factors FHI employs the below approach:

- Long lead time items are ordered Q4 of the year prior to which installation is supposed to happen. This provides a buffer if the manufacturing is delayed to still complete the project in the planned year.
- Verifying signal strength at intended distribution automation locations prior to installation so that there is greater certainty when the device is installed it will be able to function to its full capabilities.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	38	27	51	6	34	110	77	142	150	156	162	169
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	38	27	51	6	34	110	77	142	150	156	162	169

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

Prior to 2023, FHI in the historical period did not complete many significant projects in this program. Historical costs are mainly made up of enabling and updating features in existing distribution automation equipment, as well as the corresponding SCADA enhancements. In 2023 and 2024, there are costs to purchase, design, install and commission one set of remote indicators each year (approximately $50k each year).

6. INVESTMENT PRIORITY

Distribution Automation projects are discretionary investments driven by the identification of potential system enhancements that improve reliability and outage response time. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. This project ranks last, which is 13 of 13. This program is primarily driven by increased efficiency and system reliability improvements.

Health and Safety – Potential for injury, but non-life threatening.

While these investments are not specifically targeted at addressing health and safety concerns, sectionalizers do allow for better and faster coordination of protection devices, allowing faults to be isolated quicker, which helps in limiting the damage and duration of faults.

Reliability/Supply of Power - Sustained interruption of > 3 MW (greater than half a typical TS distribution feeder) of load.

Asset History and Performance – Asset history shows minimal failures.

These are new investments, not targeted at replacing existing investments. However, by enabling sectionalization and restoration of faults, the investment is able to keep power on to more customers if an asset becomes defective.

Customer and Community - Delivers on one of the top 3 priorities of customers (safe/reliable power) and is supported by over 50% of customers.

This program is designed to deliver on improved reliability to the benefit of FHI customers and was supported by over 50% of customers as an investment into new technology.

Productivity/Efficiency - Aligns with 3 (Investment reduces operating expenses, investment reduces employee time spent on tasks, liability increases with inaction).

Organizational Effectiveness – Aligns with 3 (Investment improves employee response and improves customer experience, investment supports innovation, investment supports sustainable business operations).

Environmental Impact – Addresses any one environmental issue (climate change).

These assets assist in outage events, by minimizing the customers affected, when outage events happen due to sever weather events and associated outages from climate change.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1

7. ALTERNATIVE ANALYSIS

The projects identified under system service category have been initiated because of customer feedback and the continued improvements required to operate a distribution system in a cost-effective and responsible manner. To address these issues, FHI considered the following alternatives:

a. **Do Nothing** - This option results in the perpetuation of reliability issues as well as customer dissatisfaction. Over time, with risk of increased frequency of outage events and associated prolonged outages, this option could result in notable deterioration of reliability indices at a system level. In addition, this option would be a lost opportunity for FHI customers to see the advantages of the added functionalities of remote switching working in harmony with FHI's Fault Location, Isolation, and Service Restoration (FLISR) system in creating self-healing networks, the potential benefits of which, through reduction in frequency and duration are shown in Section A1. For these reasons, this option was not considered appropriate.

b. **Integrate more manual switching points into the system** - This option is always considered as one of the alternatives for reliability enhancement. It has the characteristics of being quick and comparatively inexpensive to implement. However, it does not significantly improve the duration of outages. If additional switching points form the complete or part of the final solution, installing automated switches rather than manually operated ones is preferred as the increased upfront investment will have an enhanced long term return on system wide operational benefits.

c. **Installation of only line sensing and fault indicating devices** -These will improve operations' ability to determine the fault location, and likely improve efficiency in response times, but they cannot automatically transfer or sectionalize load like remote switches and sectionalizers, which have the ability to reduce outage length and frequency for customers. As noted above, these devices will be utilized for information purposes in strategic locations, but a more robust system that provides all the benefits of isolation and operability is preferred for selected feeders.

d. **Non-Wires Alternatives** - The main intent of distribution automation investments is to create a more flexible and responsive distribution system to disturbances on the system. Non-wires alternatives are an option that could be used to locally to augment an already modern grid, which FHI's is not at this point. To allow this type of a solution, investments would still need to be made to sectionalize feeders, but the need for automated tie points could in theory be eliminated. The challenges of non-wires solutions are the complex technical requirements to properly site, size, source and install them to serve the current and future needs of the distribution grid. It also does not provide the same level of functionality or flexibility to the distribution system as automated devices and has significantly longer deployment time compared to deploying automated switches. For these reasons, this option was not considered appropriate.

e. **Carry out proposed Distribution Automation investments (preferred option)** – The program proposes to replace/install new equipment and increase functionality. By installing remotely operable switches FHI is able to realize many benefits. One is the ability to sectionalize a feeder based on fault location. This allows FHI to only cause an outage to a portion of the customers on the feeder while the cause is determined/repaired instead of the entire feeder, saving outage minutes, and minimizing the customers affected. Also, by having remotely operable devices at tie points in the distribution system, switching to restore power can be done quickly to unaffected areas of FHIs system, and more switching for normal work can be done remotely instead of needing to send a crew to operate each device in a switching order, thus using the crews time more efficiently. It also allows more of FHI's distribution system to be integrated with FLISR which is able to automatically reconfigure the distribution system using remotely controlled devices to as many customers as possible under outage conditions in one minute or less. Finally, by installing remote fault indicators at service area demarcations where FHI is embedded to Hydro One, it can quickly identify if the outage cause is within FHI or Hydro One's service territory, allowing FHI to only send resources when needed.

8. INNOVATIVE NATURE OF THE PROJECT

This project is integral to enabling future technological functionality and to addressing future operational requirements to meet the changing needs of customers, industry, and regulators. A modernized grid is one that facilitates the use of automated and self-healing devices to distribute electricity more effectively, economically, and securely. A true modernization of the grid will allow for the deliberate incorporation of intelligent devices that will provide better visibility and operational flexibility to minimize outage impacts, efficiently use resources to identify and respond to outages, and identify areas to achieve better grid performance.

There are two main approaches to distributed automation in the industry: centralized and localized. Both require intelligent devices and a communication system. In the localized mode, the intelligent devices communicate directly to their peers to determine where the system disturbance might be and how best to restore the power to as many people as possible. This system works very well in locations where feeder routes are fixed and not subject to reconfiguration. In the centralized mode, the intelligent devices communicate to a centralized location, and the centralized system determines origin of disturbance and follow up actions. FHI's Distribution system will have a combination of these, utilizing the most effective solution for the area.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: FHI seeks to maximize factors that positively affect operational efficiency through consideration of equipment types and the analysis of constraints on the system.

- System reconfiguration utilizing remotely controlled FLISR switching devices causes fewer truck rolls;
- Information is acquired and analyzed remotely with less labour resource input; and
- Remote fault indicators at service area demarcations where FHI is embedded to Hydro One, allows quick identification of which service territory the cause of outage is in. This will allow for fewer truck rolls.

Customer Value: The addition of these devices has numerous benefits to both the customer and the LDC, some of these include:

- Enhanced visibility and control over the distribution system;
- More timely and accurate information regarding outages including anticipated restoration time that can be shared internally and with customers;
- Reduced outage duration; and,
- Increased number of customers that can be restored quickly during an outage.

Reliability: The objective of this program is to continue to meet the system reliability targets of SAIDI and SAIFI, specifically targeting worst performing feeders as identified in FHI's annual reliability report. FHI's commitment to continuous improvement seeks to positively impact these metrics through these enhancements to its system.

Safety: Although not primarily meant to address any particular safety issues, the installation of automatic reclosing devices typically helps to improve equipment protection and reduce arc-flash energy. It also has the added benefit of eliminating manual switching which reduces crew exposure to energized equipment and reduces associated safety risks, especially during major weather events where access to switches might not be optimal. It also increases safety by faster isolation of faulted conductors where feeder segmentation has been implemented.

2. INVESTMENT NEED

i. Main Driver: Reliability - System disturbances in FHI's non-contiguous service territory can lead to prolonged outages as times to restore power are dependent on potentially long travel distances. Crew call out and response times are dependant on the time of day as well as long setup times in urban areas where access can be slow and difficult due to traffic. Installing devices which can automatically segment customers during outages and re-route power to unaffected customers improves the reliability of the distribution system.

ii. Secondary Drivers: Customers - At its core, FHI exists to provide safe, reliable electricity supply to its customers. Meeting this obligation requires an understanding of customers' needs and expectations and a commitment to delivering a high level of service. FHI continuously monitors its performance in the form of OEB and corporate metrics, customer satisfaction surveys and customer preference.

Productivity/Efficiency - The effect of these investments is a potential improvement in operation efficiency and cost-effectiveness by eliminating or reducing the need for manual switching; automated restoration vs. patrolling and manual restoration; improved access to information, and identification of fault location in areas where FHI is an embedded distributor, limiting truck rolls. Based on the previous 5 years, in theory this could have resulted in 40 outages that would no longer require truck rolls and resources to drive to these communities as the devices would have indicated the cause of the outage was in Hydro One territory.

iii. Information Used to Justify the Investment: FHI uses a combination of reliability-based data (SAIDI, SAIFI) in conjunction with historical worst performing feeder data and installation costs to determine if the issue can effectively be addressed using remote switching devices. Additional information on FHI's reliability statistics can be found in Section 5.2.3.2 of the DSP. Worst performing feeder information, as shown in Section A1, is updated yearly, and assists in directing activities in this program. Customer count, diversity of customer types and length of feeder also factor in to selecting recloser locations. Illustrative examples of potential savings in SAIDI and SAIFI were also demonstrated in Section A1, showing the benefit for FHI customers in a more reliable distribution system.

For communities where FHI is an embedded distributor, customer size, distance from main Operations Center, and historical recloses and outages are examined when identifying and prioritizing installations. In the remote communities where this is applicable, over the past 5 years, this in theory, would have allowed FHI to identify 40 outages were in Hydro One territory and did not require FHI resources to be sent to investigate/patrol.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: The electricity sector is experiencing a set of changes driven by some key trends like the decentralization of energy and adoption of distributed energy resources (DERs), both of which are supported by the digital transformation. As evidenced by recent survey results, customers remain concerned about affordability, but there is an expectation and desire that FHI invests in these types of technologies. Uncertainty in the pace aside, these trends are shaping the future of the energy landscape bolstered by the electrification of heating and transportation.

To ensure that FHI can continue to deliver safe, reliable, and efficient service, it is fundamental that these necessary foundations be put in place. For any utility it is accepted practice that to continue to operate effectively into the future the system must be both remotely operable and have good data visibility into the distribution system. FHI has carefully reviewed and planned its investments considering these trends and how changing priorities over the next five years will influence expenditures.

ii. Cost-Benefit Analysis: Each grid modernization activity is reviewed on a case-by-case basis to identify optimal locations for installation. The long-term benefits of this program include improved grid resiliency and operability which can mitigate the duration of outages customers experience annually. The self-healing portion of this investment will promote further remote management of the grid thereby increasing the efficiency with which load can be transferred and restoring customers more quickly than in the past. Including automated reclosing devices, smart software along other advancements in technology, FHI will be in position to further integrate DERs, electric vehicles and the demands from other sources of electrification into its network.

iii. Historical Investments & Outcomes Observed: Historical costs for this program are indicated in Section A3 of this document. FHI is at the beginning of its grid modernization investments, and therefore has not seen the outputs of its investments yet. FHI has only installed one remote fault indicator in 2023 so far.

Investments in this program will allow FHI to keep staff and customers better informed of outages. Additionally, this program in conjunction with other FHI programs is expected to result in a net positive effect on reliability due to the sectionalizing nature of the reclosing devices.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: SYSTEM SERVICE

PROJECT: VOLTAGE CONVERSION

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

FHI is currently facing a critical decision for investments in the community of Seaforth. The two existing substations (Welsh DS and Chalk DS), operating at 4kV, have reached, or are very close to their end of useful life, with assets identified as the ACA as being in poor condition. This necessitated a strategic investment plan to ensure the continued delivery of safe and reliable power to customers. Recognizing the financial implications of replacing entire substations, the decision to create a voltage conversion program from 4kV to 27.6kV was selected as most effective solution. This also aligns with the company's commitment to providing safe, reliable, and cost effective electricity, and is typical industry practice, with many utilities moving away from 4kV systems when the option arises.

This program category consists of the targeted replacement of approximately 900m of Overhead and Underground distribution cable replaced yearly.

Historically, in this community, as existing 4kV infrastructure has been replaced, rather than like for like replacements with 4kV rated equipment, the replacements have been installed with equipment and hardware that is rated for 27.6kV voltage, as well as dual voltage transformers that can operate at both 4kV and 27.6kV.

At the end of 2023 this community had:

- approximately 6km of overhead distribution framed and insulated at 27.6kV (or could be re-insulated to accommodate 27.6kV without any other work);
- 8.2km of legacy 4kV overhead distribution that is not suitable for 27.6kV, requiring a full rebuild; and
- approximately 900m of underground cable that is not insulated for 27.6kV and requires replacement.

The main driver for the program is that the majority of these substations most critical assets, are in fair or worse condition and past, or very near, the end of their typical useful life. Additionally, a 3rd party report that was completed in 2019 recommended that both substations should be upgraded in the next 10 years, with a high-level estimate of each substation rebuild being $1.6 million (Appendix M).

Currently, this community is supplied by 27.6kV at its demarcation boundaries with Hydro One. FHI already has many communities utilizing the 27.6kV distribution level, meaning that crews are familiar with working methods at this voltage, and equipment, materials and design standards are also readily available for 27.6kV applications.

This specific program is needed now, as the conversion of the entire community at the proposed pace will take until 2033 and reports and analysis indicate investment would need to occur at the substations within this timeline. This pacing is planned to allow the substations to be removed from service prior to experiencing a failure or requiring significant capital investment to complete.

In addition, the ACA results indicate that the majority of poles and cables being replaced under this program are in poor or very poor condition, meaning that the assets being replaced are also at risk of failure, and have depreciated to a point that scheduling replacement is the appropriate course of action.

There are also challenges that come with aging substations:

- Outdated Technology: The existing substations are equipped with outdated technology that may pose challenges in meeting the increasing demands of a modern power distribution system;
- Maintenance Costs: Aging infrastructure often requires higher maintenance costs, leading to a continuous drain on resources. Frequent repairs and replacements of components contribute to operational inefficiencies;
- Reliability Concerns: As substations age, the risk of unplanned outages and service interruptions increases. This jeopardizes the reliability of FHI's power supply, impacting both residential and commercial customers; and
- Lead Times: As supply chain constraints continue, lead times for large items, such as power transformers, continue to increase. An unexpected failure could cause a significant prolonged risk until a replacement unit can be ordered and installed.

In the 2025 test year the proposed projects are:

BIRCH ST.

The scope of this project is a replacement of 5 wood poles and the addition of 7 new wood poles on Birch St. This is being done to support the long term upgrade of Seaforth from 4kV to 27.6kV and to replace 5 poles identified by the asset condition assessment as being in poor condition. The project spans approximately 320 meters. New primary conductor and new dual voltage transformers will be installed where applicable.

OAK ST. AND BIRCH ST. TIE

The scope of this project is a replacement of existing single phase conductor with a three phase underground primary conductor tie between Oak St. and Birch St. This is being done to support the long term upgrade of Seaforth from 4kV to 27.6kV and replaces the single phase infrastructure identified by the asset condition assessment as being in poor condition. The project includes the installation of 570m of underground primary conductor and the associated civil work to install ducts.

FHI is planning to remove Welsh DS from service during the forecast period (2028), which will address safety and reliability concerns by removing assets that are past their typical useful life and in poor condition from service. This will also reduce the ongoing operation and maintenance costs as inspections, testing and maintenance will no longer be required at the substations.

This voltage conversion will also bring the added benefits:

- Increased Efficiency: Upgrading the voltage from 4kV to 27.6kV will enhance the efficiency of FHI's distribution network. Higher voltage allows for reduced energy losses, optimizing power delivery to end-users;
- Capacity for Growth: The higher operating voltage provides additional capacity for future growth in electricity demand as well as DER’s, enhancing FHI's ability to meet the evolving needs of its expanding customer base;
- Cost-Effective Solution: Opting for a voltage conversion offers a more financially prudent approach compared to the wholesale replacement of substations. This allows FHI to allocate resources strategically and address the most pressing needs first;
- Removal of stocking 4kV Equipment: Voltage conversion removes the need for FHI to purchase and store inventory for 4kV applications, instead leveraging the already existing 27.6kV inventory for this community as well . At the end of this program, FHI will not have any 4kV service area left and will not require to keep any inventory; and
- Environmental Considerations: Removing power transformers past their typical useful life, and in poor condition, removes the risk of oil leaks and the associated concerns.

Although Welsh DS will be removed from service during this DSP period, decommissioning of the substation will be deferred to the next cost of service period, when it can occur for both.

2. TIMING

i. Start Date: March 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The main factors that could impact the project schedule include:
- Material procurement delays.
- Unplanned or higher priority work arises, resulting in resource constraints.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	0	0	0	0	0	0	0	217	224	228	235	240
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	0	217	224	228	235	240

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

FHI has not had a targeted 4kV voltage conversion program over the historical period. However, the scope of work required for voltage conversion is very similar to other rebuilds that FHI completes on a regular basis, and as such, FHI has used that information to help build out its forecast costs.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 7th out of 13 . As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. The asset management objectives listed below, along with the benefit of removing the need to invest significantly in 4kV substation replacements are the main factors that influence the program ranking. Not completing this program will result in FHI incurring a significant capital investment when the 4kV substations require upgrading. It is important that FHI complete the conversion program to simplify, standardize and improve the overall performance and efficiency of the distribution system and continue providing power in a cost effective manner.

Health and Safety – Non-life threatening injury, but public safety concern.

The majority of assets being replaced or removed through this program are >45 years, have been identified as being in poor to very poor condition, and as a result have some of the highest likelihoods of failure. What this means is that assets are statistically likely to fail within the planning window. Additionally, this program mainly addresses overhead distribution assets which have a potential to cause injury to both the public and FHI employees. Remote substations are also targets for copper theft, which could cause injury to the public if they are within the substation. Removing these substations also eliminates this particular risk.

Reliability/Supply of Power - Sustained interruption of one MS or embedded distribution feeder and provides for additional system capacity.

Asset History and Performance - Asset history shows intermittent failures (<1 each year) or >50% of asset class in fair or worse condition.

Customer and Community - Delivers on two of the top 3 priorities of customers (safe/reliable power, low rates) and is supported by over 60% of customers.

This program is designed to address reliability to the benefit of FHI customers and was supported by over 60% of customers who believed the proposed level of investment was at the proper level. It is also targeted at ensuring that the most cost effective solution for this community is selected to mitigate rate impacts.

Productivity/Efficiency - Aligns with 3 (Investment reduces operating expenses, investment increases liability with inaction, investment allows other projects to proceed).

By removing 4kV substations the operating expenses to own, inspect, test, and maintain each property and the associated equipment are removed. By addressing assets in poor condition, and by removing power transformers past their typical useful life, FHI reduces the potential for injury to staff and the public, and as each conversion project is completed, it allows the subsequent one to also be built and converted to 27.6kV.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses four environmental issues (climate change, risk of oil spills, removes environmentally damaging equipment, Ministry of Environment involvement).

By completing this program climate change is addressed as the new infrastructure will be built to the newest standards which are meant to address the increasing number of weather events being seen from climate change. It also addresses the risk of oil spills by removing old power transformers from service, which if a substantial oil leak were to develop could be environmentally damaging and require Ministry of Environment involvement.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1

7. ALTERNATIVE ANALYSIS

The projects identified in this category are based on a voltage conversion plan which considers the condition of the substation transformers, the loads it feeds and the age/condition of the infrastructure. To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing (Upgrade only on failure)** – FHI could continue to sporadically replace the poor and very poor condition assets in this community and rebuild them to 27.6kV standards as they are replaced. This would mean that some sections of the community would be rebuilt with others remaining at 4kV, which is not best practice and makes it more difficult to manage. While this would provide short term savings to customers, they would incur greater costs over the long term as it would necessitate investment in the existing substations to continue supplying 4kV in the community. In 2019, it was estimated that $3.2M would be required to upgrade both 4kV substations and recommended that both should be done in the next 10 years. This cost will have increased since 2019, and FHI has budgeted the proposed voltage conversion program, which is slated to be complete in 2033, at approximately $2.2M. More information around the cost can be found in Section B3 "Cost-Benefit Analysis". For these reasons, this option was not considered appropriate.

b. **Refurbish the existing 4kV lines** – In 2019 when the substation condition assessments were completed, it was determined that only 1km of line in this community was suitable to be refurbished and re-used for 27.6kV, the rest of the poles were determined to be too short, used improper conductor, or were structurally inadequate for re-use for 27.6kV. For these reasons, this option was not considered appropriate.

c. **Decrease Pacing** - FHI could decrease the pace of the voltage conversion investments, prolonging the program. While this would allow for spending in other areas, it increases the risk of a substation failure and decreased reliability to FHI customers based on the age and condition of the substation assets. It also requires prolonging the operating expenses to maintain, inspect and operate these substations. Furthermore, the majority of assets being replaced in this program have also been identified as being in poor or worse condition, so while not the main driver, the program does have the added benefit of renewing fully depreciated assets. For these reasons, this option was not considered appropriate.

d. **Carry out Voltage Conversion at proposed pacing (preferred option)**- FHI's preferred option is to carry out a full voltage conversion at the proposed pacing, with the two 4kV substations being retired from service in 2028 and 2033. With the substations containing critical assets that have been identified as being in poor condition, and therefore at risk of failure, with long lead times to replace, it is now prudent for FHI to convert its final 4kV system to 27.6kV. After this program, FHI will no longer have any 4kV within its system. This program pace offers the following advantages:
    - Allows for proper investments to still be allocated to the other needed investment programs;
    - Entire program can be done at a smaller cost than it would be to upgrade the substations, which was estimated at $3.2M in 2019;
    - Removes operating expenses that come with each substation;
    - Replaces assets that have been identified as being in poor or worse condition and are fully depreciated, minimizing stranded assets;
    - Reduces environmental risk of 50+ year old power transformers being in service; and
    - Removes the need for FHI to purchase/stock any 4kV equipment.

8. INNOVATIVE NATURE OF THE PROJECT

Although not a main driver behind this project, it will enable future technological functionality and address future operational requirements to meet the changing needs of customers, industry, and regulators. Once the remaining 4kV circuits are converted FHI will be able to further support the connection of larger loads and DER's into the distribution system.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: Upgrading 4kV rated equipment to 27.6kV equipment will result in greater operating efficiency, reduced power losses, and standardized equipment allowing for purchasing efficiencies. It will also eliminate the need to stock multiple types of equipment.

Customer Value: With the conversion of this community from 4kV to 27.6kV FHI anticipates the following benefits to customers.

- Eliminate older, end of life 4kV distribution assets;
- Provides the most cost-effective long term solution for the community;
- Reduce system losses through the elimination of substations;
- Allow for the connection of larger loads and generators;
- Conform to the standard voltage across the province making it easier to source material and expertise;
- Eliminate the use of outdated, difficult to operate and maintain equipment;
- Eliminate the need for 4kV substations and simplify the operation of the distribution system, as well as eliminating the need to invest in refurbishing and maintaining these substations.
- Aversion of potentially adverse effects on reliability and safety; and
- Avoidance of an increase to maintenance costs by needing to continue to operate and maintain these assets.

Reliability: The completion of this project is expected to address reliability over time for the following reasons:

- Reduced risk of prolonged outages associated with aged substation equipment needing replacement.
- Distribution system assets, built to today's standards are able to withstand more adverse weather conditions and, in overhead construction, have increased clearances around the conductors to assist in reducing the frequency and duration of outages.

Safety: This investment will improve safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards which will allow for improved safe work practices.

2. INVESTMENT NEED

i. Main Driver: Reliability - The main driver for this project is aimed at addressing failure risk. Most of the remaining distribution infrastructure operating at 4.16 kV that requires replacement for this category, is at the end of its service life and in poor condition, statistically making it some of the highest risk assets for failure. The two remaining 4.16 kV substations have also either surpassed or are approaching the end of their useful life, creating increased safety and reliability risks. Decommissioning the existing substations is not feasible without the complete system conversion. With rebuilt distribution assets, the system is expected be more dependable, providing customers with access to reliable electricity.

ii. Secondary Drivers: Customers - At its core, FHI exists to provide safe, reliable electricity supply to its customers in a cost effective manner. This project represents the most cost effective way for FHI to service the long term needs of this community, by removing the need to heavily invest in substation rebuilds. Additionally, removing this primary voltage level from FHI's service territory enables FHI to store less material, requiring less inventory, and the associated costs.

Productivity/Efficiency - The effect of these investments is an improvement in operation efficiency and cost-effectiveness by reducing line losses, increasing capacity for connections of new loads and DER's, as well as removing the capital and operating expenses that would otherwise be required with the 2 substations that will be removed from service as part of this program.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of the 4kV conversion program. The majority of the assets that will be replaced as part of the program are in poor condition or worse as identified by the ACA, and the 2 substations that will be removed from service as part of this program will eliminate the need for FHI to allocate significant capital into upgrading the substations in the future as they have either already surpassed or are approaching their expected service life, with critical assets in poor condition. This solution provides the most economical alternative to substation rebuilds in this community. In addition to this, by replacing assets in poor condition, this investment prevents the power supply reliability from degrading below FHI's targets. The planned replacement and conversion projects are essential in maintaining a reliable distribution system for customers.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI utilizes Utility Standards Forum design standards. These standards are based on CSA C22.3 No 1 Overhead Systems Heavy Weather Loading design standards and CSA C22.3 No 7 Underground Systems. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. FHI designs and construction facilitates the potential future incorporation of grid modernization equipment and renewable energy generation, and follows Ontario Regulation 22/04 in its design, construction, and material selection to ensure a safe and reliable system.

Projects in this category also benefit the system by eliminating older, inefficient operating voltages, and contribute toward the ultimate removal of older and inefficient substations, aligning with FHI's AM objectives.

ii. Cost-Benefit Analysis: Using the information from the 2019 Substation Condition Assessment, FHI used the 2019 estimated cost of $1.6M at each substation for a refurbishment to determine if a targeted voltage conversion program was financially responsible for this community.
While FHI acknowledges that this cost is likely now underestimating the cost of rebuilding a substation, FHI used the 2019 estimate of $1.6 M, accounting for actual inflation from 2019-2023, and using the Bank of Canada's 2% target inflation rate in forecast years, to complete a net present value calculation. This put the total cost to finish the voltage conversion of the community at $1.77M, while the cost to rebuild both substations was $3.32M (2028 and 2033). Additionally, the investment for pole and cable replacements would ultimately be needed in this community regardless of the substations, as the majority of assets being replaced have already been identified as being in poor or very poor condition and requiring replacement. This investment also removes the future operating and maintenance costs that would be associated with continuing to have both 4.16kV substations.

iii. Historical Investments & Outcomes Observed: FHI has completed several voltage conversion projects outside of the historic period and has observed many positive outcomes from these projects including but not limited to, improved system efficiency, reduction in losses, and increased standardization requiring less inventory. When end-of-life poor condition assets are replaced as part of these voltage conversion projects, this also results in maintained or improved system reliability.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: GENERAL PLANT

PROJECT: BUILDINGS

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program comprises of general investments and improvements to buildings at FHI's offices. FHI owns an administration building, built in 1959, with an expansion of the building in 1992. In addition, FHI shares an operations building, built in the 1920's with an expansion of the building in the 1950's. Both of these buildings are critical to FHI's 24/7 operations. These buildings house the office and field staff who undertake the daily operations of the business. This includes customer service, finance, engineering, field staff, and I.T. Without investments in these facilities, there will a be detrimental impact on FHI's operations that could affect both the safety of staff, as well as have an indirect impact on the reliability of the system and the ability to deliver services cost effectively. This program entails general repairs, replacements, and upgrades within these facilities, which includes security improvements, asset replacements (e.g., windows, roof, etc.), installation of EV chargers, and other general improvements.

The investments within this program have been informed by 2019 building condition assessments that were completed on both buildings. This included a detailed assessment of each building and its components, as well as recommended upgrades, timing, and budgetary pricing, that assisted FHI in creating this capital replacement plan. For some larger cost items that require replacement (e.g. roof), FHI has undertaken subsequent studies and cost estimates to better inform the timing of these replacements for the forecast period.

The work planned for 2025 involves:

- **Replacement of Admin Building Roof:** This was originally budgeted based on the 2019 building condition assessment identifying the roof, installed in 2006, as requiring replacement in this timeframe, given that it has a typical lifespan of 15-20 years. There were also noted deficiencies in the roof construction, which cause ponding on all the roof areas. An updated report was completed in 2023, recommending replacement of the roof within 2 years. FHI subsequently received pricing that has informed its forecast investment costs within this narrative.
- **Replacement of Yard Lights:** FHI's yard that houses all its pole and transformer inventory has ten light poles within the yard that are in poor condition and require replacing. These lights are relied upon by Operations staff when responding to after hour callouts that require them to pull inventory from these sites to be able to gather the equipment they need and safely work around and gather the proper equipment.
- **EV Chargers for vehicles:** As Electric vehicles become more prevalent, FHI expects their passenger vehicle fleet to also transition to EV's. As a result, chargers and accompanying electrical infrastructure needs to be installed to accommodate these vehicles.
- **Miscellaneous items:** The remaining Test Year budget is allocated towards ad-hoc works needed to support the safe and reliable continuation of FHI's operations. This typically includes a variety of works such as general asset repairs, replacements, and upgrades (e.g., plumbing, garage doors and windows, exterior, heating, and cooling, etc.) as identified by FHI's preventative inspection and maintenance activities, reactive replacements due to premature failure of any building assets and addressing any other on-going requirements to maintain the upkeep and safe working condition at FHI's facilities.

2. TIMING

i. Start Date: January 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The main factors that could impact the project schedule include:
- Supply chain constraints.
- Unplanned or higher priority work arises, resulting in budget constraints.
- Contractor availability.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	193	225	157	492	366	1061	2165	505	315	535	269	440
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	193	225	157	492	366	1061	2165	505	315	535	269	440

Future costs vary based on investments in other categories over the forecast period (e.g. fleet). This has been done to levelize overall capital investments in the forecast period.

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3 and vary year over year in accordance with specific needs identified and works undertaken.

2021,2023 and 2024 all saw significant expenditures at the administration building for renovations that were completed. These were done as a result of a detailed feasibility study that was completed in 2017. The purpose of this study was to review options for the FHI Administrative Building. The report was then used to make capital planning decisions. The following options were evaluated:

1. Renovation of the existing building at 187 Erie St.
2. Construction of a new administration building on the existing property located at 187 Erie St.
3. Construct a new FHI complex (including the administrative building, service centre, and Whyte Avenue storage facility) at a different location.

Supporting efforts also included the completion of an energy efficiency review of the existing administration building, as well as the completion of a life cycle costing analysis for all options.
This study concluded that the option to renovate the existing building was the most cost-efficient option, and it would provide FHI with the functionality that was required for current utility needs, while still providing room for additional growth in the future as can be seen in Figure 1.

Summary of Life Cycle Analysis with Capital Costs

Option	Option Name	Status	Capital Cost	Net Present Value (MARR=5%)
1	Retrofit of Existing	Base Case	$2,163,959	-$19,918,497
2	New Admin on Existing Site	Option	$3,898,027	-$38,449,888
3	New Facility on Greenfield Site	Option	$9,776,665	-$101,171,807

Figure 1: Summary of Life Cycle Analysis with Capital Costs

This renovation not only modernized the building and allowed the space to be utilized more efficiently, but it also allowed the mechanical, electrical, and plumbing systems to be updated, many of which still used much of the original 1959 installation. It also allowed these systems to work as one functional unit for the first time, as it currently had a disjointed installation between the original and renovated spaces. This renovation also allowed the building to comply with accessibility and code requirements, safely remove designated substances if required, improve the energy efficiency of the building by adding insulation to exterior wall, complete lighting upgrades, and install more efficient HVAC systems.

Once it was determined that this was the best course of action FHI undertook a multi-year renovation to complete this project.
In 2021 the washrooms on both floors were renovated. The scope for this phase of the project included:

- installation of a barrier free washroom at FHI to comply with accessibility requirements;
- Updating the plumbing for all washrooms, which included the replacement of deteriorated copper pipes; and
- Improve the insulation to exterior walls, install LED lighting, and update mechanical systems.

In 2023 the customer service and accounting areas were renovated. The scope for this phase of the project included:

- Repurpose a large part of the customer entrance foyer, which was no longer required into workspaces for staff;
- Re-organize the existing staff space for the current functional requirements and makeup of staff;
- Replace a degraded 1959 main sewer pipe, which required bi-weekly maintenance to function;
- Provide a barrier free front counter to comply with current codes and regulations;
- New and updated electrical and mechanical systems purpose built for the area.
- Designated substance removal;
- HVAC (air exchange) updates and replacement of electrical heat for occupancy comfort;
- Electrical and IT upgrade to supply requirements of a modern office (computers, printers, scanners); and
- Improve the insulation to exterior walls, updates required for current building codes, install doorways that meet accessibility requirements, and improve the security of the building between customers and staff.

In 2024, the IT and meeting space area on the first floor, and the second floor of the administration building are being renovated, to finish the project. The scope for this phase of the project includes:

- Installation of an accessible lunchroom on the first floor;
- Expansion of 1st floor meeting room to meet functional requirements of company;
- Relocation and updating of mechanical and electrical systems on first floor to properly size the ductwork capacity, and move rooftop units and furnace in central location, maximizing floor space for staff requirements;
- Addition of a 2nd floor meeting room for staff on this floor;
- Re-organizing the existing staff space for the current functional requirements and makeup of staff;

- New and updated electrical and mechanical systems purpose built for the area;
- Designated substance removal;
- Electrical and IT upgrade to supply requirements of a modern office (computers, printers, scanners); and
- Improve the insulation to exterior walls, updates required for current building codes, install doorways that meet accessibility requirements, and improve the security of the building between customers and staff.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 12 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. Under the General Plant category, FHI identifies underperforming or depreciated assets or systems based on feedback received from customers, vendors, staff, performance tracking, and operating and maintenance costs. To prioritize the execution of these projects, FHI considers additional drivers or benefits of completing the project. This typically includes improvements in customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with FHI AM objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Safety concern, not life threatening or injury requiring first aid.

This investment program is targeted at replacing facility assets that through inspections or maintenance have been identified as requiring replacement. Failing to maintain buildings and facilities increases the risk of injuries to staff or the public.

Reliability/Supply of Power - Sustained interruption of < 3 MW of load or provides for additional system capacity.

While the buildings do not have a direct impact on reliability, if staff are unable to rely upon the administration and operations buildings to function as needed, it can have an adverse effect on FHI's response to reliability issues and concerns.

Asset History and Performance - Asset history shows recurring maintenance expenses, support of products has ended.

The target assets being replaced in this program are those identified through inspections or reports as being past the end of their expected life or in a condition that necessitates replacement.

Customer and Community - Delivers on one of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 50% of customers.

Productivity/Efficiency - Aligns with 3 (Investment reduces operating expenses, investment increases liability with inaction, investment reduces employee time spent on tasks).

By addressing assets in very poor condition, FHI expects a reduction in operating expenses associated with the assets being replaced by minimizing the amount of reactive and recurring maintenance required. This in turn reduces employee time spent troubleshooting and coordinating this work and decreases the companies liability of issues that may arise from the building impacting staff's ability to work effectively.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses two environmental issues (removes hazardous equipment, reducing green house gas emissions). By completing this program climate change is addressed as the new infrastructure will be built to the newest standards and take advantage of energy efficiency advances. Based on the age of the building, updates to the building also allow for the responsible of any hazardous or environmentally damaging systems that may be present.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing –** Without investing in the ongoing repair, replacement, and upgrades of FHI's building and yard facilities, many of which have been identified as reaching or near their end of life, there is a risk that these facilities will not be fit for staff to carry out their jobs safely and efficiently. For these reasons, this alternative is not considered appropriate.

b. **Carry out the proposed pacing of investments (preferred option) -** This option allows FHI to continue investing in its operations building and yard facilities in order to support 24/7 operations. FHI evaluates the identified needs to determine which are most critical to undertake and which can be monitored and pushed out to later years. Project-specific alternatives (e.g., run to fail vs. repair vs. replace like-for-like vs. upgrade with additional functionality) are considered on a case-by-case basis depending on the identified need.

c. **Increase pacing of investments required –** This option would see FHI bring forward projects into earlier years and carry out more work each year. While this may help address certain issues quicker, it also increases the overall budget and may divert funds and resources away from other critical work in the other investment categories. For these reasons, this alternative is not considered appropriate.

d**. Decrease pacing of investments required –** This option would see FHI defer projects into future years. While this may lower costs on a short term basis, there are still several projects from the 2019 building condition assessment report that need be addressed as soon as possible (parking lot paving, windows, roof), to address the potential safety issues or significant reactive repair costs. For these reasons, this alternative is not considered appropriate.

8. INNOVATIVE NATURE OF THE PROJECT

Not applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: By investing in its facilities to keep them up to date, clean, safe, and secure, FHI ensures that staff can continue to work in a safe and comfortable environment which will enable them to maintain operational efficiency and support 24/7 operations.

Customer Value: A functional, safe, and clean environment ensures that staff can undertake their work effectively and efficiently to provide the type of high-quality service customers expect. By updating and maintaining buildings, FHI also is able to ensure that accessibility requirements for customers are met when visiting.

Reliability: While these investments have no direct impact on reliability of the network in terms of planned outages, these facilities are crucial to support continued 24/7 operation. They also house equipment and materials that are used daily to help maintain the reliability of the system.

Safety: The repair, replacement, and upgrade of damaged, obsolete or end of life building assets help mitigate any catastrophic failure which may compromise the safety of employees and the public. This work also ensures that FHI has a safe workspace and functioning building assets that meet the latest health and safety standards and regulations keeping its staff safe while carrying out their work activities.

2. INVESTMENT NEED

i. Main Driver: Non-System Physical Plant - The primary driver for this program is to renew and invest in FHI's non-system physical plant. Within the context of this program, it is to invest in FHI's facilities that house in-office & operations staff and equipment that is used for maintenance and operations.

ii. Secondary Drivers: System Maintenance and Capital Investment Support – FHI's facilities, and yard also houses equipment and vehicles used in the maintenance and construction of the distribution system. By investing in these facilities and ensuring they are fit for purpose, FHI is protecting these assets which helps to ensure that they will work and are available when needed.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of this program. The following information was used to determine the proposed projects:

- **Replacement of Admin Building Roof:** This was first identified during the 2019 building condition assessment, and then prioritized for replacement in 2025 based on the subsequent report in 2023, which highlighted replacement within the next two years.
- **Replacement of Yard Lights:** This was identified by inspections and employee feedback on the condition of the poles. They are past their useful life and their condition and state necessitate replacement to ensure lights are available when needed in the yard.
- **EV Chargers:** This is being done in partnership with fleet vehicle purchases, as FHI expects their passenger vehicle fleet to also transition to EV's. As a result, chargers and the accompanying electrical infrastructure need to be installed to accommodate these vehicles.

Costs for the assets were used based on historical purchases, feedback and quotes from vendors, budgetary costs outlined in reports, as well as forecasted cost increases. Prior to purchase, FHI enters a formal procurement process to seek multiple quotations for evaluation.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: To ensure that FHI can deliver safe, reliable, and efficient service, it is fundamental that FHI has the necessary foundations in place. A functional office space is required to house staff so customer needs can be met. In addition, it is important that field staff have the resources, tools, equipment, and space to carry out maintenance and capital projects. It is necessary to incur costs each year to maintain the administration office, operations service center and storage areas. Using inspections, third party reports, and preventative maintenance programs, FHI has carefully reviewed and planned what is required to be carried out to ensure it can still operate and delivery safe, reliable, and efficient service to its customers.

ii. Cost-Benefit Analysis: Replacements under this category are reviewed on a case-by-case basis to identify potential options. This may include repair/refurbishment, running an asset to failure, or looking for new solutions. Typically, this will involve research by staff on alternatives, as well as discussions with vendors, contractors, and consultants to determine the most appropriate path forward.

iii. Historical Investments & Outcomes Observed: Historical costs for this program are indicated in Section A3 of this document. Investments in this program have resulted in the ability for FHI staff to continue to perform all its critical services and adapt to the workforce changes that have been seen by the utility over the years. Investments in this program have also addressed accessibility, health, and safety defects. This has ensured the continued ability to operate 24/7 and deliver safe and reliable electricity supply to its customers.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not applicable.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: GENERAL PLANT

PROJECT: FLEET

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program involves investment to address FHI's fleet. FHI's Fleet replacement plan is based on the age and condition of fleet assets, using the formula outlined in Kinectrics ACA. Currently, FHI has the following Fleet assets:

Purchase Year	**Vehicle number**	**Year & Description**
1993	21	1993 TICO 1080 Ford Knuckle Boom Crane
1996	24	1996 Freightliner RBD Telelect
1997	57	1985 FORK LIFT FG-30
2005	1	2005 Freightliner M2 –C5048 Tel Elect Digger
2005	6	2005 Freightliner Posi Plus – 42' Single Bucket
2006	5	2006 Altec AM55E 55' Double Bucket Aerial Device/Material Handler
2008	18	2008 Kenworth T-170 U/G Service Truck
2009	42	2009 International 50' Single Bucket Aerial Device-Two Man Bucket
2009	7	2009 Chevrolet Silverado 2500 HD 4WD Ext. Cab Pickup Truck – Maint.
2010	4	2010 42' Single Bucket Terex Aerial Device c/w 2011 Freightliner M2 Chassis
2010	16	2010 Grand Caravan – Eng./Travel
2010	19	2010 GMC ½ Ton Extended Cab 4 x 4 Pickup – Eng
2011	23	2011 Case 580SN Backhoe
2012	2	2012 Freightliner M2-106 52' Corner Mounted Radial Boom Digger Derrick
2013	14	2013 Chevrolet Silverado 1500 4WD Ext. Cab ½ Ton Pick up Truck
2014	8	2014 Dodge 1500ST 4WD Extended Cab ½ Ton Pickup – Lead Hand
2015	10	2015 GMC Sierra Crew Cab 4WD Half-Ton Pickup Truck – Ops Mgr
2017	9	2017 GMC Savana 2500 Series Cargo Van – Maintenance
2018	3	2018 Freightliner Posi Plus – 42' Single Bucket
2019	12	2019 Grand Caravan
2022	17	2022 GMC Sierra Pickup
2023	27	2023 Ford F250 Pickup

Table 1: List of FHI Pickup and Large Vehicle Fleet Assets

Vehicles and other mobile assets form an essential component for the restoration of power during outages, the efficient construction and maintenance of a distribution system, and the safety of employees and the public. To effectively manage Fleet assets, FHI has the following objectives:

a. Provision of safe, reliable, and efficient vehicles and equipment to meet operational requirements;
b. Compliance with legislation and regulations;
c. Optimization of size and type of fleet;
d. Cost effectiveness; and
e. Environmental considerations.

To achieve these goals, FHI maintains a multi-year capital plan. This plan is essential in both short- and long-term forecasting and includes the following criteria when establishing replacement of individual vehicles:

a. Vehicle age;
b. Mileage;
c. Annual maintenance/inspection results;
d. repair history;
e. Use case requirements.

Each Fleet asset is assessed for optimal replacement. What this may mean is vehicles could be retained longer due to better-than-average condition, while others may be replaced earlier due to poorer condition. Prior to replacement, an assessment of current and future needs occurs to determine if an alternative vehicle type would be beneficial. Furthermore, FHI decides if forecasted use warrants a new replacement, or rental of the asset in the future based on use case for the asset and the associated cost.

Kinectrics ACA identified 4 passenger vehicles (36%) and 7 large fleet vehicles (70%) as being in poor or very poor condition. In 2025, FHI plans to replace their forklift (1985) and truck 14 (2013), both of which have been identified as being in poor condition. Over the rest of the forecast period FHI plans to replace 3 bucket trucks (in 2026, 2028 and 2029) and 2 passenger vehicles (in 2027), all of which have been identified as currently being in or approaching poor condition. Further information on the age, mileage and maintenance costs of the vehicles being proposed for replacement is available in section B2 and was used to compile the health index of each fleet asset in the ACA.

The vehicles proposed for replacement are:

Year	Vehicles Replaced
2025	Forklift (1985), Truck 14 (2013 Pickup Truck)
2026	Truck 24 (1996 Radial Boom Digger)
2027	Truck 8 (2014 Pickup Truck), Truck 10 (2015 Pickup Truck)
2028	Truck 6 (2005 Single Bucket Truck)
2029	Truck 1 (2005 Radial Boom Digger)

Table 2: Forecast FHI Pickup and Large Vehicle Fleet Replacement Plan

2. TIMING

i. Start Date: January 2025

ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: The main factors that could impact the project schedule include:

- Supply chain constraints, as FHI has seen increasing lead times on bucket trucks, they are ordered two or three years in advance to mitigate this risk.
- Unplanned or higher priority work arises, resulting in budget constraints.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	334	56	0	17	69	93	450	125	575	220	478	598
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	334	56	0	17	69	93	450	125	575	220	478	598

4. ECONOMIC EVALUATION

Not Applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3 and vary year over year in accordance with specific needs identified and fleet works undertaken. Some of the larger variations are explained below:

- 2018: This cost is largely driven by the purchase of a new Posiplus single bucket truck.
- 2019, 2022 and 2023: These costs involved the purchase and replacement of new passenger vehicles

The quantity and scope of replacements year-to-year is based on the best available data considering inflation, supply chain and material cost factors for these assets.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 11 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. Under the General Plant category, FHI identifies underperforming and depreciated assets or systems based on feedback received from customers, vendors, staff, performance tracking, and operating and maintenance costs. To prioritize the execution of these projects, FHI takes into account additional drivers or benefits of completing the project. This typically includes improvements in customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with FHI AM objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority. The need to maintain an up to date and reliable fleet is imperative for FHI to continue to supporting business needs. Without proper fleet management, distribution system work can fall behind, creating negative impacts to the reliability and safety of the distribution system.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – Public safety concern, not life threatening.

This investment program is targeted at replacing fleet assets that through inspections or maintenance or the ACA have been identified as requiring replacement. Failing to maintain a reliable fleet increases the risk of them not operating properly and causing potential injuries to staff or the public.

Reliability/Supply of Power - Sustained interruption of < 3 MW of load or provides for additional system capacity.

While fleet does not have a direct impact, if vehicles are unable to be relied upon at the needed times, it can have an adverse effect on FHI's response to reliability issues and concerns.

Asset History and Performance - Asset history shows recurring maintenance expenses, impacting availability of equipment.

The target vehicles being replaced in this program are those identified as being in poor or very poor condition in the ACA, and have some of the highest maintenance costs in the fleet, and have historically been removed from service for unexpected repairs and service work.

Customer and Community - Delivers on one of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 50% of customers.

Productivity/Efficiency - Aligns with 3 (Investment reduces operating expenses, investment increases liability with inaction, investment reduces employee time spent on tasks).

By addressing assets in very poor condition, FHI reduces the maintenance costs associated with older vehicles, reducing employee time spent coordinating and scheduling these activities.

Organizational Effectiveness – Aligns with 2 (Investment improves employee response and improves customer experience, investment provides sustainable business operations).

Environmental Impact – Addresses two environmental issues (climate change, reducing green house gas emissions).

By completing this program climate change is addressed as certain new vehicles will explore the viability of alternative new fuels, reducing greenhouse gas emissions.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do Nothing –** This results in increased maintenance and repair costs, does not address the significant mileage and wear on the vehicle, and adds risk to the operational effectiveness of FHI's operation and maintenance of the distribution system. The vehicles planned for replacement are past their expected service life, have increased maintenance costs, and are in poor or very poor condition. The in-service failure of these assets would negatively impact FHI's ability to respond to planned and unplanned distribution system work. For these reasons, this alternative is not considered appropriate.

b. **Refurbish Vehicles –** FHI looks to replace components of a vehicle as they age to maximize their lifespan, however this becomes infeasible when maintenance costs continue to increase, and they are already in poor overall condition, which is the case with both vehicles planned for replacement in 2025. For these reasons, this alternative is not considered appropriate.

c. **Replace Like for Like (preferred option)-** This is the preferred approach when age, maintenance and ACA data indicate that the asset requires replacement, and the following criteria are met:

- The existing functionalities of the vehicle being replaced are still required,
- Commercial availability of new technological features is not readily available.

For example, while there are some large vehicles being piloted as all electric, FHI's approach is to wait until this is a proven, reliable technology before investing. This is due to the size of FHI's fleet, and if one vehicle is unreliable it has a significant impact resource.

d. **Replace with different functionality (preferred option)-** This is the preferred approach when age, maintenance and ACA data indicate that the asset requires replacement, and the following criteria are met:

- The existing functionalities of the vehicle being replaced are no longer required or adequate,
- Commercial availability of new technological features is readily available.

For example, when replacing passenger vehicles and the forklift, FHI will examine if electric options suit their business needs. Also, when replacing bucket trucks, the number of buckets needed (single or double) and boom size are two factors that are considered.

8. INNOVATIVE NATURE OF THE PROJECT

Where economically feasible and responsible to do so, FHI will look to acquire fleet vehicles powered by alternatives to traditional fuels (e.g. Electric Vehicle).

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: Consistent management of FHI's fleet will ensure that life cycle costs and risks of in-service failure remain low. Planned replacement of the fleet ensures that the staff are using reliable and functionally relevant equipment while on the job. Unreliable fleet can negatively impact utility performance, such as reliability and employee productivity, and as vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs.

Customer Value: The replacement of fleet vehicles equip staff with reliable equipment essential to completing planned system renewal work and to respond to unplanned power interruptions.

Reliability: The replacement of end-of-life fleet vehicles allows for the continued efficient day to day operations of FHI's business. Having reliable vehicles is important to the delivery of reliable electricity to customers as outages are not unnecessarily prolonged due to vehicle breakdown.

Safety: Employee and public safety are addressed by ensuring that FHI's fleet assets are managed according to all codes, standards, and regulations as prescribed. Planned replacement also mitigates the risk of in-service failure of these assets while staff are using the vehicle, which may threaten their safety.

2. INVESTMENT NEED

i. Main Driver: Failure Risk – The main driver for this program is addressing the risk of failure of assets that are at end of typical useful life and have been identified as being in poor or very poor condition. Fleet vehicles are needed to support business needs, and over time, these units are subject to wear and tear that can impact vehicle safety, reliability, and operational efficiency. As vehicles age and mileage increases, they also incur higher operating expenses due to increasing levels of reactive repairs.

ii. Secondary Drivers: System Maintenance and Capital Investment Support – Investments into fleet vehicles, including regular maintenance, replacements when vehicle condition indicates, and additions based on staff functional requirements is essential to ensure that FHI continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities.

iii. Information Used to Justify the Investment: FHI's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of this program. Recent ACA results identified 36% of passenger vehicles (Figure 1) and 70% of fleet vehicles (Figure 2) in poor or very poor condition. These results considered factors such as age, repair history, mileage, etc. to identify and develop these health indices. This information was then used, along with looking at FHI's operational requirements and options, as well as vehicle lead times to identify asset replacement timing.

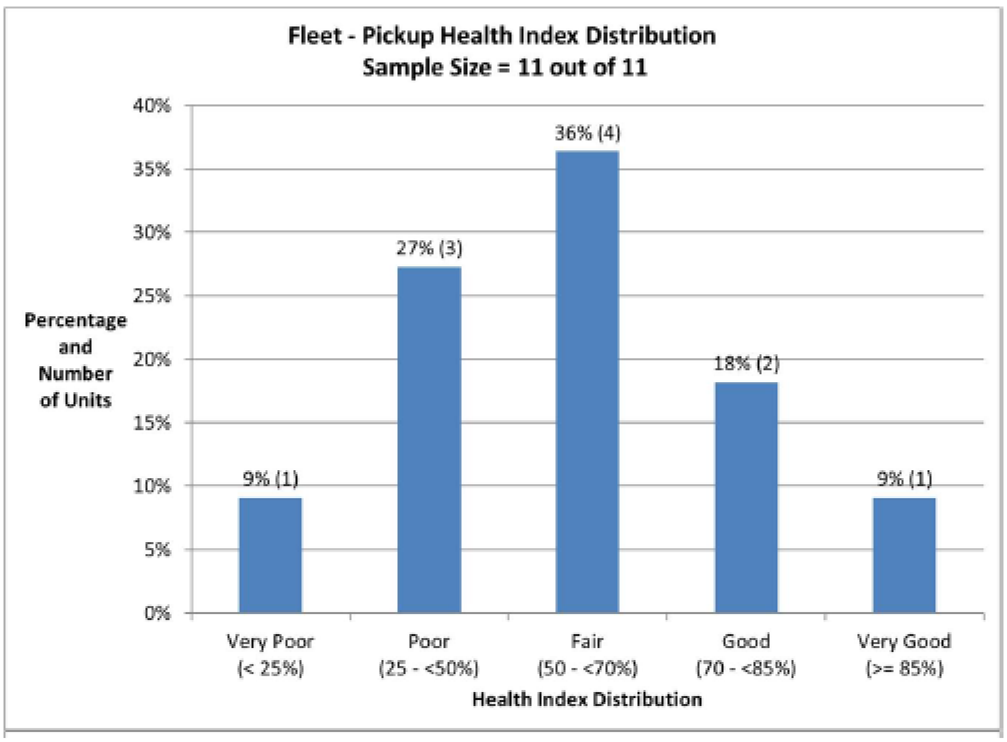


Figure 1: Health Index Distribution – Fleet Pickup Vehicles

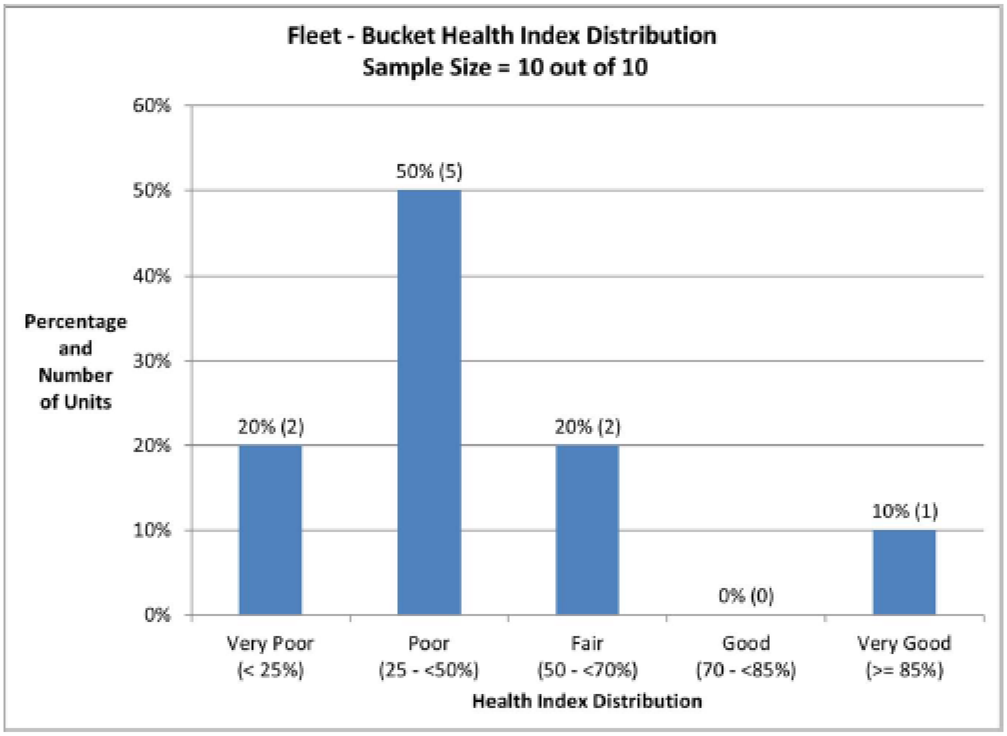


Figure 2: Health Index Distribution – Fleet Bucket Vehicles

Forecast investments are generated using informal vendor quotes for purchase price (see Table 2-1 for summary of pricing on recent purchases compared to historical) and lead times.

Vehicle Type	Cost Difference	% Difference
Single Bucket	$113,500	35%
Passenger Truck	$19,230	65%

Table 3: Typical Purchase Price Historical vs. current

As can be seen, pricing and lead times for passenger and large aerial vehicles has increased dramatically, with lead times of 2-3 years now for certain vehicles. Prior to purchase, FHI enters its formal procurement process. This involves seeking multiple quotations through a request for proposal process. All formal quotations are reviewed prior to purchase to ensure the best value is obtained. Vehicle replacements are generated using the extensive historical vehicle maintenance and repair data combined with detailed inspection and expert judgement. The vehicles proposed for replacement in the test year are further detailed below.

Vehicle 57: Forklift

Manufacturing Year: 1985

In Service Date: 1997

Functionality: Utilized by Stores and Lines on a daily basis to place, transport, and or move transformers, reels, and other skidded material within warehouse and facility yard.

	2018	2019	2020	2021	2022	2023	Total
Maintenance Costs	$440	$910	$935	$1329	$662	$6251	$30,927

Noted Issues (See below pictures):
- Bent lift frame at front
- Tires need replaced
- Rust and Corrosion
- Gear shift issues
- Numerous temporary repairs
- Almost 40 years old and has been in service at FHI for 28 years
- Increasing maintenance costs

Figure 1: Vehicle 57 side view

Figure 2: Vehicle 57 back view

Vehicle 14: Pick-up Truck

Manufacturing Year: 2013

In Service Date: 2013

Functionality: Utilized by Lines Foremen and on call staff for all associated duties.

	2018	2019	2020	2021	2022	2023	Total
Maintenance Costs	$2,257	$2748	$1138	$798	$3974	$3655	$20,806
Mileage (kms)	12058	13476	13995	11884	23653	19186	216667

Noted Issues (See below pictures):
- Very high mileage
- General rust and corrosion (mainly along doors and wheel wells)
- Interior condition (seats and liners)
- Increasing maintenance costs

Figure 3: Vehicle 14 side view

Figure 4: Vehicle 14 wheel wells

Figure 5: Vehicle 14 interior rust

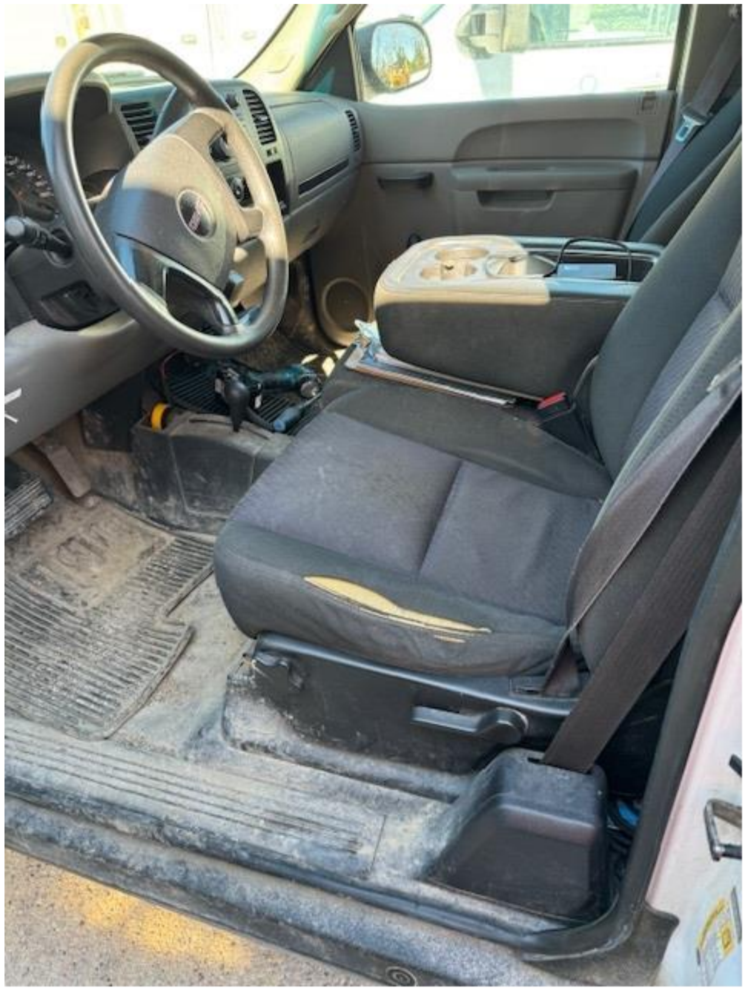


Figure 6: Vehicle 14 interior liners and seats

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: In order to maintain the distribution system, it is imperative that FHI's fleet vehicles are reliable. Reliable fleet vehicles help FHI achieve reliability targets by enabling staff to respond to outages in a timely manner. Key scorecard metrics (e.g., SAIDI, appointments met on time) are influenced by a properly operating fleet. SAIDI could increase as vehicles used to respond to outages are unavailable or break down while responding to a call.

There are also certain codes and regulations that FHI must follow, that a reliable fleet is crucial to. This includes emergency response times of 1 hour or less for all FHI's service territory, and sections of the DSC for responding to customer requests and appointments.

FHI has carefully reviewed and planned what is required to be carried out to ensure it can still operate and deliver safe, reliable, and efficient service to its customers.

ii. Cost-Benefit Analysis: Each replacement under this category is reviewed on a case-by-case basis to identify any available alternatives. This may include repair/refurbishment or purchasing a different kind of vehicle. Ongoing fleet replacement is needed to ensure that staff have continued access to reliable vehicles. When replacement is necessary, FHI gathers multiple quotes on the replacement vehicle and cost is a key factor into the ultimate decision of the vehicle purchased.

iii. Historical Investments & Outcomes Observed: Historical costs for this program are indicated in Section A3 of this document. Investments in this program allow FHI to successfully operate and maintain its distribution system in a safe and efficient manner.

iv. Substantially Exceeding Materiality Threshold: Not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

See Section A8.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: GENERAL PLANT

PROJECT: IT HARDWARE

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

This program involves the design, configuration and installation of IT and OT hardware for FHI's systems. These projects typically are needed to replace end of life assets, unsupported obsolete technology, enable new functionality, or enhance the capabilities and security of FHI's networks.

FHI's IT hardware lifecycle program provides an important foundation to the 24/7 operational needs, and business continuity of the organization. Dependency and utilization of technology has rapidly increased in the last five years. There are still assets in service which have been declared end of life by the vendor and this program will address the challenges created by the past approach, which was more ad-hoc and project based, as well as enabling FHI to have predictable cost and work planning in the future.

New hardware deployed as part of this process will be managed through a 5-year asset lifecycle. Any additional capital will be tied to special projects or expansion of the network.

In 2025, this program involves a refresh of hardware and network equipment dedicated to FHI's Operational Technology (OT) network. FHI has historically utilized a server cluster, dedicated redundant firewalls, and a wide area network comprised of fibre and wireless communications to provide capabilities needed for 40+ SCADA and metering endpoints. The proposed hardware to be refreshed will include:

- new servers,
- firewalls,
- switches, and
- remote connectivity devices.

The goal is to build a resilient network with future growth and the new AMI 2.0 project in mind, while increasing cybersecurity capabilities to address both the current and future threat landscape.

2. TIMING

i. Start Date: Jan 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing:
   - AMI Project Timelines.
   - Hardware availability.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	95	76	60	275	176	289	193	297	289	367	381	397
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	95	76	60	275	176	289	193	297	289	367	381	397

4. ECONOMIC EVALUATION

Not applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Historical costs have been provided in Section A3.

Beginning in 2021 FHI began investing higher amounts in this category as the investment strategy moved solely from replacing end of life assets like for like, to implementing backup locations, installing servers with high availability, and the associated network equipment to provide for better business continuity planning. Enhancements also were implemented to improve FHI's cybersecurity posture in order to comply with the OEB cybersecurity framework.

The majority of the current OT hardware that is planned to be replaced and enhanced as part of the network refresh, was installed prior to the Historical Period and is at end of life or end of support.

As with most components, costs have increased which is driving higher estimates compared to historical expenditures. Increasing focus on cybersecurity also requires increased investment.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 9 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. Under the General Plant category, FHI identifies underperforming or depreciated assets or systems based on feedback received from customers, vendors, staff, performance tracking, and operating and maintenance costs. To prioritize the execution of these projects, FHI takes into account additional drivers or benefits of completing the project. This typically includes improvements in customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with FHI AM objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority. With the ever-changing topology of the grid, the need for increased reliability and a greater reliance on data, this 2025 project has high importance for FHI. It will be a prerequisite to other capital projects being seen through to completion.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – High Impact Security Incident.

Following FHI's Cybersecurity response plan, this program addresses potential incidents that would be classified as a high impact event which could cause impacts to critical systems, business reputation and business operations.

Reliability/Supply of Power – While not a direct impact, failing to adequately replace and secure assets in this program has a potentially significant impact on reliability concerns if the network communications of the distribution system infrastructure are compromised or unavailable.

Asset History and Performance - Asset history shows minimal maintenance expenses.

However the new infrastructure will allow for a more standardized approach to updating and expanding the network in the future while improving the cybersecurity of the OT network.

Customer and Community - Delivers on one of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 50% of customers.

Productivity/Efficiency - Aligns with 3 (Investment allows other projects to proceed, investment increases liability with inaction, investment reduces employee time spent on tasks).

This program will coincide with other planned investment projects to allow them to proceed, increases FHI cybersecurity strength and resiliency, and will allow tasks to be standardized in the future, reducing employees time spent completing them.

Organizational Effectiveness – Aligns with 3 (Investment improves employee response and improves customer experience, investment provides sustainable business operations, investment supports innovation).

Environmental Impact – This program does not address environmental impacts.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do nothing -** Doing nothing will present a risk of equipment no longer having support and being vulnerable to new cybersecurity exploits. The grid is increasingly more dependent on this IT hardware which could result in reliability issues if the lifecycle isn't effectively managed. For these reasons, this option was not seen as appropriate.

b. **Like for like replacement (proactive) -** This would involve the majority of the current lifecycle cost but would require additional capital spend when expansion of the network is required, which is projected before the end of the next capital lifecycle. For this reason, this option was not seen as appropriate. This option would also not comply with the OEB's cybersecurity requirements.

c. **Upgrade to latest standard (preferred option) -** There have been many recent innovations in the area of the network technologies that support the grid and related cybersecurity solutions. Upgrading to the latest standard allows FHI to be flexible in enabling grid automation and technology while meeting OEB cybersecurity requirements. For these reasons this is the preferred option.

8. INNOVATIVE NATURE OF THE PROJECT

FHI has unique capabilities in both the infrastructure it maintains and its personnel. Completing this project successfully will demonstrate how infrastructure, cybersecurity and automation play an important role as the penetration of DER's on the distribution system continues to increase, with more third parties connected and integrated with FHI's systems. FHI believes this project will give them a reference design and expertise which can be shared with other utilities in the province.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: The IT hardware environment supports the 24/7 function of operational technology for FHI. Consistent investment will ensure efficiency by supporting grid management and automation applications on an ongoing basis.

Customer Value: An improved IT hardware environment will increase the capabilities to receive data from the grid. This drives customer value through making data-driven decisions, improving customer presentment, and being able to pinpoint issues before they expand.

Reliability: The dedicated IT hardware provides the underlying infrastructure for grid visibility and automation. Managing the lifecycle of this network allows for capability expansion, managing reliability levels through better identification of outage cause and more efficient real-time outage management capabilities.

Safety: Improving the cybersecurity of the network will ensure the safe function of grid automation. The threat landscape is continuously changing, and the regulatory framework is starting to recognize the need to focus on OT cybersecurity. This project will allow FHI to ensure the OEB cybersecurity requirements are met to help support safety.

2. INVESTMENT NEED

Operational technology is becoming increasingly important for FHI. As the grid advances, the need for automation increases. Yet, adding automation without accounting for the underlying IT infrastructure and cybersecurity creates significant risk for the operation of the utility. Maintaining a consistent IT hardware lifecycle allows FHI to manage total cost of ownership and provide a stable and secure operating environment.

i. Main Driver: System Capital Investment Support - By upgrading/replacing the IT equipment supporting OT, FHI will enhance its focus on resiliency and cybersecurity. There is a need to be able to support grid automation and reliability initiatives while ensuring cybersecurity is a focus in all work performed.

ii. Secondary Drivers: Business Operations Efficiency – FHI will be better positioned to consider new innovation projects or new grid-connected devices as the underlying network will be better suited to support such expansion. Having dedicated IT capacity to support engineering and operations allows systems to be customized to their unique requirements, allowing for flexibility in how systems are operated and configured. This drives efficiency in day-to-day operations as the solution is tailored to their unique needs.

iii. Information Used to Justify the Investment: FHI manages its IT assets on a 5-year asset lifecycle along with receiving vendor guidance for end-of-life devices. The resiliency and cybersecurity of the devices being deployed on the grid requires greater focus and attention as both the OEB cybersecurity framework and FHI's insurance provider are placing more focus on OT equipment. Both internal and 3rd party assessments have been performed to identify gaps and justify investment.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI adheres to a 5-year lifecycle for server and network equipment. This is a common practice amongst utilities of similar size. FHI needs in this area are more complex than some peers due to the ownership of a transmission station. This increases the infrastructure and security need as it drives a higher risk profile for FHI.

ii. Cost-Benefit Analysis: A cost-benefit analysis is considered for all IT projects. Key drivers for this project are cybersecurity and infrastructure capacity.

iii. Historical Investments & Outcomes Observed: The project budget is based on historical costs plus inflationary pressures. The benefit of doing several upgrades at once is FHI can take a much more holistic approach to achieving outcomes. Past projects have increased capabilities and security, but there have been components left lagging behind.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

See Section A8.

MATERIAL INVESTMENT NARRATIVE

INVESTMENT CATEGORY: GENERAL PLANT

PROJECT: ENTERPRISE RESOURCE PLANNING SOFTWARE UPGRADE

A. GENERAL INFORMATION ON THE PROGRAM/PROJECT

1. OVERVIEW

The Enterprise Resource Planning (ERP) software project involves the design of a comprehensive utility focused ERP solution with the required support necessary for implementation. This ERP software system is required to manage obsolescence by replacing the current aging legacy system and will expand FHI's current ERP applications with solutions based on current industry requirements. The proposed solutions are required to meet multiple business needs, accommodate multiple departmental requirements, and provide a wide array of opportunities that provide FHI's team with greatly enhanced capabilities, and functionality.

FHI's existing legacy ERP applications are a major roadblock to making timely, efficient, and cost-effective changes and enhancements. Examples include: improvements to billable project invoices, job costing allocations, inventory and warehouse management including physical inventory, employee time entry, and payroll. Expanded functionality would include job estimating, budgeting, human resources, and fixed assets. In addition, FHI has concerns about the lack of support and maintenance of its current provider. FHI's legacy ERP system (Daffron iXP v9.0) struggles with data management, integration, and increased security threats due to the age of the system, and reduced updates and support. Historically, source code has been customized by both in-house and Daffron resources. Daffron was acquired by Milsoft Utility Solutions Inc. in 2019. Limited Daffron expertise remains within Milsoft, resulting in limited support. FHI believes there is significant risk to continuing to use its legacy system.

Through the implementation of a new ERP system, FHI will be positioned to resolve constraints and realize the following benefits:

- Ability to invest in technology which will fit the unique needs of FHI's teams, help reduce reliance on paper, and improve customer and employee experiences. This also aligns with FHI's strategic plan, which has a focus on technology for the future.
- A new ERP solution will provide members with the foundation to improve decision making with real time reporting and data analytics; build future capabilities such as expanded budgeting, job estimating, and risk/profitability analysis; and provide the opportunity to implement additional modules.
- A new ERP solution that has current Canadian utility customers and greatly enhanced support and maintenance, will assist with risk mitigation.

This is expected to be a two-year project, beginning in 2024 and completed in 2025. An RFP was sent to vendors in a competitive process following FHI's purchasing policy. Three vendors submitted responses, and FHI is currently evaluating each submission against the evaluation criteria to determine its preferred vendor. Once complete the major project milestones are:

Discovery and planning	executive sponsorship, researching and selecting a system, program requirement definition, vendor selection, project planning
Design	new efficient workflows and business processes, change management, gap analysis
Development	hardware and software, configuration, customization, developing integration, data migration, training

Testing	module unit testing of basic functions to rigorous testing of full capabilities, testing of migrated data, parallel testing, introductory end-use training, documentation.
Deployment	system go-live, monitoring, troubleshooting, system adjustments, continuous improvement
Support	user feedback, additional development and configuration as needed, final training documentation

Further detail about the project can be found in the attached ERP Solution Business Case.

2. TIMING

i. Start Date: Jan 2024

ii. In-Service Date: 2024-2025

iii. Key factors that may affect timing:

- Implementation will require extensive internal efforts utilizing FHI resources.
- Data migration from the Daffron legacy system will require specialized third-party assistance.
- The new ERP solution must integrate with existing banking links, Geographic Information System (GIS), Customer Information System (CIS), and mobile workforce management systems.
- Historical information must be retained, accessible, and meet regulatory requirements.

These factors will be mitigated by having a dedicated Project Manager within FHI to coordinate and schedule internal resources, as well as coordinate with the vendor. Furthermore, data and integration issues were highlighted as requirements in the RFP stage to ensure prospective vendors understood FHI's requirements and could build them into their timeline and budget.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Overall Net Capital Expenditures

	Historical Period						Bridge Year	Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	0	0	0	0	0	0	875	875	0	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	875	875	0	0	0	0

This is a unique project to FHI, that is unlike other historical or forecast IT software investments which are typically enhancements or upgrades to existing software packages. As a result, there are no historical costs for this program. However, a budget was developed based on advice received from utilities implementing similar projects. The capital purchase, internal implementation, and external implementation costs of a new ERP solution were estimated to be in the range of $1.5 million to $2.5 million. As FHI is slightly smaller than the comparison utilities, a budget estimate of $1.75 million is being used. Currently, FHI is going through the RFP process with three vendors, all of which fall within the budget estimate to varying degrees, with costs being finalized once a vendor has been selected and a contract negotiated.

4. ECONOMIC EVALUATION

Not applicable.

5. COMPARATIVE HISTORICAL EXPENDITURES

Not applicable.

However, historical operating expenses can be found in section 6.1 of the attached ERP Solution Business Case.

6. INVESTMENT PRIORITY

Using FHI's prioritization process, this project is ranked 8 out of 13. As these are discretionary expenditures, they are performed after System Access projects and prioritized against other discretionary spending. Under the General Plant category, FHI identifies underperforming or depreciated assets or systems based on feedback received from customers, vendors, staff, performance tracking, and operating and maintenance costs. To prioritize the execution of these projects, FHI takes into account additional drivers or benefits of completing the project. This typically includes improvements in customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with FHI AM objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority.

The need to upgrade to a modern ERP system is imperative for FHI to continue to support business needs and modernize many manual and out of date tasks and work processes that currently take place. It will be a key investment to enhance FHI's decision making for investments, as well as enhance the operational efficiency of the organization, by automating and enhancing manual processes.

The following factors were assessed as part of FHI's prioritization process, along with the criteria scoring definition assigned to this program:

Health and Safety – High Impact Security Incident.

Following FHI's Cybersecurity response plan, this program replaces a software that based on its age and lack of vendor support is classified as having the potential for a high impact event which could cause impacts to critical systems, business reputation and business operations.

Reliability/Supply of Power - Sustained interruption of < 3 MW of load or provides for additional system capacity.

While the ERP system does not have a direct impact on reliability, if staff are unable to rely upon the ERP system to coordinate proper inventory management and purchasing processes to ensure that adequate stock is on hand or ordered, it can have an adverse effect on FHI's response to reliability issues and concerns.

Asset History and Performance - Asset history shows recurring and significant maintenance expenses, support of products has ended.

The software being replaced through this project has seen reduced vendor support, as well as reduced resources that are knowledgeable in the system and able to provide updates when needed.

Enhancements of product no longer occur as support is mainly available to maintain existing functionality only.

Customer and Community - Delivers on one of the top 3 priorities of customers (safe/reliable power, low rates, aesthetics over cost) and is supported by over 50% of customers.

Productivity/Efficiency - Aligns with 3 (Investment coordinates with other projects, investment increases liability with inaction, investment reduces employee time spent on tasks).

This investment is expected to reduce employee time as many manual tasks will be automated. It also decreases the companies liability of running a key system that could potentially no longer be supported by a vendor. This new software will also integrate and allow for the addition of other modules and softwares to be installed to further optimize employees time and reduce duplication of work and tasks.

Organizational Effectiveness – Aligns with 3 (Investment improves employee response and improves customer experience, investment provides sustainable business operations, investment supports innovation).

Environmental Impact – This program does not address environmental impacts.

Further information about FHI's planning and prioritization process is available in DSP Section 5.3.1.

7. ALTERNATIVE ANALYSIS

To decide on the best course of action, FHI considered the following alternatives:

a. **Do nothing -** Doing nothing will present a risk of the existing software no longer being supported by the current vendor as FHI is one of the last clients of this software in Canada. FHI, who used the same vendor for CIS, and became the last CIS client in Canada saw support and updates of the product completely cease, forcing FHI to quickly pivot to a different system, and use contractors to support the system until the new system could be in place. Completing the ERP project now, allows FHI to ensure this does not happen again. It also removes the current issues with data access and accuracy, system operation and lack of functionality, and potential regulatory non-compliance if support ceases and updates are no longer made to the software. For these reasons, this option was not seen as appropriate.

b. **Upgrade to a new ERP Platform (preferred option) -** This would allow FHI to move to a more modern ERP platform that meets the current business needs of FHI. This includes being able to use the technological advancements that inherently have been incorporated in these systems, as well as additional modules such as job estimating, budgeting and human resources. It also will have enhanced security features over the current implementation, will be used by other customers in Ontario specifically, which is expected to allow for better response to regulatory compliance requirements. The new platform will enhance the support and maintenance features as well as the timeliness of it. FHI also expects operational efficiency improvements as many tasks that are currently manually completed will be moved to an automated workflow, or will be able to be reported on through the system rather than manually created, allowing staff to focus their efforts on tasks that will add more value to FHI.

8. INNOVATIVE NATURE OF THE PROJECT

Not Applicable.

9. LEAVE TO CONSTRUCT APPROVAL

Not applicable.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

1. EFFICIENCY, CUSTOMER VALUE, RELIABILITY & SAFETY

Efficiency: It is expected that FHI will see efficiencies in this installation in the following ways:

- Better data management practices will improve administrative processes, collaboration, and reporting across the company. This will ensure important data points are being recorded, tabulated, and stored properly so necessary information from this resource is available in a timely manner to the department or employee that requires it.

- Standardized business processes will be improved by enforcing consistent workflows and procedures throughout FHI. This will enable the automation of routine tasks, reducing manual effort and improving operational efficiency. By eliminating redundant activities and optimizing resource allocation, FHI can improve productivity and accuracy.

- Implementation of an improved ERP solution centralizes data from various sources into a single, combined location. This will provide a complete view of FHI's operations, enabling better decision-making and improved data accuracy. With real-time data access, staff can make informed decisions based on up-to-date information, leading to increased responsiveness.

Customer Value: An improved ERP system will increase the capabilities to complete analysis of data points in FHI's system regarding financial, job costing, and inventory management. This drives customer value through making data-driven decisions and optimizing the use of FHI staff's time to be spent on higher value tasks.

Reliability: The new ERP system will significantly improve the reliability of the data the FHI uses to make decisions. This includes the ability to automate the creation material lists for ordering, as well as enhanced reporting and tracking ability and Key Performance Indicators (KPI) tracking. When the data from the ERP system is reliable and consistent, fewer errors are made improving the accuracy of forecasting for future needs.

Safety: This project will allow FHI to improve the cybersecurity posture of this system to help support safety.

2. INVESTMENT NEED

i. Main Driver: System Capital Investment Support - By upgrading/replacing the ERP system, FHI is able to ensure that new modules that FHI needs to properly run it's business are in place, and that the support from the vendor will be in place when there are issues or regulatory changes required to respond and update the software as needed.

ii. Secondary Drivers: Business Operations Efficiency – FHI will be better positioned to automate tasks that are currently manually completed. Examples of these are many reports in the current ERP system must be manually extracted and manipulated to be used for any kind of analysis. There are also processes in place where one person manually creates a material list, and then another person needs to manually enter it into the system for ordering. A new ERP system will allow this process to become automated, eliminating redundant work, as well as reducing the risk of human error.

iii. Information Used to Justify the Investment: Please see the attached ERP Solution Business Case.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice: FHI is seeking an upgraded ERP platform that is used by others within the industry to improve the functionality, support and maintenance of the ERP system. FHI is also looking to add modules that many other LDC's use such as budgeting, estimating and Human Resources. Utilities are constantly striving to become more efficient, which this project is intended to do by automating and enhancing several manual processes as well as improving the quality and type of data FHI can extract from the system to make better decisions.

ii. Cost-Benefit Analysis: See section 6 of the ERP Solution Business Case.

iii. Historical Investments & Outcomes Observed: FHI has seen their historical operating expenses increase just to keep up with core requirements of the ERP system as it was witnessed that customizations and other enhancements were excessive in cost, for minimal system or user improvements. As a result, FHI has had to complete many workarounds and allocate significant resources to manually complete many tasks that modern ERP systems can automate, while seeing more and more customers move away from this aging ERP system. As a result, FHI believes now is the right time to upgrade this system. Section 6 of the ERP Solution Business Case details historical operating expenses.

iv. Substantially Exceeding Materiality Threshold: See the ERP Solution Business Case for a complete justification of the investment.

4. CONSERVATION AND DEMAND MANAGEMENT

Not applicable.

5. INNOVATION

Not Applicable.

DESIGN & IMPLEMENTATION OF UTILITY FOCUSED ERP SOLUTION

February 7, 2024

TABLE OF CONTENTS

1. Executive Summary 0
  1.1 Issue 0
  1.2 Anticipated Outcomes 0
  1.3 Recommendation 0
  1.4 Justification 0
2. Business Case Team 1
3. Problem Definition 1
  3.1 Problem Statement 1
  3.2 Organizational Impact 1
  3.3 Business and Technology Risks 2
4. Project Overview 2
  4.1 Project Description 2
  4.2 Goals and Objectives 2
  4.3 Project Performance 3
  4.4 Project Assumptions 3
  4.5 Project Constraints 4
  4.6 Major Project Milestones 4
5. Strategic Alignment 5
  5.1 People 5
  5.2 Invest in New Operational Technologies 5
  5.3 Create Scale in the Utilities space 5
6. Cost Analysis 5
  6.1 Operating Expenses 5
  6.2 ERP Design & Implementation 6
  6.3 Vendor Selection 6
7. Alternate Analysis 7

1. EXECUTIVE SUMMARY

This business case outlines how the Enterprise Resource Planning (ERP) Design and Implementation Project will address current business concerns. The business case also summarizes the benefits, organizational impact, justification, and strategic alignment of the project.

1.1ISSUE

FHI's aging legacy ERP applications are a major roadblock to making timely, efficient, and cost- effective changes and enhancements. Examples include improvements to billable project invoices, job costing allocations, inventory and warehouse management including physical inventory, employee time entry, and payroll. Expanded functionality would include job estimating, budgeting, human resources, and fixed assets. In addition, FHI has concerns about the lack of support and maintenance of its current provider.

1.2ANTICIPATED OUTCOMES

Through the implementation of a new ERP system, FHI will be positioned to resolve constraints and realize benefits in the following areas:

- Invest in technology which will fit the unique needs of FHI's teams, help reduce reliance on paper, and improve customer and employee experiences. This also aligns with FHI's strategic plan, which has a focus on technology for the future.
- A new ERP solution will provide members with the foundation to improve decision making with real time reporting and data analytics; build future capabilities such as expanded budgeting, job estimating, and risk/profitability analysis; and provide the opportunity to implement additional modules.
- A new ERP solution that has current Canadian customers and greatly enhanced support and maintenance, will assist with risk mitigation.
- Integration into key corporate systems, allowing for centralized decision support and reduction in errors and the associated operating and maintenance costs from manually completing these tasks.

1.3RECOMMENDATION

To completely replace the aging legacy system with a modern ERP system that expands FHI's current ERP applications, with solutions based on industry best practices.

1.4JUSTIFICATION

In addition to mitigating the regulatory, security and administrative risks associated with the current legacy system, this new ERP solution will accommodate the evolving needs of FHI moving forward by providing scalability and flexibility to support changing company requirements and market conditions.

2. BUSINESS CASE TEAM

The following individuals are responsible for the analysis and creation of the project business case:

- Alyson Conrad Chief Financial Officer
- Dave Cullen VP, Information Technology
- Bryon Hartung VP, Engineering & Operations
- Patty Mann Director, Corporate Projects

3. PROBLEM DEFINITION

3.1PROBLEM STATEMENT

The ability to manage, analyse, and report on financial data is at the core of a utility's business operations. Like all technologies, ERP systems have a lifecycle. FHI's legacy ERP system (Daffron iXP v9.0) struggles with ease of use, data management, integration, and increased security threats. FHI staff require tools and systems that can keep pace. A modern ERP solution would play a significant role in steering FHI to success.

FHI is one of the last remaining customers on Daffron's platform in Canada. Over the years, source code has been customized by both in-house and Daffron resources. Daffron was acquired by Milsoft Utility Solutions Inc. in 2019. Limited Daffron expertise remains within Milsoft, resulting in narrow support. Because of this, FHI believes there is significant risk to continuing to use its legacy system.

3.2ORGANIZATIONAL IMPACT

The limited functionality in the Daffron system has not kept pace with changes at FHI. Multiple departments were unable to continuously improve administrative processes and instead are faced with an excessive number of manual workarounds. Performance bottlenecks, system glitches, limited integration capabilities, rising maintenance costs, and struggles to comply with cybersecurity best practices, have been identified as on-going concerns. Daffron struggles to synchronise with new applications and requirements - including regulatory - increasing IT expenditures that would be better invested in innovation. There are also risks being one of the last Canadian customers as compliance with Canadian payroll rules are manual and complex.

In addition to hindering employee productivity, persevering with an outdated ERP system will continue to increase operational expenses, data inconsistencies, and security vulnerabilities. A new ERP solution would offer flexibility, scalability, provide real time insights into business decision making, drive efficiency in operations, and ensure consistent and accurate reporting.

3.3 BUSINESS AND TECHNOLOGY RISKS

Migrating to a new ERP system is a complex project with significant costs detailed in a thorough cost benefit analysis provided in Section 6; however, the cost of doing nothing is much greater.

Below are the top five risks that have been considered:

- Lack of Canadian customers has caused Milsoft to not be responsive to local regulatory changes. This could lead to non-compliance and fines.
- Support costs will continue to increase simply to keep the system functional. There is a real possibility Milsoft stops supporting the version of Daffron FHI runs.
- In-depth system administrator knowledge of the system is required and not easily replaced providing a significant Human Resource's risk.
- The business continuity of the system is no longer possible to guarantee.
- As support lessens, the ability to export and/or migrate data to a new ERP system becomes increasingly difficult and could eventually not be possible.

4. PROJECT OVERVIEW

4.1PROJECT DESCRIPTION

The ERP project involves designing a comprehensive utility-focused ERP solution with the required support needed for implementation. This ERP software system will replace and expand FHI's current ERP applications, with solutions based on industry best practices. The proposed solutions are required to meet multiple business needs, accommodate multiple departmental requirements, and provide a wide array of opportunities that provide FHI's team with greatly enhanced capabilities, and functionality.

4.2GOALS AND OBJECTIVES

- Better data management practices will improve administrative processes, collaboration, and reporting across the company. This will ensure important data points are being recorded, tabulated, and stored properly so necessary information from this resource is available in a timely manner to the department or employee that requires it.

- Standardized business processes will be improved by enforcing consistent workflows and procedures throughout FHI. This will enable the automation of routine tasks, reducing manual effort and improving operational efficiency. By eliminating redundant activities and optimizing resource allocation, FHI can improve productivity.

- Implementation of an improved ERP solution centralizes data from various sources into a single, combined location. This will provide a complete view of FHI's operations, enabling better decision-making and improved data accuracy. With real-time data access, staff can make informed decisions based on up-to-date information, leading to increased responsiveness.

- A new ERP solution can assist FHI in complying with industry-specific regulations and standards. By incorporating compliance features, such as financial controls, data security measures, and audit trails, an improved ERP system will help meet regulatory requirements and maintain data integrity.

- This new system will accommodate the evolving needs of FHI moving forward by providing scalability and flexibility to support changing company needs and market conditions.

4.3PROJECT PERFORMANCE

The following indicators will be monitored to ensure project performance:

- Project schedule and budget adherence.

- ERP software investment is a partnership. Quality and responsiveness of by the implementation partner includes issue resolution time, support response times, and user satisfaction with services.

- Higher system adoption and utilization rates indicate successful user acceptance and integration of the ERP system into daily operations. Satisfied employees will be more confident in their role and provide improved productivity.

- Process improvements can be monitored by measuring the extent the new ERP system results in tangible change in key business practices.

- Data accuracy and integrity are critical for system reliability and can be assessed by monitoring errors, discrepancies, and data validation.

- System uptime, response times, and system availability contribute to system stability and performance after implementation which is crucial for smooth operations and user satisfaction.

- A new ERP solution would provide operational analytics resulting in better business decisions and eliminate barriers to industry benchmarking.

4.4PROJECT ASSUMPTIONS

The project assumptions are as follows:

- Vendor selection will be complete by April 2024 with project implementation by the end of 2025.

- The successful implementation partner will have experience with the Canadian utility sector and have an extensive understanding of the requirements of Ontario Local Distribution Companies.

- The proposed ERP solution will provide improved functionality, administrative efficiencies, business insights, and cybersecurity practices.

- Other than the new ERP solution, no additional hardware or software is required to support.

4.5 PROJECT CONSTRAINTS

- Implementation will require extensive internal efforts utilizing existing FHI resources.

- Data migration from the Daffron legacy system will require specialized third-party assistance.

- The new ERP solution must integrate with existing banking links, Geographic Information System (GIS), Customer Information System (CIS), and mobile workforce management systems.

- Historical information must be retained, accessible, and meet regulatory requirements.

4.6 MAJOR PROJECT MILESTONES

Discovery and planning	executive sponsorship, researching and selecting a system, program requirement definition, vendor selection, project planning
Design	new efficient workflows and business processes, change management, gap analysis
Development	hardware and software, configuration, customization, developing integration, data migration, training
Testing	module unit testing of basic functions to rigorous testing of full capabilities, testing of migrated data, parallel testing, introductory end-use training, documentation.
Deployment	system go-live, monitoring, troubleshooting, system adjustments, continuous improvement
Support	user feedback, additional development and configuration as needed, final training documentation

5. STRATEGIC ALIGNMENT

The ERP Design and Implementation project is in direct support of several of FHI's strategic initiatives.

5.1PEOPLE

The ERP Design and Implementation project will contribute to FHI's initiative to create a positive culture that puts staff first by fostering two-way dialogue, and providing a positive technology driven solution that streamlines efforts, reduces workloads, and improves staff experience. In addition to FHI's employees, this improved system will progress the level of service FHI provides to our communities.

5.2INVEST IN NEW OPERATIONAL TECHNOLOGIES

FHI strives to be a leader in the adoption and utilization of technology. By working with FHI's internal teams to better understand their day-to-day processes, FHI can successfully implement an ERP solution that fits the unique needs of a local distribution company, reduces reliance on paper, and improves customer and employee experiences. At the same time FHI will reduce costs, improve operational efficiencies, and enhance security.

5.3CREATE SCALE IN THE UTILITIES SPACE

FHI recognizes the value of relationship building with community stakeholders and emphasizes the importance of collaboration with peers in the energy industry. This ERP design and implementation project provides opportunities to benchmark with other LDCs, the potential to share services, and will contribute to setting the standards for industry best practices.

6. COST ANALYSIS

6.1OPERATING EXPENSES

The last significant Daffron software upgrade was completed in 2015 when the software changed from the AS400 green screen interface to the iXP windows interface. In comparison to the AS400 environment, this implementation resulted in a more user-friendly environment for staff but did not significantly improve administrative processes. In addition, custom programming was required to maintain functionality in both the Financial Management System (FMS) and Work Management System (WMS) modules. Daffron invoiced amounts related to this upgrade were $158,639 in total.

Base licensing, and fees associated with maintaining custom programming represent an approximate annual expense of $70,000. In 2021, Milsoft advised that they would no longer be developing the platform, and these fees were suspended. Support hours were continued with a focus on maintenance. Support and additional custom programming requests increased steadily except for 2018 and

2019 when custom requests were limited to critical needs due to rising costs. Even with limits in place, in 2020 these expenses totaled $56,343 and it was clear that FHI's legacy ERP system was becoming excessively difficult to maintain. The annual operating and maintenance expense to maintain the current Legacy system are estimated below:

Daffron iXP	Annual Expenses	
Base Licensing & Fees*	$	70,000
Support & Custom	$	65,000
IT Systems Maintenance	$	16,500
Hardware Maintenance	$	40,000
Total	**$**	**191,500**

**Base licensing and fees were suspended in 2021 after Milsoft advised they would no longer be developing the platform.*

With the design and implementation of a new ERP solution, the above IT resources (system administrator) required for Legacy maintenance would be focused on higher value work. A standardized platform with an existing Ontario utility install base will ensure supportability and maintain costs at a reasonable level.

Based on advice received from utilities implementing similar projects, the operating and maintenance expenses were estimated to be in the range of $200,000 to $250,000. ERP requirements are not directly proportional to utility size; however, as FHI is slightly smaller than the comparison utilities, a budget estimate of $200,000 is being used.

6.2ERP DESIGN & IMPLEMENTATION

Based on advice received from utilities implementing similar projects, the capital purchase, internal implementation, and external implementation costs of a new ERP solution were estimated to be in the range of $1.5 million to $2.5 million. As FHI is slightly smaller than the comparison utilities, a budget estimate of $1.75 million is being used. This total capital value is spread equally across the 2024 and 2025 budget years.

6.3 VENDOR SELECTION

The above estimates will be replaced with actuals once vendor proposals have been reviewed and a preferred implementation partner selected. Once this occurs, the business case will be revised.

A minimum of three proposals will be reviewed and compared. If vendor response through the online bidding platform is insufficient, vendors will be contacted directly and invited to participate. Proposal scoring will be based on business information, information technology, module functionality, solution performance, reporting analytics, implementation strategies, compatibility, and cost.

7. ALTERNATE ANALYSIS

The only alternate approach would be to remain with the legacy ERP system and accept the risks associated with data access, system operation, and regulatory noncompliance – the latter of which could result in fines and suspension of FHI's distribution license.

Appendix B

Third-Party Building Assessment Report

Festival Hydro Operation Building
Building Condition Survey

Prepared for:

Ms. Patty Mann

Festival Hydro Inc.
187 Erie Street
Stratford, ON N5A 6T5

Prepared by:

NA Engineering Associates Inc.
107 Erie Street
Stratford, ON

Date: September 28, 2020

Project Number: 19-1045

TABLE OF CONTENTS

EXECUTIVE SUMMARY 5

1. ACRONYMS LISTING 7

2. INTRODUCTION 8

2.1 TERMS OF REFERENCE 8
2.2 SCOPE OF WORK 9

3. METHODOLOGY/ PREAMBLE 11

3.1 AVAILABLE DRAWINGS/DOCUMENTATION 14
3.2 COSTING 14

4. COMPONENT ASSESSMENT 15

A SUBSTRUCTURE SYSTEM 15

A10 FOUNDATIONS 15
A40 SLABS ON GRADE 16

B SHELL SYSTEMS 17

B10 SUPERSTRUCTURE 17
B20 EXTERIOR VERTICAL ENCLOSURES 19
B30 ROOFING 22

C INTERIOR SYSTEMS 25

C30 INTERIOR FINISHES 25

BARRIER FREE BUILDING ANALYSIS: FESTIVAL HYDRO OPERATION BUILDING 30

D SERVICES SYSTEMS 31

D20 PLUMBING 31
D30 HVAC 33
D40 FIRE PROTECTION SYSTEMS 39
D50 ELECTRICAL SYSTEMS 40
D60 COMMUNICATIONS 43
D70 ELECTRICAL SAFETY AND SECURITY FIRE ALARM 44

G BUILDING SITEWORK SYSTEMS 46

G20 SITE IMPROVEMENTS 46
G30 SITE CIVIL/MECHANICAL UTILITIES 49

APPENDIX A – PHOTOS 51

APPENDIX B - COSTING 71

ABSTRACT OF REVISIONS

REV. NO.	DATE	REVISION
A	2019OCT20	ISSUED FOR CLIENT REVIEW
0	2020SEP28	FINAL ISSUE

The following individuals were responsible for the preparation and review of this report:

Brad Miller – Project Manager
Mary Ferenc, P.Eng., - Structure
Katie Rooyakkers, P.Eng., - Civil
Haritos Aroutzidis – Interior Finishes
Jim Culliton, BA, Sc – Building Exteriors, Roofing
Amir Angardi, P.Eng. – Electrical Systems
Hasan Oktem, Ph.D., P.Eng. – Mechanical Systems

Approved by:

Mary Ferenc, P.Eng.

Jim Culliton, BA.Sc.

Amir Angardi., P.Eng

Hasan Oktem, Ph.D., P.Eng.

Issued by:

Brad Miller

Date: September 28, 2020

EXECUTIVE SUMMARY

The Operations Buildings are very active, heavily used structures. Festival Hydro field staff, heavy industrial trucks, power distribution tools and equipment, and storage areas for utility materials make use of these buildings daily.

The buildings structures are performing in an adequate manner. A tiny amount of deterioration on the masonry wall at one of the entrances in the 1920's section of the building could be repaired.

The roof on the sloping section of the building is finished with asphalt shingles and currently in poor condition. We were advised that this roof is scheduled to be replaced with a pre-finished metal system. The roof areas on the 'flat' portions of the building are 4 ply, built-up. There were no deficiencies reported, but heavy application of mastic/sealant at one of the roof top units suggests that there have been problems in this area of the roof in the past. We suspect that a replacement roof top unit has been installed that did not fit the curb perfectly and additional sealant was required to stop leaks. Well installed, built up asphalt roof systems can provide many years of adequate service. In spite of their satisfactory performance, they have reached or will exceeded their anticipated life expectancy and funds should be set aside for replacing them in the next few years. Access to the 'flat' sections of the roof requires that a temporary, external ladder be set up. The roof edges have been modified to make it easy and convenient to tie off. Consideration should be given to installing a permanent ladder/staircase to access the roof system.

The interior finishes are presently quite adequate, but well used. It is our opinion that both the 1920's and 1950's garage areas could be repainted. Upgrading the wall/ceiling finishes would significantly brighten these work spaces. The exposed concrete in the Operations Garages is in need of attention. The exposed concrete is currently deteriorating and is under distress in some areas where the work vehicles travel. Given its age and current condition, painting the floor will not be successful.

The administrative area was noted to be in good condition but would benefit from some minor paint touch ups as part of the buildings ongoing maintenance program. It is under our recommendation that the Operations Office Areas Male Change Room/ Shower be re-done to upgrade it to bring it closer to compliance with the current building code. The room is original to the building and is in no way compliant with today's accessibility requirements. It is extremely undersized and inefficient in its layout design.

The base building mechanical system installed when the building was constructed in the 1950's is largely still in place. Mechanically, we were not advised of any significant issues with these buildings. In general, repairs/replacements to equipment/systems undertaken as part of the ongoing maintenance program have been completed as required and at present, they appeared to be working in a satisfactory manner. Some of the equipment has reached or exceeded its anticipated life span and will require replacement in the coming couple of years.

The building mechanical system in the garage areas is gas fired, make up air units, as well as ceiling hung unit heaters of varying ages and conditions. Roof top units and perimeter electric baseboard heaters provide heating and cooling to the office administrative areas. The large garage area has a number of large exhaust fans.

The HVAC system is monitored and controlled by a building automation system. This system has been added/modified/upgraded since the building was originally constructed to correspond with changes to the buildings mechanical systems.

Plumbing is original in most areas of the buildings. Renovations have been completed to the administration area washroom and this portion of the building is presently in good condition. The washrooms in the garage areas are well used and could potentially be upgraded with modern, low flow, hands free fixtures.

Similar to the mechanical systems, much of the base buildings electrical systems are original and now 60+ years old. The lighting system is a combination of fluorescent and metal halide fixtures. Some maintenance is required to replaced damaged fixtures and burnt out tubes. Upgrades have been made to the buildings lighting system. LED fixtures have been installed in the administration/office area. A similar upgrade in the garage areas should be considered. An emergency generator installed in 1996 was noted to be in good condition.

The site is well used, by large industrial vehicles. At present, asphalt drive lanes, curbs and parking areas are in poor/fair condition. Consideration could be given to completing a number of upgrades.

The Operations Building / Works Yard is an industrial style site hence does not get a lot of attention to things such as landscaping. Improving / upgrading landscaping would improve the site's aesthetics, but not add anything in terms of use/performance of the facility.

1. ACRONYMS LISTING

Acronym	Meaning
A	Amperage
AHU	Air Handling Unit
ASB	Auxiliary Security Building
ASHREA	American Society of Heating, Refrigerating and Air-Conditioning
BOMA	Building Owner's & Management Association
Cat	Category
CO	Carbon Monoxide
DS	Disconnect Switch
EMT	Electrical Metal Tubing
EXP	Explosive
FA	Fire Alarm
FFH	Fan Force Heater
HID	Metal Halide
HCFC	Hydrochlorofluorocarbons
IR	Infra-Red
kV	Kilovolt
kVA	Kilovolt-Ampere
LAN	Local Area Network
LED	Light Emitting Diode
NAE	NA Engineering Associates Inc.
NFPA	National Fire Protection Association
Non-EXP	Non-Explosive
NOx	Nitrogen Oxide
OBC	Ontario Building Code
PA	Public Address
Ph	Phase
RTU	Roof Top Unit
SB10	Supplementary Standards
SWBD	Switch Board
TV	Television
UPS	Uninterruptible Power Supply
V	Volt
W	Watts

2. INTRODUCTION

2.1 TERMS OF REFERENCE

NA Engineering Associates Inc. was retained by Ms. Patty Mann of Festival Hydro to undertake a building condition assessment of the Festival Hydro Operation Building located at 161 Wellington St., Stratford.

DESCRIPTION OF BUILDING

The building is actually two 'connected' buildings which form the Operation Building. The original section of the building is a single storey building with a small mezzanine that was apparently constructed in the 1920's. Given the 'shape' and features of the building, it was most likely originally constructed as a church.

The building is constructed with a masonry stone foundation, multi-wythe, structural brick walls and a wood framed, sloping roof. The 1920's section of the Operation Building includes three vehicle service / repair bays. The roof on this portion of the building is currently covered with asphalt shingles that are in poor condition. We were advised that a contractor has been hired to install a new, pre-finished metal roof on this section of the building.

Size of the 1920's section of the building is approximately 3200 ft^2.

The second area of the building was constructed in the mid 1950's and includes; offices, washrooms, a lunchroom, loading dock/receiving area, mezzanine, and a 5-bay commercial service garage section. The administrative portion of the building is covered with masonry brick cladding. The garage area is clad with pre-finished metal siding. We suspect that when the 1950's section of the building was constructed, it was connected to the 1920's section of the building.

Size of the 1950's section of the building is approximately 2,400 ft^2. (offices/administration), 11,000 ft^2. (garage area/parts warehouse), and 600 ft^2. loading dock.

Item	Description
Building Name	Operation Building
Building Use	Heavy Vehicle Garages / Material & Equipment Storage / Supporting Administrative Area / Loading Dock
Year Built	1920 / 1956
Number of Storey	1 Storey
Gross Building Area (SF)	18,000 ft^2

2.2 SCOPE OF WORK

The scope of this assessment is to complete a building condition assessment (BCA) of the major building systems and components. Building systems and components reviewed as part of this assessment included;

- Civil / municipal building and site features
- Building structural components
- Building envelope systems which included the roofs, windows, doors, and exterior walls
- Mechanical systems and components; heating, ventilation, and plumbing
- Electrical systems and components, and
- Interior finishes / accessibility

It should be emphasized that the study was a visual survey only. No destructive testing was undertaken. Where conditions were noted that suggested a need for some destructive testing these would be identified to the client.

The BCA undertaken by NAE is completed in accordance with the ASTM Standard Guide for Property Condition Assessments: Baseline Property Condition Assessment Process (E 2018-08) and consisted of the following:

- Obtain relevant documentation i.e. building drawings, previous reports, etc., for our review prior to visiting the site,
- Interviews with Festival Hydro staff familiar with the building,
- To assist with the site walk-through, we were assisted by KRR Refrigeration, a contractor familiar with the mechanical equipment and Braeme Electric, a contractor familiar with the electrical equipment,
- Walk-through site assessment visit;
- Preparation of property condition assessment report.

ASTM defines a physical deficiency as a conspicuous defect or significant deferred maintenance of a site's material systems, components, or equipment as observed during the site assessor's walk-through site visit. Included within this definition are material systems, components, or equipment that are approaching, have reached, or have exceeded their expected useful life (EUL) or whose remaining useful life (RUL) should not be relied upon in view of actual or effective age, abuse, excessive wear and tear, exposure to the elements, lack of proper or routine maintenance, etc.

A mechanical engineer along with a representative from KRR Refrigeration and an electrical engineer along with a representative from Braeme Electric undertook the review of the mechanical systems (heating, ventilation, and plumbing), and electrical systems (power distribution, exterior lighting, and fire & life safety systems at the property. The review included discussions with the site representative and review of any available maintenance information.

A visual walk-through assessment of the mechanical systems, electrical systems, and fire & life safety systems was conducted to determine the type of systems present, age, and aesthetic condition. No testing of any of the systems reviewed was undertaken, nor were the performance of any systems evaluated.

It was assumed that at the time of construction of both the original 1920's building section as well as the 1950's addition, the design would have met the requirements of any building codes/regulations in effect at the time. A detailed code compliance with applicable Building Codes and/or Fire Codes was not part of the scope of this assessment.

Replacement and repair costs are based on unit rates published in applicable industry standards, combined with local experience gained by NAE. The quantities associated with each item have been estimated and do not represent exact measurements or quantities.

3. METHODOLOGY/ PREAMBLE

Wednesday, September 4th, 2019, Brad Miller (Project Manager/Project Coordination and Administration), Mary Ferenc (Structural), Jim Culliton (Building Envelope), Hasan Oktem (Mechanical Systems and Components), Amir Angardi (Electrical Systems and Components) and Haritos Aroutzidis (Accessibility, Interior Finishes and Furniture), all of NA Engineering Associates Inc., completed a visual review of the Festival Hydro Operation Building. We were assisted in completing the evaluation of the mechanical equipment by Garnet Mueller, KRR Refrigeration. We were assisted in completing the evaluation of the electrical equipment by Rory Mc Cuaig, Braeme Electric. Both contractors work on the building on an ongoing basis and are quite familiar with the systems. Prior to undertaking the survey, we met with Patty Mann and Chris de Silva to explain our process. They indicated that we were able to access the majority of areas of the building site. Access to locked areas of the building was provided by Festival Hydro staff.

On the day of the review the weather was overcast and approximately 15 degrees Celsius. Components that were readily visible were reviewed during our site visit.

No destructive or intrusive testing was conducted.

The following assessment has divided the buildings major components or systems using the Uniformat method. Uniformat is a standard for classifying building specifications, cost estimating, and cost analysis in the U.S. and Canada. The elements are major components common to most buildings. The system can be used to provide consistency in the economic evaluation of building projects.

Component Rating	
Rating for Building Systems and Components	**Definition**
Very Good	Asset is physically sound and is performing its function as originally intended. Required maintenance costs are well within standards and norms. Typically, asset is new or recently rehabilitated.
Good	Asset is physically sound and is performing its function as originally intended. Required maintenance costs are within acceptable standards and norms. Typically, asset has been used for some time but is within mid-stage of its expected life.
Fair	Asset is showing signs of deterioration and is performing at a lower level than originally intended. Some components of the asset are becoming physically deficient. Required maintenance costs exceed acceptable standards and norms are increasing. Typically, asset has been used for a long time and is within the later stage of its expected life.
Poor	Asset is showing significant signs of deterioration and is performing to a much lower level than originally intended. A major portion of the asset is physically deficient. Required maintenance costs significantly exceed acceptable standards and norms. Typically, asset is approaching the end of its expected life.
Expired	Asset is physically unsound and/or not performing as originally intended. Asset has higher probability of failure or failure is imminent. Maintenance costs are unacceptable and rehabilitation is not cost effective. Replacement/major refurbishment is required.
Maintenance	Cost associated with components condition that are required to ensure the component continues to perform as intended and meets it service life expectancy.

Building systems useful life is based on Building Owners and Managers Association (BOMA) publication of “Preventive Maintenance; Best Practices to Maintain Efficient and Sustainable buildings. The following list of systems and average useful life years is based on regular preventive maintenance properly performed at prescribed frequencies. Many factors can affect the average useful life and like any average, individual systems and or components will have lifetimes far from averages. Lifetimes can often be extended significantly through robust maintenance programs that go beyond the norm.

Climate conditions and challenging environments will often shorten life expectancies. Whereas selecting equipment with heavy duty features will lengthen the components life expectancies.

Due to hardware and software revisions, control equipment for HVAC, fire alarms and security may become obsolete as vendor may no longer support them. As such the life expectancy of these components will be shortened.

The following table is based on BOMA and general industry standards.

Building Elements	Typical Useful Life
A-B Substructure & Shell	
A 1010 Standard Foundations	Life of Building
A 4010 Slab on Grade	Life of Building
B1010 Floor Construction	Life of Building
B1020 Roof Construction	Life of Building
B1030 Structure Support	Life of Building
B1080 Stairs	75
B2010 Exterior Walls	35-50
B2020 Exterior Windows	30
B2050 Exterior Doors	40
B3010 Roof Coverings	20-30
B3010 Metal Roofing	30-50
C Interiors	
C1010 Partitions	75
C1030 Interior Doors	40
C2010 Wall Finishes	5-15
C2020 Stair Finishes	35-50
C2030 Floor Finishes	12-15
C2050 Ceiling Finishes	13-25
D Services	
D1010 Elevators & Lifts	10-50
D2010 Domestic Water Distribution	20-30
D2020 Sanitary Waste	30
D2040 Rain Water Drainage	35
D2050 General Service Compressed Air	20
D3020 Heat Generating Systems	25
D3030 Cooling Generating Systems	20
Building Elements	Typical Useful Life
D3040 Distribution Systems	30
D3060 Ventilation	25
D4010 Fire Suppression	25-40
D4020 Standpipes	25-40
D5020 Electrical Service & Distribution	20-40
D5040 Lighting & Branch Wiring	20
D5080 Miscellaneous Electrical Systems	25
D6010 Data Communications	15
D6020 Voice Communications	15
D6030 Audio-Video Communications	15
D7050 Detection and Alarm	10-15
E – Equipment and Furnishing	

E2010 Fixed Millwork	15-20
G – Building Site	
G2030 Pedestrian Paving	30

3.1 AVAILABLE DRAWINGS/DOCUMENTATION

We were not provided with some drawings prepared when some interior renovations were completed to the building in 1996. We were also provided with some reports/additional information regarding proposed renovations.

3.2 COSTING

The repair/replacement costs included in each section are Class "5" budget estimates only with variances of minus 50% to plus 100%. Class "5" is defined under the American Association of Cost Engineers, as the concept screening stage of a project, where judgement is used based on past experiences of similar work. These are quoted in 2019 dollars. Actual costs may vary dependent on the scope of work performed. The estimated costs may vary depending on who undertakes the work and the quantity of work requested through a tender process. Cost may also be less if Festival Hydro maintenance complete some of the work noted in the report. Costs exclude engineering, furniture removal and replacement, permits costs (where applicable) and overhead profit. Costs provided are strictly replacement cost of components and do not include associated cost related to all possible replacement scenarios. Tactical planning window of replacements are 25 years. Typical maintenance costs for elements that are considered as preventative and or isolated component replacement costs has been included as a separate line items referenced to Appendix B "Costing".

4. COMPONENT ASSESSMENT

A SUBSTRUCTURE SYSTEM

A10 FOUNDATIONS

Item	Description
A1010 Standard Foundations	Standard Foundation – 1956 and 1920's
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The Festival Hydro Operation Building consists of a single storey office building with truck bays and a warehouse to the east which were constructed around 1956 and an older building with truck bays to the north which appears to have been constructed in the 1920's. The older building has a partial basement area but most of the basement area has been blocked off. No structural drawings for any of the buildings on the site were provided for review.

The north building with truck bays has a combination of stone foundation and a concrete block foundation. At some time two courses of flat face concrete block were added at the top of the stone foundation. Part of the building has a stone looking concrete block foundation.

The office building, truck bays and warehouse to the east have cast-in-place concrete foundation walls.

Component Condition:

The north building with truck bays has a number of different foundation materials. One area has a stone block foundation and another area has a stone rubble foundation where at some time two courses of concrete block were added at the top of this foundation. This was most likely a replacement of the upper part of the stone rubble which may have been crumbling. The two courses of block have cement parging. Over time, some of which has fallen off in a number of areas. The parging acts as a protective layer for the concrete block. Some mortar between the stone block foundations has cracked or fallen out. This was mostly noted at corners.

The current condition of the foundations for the single storey 1950's - office building / truck bays and warehouse to the east could not be directly observed anywhere. On the interior of the office portion of the building, the walls were finished with drywall. On the exterior the foundation walls could be reviewed around the perimeter of the building. Here we noted some cracks and one spall exposing the reinforcing. On the east truck bay and warehouse building, the foundations were not visible as they were covered with metal siding right down to grade.

There were no reported issues on any of the buildings. The foundation wall and footings are considered to be functioning as intended.

Component Recommendation:

Given that the buildings have been in use since constructed with no reported issues, it is our opinion that foundation is in good condition. The expected useful life of concrete foundations typically are 100 years, as such major repairs of the foundations are not anticipated.

The stone foundations will require maintenance such as mortar joint re-pointing and parging. This should be reviewed and completed on a regular basis to avoid damage to the stone.

A40 SLABS ON GRADE

Item	Description
A4010 Standard Slabs-on-Grade	Standard Slabs-on-Grade – 1956 and 1920's
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

No drawings for the floor slabs were available and therefore, thicknesses and reinforcing is not known.

Component Condition:

The current condition of the slab on grade in the office portion of the building could not be observed since they are covered with finishes. There was no evidence of any type of cracking or settlement which would indicate that they are not performing as intended. The slabs in the warehouse and truck bays to the east were noted to have cracks throughout. This was the same in the north truck bays. Cracks in concrete slabs on grade is not unusual given their age and heavy use. In both areas of the truck bays, the slab on grades are considered to be functioning as intended.

Component Recommendation:

The expected useful life of concrete slab on grade is typically the life of the building, however for reporting purposes we state it as 100 years. Major repair of any of the slabs is not anticipated within a 25-year period. Minor repairs such as filling in of cracks will be required to ensure no tripping hazards arise because of the cracking.

B SHELL SYSTEMS

B10 SUPERSTRUCTURE

Item	Description
B1020 Roof Construction	Roof Construction – 1956 and 1920's
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

No structural drawings for any of the buildings at the Festival Hydro Operation Building were provided for review.

The single storey office building roof consists of a metal roof deck over open web steel joists. The open web steel joists are supported on the exterior load bearing concrete block walls and there are steel beams and columns through the centre of the building. This was observed by removal of ceiling tiles in the building.

The roof construction for the truck bays and warehouse to the east is exposed and consists of metal roof deck over open web steel joists. The joists are supported on steel beams and columns.

The truck bay to the north is an older building. Although it could not be observed, the roof structure appears to be wood "A" frame construction bearing on the two load bearing side walls.

Component Condition:

The current condition of the roof construction in the single storey office was found to be good. The current condition of the roof construction in the east truck bay and warehouse also appeared to be in good condition.

The roof construction of the north building could not be viewed as it is covered. The underside of the ceiling which would be the bottom of the wood framing did not appear to have visible stress signs. The ridge of the roof also appeared straight. It was concluded that the roof structure is in good condition.

Component Recommendation:

The expected useful life of a structural steel support system is typically the life of the building, however, for reporting purposes we state it as 100 years. Major repair of the roof structure and support elements is not anticipated within the 25-year period for the office building and the east truck bays and warehouse.

The wood roof framing of the north building will have a long life if the structure is protected from moisture which would cause rotting of the wood. Currently, this can only be verified by going up into the roof structure and reviewing the structure.

Item	Description
B1030 Structure Support	Structure Support - 1956 and 1920's
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The support structure for the administration building consists of load bearing concrete block walls, and steel columns. Original structural drawings were not provided for review.

The support structure for the east truck bays and warehouse consists of steel columns and beams and load bearing concrete block.

The north truck bay support structure has multi-wythe yellow-brick load bearing walls with brick pilasters on the two long sides, which support the roof structure. The end walls are multi-wythe yellow brick with brick pilasters. The east wall has three overhead doors with brick pilasters between.

Component Condition:

The current condition of the structural supports in the office building could only be observed in certain locations. Where noted, the supports all appeared to be in good condition with no indication of displacement, such as cracked glass or cracks in the block.

The current condition of the steel columns and beams in the east truck bay and warehouse appeared to be in good condition. Some cracking of the concrete block between the columns was noted.

The multi-wythe walls of the north truck bay all appeared to be in good condition. No major cracking was noted. Some damage to the exterior-wythe brick was noted as were previous repairs to the exterior-wythe brick. Damage to the brick on the interior of the building was noted along the base at the exterior doors. This would be caused by prolonged exposure to water and de-icing salts.

Component Recommendation:

The expected useful life of concrete block and steel columns is typically the life of the building, however, for reporting purposes we state it as 100 years. Major repairs of the structural steel columns are not anticipated within the 25 yr. study period. Concrete block also would not require repairs within this time.

Larger cracks in the concrete block can be routed and filled.

Exterior brick on the north building should be reviewed on a regular basis for damage including spalls, delaminations and mortar cracking. These should be repaired prior to winter freeze-thaw events. Damage to the interior brick along the slab should also be reviewed and repaired on a regular basis with more damage noted near doors.

B20 EXTERIOR VERTICAL ENCLOSURES

Item	Description
B2011 Exterior Wall Construction (1920)	Exterior Walls Solid Brick (1920's) Brick cladding / Pre-finished metal siding
Component Condition	Fair - Good
Replacement Year / Replacement Cost	2020 / $5,000 (repair damaged areas, optional)

Component Description:

The oldest section of the building is constructed with a solid, multi-wythe brick wall. The 1950's portion of the building is constructed with brick cladding on the administrative area as well as at the loading dock. The other three elevations are clad with pre-finished metal siding.

Component Condition:

Overall, all of the walls were noted to be in fair to good condition. On the oldest section of the building there were some minor areas of deterioration but nothing that was expected to affect the performance of the building. The oldest section of the building may have originally been constructed as a school or perhaps a church. Large, prominent windows part of the original building have been blocked up and closed in. Similarly, windows for the basement area have been blocked in and closed up.

With regards to the thermal insulation in the walls, current buildings would be constructed with R-20+ thermal insulation with the exact value being determined by the building's use / heat loss & heat gain calculations. We don't suspect that there is any wall insulation in the old, 1920's area of the building and even the 1950's section would have used a minimal amount of insulation. Given the fact that the majority of the space in this building is commercial vehicle garage area, the requirement for highly insulated wall systems decreases significantly.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement is anticipated in the next five years.

Some minor repairs could be completed, but even these would be done simply for aesthetic reasons.

Item	Descript
B2011.1 Exterior Wall Sealant	Caulking at window and door frames
Component Condition	Poor / Fair / Good
Replacement Year / Replacement Cost	2020 - $5,000 (budget for every 3 years)

Component Description:

The exterior doors and windows are all sealed to the walls with caulking. There is caulking applied at the windows in the oldest section of the building, the windows in the 1950's building as well as at the 6 doors that provide access into and out of the building.

There appear to have been several projects completed over the years to install vinyl windows in the 1920's building, replace the windows in the 1950's building, and replace doors for security reasons. As part of these projects the caulking and sealants were replaced.

Component Condition:

At the time of this review, there were a few areas where the caulking was in poor condition, e.g. west door, 1920 building and it should be repaired within the next 1 – 2 years. Areas that have been repaired within the last 3 – 5 years were noted to be in fair condition and should perform for another 4 – 6 years. We did not notice any areas where new caulking had been installed within the last couple of years.

Component Recommendation:

On this building there are a relatively few number of windows and 6 doors. Being a service garage, with overhead doors open quite often the requirement to keep the building envelope weather tight are significantly less than at the Administrative Building. We would recommend that as part of the buildings ongoing maintenance, the caulking on the windows and doors should be reviewed annually and areas of deterioration repaired.

Item	Description
B2021 Windows	Vinyl Retrofit Windows
Component Condition	Fair / Good (1996)
Replacement Year / Replacement Cost	2020 / $2,000 (miscellaneous repairs)

Component Description:

This building, both areas have 8 windows; 3 in the old section of the building on the Wellington St. elevation and 5 in the 1950's section. All of the windows have been added sometime within the last 20 years.

Component Condition:

The windows all appeared to be in fair/good condition and should provide several years of satisfactory service. These windows appear to be a medium/heavy duty residential, vinyl window installed in a commercial application. In this application there will be some damage to window hardware.

Component Recommendation:

Damaged hardware should be replaced as part of an ongoing maintenance program. We did not see any failed sealed units. Again, if sealed units fail, they should be replaced.

Item	Description
B2030 Exterior Doors & Entrances	Metal doors, metal frames
Component Condition	Very Good
Replacement Year / Replacement Cost	Ongoing / $1,000 (miscellaneous repairs as required)

Component Description:

There are 6 doors which provide entrances/exits for the building;

- Two to the 1920's section of the building
- The original 'front' Wellington St. entrance to the 1950's section of the building
- Two at the loading dock; one to the administrative area/one to the receiving area
- An emergency exit on the east elevation.

Component Condition:

With the exception of the original entrance to the 1950's section of the building the doors appear to have been installed within the last couple of years. A security upgrade has been undertaken within the last couple of years that includes new, metal frame, insulated metal doors that has added security card access / controls to doors which provide entry into the building. Doors, door hardware, security card readers, hinges, weather stripping, etc. all appeared to be in very good condition and operating properly.

Component Recommendation:

These doors are in very good condition and should perform as required for the next 10 years + years provided regular maintenance takes care of worn out and/or damaged broken components.

Item	Description
B2035 Overhead Garage Doors	
Component Condition	Good
Replacement Year / Replacement Cost	Ongoing / $2,500 (annual, misc. repairs as

Component Description:

There are 8 overhead garage doors; 3 in the 1920's section of the building and 5 in the 1950's building. All of the doors are segmented, power operated overhead style doors. At the time of our site review, 7 of the 8 doors were in the open position.

Component Condition:

We would estimate that the overhead doors are 12 – 15 years old, perhaps older. We were not advised of any issues with door operation.

It would appear that the garage areas are required to accommodate larger and larger vehicles. Looking at the truck installed in the one bay, there is very little clearance between the manlift installed on the vehicle and the interior face of the overhead door. The equipment that is using these garage bays seems to be at its limit in terms of size.

Component Recommendation:

These doors are in good condition and should perform as required for the next 7 - 10 years + years provided regular maintenance takes care of worn out and/or damaged broken components.

B30 ROOFING

Item	Description
B3011 Roof Finishes	1920 Bldg – Asphalt shingles 1950 Bldg – Built up asphalt roof
Component Condition	1920 Bldg – To be replaced 1950 Bldg - Fair
Replacement Year / Replacement Cost	1920 Bldg – 2019 - $10,000 1950 Bldg – Garage Area / Ldg Dock - 2022 -24 $200,000 1950 Bldg – Admin Area – 2024 – 2026 - $50,000 Install permanent access ladder/hatch - $25,000

Component Description:

The sloping roof on the 1920 section of the operations centre is roofed with asphalt shingles.

The roof over the 1950 section of the building is a built-up asphalt roof system. The drawings prepared for the 1996 renovation also indicated that the roof was to be replaced. We have assumed that it was replaced at least once (1996) since the building was originally constructed. The roof over the administrative part of the building appears to be newer than the garage area and loading dock, but all areas are most likely 23 years old.

Component Condition:

On the old building, there is an area of the shingled roof where the shingles have been blown off and we suspect that the roof leaks. We were advised that the shingled roof is scheduled to be replaced with a new, pre-finished metal roof in 2019 which should provide many years (35+ of satisfactory performance).

For the 1950 section of the building, we were not advised of any roof leaks. There is one roof top unit that has had several generous applications of sealant applied where the unit sits on the curb. We suspect that a new unit was set on an old curb and the resulting 'gap' between the curb and the unit was sealed with mastic and caulking (on several occasions). At the time of our visit, we suspect that this detail is not leaking. When the roof is replaced, a proper sized curb should be installed. Based on a visual review of the 3 roof areas, they appear to be in fair condition. We did not notice any ridges, splits, or other deterioration which could lead to leaks developing in the near future.

Access to the roof is provided by an external ladder set up on the side of the building at the loading dock and locked into position with a chain. It would be better is a more permanent access ladder, staircase to a hatch was installed on the interior. This would make access easier and safer and promote doing routine maintenance on the roof.

There are a few roof penetrations that rely on caulking to seal them properly. At the time of our site review these all appeared to be well sealed.

The perimeter metal counter flashings were noted to be in good condition.

A couple of items were noted;

There is a fair amount of ponding on the roof. This roof is surfaced with a layer of 3/8" pea stone. The pea stone hides some of the 'shallow' areas of ponding so ponding is not as noticeable as it is on the 2-ply modified bituminous roof system on the Administration Building.

There is a small amount of debris that should be cleaned up at the drains.

The 'caulked' joint at the base of the one unit will need to be re-sealed regularly to prevent leaks from developing at this location.

Component Recommendation:

Access to these roof areas is provided by a temporary ladder set up on the exterior of the building. A convenient system has been constructed at the roof level to secure the ladder at the top increasing the safety associated with this approach to getting onto the roof. Today, most clients are installing systems to access the roof that don't use temporary ladders. This eliminates a safety concern. We would recommend that consideration be given to installing some type of permanent access to these roofs. An internal, permanent ladder would be good, an internal, permanent staircase to a platform / short ladder / roof hatch would be better.

Clean the drains and roof regularly (every 2 – 3 months).

Do a general walkover in spring and fall to check for any damage.

Built up asphalt roofs have a life expectancy of 15 – 20 years. It is our opinion that these roofs have exceeded their anticipated life expectancy but are still performing in a satisfactory manner. It should be kept in mind that the majority of the roof covers the vehicle storage area where leaks can be tolerated much better than in office/administrative space. We have budgeted for replacement of the roof over the vehicle storage area in 3 – 5 years and the roof over the administrative area in 5 – 7 years. We would recommend that consideration be given to using another built up asphalt roof system but concerns with odors are making it more and more difficult to use this type of roof system.

C INTERIOR SYSTEMS

C30 INTERIOR FINISHES

Item	Description
C3021 Wall Finishes to Interior Walls	Paint Block Wall Covering - Operation Office
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The majority of the interior walls, doors and trim are finished with paint that was reportedly refinished approximately 11 years ago.

Component Condition:

The interior paint finish was observed to be in good condition, with isolated areas of chipped or damaged finish observed; with would be due to high usage.

Component Recommendation:

Repairs to isolated areas of impact damage to the interior paint finish is recommended to improve the aesthetic of the building. The interior doors and frames were also observed to require refinishing in select areas.

Item	Description
C3022 Wall Finishes to Interior Walls	Paint Block Wall Covering - Operation Garages
Component Condition	Poor/Fair
Replacement Year / Replacement Cost	2021 / $100,000

Component Description:

Original Garage 1920s - The majority of the interior walls in the operations original garage are painted block walls to about approximately five feet above grade, then it looks to be is exposed block to the underside of the ceiling board.

Garage 1950s - The majority of the interior walls in the operations 1950s garage are painted block wall to the underside of the exposed structure and metal deck.

Component Condition:

Original Garage 1920s - Most interior paint finish was observed to be in poor condition, with areas of flaked or damaged paint; this is would be due to the age of the building as well as this area being in high and heavy use.

Garage 1950s - Most interior paint finish was observed to be in fair condition, with areas of flaked or damaged paint; this is would be due to this area being heavily used.

Component Recommendation:

Original Garage 1920s – Painting the walls/ceiling would be a considerable upgrade and is recommended to improve the aesthetic of the building. The floor is exposed concrete. Without the benefit of some heavy surface preparation, we do not anticipate that painting the floor or applying a commercial finish would stay in place. Upgrading the interior finishes in the garage area is not considered a high priority, as this building does not have customers occupying any of the Operations Garage spaces.

Garage 1950s – The walls and ceiling would benefit from new paint. An interior paint refinish is recommended to improve the aesthetics of the building. This action is not considered a high priority, as this building does not have customers occupying any of the Operation Garage spaces, however this would be convenient and easy.

Item	Description
C3023 Flooring	Vinyl Floor Tiles - Operations Office
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The building's flooring is finished with vinyl floor tiles in the shop office space, lunch room, corridors, barrier free washroom and change room. The flooring is not original to the building construction. It is assumed that the flooring was installed in 2007 during a small renovation.

Component Condition:

The vinyl tiles were observed to be in good condition with no isolated areas requiring refinishing. The flooring is reportedly refinished on an ongoing basis.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, there is no replacement at this time needed of the vinyl tile flooring. Continued annual refinishing of the vinyl tile is recommended to preserve its aesthetic.

Item	Description
C3024 Flooring	Terrazzo Flooring – Operations Office
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Terrazzo flooring is provided in the male washroom/ change room. The terrazzo appears to be refinished as part of the buildings ongoing maintenance program.

Component Condition:

Terrazzo flooring is an incredibly resilient flooring material. Based on our condition assessment, we find that the terrazzo flooring is considered to be in good condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the terrazzo is anticipated in the next five years (2020 to 2025).

Item	Description
3025 Flooring	Exposed Concrete – O.B.G 1920s & 1950s
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The interior floor system for the operations building garages (1920s & 1950s) are exposed concrete.

Component Condition:

Interior operations building garages were observed to be in good/fair condition, with only minor cracking/flaking to the concrete surface. They are well worn.

Component Recommendation:

Given their current condition, we suspect that it would be difficult to either paint or refinish the operation building garage floors without a substantial preparation phase. Ongoing cleaning, undertaken as part of the building's maintenance program should be undertaken.

Based upon our condition assessment, we found that the there are no major repair/replacement of the exposed concrete, and there is anticipated that in the next five years (2020-2025).

Item	Description
C3025 Ceiling Finishes	Sus. Ceiling Tile – Operations Office Area
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

A suspended ceiling tile ceiling is provided in the Operation Office Areas.

Component Condition:

The acoustic tiles were observed to be in good condition overall, with no isolated areas of staining. However, there were locations with some (minor) damage. The age of the tiles is unknown/ unverified.

Component Recommendation:

Based upon our condition assessment, we found that the there are no major repair/replacement of the suspended acoustic tiles anticipated in the next five years (2020-2025). An ongoing program to replace tiles is recommended since this is easy and convenient.

Item	Description
3026 Ceiling Finishes	Ceiling Board – Operation Building Garage 1920s
Component Condition	Good
Replacement Year / Replacement Cost	2021 / 10,000

Component Description:

There appears to be a ceiling board that is provided in the Operation Building Garage (1920s) location.

Component Condition:

The ceiling board was observed to be in good condition overall, with no noticeable areas of damage. The age of the tiles is unknown. We assumed that the ceiling is original to the garage renovation completed when the 1950's section of the building was constructed.

Component Recommendation:

Based upon our condition assessment, we found that the there are no major repair/replacement of the ceiling board anticipated in the next five years (2020-2025).

Item	Description
3027 Ceiling Finishes	Exposed Painted M. Deck – Operations Building Garage 1950s
Component Condition	Fair / Good
Replacement Year / Replacement Cost	2024 / 20,000

Component Description:

The ceiling in the Operation Building Garage (1950's) is exposed painted metal deck.

Component Condition:

The painted exposed metal deck is observed to be in good condition overall, with some areas of paint chipping/flaking (minor).

Component Recommendation:

The work space aesthetics could be improved by painting the ceiling in this area of the building. This is not an upgrade that is recommended as a result of any shortcoming in the performance of the building. Based upon our condition assessment, we would suggest repair/replacement of the painted exposed metal in the next four years (2024). It is recommended that a new coat of paint should be applied since this is easy and convenient.

BARRIER FREE BUILDING ANALYSIS: FESTIVAL HYDRO OPERATION BUILDING

Item	Description
Barrier Free Analysis	Private and Public Spaces
Building Barrier Free Condition	Fair/ Limited
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

During our building condition assessment of both buildings (Administration and Operations), we were tasked with reviewing the current building design, and to see if it conforms to today's AODA and current Accessibility Code Standards. For this exercise we chose to use the Regional Municipality of Waterloo Accessibility Design Standards as an acceptable example of an accessible design standard for municipal facilities.

After completing a thorough site visit, we completed a 47-section checklist which in each section there were various subsections that outline specific criteria for said sections. We have concluded that this current building does not meet a great deal of the accessibility code standards of today.

- **Bathrooms –** There are two bathrooms/change rooms in the shop building, the women's change room and universal barrier free washroom seems to have been a renovated space and has been made to comply with Accessibility code standards, i.e. millwork, size of room, mounting heights, etc.…The men's washroom/change room does not comply at all from the mounting heights of everything to the operability of fixtures and fountains. This space needs extensive remodeling to be upgraded to comply with today's standards.
- **Hallways and Paths of Travel –** All corridors in this building are a good size and conform to the current Accessibility Code Standards. However, the use of corridors for storage or to keeping any files is not in compliance as it narrows the hallway.
- **Furniture –** Some furniture does comply to today's accessibility code standards, however the majority of it does not. This includes desk and chairs.

Based on information provided and observations noted during the accessibility review, due to the lack of accessibility in both private and public spaces, along with 'dated' building design makes retrofitting difficult, costly, and disruptive. There are significant changes that need to be made in order to bring this building up to today's standards based on Accessibility Code Standards. It is not mandatory to make any changes, however today, accessibility is becoming more relevant and is now integrated into most new building designs.

D SERVICES SYSTEMS

D20 PLUMBING

Item	Description
D20 Plumbing	D20 Plumbing – Plumbing Piping
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $5,000

Component Description:

The majority of the water distribution system including domestic water, domestic hot water, sanitary and storm piping is either concealed behind interior finishes or encapsulated behind the walls and floors in the office area. Where observed the water piping was copper and sanitary piping is cast iron and dates to the building's original construction of 1920/1950. Some of the piping would have been changed as part of the renovations completed in 1996. The copper piping distributes domestic water to the various plumbing fixtures in the building. Cast iron piping is used for sanitary drains from the plumbing fixtures and storm drains from roof drains. A bronze body construction double backflow preventer and water meter has been installed per Ontario Building Code requirements.

We were not sure if either of the garages have an oil grit separator(s).

Component Condition:

No significant problems were reported with the building's plumbing piping system and backflow preventer. Based on the operating condition, the plumbing piping is considered to be in fair condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the plumbing piping is anticipated in the next five years (2020 to 2025). We budgeted for flushing buried sanitary and storm piping and also for camera inspection that may be required.

Item	Description
D2010.60 Plumbing Fixtures	Plumbing Fixtures
Component Condition	Fair / Poor
Replacement Year / Replacement Cost	2020 / $5,000

Component Description:

The truck bay area is equipped with one small washroom including one sink with a manual faucet and one water closet with a water tank.

The office area has two washrooms, one of them combined with showers, one round multi-user sink, two water closets and three urinals with flush valves. The second washroom is a barrier free washroom with one shower, one sink with a manual faucet, one shower with a mixing valve and one water closet with a water tank.

The plumbing fixtures are not the low-flow/flush water efficient style, nor are they hands free activated fixtures.

A drinking water fountain is located in the office area washroom.

Component Condition:

Based on observed conditions, the fixtures in the truck bay washroom appear to be very well used and in poor condition. The sink in the truck bay area is broken and should be replaced. The office area washroom fixtures are in fair to good condition although they are not the modern low-flow efficient / hands free styles.

Component Recommendation:

We recommend replacement of the broken sink serving the truck bay area.

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the plumbing fixtures is anticipated in the next five years (2020 to 2025) for the office area washrooms. An upgrade of the washroom sink faucets and urinal flush valves to modern low-flow electronic fixtures is recommended. An upgrade action has been included in 2020-2025 for budgeting purposes.

Item	Description
D2010.20 Hot Water Equipment	Domestic Hot Water Heater
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $500

Component Description:

The truck bay area has a 12-gallon capacity electric water heater, manufactured by Brandford White, serving the truck bay washroom.

Two electrical water heaters serve two washrooms separately. One 25 gallons heater is located in a vault manufactured by Rheem. A second 40 gallons electrical domestic water heater is located in the mechanical room dedicated to the washroom/change room area.

Component Condition:

There is no insulation on either the hot or cold-water lines for the small water heater in the truck bay area. Ideally, these should be insulated.

Based on the observed condition, the all domestic hot water heaters are considered to be in good condition. Electrical domestic water heaters typically have a useful life of 15 years. These water heaters appear to be approximately 10 years old. We expect 5 - 7 more years of service life for the water heaters.

Component Recommendation:

Water heaters are generally replaced when they fail. Based on our visual observations noted during the site assessment visit, no major repair/replacement of the domestic water heaters are anticipated in the next five years (2020 to 2025).

The domestic cold water and hot water piping for the domestic water heater located in a small truck bay area should be thermally insulated. We allowed $500 for the insulation in 2020.

D30 HVAC

Item	Description
D3012 Gas Supply System	D3012 Gas Supply System
Component Condition	Fair
Replacement Year / Replacement Cost	2020/$500

Component Description:

Natural gas pipe lines supply fuel to the building heating equipment through a gas meter and pressure regulator. The buildings heating equipment includes 2 rooftop units on low roof over the office area of the building and two make up air units with 100% fresh air on the high roof over the truck bay area. There are also 5 gas fired, ceiling hung, unit heaters serving the truck bays and warehouse.

The gas lines pressure is between 7” to 14” WC which is classified as a low-pressure system.

Component Condition:

The natural gas pipelines were observed to generally be in good condition, with some corrosion observed on the exterior on the high roof area.

Component Recommendation:

Based on our visual observations noted during the site assessment visit, no major repair/replacement of the natural gas pipelines is anticipated in the next five years (2020 to 2025).

We recommend painting the natural gas piping located on high roof which includes rust cleaning, primer application and 2 coats painting.

Item	Description
D3031.4 Window type A/C Unit	D3031.4 Window type A/C Unit
Component Condition	Poor
Replacement Year / Replacement Cost	2020 /$7,500

Component Description:

We observed a window type air conditioning unit servicing small office area in the warehouse area.

Component Condition:

The unit is in poor condition and may not be operable.

Component Recommendation:

To replace the window type air conditioner would cost approximately $1,500.00. This type of equipment is not very energy efficient, is noisy, and doesn't have a very long-life span. Consideration might be given to installing something better. Based on information provided and observations noted during the site assessment visit, we recommend replacement of existing windows AC unit with new split type air conditioner and room thermostat. The anticipated construction cost is $7,500.

Item	Description
D3041 Air Distribution Systems	Distribution Systems – Duct System
Component Condition	Fair
Replacement Year / Replacement Cost Study Year / Study Cost Repair Year / Repair Cost	NA / NA

Component Description:

There is no duct work in the 1920's section of the building. A system of galvanized ductwork and rectangle ceiling diffusers distributes air in the office area and is common to both the cooling and heating systems. The ductwork is built of sheet metal and varies in size. The majority of ductwork is considered to be original to construction of the building in the 1950's, making it now 60 years old. Multiple VVT, variable volume and temperature control dampers associated with zone thermostats provide zone temperature control in the building.

Component Condition:

For the office area of the 1950's building, the duct system and VVT control dampers are original to the building but noted to be in fair condition.

Component Recommendation:

Expected service life of the galvanized ductwork, diffusers, and VVT dampers is 30 years. The distribution ductwork in this building has significantly exceeded this but is still performing in a satisfactory manner. Unless there is a significant re-organization of space, we don't anticipate any significant upgrades being required.

Item	Description
D3042 Exhaust Ventilation Systems	D3042 Exhaust Ventilation Systems
Component Condition	Fair/ Poor
Replacement Year / Replacement Cost	2020-2022 / $75,000

Component Description:

Inline exhaust fans are located in each washroom above the ceiling and are vented to the exterior wall or roof.

Two exhaust fans; one wall mounted axial exhaust fan and one exhaust fan serving welding fume hoods in the truck bay area, are used as part of vehicle maintenance.

The truck bay area also has three ceiling ventilation fans which are normally used during the summer time. The large truck bay area has two roof exhaust fans for emergency exhaust ventilation.

The emergency exhaust fans serving repairing garages are required to be interlocked with CO and NO2 sensors located low level and high level respectively in accordance with OBC. We are not informed that the CO and NO2 detectors are available or operational.

Component Condition:

Based on our visual review, the washroom and locker room exhaust fans in the office area are operating properly and considered to be in fair condition.

The truck bay welding area exhaust fan is original and in fair condition. However, in the same area the axial exhaust fan is in poor condition.

The ceiling ventilation fans are in fair condition, but some maintenance and cleaning are required for proper operation.

Two exhaust fans serving the large truck bay are original and in poor condition. The ventilation hoods on the roof serving the exhaust fans are in poor condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, we recommend replacement of one axial exhaust fan serving the truck bay area and two roof exhaust fans serving the large truck bay area with the allowed cost of $75,000. The work in the large truck bay area also is included with two new exhaust air hoods on the roof and CO and NOx alarm system. CO concentration is limited to not more than 100 ppm. NO^2 concentration is limited to not more than 3 ppm. The detector installations should be provided by the manufacturer.

Item	Description
D3052 Rooftop Units	D3052 Rooftop Units – Lower Roof Unit
Component Condition	Fair
Replacement Year / Replacement Cost	NA / NA

Component Description:

The office area is serviced by two rooftop units (RTU) located on the lower roof that were manufactured by Carrier in 2013 and 2010. The equipment has model number 48HCEA05A2A1A080A0 and serial number 4313C83492 and 1510G20180 respectively. The RTUs supply both cooling and heating to the office area. The RTUs use natural gas for heating and electrical for cooling (4.0 Tons). The units have been charged non-ozone depleting R410A refrigerant.

Component Condition:

The RTUs were observed to be in good condition and are reported to operate properly. Some damage to the RTUs condenser fans was also observed. Based on expected service life, these units should be in service 13 and 10 more years respectively.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the rooftop units are anticipated in the next five years (2020 to 2025) with regular maintenance.

Item	Description
D3052 MUA Units	D3052 MUA Units – Truck Bay Area
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $80,000

Component Description:

The large truck bay area is serviced by two make up air units (MUA) with 100% fresh air. The units do not have name plates and equipment information. They supply heating to the large bay area. No cooling is available which is common for repair garages. The units use natural gas and are mounted on roof curbs.

Component Condition:

Based on observed condition, these MUAs are considered to be in poor condition. Expected service life of MUA units averages 20 years. These units appear to have well exceeded their anticipated life expectancy. We were not made aware of any complaints about their operation, but this is a vehicle garage / warehouse hence performance requirements will be lower.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, we recommend replacement of two MUA units in 2020. New units should be interlocked with the building automation system and system set points should be scheduled for day and night for energy efficiency. The anticipated replacement cost would be $80,000 which includes BAS connections, roof curbs, supply air diffusers, return air grilles with galvanized ductwork and disconnect switches.

Item	Description
D3020.70 Unit Heaters	D3020.70 Unit Heaters
Component Condition	Fair
Replacement Year / Replacement Cost	2020-2025 / $20,000

Component Description:

The large truck bay includes two gas-fired unit heaters and the small truck bay area includes three gas-fired unit heaters. The 5 units are manufactured by different suppliers. All of the unit heaters are hung from the roof structure members and vented to the outside with stainless steel vent pipe. The combustion air is provided from the truck bays. The natural gas piping is properly done with required shut off valve.

Component Condition:

We were not able to inspect the units name plates. It would appear that they were installed in different years. Based on the observed condition, the unit heaters were generally considered to be in fair condition. Expected service life of unit heaters average 15 - 20 years.

Component Recommendation:

Unit heaters installed in the vehicle repair areas / warehouse appear to have reached or exceeded their anticipated life span. We would recommend that some of the units be replaced within the next 5 years. We have set aside a budget of $20,000 to replace these units.

Item	Description
D3060 Heat Recovery Ventilators	D3060 Heat Recovery Ventilators
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $500

Component Description:

A heat recovery ventilator installed in the truck bay serves the office area washroom / change room to increase energy efficiency. We couldn't access the units name plate during the site visit however the unit is manufactured by Venmar. The HRV captures heat from the stale air leaving the washroom / change room and uses it to preheat the fresh air coming into the washroom / change room. Similarly, the HRV can reverse this process during the cooling season, removing some of the heat from the incoming air and transferring it to the outgoing air.

Component Condition:

The unit is reported to operate as intended and is considered to be in fair condition based on age and reported operating condition. The expected service life of the unit is 25 years with regular maintenance. We recommend periodical filter replacement and plate and frame cleaning per the manufacturer's instruction. The vapour barrier on the supply and return ductwork insulation is in poor condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the heat recovery ventilator is anticipated in the next five years (2020 to 2025). However, we have allocated $500 for fixing the duct thermal insulation.

Item	Description
D3020.70 Cabinet Heaters	D3020.70 Cabinet Heaters
Component Condition	Fair
Replacement Year / Replacement Cost	NA / NA

Component Description:

An electric cabinet heater is serving the entrance of the building. The unit has a built-in thermostat.

Component Condition:

The electrical cabinet heater is in fair condition and serving as intended. Expected service life of the electric cabinet heaters is 15 years. Based on observed condition, the baseboard heaters are considered to be in fair condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the cabinet unit heater is anticipated in the next five years (2020 to 2025).

Item	Description
D3060 HVAC Instrumentation and Controls (BAS)	D3060 HVAC Instrumentation and Controls – Building Automation System
Component Condition	Fair
Replacement Year / Replacement Cost	NA / NA

Component Description:

The building has a building automation system (BAS). We did not access the operation of the BAS system during the site inspection. We assumed two rooftop units have been connected to the BAS system and the room temperatures are monitored via BAS system.

Component Condition:

There were no complaints / comments received about the BAS system. Based on the lack of comments, we assume that it is operating as intended.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the BAS system is anticipated in the next five years (2020 to 2025).

D40 FIRE PROTECTION SYSTEMS

Item	Description
D4030 Fire Protection Specialties	D4030 Fire Protection Specialties
Component Condition	Fair
Replacement Year / Replacement Cost	NA / NA

Component Description:

The building is fully fire sprinklered including truck bays, warehouse and offices. A dry sprinkler system is used for truck bays and a wet sprinkler system is dedicated to office areas. The sprinkler check valves are located in the warehouse. The fire sprinkler system doesn’t have a backflow protector. Backflow protection is required with a double check valve assembly per O.B.C.

Component Condition:

Expected service life is 25 years for sprinkler heads and 40 years for sprinkler piping. The age of the system is well beyond the expected service life. Per our visual inspections, the fire sprinkler system is in fair condition and still performing as anticipated.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major issue of the fire sprinkler system is anticipated in the next five years (2020 to 2025). The fire sprinkler system requires annual inspection by a certified agency per NFPA 25.

D50 ELECTRICAL SYSTEMS

Item	Description
D5020 Electrical Service and Distribution	Electrical Service and Distribution – 1956 Original
Component Condition	Fair
Replacement Year / Replacement Cost	

Power System / Component Description:

The available power systems that service the FH Service Building are described as follows:

- Class IV - Normal Power Supply
- Class II - Emergency Power Supply

<u>Normal Power Distribution:</u>

The electrical service for the Operations Building is provided via ground mounted step-down transformer rated at 500kVA 27600V:347/600V located under Hydro pole. Main switch board rated 400A 600V 3PH 4W, located inside garage, is being fed from transformer and feeds the following:

Automatic Transfer Switch was manufactured by ASCO, rated 200A 600V 3PH that feeds the splitter rated 225A 600V 3PH 4W. Splitter feed the following:

- 45kVA transformer Mechanical Room rated 600V:120/208V that feeds Panel A
- 112.5kVA transformer rated 600V:120/208V that feeds Electrical Service Main Switch rated 200A
- 5kVA transformer rated 600V:120/240V that feeds Sub Panel
- AHVC Unit rated 40A 600V 3PH
- AHVC Unit rated 30A 600V 3PH

Emergency Power Distribution:

A standby diesel generator (Made by Sommers Generator Systems) rated 150kW 347/600V 3PH 4W located outside the Operations Building. The generator feeds the transfer switch in the garage area.

Power System / Component Condition:

The electrical distribution system was installed in or about 1956; this would make the systems about 60+ years old.

The transfer switch was installed in 1996; this would make the systems about 23 years old.

An electrical distribution system has a life expectancy of 30 years.

Power System / Component Recommendation:

The existing power distribution equipment based on information provided during the site assessment visit appears to be in good working condition, but main distribution panel was old, quite rusted and needs to be clean and painted. As electrical equipment gets older, replacement parts become difficult to obtain and operation of breakers/switches may not be that reliable.

It should be noted that provision for the infra-red (IR) scanning and coordination study shall be taken into consideration to identify issues not visible to the naked eye and to ensure the safety of the personnel.

Also, it should be noted that it is mandatory by the Ontario Electrical Safety Code (OESC) requirements, that the existing major power distribution equipment shall be tested and maintained regularly (recommended every 5 years). Accordingly, provisions shall be taken to frequently update the arc-flash, short circuit fault protection, infrared scan and regular maintenance for the major power distribution equipment to avoid costly failures and to properly field mark equipment of the potential arc flash and electric shock hazards.

Item	Description
D5040 Lighting	D5040 Lighting – Upgraded at some point
Component Condition	Fair / good
Replacement Year / Replacement Cost	2021 / 50,000

Lighting System / Component Description:

The existing lighting system that illuminates the storage and garage consists of a combination of 4’-0” Long fluorescent suspended / surface light fixtures, and 2’x4’ light fixture. Lamps are standard fluorescent 32W-T8.

In general, the existing lighting system is old. Some lamps were not in working condition and some were missing. Some lamps were burned out and need to be replaced. It is recommended that the fixtures be replaced with new LEDs to improve energy efficiency and provide longer life expectancy.

Lighting is 120V powered by the light panel.

The existing lighting system that illuminates the offices are LED. Based on the site visit assessment, the interior lighting is in good condition.

Lighting Controls:

In storage and truck bays the lighting is controlled by conventional switches located in accessible locations. In the office area all the lighting is controlled by occupancy sensor and is in good condition.

Exit sign Emergency lighting:

All the lighting through the service building is on emergency power, exit signs were found throughout the entire building covering exit pathways. Exit signs have been upgraded within the last few years.

Lamp Types:

Florescent fixtures are the main source of the interior lighting that illuminates the storage and truck bays and LED fixtures are the main source of the office building.

Lighting System / Component Condition:

Lighting levels are generally acceptable in the office building, but the storage and truck bays may be below the IESNA standards.

Lighting System / Component Recommendation:

In the storage and truck bays, a strategic short-term and long-term planning is required for any future modifications or upgrades to the lighting system to meet the latest OBC/ SB10/ ASHRAE 90.1 standards for energy management. It is recommended that existing fluorescent light fixtures to be replaced with new LED’s.

Item	Description

D5080 Miscellaneous Electrical Systems	D5080 Miscellaneous Electrical Systems – 1956 Original
Component Condition	
Replacement Year / Replacement Cost	

Miscellaneous Electrical System / Component Description:

Wiring is original to the building and consists of wires in EMT conduits and cables.

Miscellaneous Electrical System / Component Condition:

The current condition and type of wiring installed at this building was not entirely inspected during the site reviews. The majority of the wiring/cables run in EMT conduits. Flex or Teck 90 cables were also available for the large mechanical equipment.

Miscellaneous Electrical System / Component Recommendation:

It is recommended that the wiring system be inspected on a regular basis and make any upgrades as needed if damaged or defective components are discovered.

D60 COMMUNICATIONS

Item	Description
D6010 Data Communications	Phone system.
Component Condition	Fair
Replacement Year / Replacement Cost	

Public Address System / Component Description:

The PA system consists of surface ceiling mounted speakers located throughout the building and is powered by the telephone system.

Public Address System / Component Condition:

The PA system speakers have a very long-life span however upgrading to the latest technology may be desirable.

Public Address System / Component Recommendation:

Upgrade the PA system and equipment as deteriorated components fail.

Item	Description
D6020 Voice Communications	D6020 Voice Communications – 1956 Original
Component Condition	Fair
Replacement Year / Replacement Cost	Upgraded on an ongoing basis

Voice Data / Component Description:

Voice/Data drops for the office area is provided via outlets.

Voice Data / Component Condition:

The current condition and type of wiring installed at this building was not entirely inspected during the site reviews.

Voice Data / Component Recommendation:

It is recommended that the wiring system be inspected on a regular basis and make any upgrades as needed if damaged or defective components are discovered.

D70 ELECTRICAL SAFETY AND SECURITY FIRE ALARM

Item	Description
D7050 Detection and Alarm	D7050 Detection and Alarm –
Component Condition	Fair
Replacement Year / Replacement Cost	

Fire Alarm System / Component Description:

The buildings fire alarm devices which are connected to the security system, consists of a Chubb Edwards security panels. The security system monitors smoke detectors and carbon monoxide detectors located throughout the building.

The manufacturer-recommended lifespan of automatic smoke detectors is typically 10 years, while the balance of fire alarm system components is typically rated for a lifespan of approximately 15 years. It is possible to extend this lifespan where a system is well maintained and is not exposed to harsh conditions, provided the availability of replacement parts does not become an issue.

Fire Alarm and Security System / Component Condition:

The security and fire alarm system control unit appears to be undergoing regular testing and inspection in accordance with the current code requirements. The control panel appears to be in good condition.

Fire Alarm System / Component Recommendation:

The manufacturer-recommended lifespan of automatic smoke detectors is typically 10 years, while the balance of fire alarm system components is typically rated for a lifespan of approximately 15 years. It should be expected that annual maintenance costs will begin to increase after 8-10 years of installed life as detectors begin to exhibit signs of failure requiring replacement. It is possible to extend this lifespan where a system is well maintained and is not exposed to harsh conditions, provided the availability of replacement parts does not become an issue.

When properly implemented, an inspection and maintenance program in compliance with CAN/ULC-S536 will serve to identify when the system components begin to approach end of life.

G BUILDING SITEWORK SYSTEMS

G20 SITE IMPROVEMENTS

Item	Description
G2020.10 Paving Lot Pavement	Asphalt Paved Parking Lot
Component Condition	Poor
Replacement Year / Replacement Cost	2020 / $450,000

Component Description:

The approximately 4,900 m2 asphalt area consists of two areas, the largest of which is located to the north of the building consist of a parking area and as well as storage and works areas. The other area is located to the south of the building consisting of parking and loading bay area. It appears that the asphalt was last refinished prior to 2004 similarly to the other site, so the estimated age currently would be approximately 15 years.

Component Condition:

Although the center aisle of the entrance into the north area was recently repaved the remainder of the asphalt is in poor condition. The condition of the asphalt could be attributed to the higher loads experienced in this area.

Component Recommendation:

Continuation of current maintenance (sealing cracks, taring, etc.) will extend the useful life of the asphalt. However, a typical lifespan of asphalt is 15 years and since the asphalt is estimated to be greater than 15 years in age it is recommended for it to be resurfaced. At the time of resurfacing a geotechnical assessment is recommended to provide design input for the pavement structure with the current use of the areas. With the current condition it is assumed that the substructure is adequate, however at the time of resurfacing it is recommended to complete investigation of the subsurface structure to confirm. Adequate subsurface structure can greatly extend the life of the asphalt. In the event the subsurface is not adequate, full reconstruction would be recommended.

Item	Description
G2020.20 Parking Lot Curbs and Gutters	Concrete Curbs
Component Condition	Poor
Replacement Year / Replacement Cost	2020 / $13,250

Component Description:

Approximately 265 m of concrete barrier curbs surround the asphalt areas on site.

Component Condition:

Most of the curb appears to be poor condition, significant cracking and wearing was observed.

Component Recommendation:

Replacement of the curb is recommended.

Item	Description
G2020.40 Parking Lot Pavement Markings	Pavement Markings
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Pavement markings include painted lines delineating the parking spaces, accessible parking spaces and no parking areas.

Component Condition:

The pavement markings appear to have recently been repainted and in good condition.

Component Recommendation:

At this time the pavement markings do not require re-painting, however if the asphalt is replaced it will need to be re-painted at that time.

Item	Description
G2030.10 Pedestrian Pavement (concrete)	Concrete walkways
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $1,500 (Walkway on west side)

Component Description:

Approximately 100 m^2 concrete paved walkways are located along the north-east side of the building and from the sidewalk along Wellington St. to the entrance on the west side of the building. The walkways provide employees access to the building entrances.

Component Condition:

The concrete paved walkways were in fair condition, however, showed evidence of heaving, cracking and degradation.

Component Recommendation:

Localized repairs are recommended of areas that are showing signs of degradation, including inspection of the base material to ensure it is not attributing to the condition of the walkways. The walkway on the west appears to be closer to the end of life and is recommended to be replaced.

Item	Description
G2060.20 Fence and Gates	Fence and Gates
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $32,000 (Fence)
Replacement Year / Replacement Cost	2045 / $10,000 (Gates)

Component Description:

Fencing surrounds the north asphalt area with a gate at the access to George St. and another prior to the parking adjacent to Wellington Street. The fencing and gate are chain link and the gates appear to be manually opened. The fence appears to be from the original construction, while the gates appear to be recently replaced.

Component Condition:

The gates appear to be recently replaced and are in good condition. However, the exterior site fencing appears to be original and shows significant rusting as well has some locations of deformation and overgrowth and appear to be in fair condition.

Component Recommendation:

Since it appears that the fence is showing signs of wear and is over 60 years, which is the life expectancy, it is recommended that the fence be replaced.

Item	Description
G2080 Landscaping	Landscaping
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

There is a small amount of landscaping in front of the 1950's building along Wellington St. There are no issues with landscaping, but it would benefit from some work. The Operation Building is more of an industrial style site than what the Administration Building was. The perimeter fence is overgrown and would benefit from some maintenance.

Component Condition:

The intentional landscaping appears to be in good condition, however adjacent to the railway and along the fence line, it appears to be unmaintained.

Component Recommendation:

Undertake some maintenance to the landscaping on an ongoing basis. No major repair/replacement of the landscaping is anticipated in the next five years.

G30 SITE CIVIL/MECHANICAL UTILITIES

Item	Description
G3010 Water Utilities	Water Service
Component Condition	Good
Replacement Year / Replacement Cost	2026 / $3,500

Component Description:

The site is serviced from the municipal water system through a service connecting to the watermains within the adjacent streets, assumed to be approximately 20 m of servicing.

Component Condition:

Deficiencies or issues such as low or inadequate capacity were not reported at the time of the assessment. The water service(s) were not directly observed but are expected to be in good condition based on reported operating condition.

Component Recommendation:

Since no deficiencies have been report, major repair/replacement of the underground utilities is anticipated in the next five years.

Item	Description
G3020 Sanitary Sewerage Utilities	Sanitary Services
Component Condition	Good
Replacement Year / Replacement Cost	2026 / $3,500

Component Description:

The site is serviced from the municipal sanitary system through a service connecting to the sanitary sewer within the adjacent streets, assumed to be approximately 20 m of servicing.

Component Condition:

Deficiencies or issues such as low or inadequate capacity were not reported at the time of the assessment. The water service(s) were not directly observed but are expected to be in good condition based on reported operating condition.

Component Recommendation:

Since no deficiencies have been report, major repair/replacement of the underground utilities is anticipated in the next five years.

Item	Description
G3030 Storm Drainage Utilities	Storm Sewer
Component Condition	Good/Fair
Replacement Year / Replacement Cost	2045 / $45,500

Component Description:

The stormwater management (SWM) system on-site consists of a series of storm sewer and catch basins which collect the surface runoff from the asphalt areas and walkways on site. The age of the system is unknown however, has been assumed that they were installed when the 1950's building was constructed.

Component Condition:

During the site visit, ponding due to failure of the SWM system was not observed and no issues with the piping and catch basin system was reported and appears to be in good condition.

Component Recommendation:

The overall system being in good condition requires no repair or replacement.

APPENDIX A – PHOTOS

A Substructure Systems

Single storey office building


Loading dock area adjacent to single storey office building.


Spalled concrete at rebar.


Cracking in foundation wall


East truck bay and warehouse building


Siding covering the north truck bay and warehouse building.


Roof structure of east truck bay


Crack in block wall of east truck bay building.


Missing mortar on stone block foundation of north truck bay building.


Stone rubble and concrete block with damaged parging on north truck bay building.


Interior of north truck bay building.

B Shell Systems

General view, west elevation of the 1920's Building

North and east elevation – 1920's Building

South elevation, 1920's building / west elevation, 1950's Building

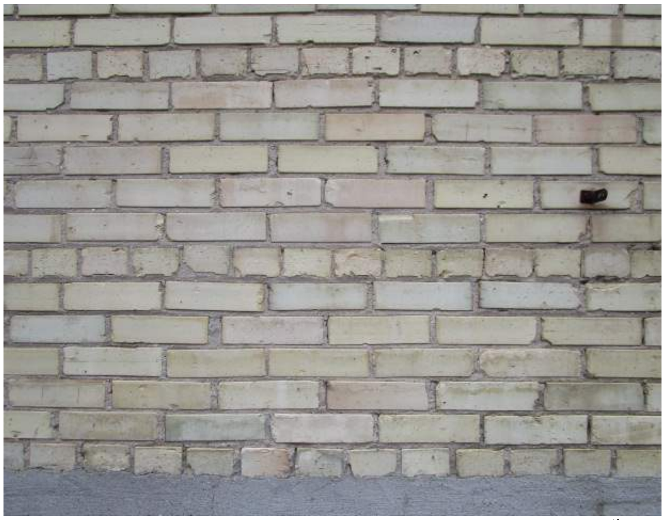
Loading dock – 1950's Building

South elevation – 1950's Building Prefinished metal siding

East elevation – 1950's Building Pre-finished metal siding.

North elevation / 5 overhead doors & 1 man door – 1950's Building

Previous brick masonry repairs – 1920 Building



Brick masonry pattern, bonding course every 6th row. Overall, masonry was found to be in good condition

Tiny amount of masonry deterioration at the base of the door frame

Original windows have been blocked in. Small, vinyl windows have been installed

Original, entrance area to 1950's section of building. Original windows have been replaced with vinyl slider style windows.

Upgraded, insulated metal door and frame installed in the 1920 section of the building

New metal doors / metal frames installed to provide access to the office area and the receiving area

Metal door to garage area of the 1950 Building

Very tight clearance between truck and garage door.

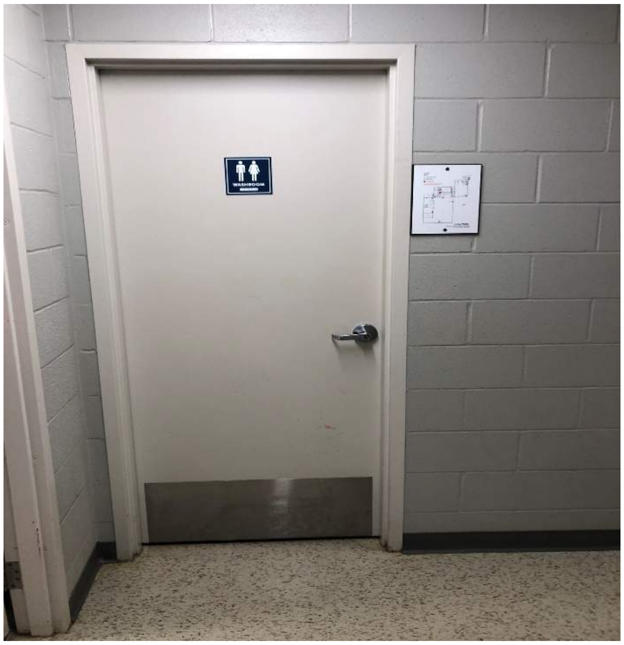
Shingled roof on 1920 Building, built – up asphalt roof over office area, 1950 Building.

Built up asphalt roof over vehicle garage area, 1950's Building

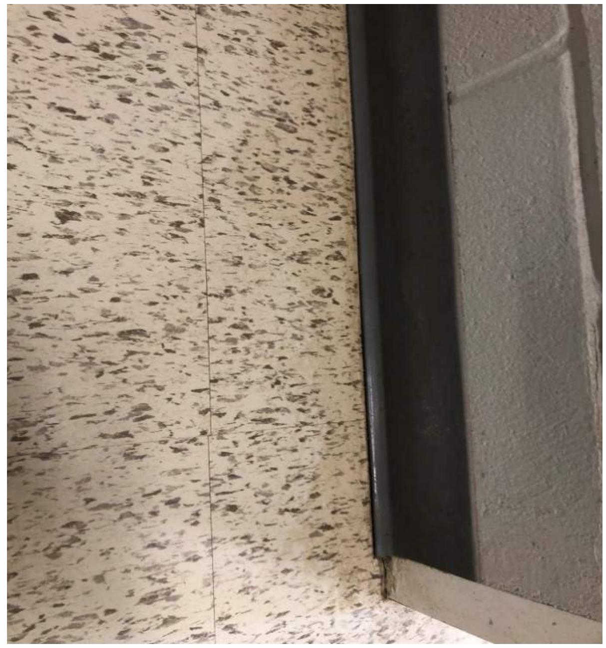
Roof cone for gas line, storm collar, well sealed with caulking

Debris at drain should be cleaned up to promote drainage of the roof.

C Interior Systems



Painted Block Wall Covering / Painted metal door frame



Interior Wall Finishes – Flooring / Wall Trim

Ceiling – Suspended Ceiling Tile

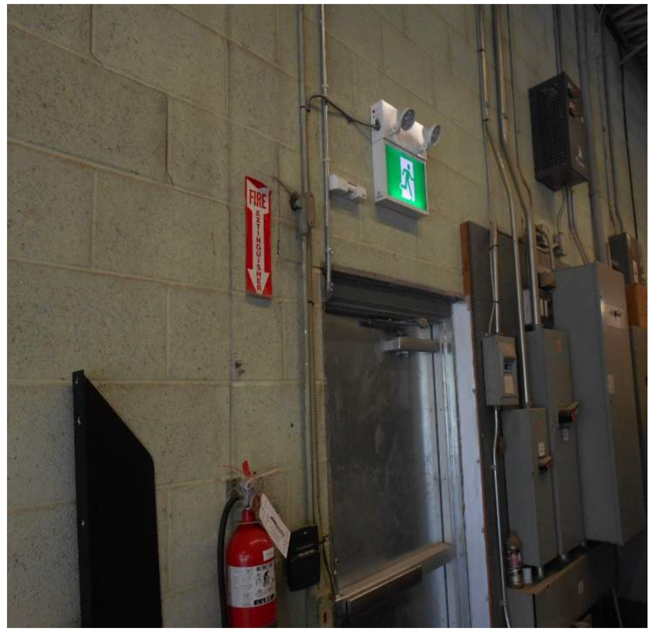
Flooring - Vinyl Floor Tiles

Flooring – Terrazzo

Ceiling - Ceiling Board (1920's section of building)

Ceiling – Exposed Painted Metal Deck

Flooring - Exposed Concrete

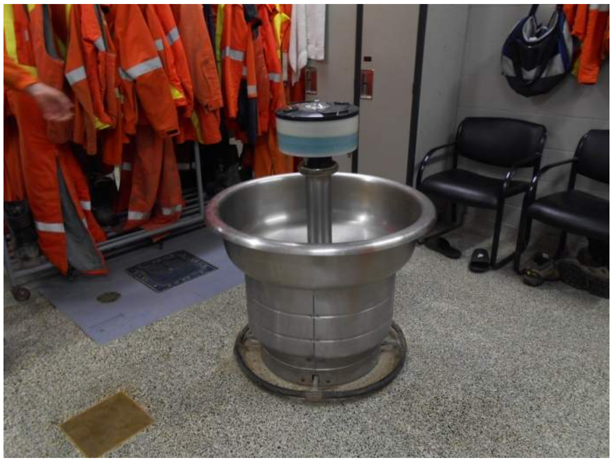


Wall Finishes Garage – Painted Block 1920s

Wall Finishes Garage – Painted Block 1950s

D Service Systems

MECHANICAL



Round sink in office area washroom

Broken washroom sink in truck bay washroom

Domestic water heater in truck bay area

Domestic water meter and backflow preventer


Domestic hot water heater in vault


Barrier free washroom in office area


Cabinet heater in entrance


Kitchenette sink


Rectangle ceiling diffuser


Two exhaust fans in truck bay area


BAS / Security System control panels.


Unit heater in truck bay area


Fire sprinkler check valves


Heat recovery ventilator


Unit heater and ceiling fan


Rooftop unit serving office area


MUA unit serving large truck bay area


Exhaust fan hood for truck bay area

ELECTRICAL

Main Incoming Service

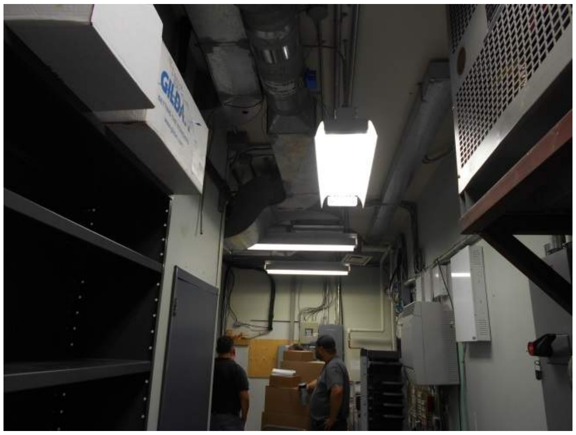
Main Transformer

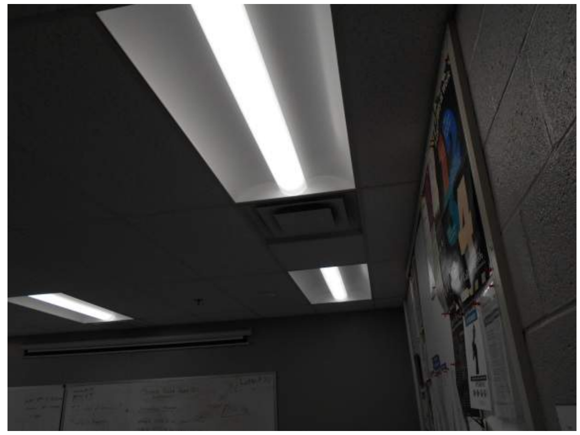
Diesel Generator

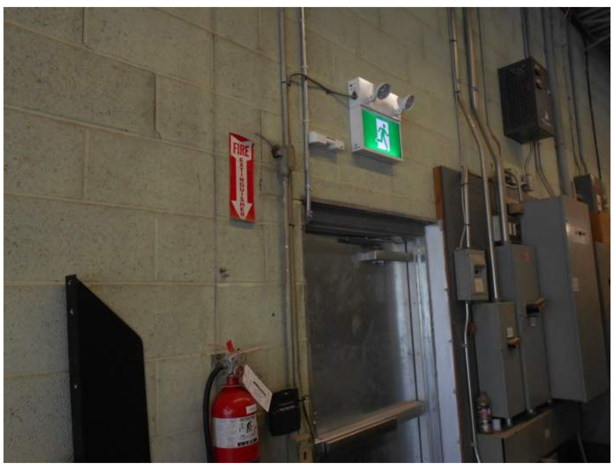
Main Distribution Panel and Transfer Switch

Garage Panel

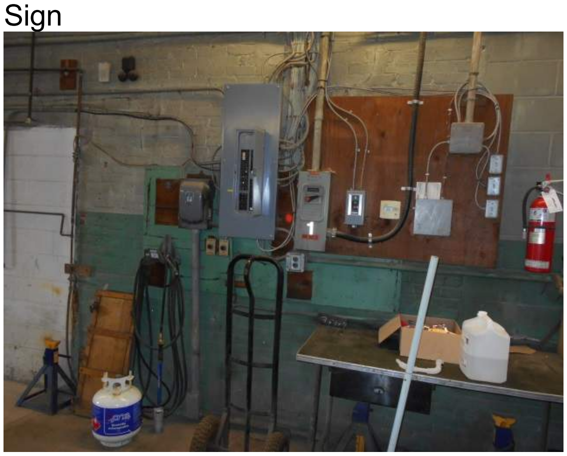
Ceiling Hung Light Fixtures


Ceiling Hung Light Fixtures.


2’x4’ Recessed LED Light Fixture


Emergency Battery with two Heads and Exit Sign


Exterior Light Fixture


Disconnect Switch


BAS / Security System control panels

G Building Sitework Systems


Deterioration in asphalt at loading bay


Deterioration in asphalt at loading bay


Deterioration in asphalt area north of building


Deterioration in asphalt area north of building


Deterioration in concrete curb


Deterioration in concrete curb

Area of deterioration on concrete walkway

Concrete apron at entrance to garage area.

Chain link fencing

Overgrown chain link fencing

G30 SITE CIVIL/MECHANICAL UTILITIES


Storm Catch basin


Storm Catch basin

APPENDIX B - COSTING

2019 CURRENT YEAR | 50 study length in years | 0.06 INTEREST RATE | 0.02 Inflation RATE

NAME: Festival Hydro Operations Building
ADDRESS: Wellington St., Stratford, ON
JOB NO.: 19-1045

1,281,000 62,133.89 1,150,847

element count 58

2,763,500

Festival Hydro Operations Building

CURRENT REPLACEMENT COSTS

October 23, 2019

TIME LINE OF EXPENDITURES (in thousands of dollars)

Uniformat Description	Element Description	Cost * (current $)	Future Repair / Replace Cycles (YR's)	Present Age (YR's)	Remaining Life (YR's)	First Year of Cycle (date)	Equivalent Annual Cost (current $'s)	Required Current Reserve Fund Balance (current $'s)	2019 (0)	2020 (1)	2021 (2)	2022 (3)	2023 (4)	2024 (5)	2025 (6)	2026 (7)	2027 (8)	2028 (9)	2029 (10)	2030 (11)	2031 (12)	2032 (13)	2033 (14)	2034 (15)	2035 (16)	2036 (17)	2037 (18)	2038 (19)	2039 (20)	2040 (21)	2041 (22)	2042 (23)	2043 (24)
SUBSTRUCTURE																																	
A1010	Standard Foundations (1920 Bldg.) (Parging)	3,000	120	90	30	2020	25.00	2,250.00		3								3								3							
A1010	Standard Foundations (1950 Bldg.)(minor repairs)	2,000	100	63	37	2022	20.00	1,260.00				2								2							2						
A4010	Standard Slabs-on-Grade (1920 Bldg.)	3,000	100	90	10	2020	30.00	2,700.00		3									3	3													
A4010	Standard Slabs-on-Grade (1950 Bldg.)	3,000	100	93	7	2020	30.00	2,790.00		3						3				3													
SHELL																																	
B1020	Roof Construction (1920 Bldg.)	2,000	100	63	37	2019	20.00	1,260.00	2																				2				
B1020	Roof Construction (1950 Bldg.)	3,000	100	63	37	2025	30.00	1,890.00		3			3		3															3			
B1030	Structural Support (1920 Bldg.)	5,000	100	63	37	2021	50.00	3,150.00			5										5										5		
B1030	Structural Support (1950 Bldg.)	5,000	100	63	37	2021	50.00	3,150.00			5																				5		
B2011	Exterior Walls	5,000	91	90	1	2020	54.95	4,945.05		5																							
B2011.1	Exterior Wall Sealant - Doors and Windows	5,000	3	1	2	2021	1,666.67	1,666.67			5			5			5			5			5			5			5			5	
B2021	Exterior Windows (minor repairs)	2,000	2	1	1	2020	1,000.00	1,000.00		2		2		2		2		2		2		2		2		2		2		2		2	
B2030	Exterior Doors and Entrances (biannual maintenance)	1,000	3	1	2	2021	333.33	333.33			1			1			1			1			1			1			1			1	
B2030	Overhead (biannual maintenance)	1,000	3	1	2	2021	333.33	333.33			1			1			1			1			1			1			1			1	
B3010	Roofing - 1920 Bldg / Shingled Roof	10,000	20	20	0	2019	500.00	10,000.00	10																				10				
B3010	Roofing - 1950 Bldg / Flat Roof - Install access ladder/stairs	25,000	20	19	1	2020	1,250.00	23,750.00		25																				25			
B3010	Roofing - 1950 Bldg / Flat Roof - Garage/Loading Dock Area	200,000	35	31	4	2023	5,714.29	177,142.86					200																				
B3015	Roofing - 1950 Bldg / Flat Roof - Administration Area	50,000	37	31	6	2025	1,351.35	41,891.89							50																		
INTERIORS																																	
C1030	Interior Doors				0																												
C3012	Wall Finishes (Paint / Administrative Area)		27	20	7																												
C3012	Wall Finishes (Paint / Garage Area - 1920 Bldg.)	40,000	30	28	2	2021	1,333.33	37,333.33			40																						
C3012	Wall Finishes (Paint / Garage Area - 1950 Bldg.)	60,000	35	31	4	2023	1,714.29	53,142.86					60																				
C3024	Flooring (Vinyl / Administrative area)		27	20	7																												
C3024	Flooring (Terrazo - washroom/changeroom)		64	20	44																												
C3025	Flooring - Exposed concrete - Garage areas																																
C3025	Ceiling Finishes - Suspected Acoustic Panels		75	63	12																												
C3026	Ceiling Finishes - Ceiling Board (1920 Bldg.)	10,000	30	28	2	2021	333.33	9,333.33			10																						
C3027	Ceiling Finishes - Exposed str. steel / metal deck (1950 Bldg.)	20,000	35	31	4	2023	571.43	17,714.29					20																				
SERVICES																																	
D2010	Domestic Water Distribution (flush buried sanitary/storm)	5,000	63	62	1	2020	79.37	4,920.63		5																							
D2010.6	Plumbing Fixtures	10,000	63	61	2	2021	158.73	9,682.54			10																						
D2010.20	Hot Water Equipment	5,000	15	5	10	2029	333.33	1,666.67											5														
D3012	Gas Supply System	1,500	25	23	2	2021	60.00	1,380.00			2																						
D3020.7	Heating Systems - Unit Heaters	10,000	30	27	3	2022	333.33	9,000.00				10																					
D3020.7	Heating Systems -Unit Heaters	15,000	30	22	8	2027	500.00	11,000.00									15																
D3020.7	Heating Systems - Cabinet Heaters	15,000	30	22	8	2027	500.00	11,000.00									15																
D3031.4	Cooling Systems - (window air conditioner unit replacement)	5,000	15	14	1	2020	333.33	4,666.67		5															5								
D3041	Facility Air Distribution Systems (Administrative area)	0	63	0	63																												
D3042	Exhaust Ventilation Systems	75,000	65	63	2	2021	1,153.85	72,692.31			75																						
D3052	Rooftop Units - Administrative Area				0																												
D3052	Rooftop Units - Make Up Air Units - Truck Bay Area	80,000	20	19	1	2020	4,000.00	76,000.00		80																				80			
D3060	Heat Recovery Ventilators	500	25	24	1	2020	20.00	480.00		1																							
D3060	HVAC Instrumentation and Controls				0																												
D4030	Fire Protection Systems (sprinkers)	10,000	63	62	1	2020	158.73	9,841.27		10																							
D5020	Electrical Service and Distribution		63		63																												
D5040	Lighting	50,000	30	28	2	2021	1,666.67	46,666.67			50																						
D5080	Miscellaneous Electrical Systems (wiring/power distribution)	15,000	3	1	2	2021	5,000.00	5,000.00			15			15			15			15			15			15			15			15	
D6020	Voice Communications				0																												
D7050	Fire Detection and Alarm				0																												
BUILDING SITE WORKS																																	
G2020.1	Paving Lot Pavement	450,000	15	14	1	2020	30,000.00	420,000.00		450															450								
G2020.2	Concrete Gutters - Replacement	13,500	50	44	6	2025	270.00	11,880.00							14																		
G2020.4	Paving Lot Pavement Markings				0																												
G2030.1	Pedestrian Pavement - Concrete walkways	1,500	25	24	1	2020	60.00	1,440.00		2																							
G2060.2	Fence and Gates (Fencing)	32,000	63	62	1	2020	507.94	31,492.06		32																							
G2060.2	Fence and Gates (Gates)	10,000	40	15	25	2044	250.00	3,750.00																									
G2080	Landscaping (maintenance contract)				0																												
G2020.1	Exterior Stairs and Ramps	15,000	64	63	1	2020	234.38	14,765.63		15																							
SITE CIVIL / MECHANICAL UTILITIES																																	
G3010	Water Utilities (maintenance)	3,500	68	63	5	2024	51.47	3,242.65						4																			
G3020	Sanitary Sewage Utilites	3,500	68	63	5	2024	51.47	3,242.65						4																			
G2030	Storm Drainage Utilities		90	64	26																												
	COMPONENT SUB-TOTAL ONLY								12.0	643.0	218.5	14.0	283.0	31.0	66.5	5.0	52.0	5.0	8.0	32.0	5.0	2.0	22.0	2.0	455.0	27.0	2.0	2.0	34.0	110.0	10.0	24.0	0.0
	INTEREST (at 6.0%)								0.7	38.6	13.1	0.8	17.0	1.9	4.0	0.3	3.1	0.3	0.5	1.9	0.3	0.1	1.3	0.1	27.3	1.6	0.1	0.1	2.0	6.6	0.6	1.4	0.0
	INFLATION (at 2.0%)								0.0	12.9	8.8	0.9	23.3	3.2	8.4	0.7	8.9	1.0	1.8	7.8	1.3	0.6	7.0	0.7	169.6	10.8	0.9	0.9	16.5	56.7	5.5	13.8	0.0
	CLOSING BALANCE								**12.7**	**694.4**	**240.4**	**15.7**	**323.3**	**36.1**	**78.9**	**6.0**	**64.0**	**6.3**	**10.2**	**41.7**	**6.6**	**2.7**	**30.3**	**2.8**	**651.9**	**39.4**	**3.0**	**3.0**	**52.6**	**173.3**	**16.1**	**39.3**	**0.0**
	Present value of closing balance								**12.7**	**680.8**	**231.1**	**14.8**	**298.7**	**32.7**	**70.0**	**5.3**	**54.7**	**5.3**	**8.4**	**33.5**	**5.2**	**2.1**	**23.0**	**2.1**	**474.9**	**28.2**	**2.1**	**2.1**	**35.4**	**114.4**	**10.4**	**24.9**	**0.0**

2019 CURRENT YEAR

50 study length in years

NAME: Festival Hydro Operations Building
ADDRESS: Wellington St., Stratford, ON
JOB NO.: 19-1045
element count: 58

Festival Hydro Operations Building

CURRENT REPLACEMENT COSTS

October 23, 2019

Uniformat Description	Element Description	2044 (25)	2045 (26)	2046 (27)	2047 (28)	2048 (29)	2049 (30)	2050 (31)	2051 (32)	2052 (33)	2053 (34)	2054 (35)	2055 (36)	2056 (37)	2057 (38)	2058 (39)	2059 (40)	2060 (41)	2061 (42)	2062 (43)	2063 (44)	2064 (45)	2065 (46)	2066 (47)	2067 (48)	2068 (49)	2069 (50)
SUBSTRUCTURE																											
A1010	Standard Foundations (1920 Bldg.) (Parging)	3								3								3								3	
A1010	Standard Foundations (1950 Bldg.)(minor repairs)		2								2								2								2
A4010	Standard Slabs-on-Grade (1920 Bldg.)																										
A4010	Standard Slabs-on-Grade (1950 Bldg.)																										
SHELL																											
B1020	Roof Construction (1920 Bldg.)																2										
B1020	Roof Construction (1950 Bldg.)															3		3		3							
B1030	Structural Support (1920 Bldg.)								5										5								
B1030	Structural Support (1950 Bldg.)																		5		6						
B2011	Exterior Walls																										
B2011.1	Exterior Wall Sealant - Doors and Windows		5			5			5			5			5			5			5			5			5
B2021	Exterior Windows (minor repairs)	2		2		2		2		2		2		2		2		2		2		2		2		2	
B2030	Exterior Doors and Entrances (biannual maintenance)		1			1			1			1			1			1			1			1			1
B2030	Overhead (biannual maintenance)		1			1			1			1			1			1			1			1			1
B3010	Roofing - 1920 Bldg / Shingled Roof																10										
B3010	Roofing - 1950 Bldg / Flat Roof - Install access ladder/stairs																	25									
B3010	Roofing - 1950 Bldg / Flat Roof - Garage/Loading Dock Area															200											
B3015	Roofing - 1950 Bldg / Flat Roof - Administration Area																			50							
INTERIORS																											
C1030	Interior Doors																										
C3012	Wall Finishes (Paint / Administrative Area)																										
C3012	Wall Finishes (Paint / Garage Area - 1920 Bldg.)								40																		
C3012	Wall Finishes (Paint / Garage Area - 1950 Bldg.)															60											
C3024	Flooring (Vinyl / Administrative area)																										
C3024	Flooring (Terrazo - washroom/changeroom)																										
C3025	Flooring - Exposed concrete - Garage areas																										
C3025	Ceiling Finishes - Suspected Acoustic Panels																										
C3026	Ceiling Finishes - Ceiling Board (1920 Bldg.)								10																		
C3027	Ceiling Finishes - Exposed str. steel / metal deck (1950 Bldg.															20											
SERVICES																											
D2010	Domestic Water Distribution (flush buried sanitary/storm)																										
D2010.6	Plumbing Fixtures																										
D2010.20	Hot Water Equipment	5															5										
D3012	Gas Supply System			2																							
D3020.7	Heating Systems - Unit Heaters									10																	
D3020.7	Heating Systems -Unit Heaters														15												
D3020.7	Heating Systems - Cabinet Heaters														15												
D3031.4	Cooling Systems - (window air conditioner unit replacement)							5															5				
D3041	Facility Air Distribution Systems (Administrative area)																										
D3042	Exhaust Ventilation Systems																										
D3052	Rooftop Units - Administrative Area																										
D3052	Rooftop Units - Make Up Air Units - Truck Bay Area																	80									
D3060	Heat Recovery Ventilators		1																								
D3060	HVAC Instrumentation and Controls																										
D4030	Fire Protection Systems (sprinkers)																										
D5020	Electrical Service and Distribution																										
D5040	Lighting								50																		
D5080	Miscellaneous Electrical Systems (wiring/power distribution)		15			15			15			15			15			15			15			15			15
D6020	Voice Communications																										
D7050	Fire Detection and Alarm																										
BUILDING SITE WORKS																											
G2020.1	Paving Lot Pavement							450															450				
G2020.2	Concrete Gutters - Replacement																										
G2020.4	Paving Lot Pavement Markings																										
G2030.1	Pedestrian Pavement - Concrete walkways		2																								
G2060.2	Fence and Gates (Fencing)																										
G2060.2	Fence and Gates (Gates)	10																									
G2080	Landscaping (maintenance contract)																										
G2020.1	Exterior Stairs and Ramps																										
SITE CIVIL / MECHANICAL UTILITIES																											
G3010	Water Utilities (maintenance)																										
G3020	Sanitary Sewage Utilites																										
G2030	Storm Drainage Utilities																										
		20.0	26.0	3.5	0.0	24.0	0.0	457.0	127.0	15.0	2.0	24.0	0.0	2.0	52.0	285.0	17.0	135.0	12.0	55.0	28.0	2.0	455.0	24.0	0.0	5.0	24.0
		1.2	1.6	0.2	0.0	1.4	0.0	27.4	7.6	0.9	0.1	1.4	0.0	0.1	3.1	17.1	1.0	8.1	0.7	3.3	1.7	0.1	27.3	1.4	0.0	0.3	1.4
		12.8	17.5	2.5	0.0	18.6	0.0	387.3	112.3	13.8	1.9	24.0	0.0	2.2	58.4	332.0	20.5	169.0	15.6	73.9	38.9	2.9	676.4	36.9	0.0	8.2	40.6
		34.0	**45.1**	**6.2**	**0.0**	**44.1**	**0.0**	**871.8**	**247.0**	**29.7**	**4.0**	**49.4**	**0.0**	**4.3**	**113.5**	**634.1**	**38.6**	**312.1**	**28.3**	**132.2**	**68.6**	**5.0**	**1,158.7**	**62.3**	**0.0**	**13.5**	**66.0**
		20.7	**26.9**	**3.6**	**0.0**	**24.8**	**0.0**	**471.8**	**131.0**	**15.5**	**2.1**	**24.7**	**0.0**	**2.1**	**53.5**	**292.9**	**17.5**	**138.6**	**12.3**	**56.4**	**28.7**	**2.0**	**466.0**	**24.6**	**0.0**	**5.1**	**24.5**

APPENDIX C – INTERIOR FINISHES

Room No.	Room ```	Walls: Poured Conc.	Walls: Conc. Block	Walls: Masonry Brick	Walls: Drywall	Flooring: Terrazzo	Flooring: Non-Slip Vinyl Tile	Flooring: Vinyl Composite Tile	Flooring: Ceramic Mosaic	Flooring: Concrete	Base: Rubber	Base: Terrazzo	Base: Conc. Block	Base: Ceramic Mosaic Tile	Ceilings: Acoustic Tile	Ceilings: Gypsum Board	Ceilings: Exposed	Doors, Hardware, Frames (A. Hollow Metal B. Wood C. Alum.): Door	Frame	Hardware	Window Coverings (A. Blinds B. Curtains)	Millwork	Remarks (Condition: 1. Good 2. Fair 3. Poor; Recommendations: A. Repair &/or Repaint B. Replace C. Repaint/Reseal)	Furniture: Item (1. Desk 2. Desk Chair 3. Filing Cabinet 4. Kitchen Table 5. Kitchen Chair 6. Lounge Chair 7. Upholstered Chair 8. Couch 9. Chair)	(10. Table 11. Bed 12.Storage Cabinet 13. Ottoman/Bench 14. Locker 15. Toilet Partition 16. Refrigerator 17. Range/Toaster 18. Microwave 20. Dryer)	Quantity	Condition (1. Good 2. Fair 3. Poor; Recommendations: A. Repair &/or Repaint B. Replace C. Repaint/Reseal)
First Floor																											
101	Water Superintendent																	B	B	C	A		Good/ N/A	(1-1,2-1,3-1,9-1,12-1)		5	Good - No Recommendation
104	Electrical Department Supervisor																	B	B	C	A		Good/ N/A	(1-3,2-3,3-1,12-1)		8	Good - No Recommendation
102	Forman Office																	B	B	C	A		Good/ N/A	1-1,2-1,3-1,9-1,12-1)		5	Good - No Recommendation
105	Elec. Room																	B	B	C	N/A		Good/ N/A	N/A	N/A	N/A	N/A
103	B.F. Washroom/ Female Change Rm.																	B	B	C	N/A		Good/ N/A	14-1,		1	Good - No Recommendation
106	Male Locker Room																	B	B	C	N/A		Fair/A	13-3,		3	Poor - A,B,C
107	Male Washroom/Shower																	B	B	C	N/A		(2/1), (A,B,C)	(9-2,14-25,15-1,		27	Poor - A,B,C
127	Corridor																	B	B	C	N/A		Good/ A	(3-1)		1	Good - No Recommendation
129	Lunch Room																	B	B	C	A		Good/ N/A	1-12,2-16		28	Good - No Recommendation
108	Kitchen																	N/A	N/A	N/A	N/A		Good/ N/A	16-1,18-2,17-1		4	Good - No Recommendation
109	Office																	B	B	C	N/A		Good/ N/A	1-2,2-2		4	Good - No Recommendation
126	Mech. Room																	B	B	C	N/A		2/A	N/A	N/A	N/A	N/A
110	Addition Garage Area																	B	B	C	N/A		3/A,C	N/A	N/A	N/A	N/A
111	Original Garage Area																	B	B	C	N/A		3/A,C	N/A	N/A	N/A	N/A

APPENDIX D - ACCESSIBILITY CHECKLIST

DETAILED EVALUATION INCLUDED IN APPENDIX D – ADMINISTRATIVE BUILDING

APPENDIX E – FLEXIBLE PAVEMENT SURVEY

Flexible Pavement Condition Evaluation Form

Project: Festival Hydro, Wellington St., Stratford, On

Location : North Asphalt Area

				Severity of Distress					Density of Distress				
				Very Slight	Slight	Moderate	Severe	Very Severe	Few	Intermittent	Frequent	Extensive	Throughout
									<10	10-20	20-50	50-80	80-100
Pavement				1	2	3	4	5	1	2	3	4	5
Surface Defects		Ravelling & C. Agg. Loss	1				X						X
		Flushing	2										
Surface Deformation		Rippling and Shoving	3										
		Wheel Track Rutting	4		X					X			
		Distortion	5		X					X			
Cracking	Longitudinal Wheel Track	Single and Multiple	6			X				X			
		Alligator	7			X					X		
	Centre Line	Single and Multiple	8										
		Alligator	9										
	Pavement Edge	Single and Multiple	10										
		Alligator	11										
	Transverse	Half, Full and Multiple	12										
		Alligator	13										
	Longitudinal Meander and Midlane		14					X					X
	Random		15					X					X

Festival Hydro Administration Building
Building Condition Survey

Prepared for:

Ms. Patty Mann
Festival Hydro Inc.
187 Erie Street
Stratford, ON N5A 6T5

Prepared by:

NA Engineering Associates Inc.
107 Erie St., Suite no. 2
Stratford, Ontario – N5A 2M5

Date: September 28, 2020

Project Number: 19-1044

NA ENGINEERING ASSOCIATES INC
Consulting Engineers
107 ERIE STREET, SUITE 2
STRATFORD ONTARIO
N5A 2M5
PHONE 519 273 3205
FAX 519 273 7133
www.naeng.com

TABLE OF CONTENTS

EXECUTIVE SUMMARY 5

1. ACRONYMS LISTING 8

2. INTRODUCTION 9

2.1 TERMS OF REFERENCE 9
2.2 DESCRIPTION OF BUILDING 9
2.3 SCOPE OF WORK 10

3. METHODOLOGY/ PREAMBLE 12

3.1 AVAILABLE DRAWINGS/DOCUMENTATION 15
3.2 COSTING 15

4. COMPONENT ASSESSMENT 16

A SUBSTRUCTURE SYSTEM 16

A10 FOUNDATIONS 16
A40 SLABS ON GRADE 17

B SHELL SYSTEMS 18

B10 SUPERSTRUCTURE 18
B20 EXTERIOR VERTICAL ENCLOSURES 20
B30 ROOFING 24

C INTERIOR SYSTEMS 27

C10 INTERIOR CONSTRUCTION 27
C20 STAIRS 27
C30 INTERIOR FINISHES 28

BARRIER FREE BUILDING ANALYSIS: FESTIVAL HYDRO ADMIN BUILDING 33

D SERVICES SYSTEMS 34

D20 PLUMBING 34
D30 HVAC 36
D40 FIRE PROTECTION SYSTEMS 43
D50 ELECTRICAL SYSTEMS 44
D60 COMMUNICATIONS 47
D70 ELECTRICAL SAFETY AND SECURITY SYSTEM 48

G BUILDING SITEWORK SYSTEMS 49

G20 SITE IMPROVEMENTS 49
G30 SITE CIVIL/MECHANICAL UTILITIES 53

APPENDIX A – PHOTOS

APPENDIX B - COSTING

APPENDIX C – INTERIOR FINISHES

APPENDIX D – ACCESSIBILITY CHECKLIST

APPENDIX E – FLEXIBLE PAVEMENT CONDITION EVALUATION FORM

ABSTRACT OF REVISIONS

REV. NO.	DATE	REVISION
A	2019OCT01	ISSUED FOR CLIENT REVIEW
0	2020SEP28	FINAL ISSUE

The following individuals were responsible for the preparation and review of this report:

Brad Miller – Project Manager
Mary Ferenc, P.Eng., - Structure
Katie Rooyakkers, P.Eng., - Civil
Haritos Aroutzidis – Interior Finishes
Jim Culliton, BA, Sc – Building Exteriors, Roofing
Amir Angardi, P.Eng. – Electrical Systems
Hasan Oktem, Ph.D., P.Eng. – Mechanical Systems

Approved by:

Mary Ferenc, P.Eng.

Jim Culliton, BA.Sc.

Amir Angardi., P.Eng

Hasan Oktem, Ph.D., P.Eng.

Issued by:

Brad Miller

Date: September 28, 2020

EXECUTIVE SUMMARY

Festival Hydro provides power to customers in Stratford as well as a number of surrounding areas. Their facilities include an Administrative building located at 187 Erie St. as well as a works across Wellington St. NA Engineering Associates Inc. (NAE) was retained by Festival Hydro to complete a Building Condition Assessment of both the Administrative Building as well as the Operations Building.

NAE were provided with the drawings for the original section of the building which indicate that it was constructed in 1959. An addition was built onto the original building in 1992. As part of the construction of the addition, considerable modifications were made to the mechanical systems in the 1959 building. The size of the building is 11,000 sq. ft. The outside of the building is well landscaped with parking areas located on the north side of the building. A drive lane runs from Erie St. through to Wellington St. A turning lane/drop off from Wellington St. provides access to the employee entrance on the upper level.

The buildings foundations could not be observed but are presumed to consist of poured, cast-in-place concrete footings and slab on grade. There was no evidence at the time of our visit of any concerns with either the buildings foundation and/or slabs on grade.

The drawings provided by Festival Hydro show the exterior walls for the 1959 portion of the building are comprised of a yellow face brick, cavity, back up block, a 2" thick layer of thermal insulation installed on the inside face of the block, then a plaster finish. The 1992 addition has been constructed to match the original portion of the building with a yellow, brick, masonry cavity wall constructed on a 6" steel stud back up wall. For this area of the building, the thermal insulation would be provided in the stud space. We did not do any cut tests or test openings to confirm the composition of the wall, or the condition of any of the wall components.

The masonry walls were all noted to be in very good condition. It is our opinion that the large perimeter overhang works very well in terms of keeping at least some of the elements off of the brick walls.

The roof is a 2-ply modified bituminous system installed in 2006 by Flynn. A number of repairs appear to have been completed to the membrane after the study completed by Stantec in 2013. Overall, the roof appears to be performing in a satisfactory manner. The one large issue is a large amount of ponding. On the canopy, the ponded water freezes. It would be a considerable improvement to replace the roof with one that incorporates tapered insulation and eliminates the ponding.

The windows and doors appear to be original, part of the 1959 building or installed as part of the 1992 addition. At present, the windows and doors appear to be performing in a satisfactory manner. Where required, e.g. failed sealed units, repairs have been made. That said, repairs appear to be occurring at an increasing rate and the glazing tape in the window frames appears to be failing. Consideration should be given to replacing the glazing in at least the 1959 section of the building.

Interior finishes include carpeting and vinyl tiles in employee areas and terrazzo in the front circular area. Ceilings are generally finished with acoustic tiles and painted gypsum board or plaster. Walls are generally painted or covered with wall paper. Furniture/millwork was noted to be in satisfactory condition. Overall, the interior finishes and furniture were viewed as adequate, albeit somewhat dated, but certainly functional.

There is one set of interior stairs with terrazzo tread and risers and stylish polished metal railings. The stairs were noted to be in very good condition.

Heating, cooling, and fresh air is provided by 5 different air handling units. Units vary in age and condition, but all were operating well at the time of our site visit. Units on the upper roof supply heating and cooling to the second floor and general offices. The middle and rear areas of the main level are heated and cooled with the interior units installed in the mechanical room. The building has a building automation system for the rooftop units, while a programmable thermostat controls the interior units.

The server room is cooled by 3 dx-split units mounted on the exterior wall and roof. The original building heating system included electric baseboard heaters and in floor electric, radiant heating. Multiple control system can work against each other. The current heating and cooling system is quite ‘cumbersome’ for a building of this size and use and presents significant opportunities for improvement; better control, lower maintenance cost, easier operation and energy savings.

The washroom fixtures are standard tank style toilets, urinals, and centre set faucets. There are no hands-free fixtures. Some of the toilets are new, low-flow fixtures. There is no provision for any type of accessible washroom. Electric water heaters supply hot water.

Electricity is fed below grade to the main disconnect in the rear electrical room. Power is supplied to the building at 600Volts but stepped down to 120/208V by a secondary transformer located in the electrical room. The secondary distribution panel and disconnect is rated for 600 amps at 120/208V. Low voltage power is used for lighting, power for the various mechanical equipment and receptacles.

Lighting is provided by compact fluorescent fixtures and T-8 linear fixtures. Overall, lighting levels appeared to be adequate. We were not made aware of any complaints with the buildings lighting.

A security system is also provided that is comprised of cameras, motion detectors, and door contacts. Access into and out of the building, as well as into certain areas of the building are tightly controlled by a programmable card access system. Backup power to the building security and lighting systems is provided by a generator located at the Operations Building on Wellington St.

A fire alarm system is provided in the building addition and vault area. The system includes smoke and heat detectors. Fire extinguishers are located though out the building

The site has a large asphalt parking area located at the front (north) of the building. This provides staff as well as visitors parking. A drive lane runs through the property. A concrete paved surface is provided for staff and customer access to and from the building.

Concrete stairs are located along the north, south, and east elevation.

The site is generally well landscaped. At the time of our visit, some maintenance was required for the garden areas. There is a rail line adjacent to the property on the south side. This is quite overgrown and poorly kept by the owners of this property.

Overall, given the age of the building it was noted to still be in fair to good condition. Construction of the 1992 addition, included a substantial renovation to the building. Any required repairs and upgrades to virtually all of the different building systems and components have been completed over the years.

There are some notable shortcomings with the existing building more related to functionality than the condition of systems and/or components. Accessibility does not meet current standards for a building of this nature and use. Consideration should be given to upgrading the washrooms as well as installing an elevator. Security for workers in the front, circular area could be improved. Mechanically and electrically systems have been modified to meet requirements on an ongoing basis. But in both cases current systems are old, outdated, and require significant ongoing maintenance.

1. ACRONYMS LISTING

Acronym	Meaning
A	Amperage
AHU	Air Handling Unit
ASB	Auxiliary Security Building
ASHREA	American Society of Heating, Refrigerating and Air-Conditioning
BOMA	Building Owner's & Management Association
Cat	Category
CO	Carbon Monoxide
DS	Disconnect Switch
EMT	Electrical Metal Tubing
EXP	Explosive
FA	Fire Alarm
FFH	Fan Force Heater
HID	Metal Halide
HCFC	Hydrochlorofluorocarbons
IR	Infra-Red
kV	Kilovolt
kVA	Kilovolt-Ampere
LAN	Local Area Network
LED	Light Emitting Diode
NAE	NA Engineering Associates Inc.
NFPA	National Fire Protection Association
Non-EXP	Non-Explosive
NOx	Nitrogen Oxide
OBC	Ontario Building Code
PA	Public Address
Ph	Phase
RTU	Roof Top Unit
SB10	Supplementary Standards
SWBD	Switch Board
TV	Television
UPS	Uninterruptible Power Supply
V	Volt
W	Watts

2. INTRODUCTION

2.1 TERMS OF REFERENCE

NA Engineering Associates Inc. was retained by Ms. Patty Mann, Senior Manager of Project and Accommodations at Festival Hydro to complete a visual review of the Festival Hydro Administration Building, located at 187 Erie St., Stratford, Ontario.

2.2 DESCRIPTION OF BUILDING

The original portion of the building was constructed in 1959. An addition was constructed to the building in 1992 The facility includes a customer reception counter/customer service area, offices, vault, service rooms and washrooms.

Item	Description
Building Name	Administration Building
Building Use	Office Group D
Year Built	1959 Original Area / 1992 Addition
Number of Storey	2 Storey
Gross Building	11,000 ft^2

The Festival Hydro Administration Building was constructed as headquarters for this local utility. We are confident that when the building was constructed, it took advantage of technology, systems, and products that were typical for a building of this type. The circular customer service area was originally heated with electric radiant heating. When originally constructed, there were no computers, no legislation regarding accessibility, and significantly lower standards in terms of energy performance. The original section of the building is now 60 years old. An addition was constructed in 1992 to provide some additional space.

At the time of the 1992 addition, significant renovations were completed to the mechanical system installed in the original section of the building.

2.3 SCOPE OF WORK

The scope of this assessment is to complete a building condition assessment (BCA) of the major building systems and components. Building systems and components reviewed as part of this assessment included;

- Civil / municipal building and site features
- Building structural components
- Building envelope systems which included the roofs, windows, doors, and exterior walls
- Mechanical systems and components; heating, ventilation, and plumbing
- Electrical systems and components, and
- Interior finishes / Accessibility

It should be emphasized that the study was a visual survey only. No destructive testing was undertaken. Where conditions were noted that suggested a need for some destructive testing these would be identified to the client.

The BCA undertaken by NAE is completed in accordance with the ASTM Standard Guide for Property Condition Assessments: Baseline Property Condition Assessment Process (E 2018-08) and consisted of the following:

- Obtain relevant documentation i.e. building drawings, previous reports, etc., for our review prior to visiting the site,
- Interviews with Festival Hydro staff familiar with the building,
- To assist with the site walk through, we were assisted by KRR Refrigeration, a contractor familiar with the mechanical equipment and Braeme Electric, a contractor familiar with the electrical equipment,
- Walk-through site assessment visit, and
- Preparation of building condition assessment report.

ASTM defines a physical deficiency as a conspicuous defect or significant deferred maintenance of a site's material systems, components, or equipment as observed during the site assessor's walkthrough site visit. Included within this definition are material systems, components, or equipment that are approaching, have reached, or have exceeded their expected useful life (EUL) or whose remaining useful life (RUL) should not be relied upon in view of actual or effective age, abuse, excessive wear and tear, exposure to the elements, lack of proper or routine maintenance, etc.

The review was based on a visual walk-through of visible and accessible components of the site and building. No destructive testing was undertaken.

A mechanical engineer along with a representative from KRR Refrigeration and an electrical engineer along with a representative from Braeme Electric undertook the review of the mechanical systems (heating, ventilation, and plumbing), and electrical systems (power distribution, exterior lighting, and fire & life safety systems, at the property. The review included discussions with the site representative and review of any available maintenance information. A visual walk-through assessment of the mechanical systems, electrical systems, and fire & life safety systems was conducted to determine the type of systems present, age, and aesthetic condition. No testing of any of the systems reviewed was undertaken, nor were the performance of any systems evaluated.

It was assumed that at the time of construction of both the original building as well as the addition constructed in 1992, the design would have met the requirements of the building code in effect at the time. A detailed code compliance with applicable Building Codes and/or Fire Codes was not part of the scope of this assessment.

Replacement and repair costs are based on unit rates published in applicable industry standards, combined with local experience gained by NAE. The quantities associated with each item have been estimated and do not represent exact measurements or quantities.

3. METHODOLOGY/ PREAMBLE

Wednesday, September 4th, 2019, Brad Miller (Project Manager/Project Coordination and Administration), Mary Ferenc (structural), Katie Rooyakkers (civil/municipal), Jim Culliton (Building Envelope), Hasan Oktem (Mechanical Systems and Components), Amir Angardi (Electrical Systems and Components) and Haritos Aroutzidis (Interior Finishes and Furniture / Accessibility) all of NA Engineering Associates Inc. completed a visual review of the Festival Hydro Administration Building. We were assisted in completing the evaluation of the mechanical equipment by Garnet Mueller, KRR Refrigeration. We were assisted in completing the evaluation of the electrical equipment by Rory McCuaig, Braeme Electric. Both contractors work on the building on an ongoing basis and are quite familiar with the systems. Prior to undertaking the survey, we met with Patty Mann and Chris de Silva to explain our process. They indicated that we were able to access the majority of areas of the building site. Access to locked areas of the building was provided by Festival Hydro staff.

On the day of the review the weather was overcast and approximately 15 degrees Celsius. Components that were readily visible were reviewed during our site visit.

No destructive or intrusive testing was conducted.

The following assessment has divided the buildings major components or systems using the uniformat method. Uniformat is a standard for classifying building specifications, cost estimating, and cost analysis in the U.S. and Canada. The elements are major components common to most buildings. The system can be used to provide consistency in the economic evaluation of building projects.

Component Rating	
Rating for Building Systems and Components	**Definition**
Very Good	Asset is physically sound and is performing its function as originally intended. Required maintenance costs are well within standards and norms. Typically, asset is new or recently rehabilitated.
Good	Asset is physically sound and is performing its function as originally intended. Required maintenance costs are within acceptable standards and norms. Typically, asset has been used for some time but is within mid-stage of its expected life.
Fair	Asset is showing signs of deterioration and is performing at a lower level than originally intended. Some components of the asset are becoming physically deficient. Required maintenance costs exceed acceptable standards and norms are increasing. Typically, asset has been used for a long time and is within the later stage of its expected life.
Poor	Asset is showing significant signs of deterioration and is performing to a much lower level than originally intended. A major portion of the asset is physically deficient. Required maintenance costs significantly exceed acceptable standards and norms. Typically, asset is approaching the end of its expected life.
Expired	Asset is physically unsound and/or not performing as originally intended. Asset has higher probability of failure or failure is imminent. Maintenance costs are unacceptable, and rehabilitation is not cost effective. Replacement/major refurbishment is required.
Maintenance	Cost associated with components condition that are required to ensure the component continues to perform as intended and meets it service life expectancy.

Building systems useful life is based on Building Owners and Managers Association (BOMA) publication of “Preventive Maintenance; Best Practices to Maintain Efficient and Sustainable Buildings”. The following list of systems and average useful life years is based on regular preventive maintenance properly performed at prescribed frequencies. Many factors can affect the average useful life and like any average, individual systems and or components will have lifetimes far from averages. Lifetimes can often be extended significantly through robust maintenance programs that go beyond the norm.

Climate conditions and challenging environments will often shorten life expectancies. Whereas selecting equipment with heavy duty features will lengthen the components life expectancies.

Due to hardware and software revisions, control equipment for HVAC, fire alarms and security may become obsolete as vendors may no longer support them. As such the life expectancy of these components will be shortened.

The following table is based on BOMA and general industry standards.

Building Elements	Typical Useful Life
A-B Substructure & Shell	
A 1010 Standard Foundations	Life of Building
A 4010 Slab on Grade	Life of Building
B1010 Floor Construction	Life of Building
B1020 Roof Construction	Life of Building
B1030 Structure Support	Life of Building
B1080 Stairs	75
B2010 Exterior Walls	35-50
B2020 Exterior Windows	30
B2050 Exterior Doors	40
B3010 Roof Coverings	20-30
B3010 Metal Roofing	30-50
C Interiors	
C1010 Partitions	75
C1030 Interior Doors	40
C2010 Wall Finishes	5-15
C2020 Stair Finishes	35-50
C2030 Floor Finishes	12-15
C2050 Ceiling Finishes	13-25
D Services	
D1010 Elevators & Lifts	10-50
D2010 Domestic Water Distribution	20-30
D2020 Sanitary Waste	30
D2040 Rain Water Drainage	35
D2050 General Service Compressed Air	20
D3020 Heat Generating Systems	25
D3030 Cooling Generating Systems	20
Building Elements	Typical Useful Life
D3040 Distribution Systems	30
D3060 Ventilation	25
D4010 Fire Suppression	25-40
D4020 Standpipes	25-40
D5020 Electrical Service & Distribution	20-40
D5040 Lighting & Branch Wiring	20
D5080 Miscellaneous Electrical Systems	25
D6010 Data Communications	15
D6020 Voice Communications	15
D6030 Audio-Video Communications	15
D7050 Detection and Alarm	10-15
E – Equipment and Furnishing	

E2010 Fixed Millwork	15-20
G – Building Site	
G2030 Pedestrian Paving	30

3.1 AVAILABLE DRAWINGS/DOCUMENTATION

The following drawings were used as reference to conduct our visual observations;

- Original 1959 set of construction drawings
- Drawings for 1992 addition

Several reports completed previously on the building including a condition report undertaken in 2013 by Stantec.

3.2 COSTING

The repair/replacement costs included in each section are Class "5" budget estimates only with variances of minus 50% to plus 100%. Class "5" is defined under the American Association of Cost Engineers, as the concept screening stage of a project, where judgement is used based on past experiences of similar work. These are quoted in 2017 dollars. Actual costs may vary dependent on the scope of work performed. The estimated costs may vary depending on who undertakes the work and the quantity of work requested through a tender process. Cost may also be less if maintenance complete some of the work noted in the report. Costs exclude engineering, furniture removal and replacement, permits costs (where applicable) and overhead profit. Costs provided are strictly replacement cost of components and do not include associated cost related to all possible replacement scenarios. Tactical planning window of replacements are 25 years. Typical maintenance costs for elements that are considered as preventative and or isolated component replacement costs has been included as a separate line items referenced to Appendix B "Costing".

4. COMPONENT ASSESSMENT

A SUBSTRUCTURE SYSTEM

A10 FOUNDATIONS

Item	Description
A1010 Standard Foundations	A1010 Standard Foundation – 1959 Original
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The buildings walls are supported by cast in place reinforced concrete foundation walls and footings. Original structural drawings from 1958, were provided for review. These drawings indicate thickness of walls and footings. Some of the footings have what appear to be piers/caissons supporting the footings, but the drawings do not indicate size and depth. This occurs in the round section of the building and part of the building toward the east.

In 1992 a small two storey addition was constructed on the north side at the east end of the building. A structural drawing was provided for review. The foundations were cast-in-place concrete walls and footings.

Component Condition:

The current condition of the foundations could not be directly observed. On the interior the walls were finished with plaster or drywall, and only small areas could be seen from the exterior. From what could be observed, there is no indication of settlement on the exterior, or cracks in the interior finishes. Small cracks around the perimeter appear to be shrinkage cracks in the concrete parging. The foundation wall and footings are considered to be functioning as intended.

Foundations in the addition could not be directly observed. On the interior, walls were finished. Only some sections on the exterior could be seen and this was at a stair on the north side where there is a change in grade. The foundations in these locations appeared in good condition.

Component Recommendation:

Given that the building has been in use since constructed in 1958 with no reported issues, it is our opinion that the foundations are in good condition. The foundations for the addition also had no reported issues. The expected useful life of concrete foundations typically is 100 years, as such major repairs of the foundations are not anticipated within the life of the building

A40 SLABS ON GRADE

Item	Description
A4010 Standard Slabs-on-Grade	A4010 Standard Slabs-on-Grade – 1959 Original
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Limited structural drawings from 1958 were provided. From these, it was determined that the slabs-on-grade were 6" thick with welded wire mesh reinforcing. The drawings also show insulation below all slabs.

The slab on grade in the addition is 4" with no insulation below noted on the drawings.

Component Condition:

The current condition of the slab on grade, both in the original building area and in the addition could not be directly observed since the slabs were covered by finishes. No indications of settlement, cracks in the concrete slab on grade in the main areas of the building were visible and were not noted or reported. The slab on grade is considered to be functioning as intended.

Component Recommendation:

The expected useful life of a concrete slab on grade is typically the life of the building, however for reporting purposes we state it as 100 years. Major repair of the slab is not anticipated within the life of the building.

B SHELL SYSTEMS

B10 SUPERSTRUCTURE

Item	Description
B1020 Roof Construction	B1020 Roof Construction – 1959 Original
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Original structural drawings from 1958 were provided for review. The building consists of two floors starting at the east end and extending partially over the round section. The remaining area of the round section is a single storey. The higher roof consists of metal roof deck over steel joists. The joists are supported on the exterior walls. There is a canopy around the second -floor building perimeter which is constructed of metal deck and steel “C” channels. This canopy is slightly lower than the roof. The “C” channels extend through the exterior wall into the interior and appear to be connected to the bottom chord of the roof joists.

The single storey roof system consists of metal roof deck over steel beams and steel “C” channels around the perimeter forming the canopy. The beams and channels are supported by steel beams and columns.

The two storey addition constructed in 1992, has metal roof deck over open web steel joists. There are “C” channel outriggers framing a canopy to match the existing building. Steel beams and columns support the open web steel joists and “C” channel outriggers.

Component Condition:

The current condition of the roof construction could only be directly observed from below in limited locations; however, no reported issues were identified to NAE. Therefore, roof construction is considered to be functioning as intended

Component Recommendation:

The expected useful life of a structural steel support system is typically the life of the building, however for reporting purposes we state it as 100 years. Major repair of the roof structure and support elements is not anticipated within the life of the building.

Item	Description
B1030 Second Floor Construction	B1030 Second Floor Construction – 1959 Ori
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Original structural drawings from 1958 were provided for review. The second storey framing starts at the east end and extends partially over the round section at the west. The floor framing consists of metal floor deck over steel beams spaced at approximately 24" o.c. The metal floor deck has concrete poured over it for a total thickness of 4". The floor beams are supported on the exterior walls in the straight section and on steel beams and columns at the round section.

The second floor of the 1992 addition consists of metal floor deck over open web steel joists. The metal floor deck has concrete for a total thickness of 4". The open web steel joists are supported by steel channels and columns.

Component Condition:

The current condition of the second-floor construction, in the original section could not be reviewed as the underside of the floor framing is covered with drywall. No reported issues were identified to NAE; therefore, the floor construction is considered to be functioning as intended.

The second-floor construction of the addition was noted to be as per the drawings and appeared to be in good condition.

Component Recommendation:

The expected useful life of a structural steel support system is typically the life of the building, however for reporting purposes we state it as 100 years. Major repair of the floor structure and support elements is not anticipated within the life of the building.

Item	Description
B1030 Structure Support	B1030 Structure Support – 1958 Original
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The support structure for the administration building consists of 8" load bearing concrete block walls, and steel columns. Original structural drawings were provided for review.

Component Condition:

The current condition of the structural supports could not be observed because of finishes on all walls and around all columns, both in the original building and in the addition. There were no indications of displacement, such as cracked glass or cracks in plaster noted during the review. One area on the exterior south wall had step cracking of the exterior brick but this crack could not be noted on the interior, nor could any sign of a cracked foundation be observed. Therefore, the structure supports are considered to be functioning as intended.

Component Recommendation:

The expected useful life of concrete block and steel columns is typically is the life of the building, however for reporting purposes we state it as 100 years. Major repairs of the structural steel columns is not anticipated within the life of the building. Also, the concrete block back up wall should not require repairs within this time.

B20 EXTERIOR VERTICAL ENCLOSURES

Item	Description
B2011 Exterior Wall Construction	Exterior Walls – Brick Veneer
Component Condition	Good
Replacement Year / Replacement Cost	2020 / $5,000 (repair damaged areas, optional)

Component Description:

The exterior wall cladding on both the original section of the building (1959) as well as the addition constructed in 1992 is a masonry, brick cavity wall. The 1959 drawings show that the exterior walls are constructed with face brick, airspace, 8" back up block and 2" thick insulation and strapping. Weep holes above the lintels and at the base of the wall indicate that it is a cavity wall. The masonry wall on the 1959 portion of the building is constructed with a header course every sixth row to tie the face brick to the back-up wall. The thermal insulation in the original portion of the building would have an R-Value of 8 – 10 (maximum).

A similar brick pattern was used on the 1992 addition. The 1992 addition is constructed with face brick installed on a 6" steel stud back up wall. The thermal insulation in the wall system on this area of the building would be R-20.

Component Condition:

The exterior walls on both the original portion of the building as well as the addition, both appeared to be in good condition. We noticed one small step crack on the south elevation and a tiny amount of brick deterioration in a couple of isolated locations. The original building was constructed with large overhangs on three of the elevations. These would provide shade/protection for the exterior walls and have contributed to their performance. Overall, the exterior brick masonry walls appear to be performing in a satisfactory manner.

With regards to the thermal insulation in the walls, current buildings would be constructed with R-20+ thermal insulation with the exact value being determined by the building's use / heat loss & heat gain calculations.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement is anticipated in the next five years.

Some minor repairs could be completed, but even these would be done simply for aesthetic reasons.

Item	Descript
B2011.1 Exterior Wall Sealant	B2011.1 Exterior Wall Sealant
Component Condition	Poor / Fair / Good
Replacement Year / Replacement Cost	2020 - $5,000 (budget for every 3 years)

Component Description:

The exterior doors and windows are all sealed to the brick masonry wall with caulking. There are also a number of expansion joints/control joints in the brick that have been sealed with caulking.

Component Condition:

When the building was originally constructed, all of the windows, doors, and masonry joints were sealed with caulking. Over time, as problems have arisen at different locations, the caulking was repaired. Given the number of different colours, types, etc., of caulking noted, we suspect that every 2 – 4 years, the worst areas are repaired.

At the time of this review, there were areas where the caulking was in poor condition and it should be repaired within the next 1 – 2 years. Areas that have been repaired within the last 3 – 5 years were noted to be in fair condition and should perform for another 4 – 6 years. There were a couple areas that looked like they have been re-caulked within the last 1 – 2 years. These areas were in good condition and should perform as intended for another 7 – 9 years.

Component Recommendation:

We have made a recommendation to replace the existing windows/glazing within the next 1 – 3 years. This is a costly project. If the glazing / interior exterior doors currently installed in the building are not replaced and a decision is made to simply maintain the existing building envelope, then funds should be set aside every 3 years to repair damaged / leaking areas of caulking.

If all windows and doors are replaced, part of that project would include installing all new sealant.

Item	Description
B2021 Windows	Commercial glazing
Component Condition	Poor - Fair (1959) / Good (1992)
Replacement Year / Replacement Cost	2020 / $200,000

Component Description:

The building windows (both the original 1959 and 1992 addition) consist of double-glazed fixed windows in metal frames. A large section of commercial glazing is installed in the front/round section of the building. All of the windows are original to construction of the building and the addition. Interestingly, there are no operating windows in either the original section of the building or the addition. The windows are all fabricated with insulated, sealed units set in a metal frame. Looking at the date stamps in the sealed units, there are quite a few of them that have been replaced over the years. We noticed units with date stamps, 1998, 2016 and 2018. There are quite a few with 2016/2018 date stamps which could suggest that more and more sealed units are failing. It would appear that as sealed units have failed, they have been replaced.

There is an operable window on the south elevation that provides access to the canopy roof. This is not the perfect location in terms of taking roof maintenance equipment and materials onto the roof or taking garbage and debris off of the roof.

There is a tiny amount of surface corrosion noted on some of the lintels. The corrosion does not appear to have extended back into the brick mortar/masonry section of the wall. The lack of corrosion can most likely be attributed to the large overhangs which protect the windows and exterior walls.

There were several areas noted where the sealing tape that the glazed units are set in is failing and weeping down onto the glazing.

Component Condition:

In spite of being 60 years old, the original windows frames / glazing appears to be in fair condition. Given the date stamps on the sealed units, they appear to be failing at a greater rate. Also, evidence of the sealed units glazing tape failing, suggests that a significant rehabilitation of the windows be considered.

The windows in the 1992 addition are only 27 years old and should perform in a satisfactory manner for several more years.

Component Recommendation:

If a decision is made to undertake a substantial renovation of the building, consideration should be given to replacing the original glazing/ windows completely. The sealed units appear to be failed at an increasing rate and the sealing tape is failing on windows where the sealed units are still fine.

Item	Description
B2030 Exterior Doors & Entrances	Painted, metal framed units, various ages
Component Condition	Good
Replacement Year / Replacement Cost	Ongoing / $1,000 (miscellaneous repairs)

Component Description:

There are 9 entrances/exits which provide entrances/exits for the building.

- Main customer entrance on the west elevation; single door equipped with power door operator. This unit appears to have been installed in 2012.
- Doors to the conference room (2) are fully glazed but do not appear to be used any longer.
- Access doors for staff and are provided on the east and west elevations of the building. The east entrance is a double aluminum framed door with a glazed section/vision panel that was installed in 1992. The staff entrance on the second floor is a single door with vision panel.
- There are two emergency exits, one on the north elevation from the lower level and one on the lower level of 1992 addition on the west elevation. Both are painted metal doors in metal door frames with vision sections
- There are two solid, painted metal doors on the upper level, south elevation providing access to the lunch room and a metering room.

Component Condition:

All of these doors were noted to be in good condition. A security upgrade has been undertaken within the last few years that has added security card access / controls to doors which provide access into and out of the building at every door. Door hardware, hinges, weather stripping, etc. all appeared to be in good condition and operating properly. The only exception to this is the doors on the conference room which no longer appear to be used and are permanently locked closed.

Component Recommendation:

These doors are in good condition and should perform as required for the next 7 – 10 years. It is always possible, that hinges, hardware, etc., fails as a result of usage, damage etc. These items should be repaired as part of the buildings ongoing maintenance program.

The existing doors/entrance exits have been modified over the years. Any significant renovation project/window & glazing replacement should consider replacing the doors.

B30 ROOFING

Item	Description
B3011 Roof Finishes	Two-ply, modified bituminous roof system
Component Condition	Fair
Replacement Year / Replacement Cost	2021 – 2026 / $240,00 - $260,000 2020 - $25,000 – improved access

Component Description:

NA Engineering Associates Inc. was retained by Festival Hydro to prepare specifications and tender documents to replace the roof on the Administrative Building in 2006, making the roof now 13 years old.

The roof was installed by Flynn and is comprised of the following components;

- Kraft asphalt vapour barrier, adhered to the metal deck
- 3” thick layer of polyisocyanurate insulation adhered to the vapour barrier
- ½” thick layer of high-density fiberboard adhered to the insulation
- Modified base sheet, modified cap sheet and modified base/cap flashing membrane.

Component Condition:

We were not advised of any roof leaks. Based on a visual review of the roof, it appears to be in satisfactory condition. We did not notice any ridges, splits, or other deterioration which could lead to leaks developing in the near future.

Access to the roof is provided by temporary, portable ladders set up at specific locations designed to permit easy tie off. It would be much safer to install a better system for getting onto the roof; door from upper level onto roof, roof hatch/permanent access ladder upper roof.

There are a number of areas where the membrane has been patched. We suspect that this was completed in 2014 after the survey done by Stantec to fix blisters. We did not see any blisters at the time of our visit, but cool, wet weather at the time of this review makes these more difficult to see.

This roof was constructed with a layer of thermal insulation, R-20, typical for current re-roofing projects.

The perimeter metal counter flashings were noted to be in good condition.

A couple of items were noted;

There is a fair amount of ponding on all of the roof areas; lower, upper, and lower canopy. This roof slab is constructed dead flat. The lower level meets the masonry wall for the second level and because of the location of the masonry wall weepers, it is difficult to add sufficient tapered insulation to eliminate ponding. The roof drains on lower level drain run down the outside of the building and dump onto the sidewalk behind the 'feature' masonry wall surrounding the circular area of the building. It is impossible to keep these types of drains from freezing up and the spill water creates a slip hazard.

This building sits in a location where there are lots of large trees. The smallest amount of leaves, debris, etc., partially blocks the drains which adds to the problem of ponded water. We would recommend that say every couple of months the drain screens be well cleaned and debris on the roof, which will make its way to the drains is cleaned up (put in bags taken off the roof).

Component Recommendation:

Clean the drains and roof regularly (every 2 – 3 months).

Do a general walkover spring and fall to check for any damage.

Modified bituminous roofs have a life expectancy of 15 – 20 years. With proper maintenance, this roof should achieve a life span of 20 years. If a decision is made to renovate the building, we suspect that there would be new equipment placed on the roof. Given the current age of the roof and issues with ponding, consideration should be given to replacing the roof.

Item	Description
B3015 Roof Eaves and Soffits	Cement board/panels/transite
Component Condition	Good – couple of cracks
Replacement Year / Replacement Cost	2020 - $2,000 (maintenance repair)

Component Description:

The lower roof extends well past the circular, glazed area on the bottom level. This area of soffit is clad with a cement board

Component Condition:

There are a couple of cracks on the underside of the soffit. The cracks appear to have been there for many years and some attempts have been made to repair them.

The cracks do not appear to be affecting the performance of the building envelope, it is more of an aesthetic issue.

Component Recommendation:

The cracking occurs in a straight line suggesting it is along the edge of a board or panel. The easiest and least costly repair would be to use a high quality, exterior grade sealant and caulk the cracks

C INTERIOR SYSTEMS

C10 INTERIOR CONSTRUCTION

Item	Description
C1021 Interior Doors	C1021 Interior Doors
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The interior doors consist of wood doors set in wood frames in the original building. The addition is equipped with hollow metal doors set in metal frames. All doors are finished with a paint coating.

Component Condition:

The interior doors were observed to be in good/fair condition, with only minor deterioration observed to their surface finish.

Door hardware / hinges / etc., appeared to be working properly.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the interior doors is anticipated in the next five years (2019-2023).

C20 STAIRS

Item	Description
C2010 Stair Construction	C2010 Stair Construction
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Concrete cast stairs are provided in the building to provide access to the second floor. The stairs are original to construction of the building in 1959 and the tread is finished with terrazzo. Aluminum handrails are provided on both sides of the stairway.

Component Condition:

The building stairs were observed to be in good condition. The handrails were well fastened to the building and the tread finish was in good condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the stairway is anticipated in the next five years (2019-2023).

C30 INTERIOR FINISHES

Item	Description
C3012 Wall Finishes to Interior Walls	Vinyl Wall Covering (Wall Paper)
Component Condition	Poor
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The general office and corridor walls are finished with wallpaper that is quite dated, but most likely not original to the construction of the building in 1959.

Component Condition:

The wallpaper is dated and is peeling in a number of locations. Based on observed condition, the wallpaper is considered to be in poor condition.

Component Recommendation:

Replacement of the wallpaper is recommended to improve the aesthetic of the building interior.

Item	Description
C3012 Wall Finishes to Interior Walls	Paint Wall Covering
Component Condition	Fair
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The majority of the interior walls, doors, and trim are finished with paint that was reportedly refinished approximately 11 years ago.

Component Condition:

Most interior paint finish was observed to be in good condition. There are isolated areas with scratches and marks, most likely as a result of building usage.

Component Recommendation:

An ongoing program to fix damages to the interior paint finish is recommended to improve the aesthetic of the building. The interior doors and frames were also observed to require refinishing in some locations. This action is not considered a priority, as the majority of interior paint finish is not located in customer areas/areas of the building which would normally be accessed by the public.

Item	Description
C3024 Flooring	Vinyl Floor Tiles
Component Condition	Fair
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Building flooring is finished with vinyl floor tiles in the addition, 2nd floor lunch room and metering rooms. The flooring is not original to the building construction. It is assumed that the vinyl flooring in the 1959 section of the building was installed in 1992 during construction of the addition.

Component Condition:

The vinyl tiles were observed to be in fair condition with isolated areas requiring refinishing. An ongoing program to clean and polish the floors keeps them in good condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, replacement of the vinyl tile flooring is not recommended for the next 5 years. Continued annual refinishing of the vinyl tile is required to keep the tiles in good condition.

Item	Description
C3024 Flooring	Terrazzo Flooring
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Terrazzo flooring provided in the general office area along the north elevation and on the stairway, treads leading to the second floor. The terrazzo appears to be well maintained.

Component Condition:

Terrazzo flooring is an incredibly resilient flooring material. At the time of our site review, the terrazzo flooring was noted to be in good condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the terrazzo is anticipated in the next 10 years.

Item	Description
C3025 Carpeting	C3025 Carpeting
Component Condition	Poor
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The hallways and most office areas are carpeted that was reportedly replaced 10 – 11 years ago.

Component Condition:

The replaced carpet flooring was observed to be in good condition with no signs of wear or unraveling observed.

Component Recommendation:

With carpet, the areas which get the most use will wear out much quicker than other areas. We did not see any areas where the carpet was in such poor condition that it could create a hazard. At such time as offices/hallways are renovated, the carpet flooring should be replaced. This would occur on an as-needed basis.

Item	Description
C3031 Ceiling Finishes	C3031 Ceiling Finishes – Acoustic Tile
Component Condition	Poor/Fair
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The space located on the second floor at the front of the building is finished with an acoustic, fiberboard, tile ceiling that is glued to a sheathing attached to the joists. The finish appears to be original to construction of the building in 1959.

Component Condition:

The original acoustic tile ceiling is dated. Based on age, the acoustic tile ceiling is considered to be in poor condition.

Component Recommendation:

A replacement of the original acoustic tile ceiling is recommended to improve the aesthetic of the building interior. Replacement may be considered a priority due to the deterioration of some panels and the possibility of them falling. Replacement of the ceiling tiles should be completed as part of upgrades to the mechanical system when it would need to be removed and re-installed.

Item	Description
C3031 Ceiling Finishes	Suspended Acoustic Panel Ceiling
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

A suspended acoustic tile ceiling is provided in the majority of the building spaces on the first floor and in the addition.

Component Condition:

The acoustic tiles were observed to be in good condition overall, with isolated areas of staining. There was no evidence of any type of extensive damage. The age of the tiles was n presumed to be during the construction of the addition in 1992. The 1992 project included modifications to the duct work in the service area. We presumed that the original ceiling was taken down to accommodate installation of the duct work, then, new, suspended ceiling installed.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the suspended acoustic tiles is anticipated in the next five years (2020 - 2025). An ongoing program to replace stained tiles is recommended since this is easy and convenient.

Item	Description
C3031 Ceiling Finishes	Lathe & Plaster Ceiling – Entrance
Component Condition	Fair
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The east employee entrance to the building is provided with a vestibule with a stucco and lathe and plaster ceiling finish. The ceiling finish is likely original to construction of the 1959 section of the building.

Component Condition:

The ceiling finish in the employee entrance area was observed to be in fair condition. Areas where moisture had damaged the finish was visible during the site assessment.

Component Recommendation:

Replacement or repair to damaged areas of ceiling is recommended to ensure the plaster ceiling does not fall from the supporting lathe. Keeping the ceiling in a good state of repair also provides for a positive impression for staff going in and out of the building.

BARRIER FREE BUILDING ANALYSIS: FESTIVAL HYDRO ADMIN BUILDING

Item	Description
#1 Barrier Free Analysis	Private and Public Spaces
Building Barrier Free Condition	Poor/ Limited
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

During our building condition assessment, we were also tasked with review the current building design, and to see if it conforms to today's AODA and current Accessibility Code Standards. For this exercise we chose to use the Regional Municipality of Waterloo Accessibility Design Standards as an acceptable example of a very good accessible design standard that can be applied to a public, institutional building.

After completing a thorough site visit which had NAE complete a 47-section checklist which in each section there were various subsections that outline specific criteria for said sections. We have concluded that this current building does not meet a great deal of the accessibility code standards of today. With exception to the public occupied spaces, to which seem to have been renovated to allow for barrier free door operators and a lowered service window.

Bathrooms – All bathrooms in this building do not conform to any current barrier free standards. i.e. millwork, size of room, mounting heights, etc.…

Hallways and Path of Travel – All corridors in this building are too small to conform to the current Accessibility Code Standards.

Furniture – Some furniture does comply to today's accessibility code standards, however the majority of it does not. This includes desk and chairs.

Parking – While there are barrier free parking locations on site, they do not meet today's current accessibility code standards (the path of travel one must take has them exiting their vehicles in a space that currently has vehicles traveling in and out of the lot). Issue pertaining to grading and curb heights are also not in compliance with today's accessibility code standards.

Based on information provided and observations noted during the accessibility review, due to the lack of accessibility in both private and public spaces, along with an old building design that makes any retrofitting costly and labor intensive. There are significant changes that need to be made in order to bring this building up to today's standards based on Accessibility Code Standards that we used for the revision of said building. It is not mandatory to make any changes, however in today's world, accessibility is becoming more relevant and is now integrated into most new building design.

These types of improvements would normally not come out of a maintenance budget, rather be part of a capital program to upgrade the building.

D SERVICES SYSTEMS

D20 PLUMBING

Item	Description
D20 Plumbing	D20 Plumbing – Plumbing Piping
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $5,000 (repairs)

Component Description:

The majority of the water distribution system including domestic water, domestic hot water, sanitary and storm piping is either concealed behind interior finishes or encapsulated behind the walls and floors. Where observed the water piping was copper and sanitary piping is cast iron and dates to the building's original construction of 1959 (original portion of the building) as well as the 1992 addition. The copper piping distributes domestic water to the various plumbing fixtures in the building. Cast iron piping is used for sanitary drains from the plumbing fixtures and storm drains from the roof drains.

A bronze body construction double backflow preventer and water meter has been installed in the mechanical room per Ontario Building Code requirements.

Component Condition:

We were advised that there are occasional blockages in the sanitary sewage waste line that leaves the building. This is most likely the result of corrosion, debris, etc., typical for sanitary piping of this age.

No significant problems were reported with the building's plumbing piping system and backflow preventer. Based on the operating condition, the plumbing piping is considered to be in fair condition.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the plumbing piping is anticipated in the next five years (2020 to 2025). We budgeted flushing buried sanitary and storm piping and also camera inspection may be required.

Item	Description
D2010.60 Plumbing Fixtures	D2010.60 Plumbing Fixtures
Component Condition	Good
Replacement Year / Replacement Cost	2020 / $10,000

Component Description:

The administration building is equipped with two washrooms, one janitor’s room, and one kitchenette on the ground floor and two washrooms, one janitor’s room and one kitchenette on the second floor. The plumbing fixtures include standard tank style water closets, countertop lavatories and kitchen sinks with manual faucets. Urinals are equipped with manual flush valves. There are a few plumbing fixtures are low-flow/flush water efficient style.

There are no hands-free fixtures.

The janitor’s rooms include cast iron service sinks.

A drinking water fountain is located on the ground floor corridor.

None of the washrooms are barrier free.

Component Condition:

Based on observed condition, the fixtures appear to be in fair condition.

Component Recommendation:

The fixtures currently installed in the building will provide satisfactory service for several years. Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the plumbing fixtures is anticipated in the next five years (2020 to 2025).

An upgrade of the washroom sink faucets and urinal flush valves to modern low flow electronic fixtures is recommended. An upgrade action has been included in 2020 for budgeting purposes.

Consideration should be given to	Description
D2010.20 Hot Water Equipment	Domestic Hot Water Heater Water Softener
Component Condition	Hot Water Heater – Good Water Softener – Poor/Fair
Replacement Year / Replacement Cost	Water Softener - 2022 / $3,000

Component Description:

The kitchenette and washroom faucets are provided with hot water by a single domestic hot water heater located in the rear mechanical room. The heater was manufactured by John

Wood in 2014 and has model number of JW8-50SDE1. The heater has a capacity of 48 Gallons and consumes 3,800W.

A water softener manufactured by Myers, with a salt tank is located in the rear mechanical room for domestic cold and hot water services.

Component Condition:

Based on observed condition, the domestic hot water heater is considered to be in good condition. Electrical domestic water heaters typically have a useful life of 15 years. We expect 10 more years as the service life for the domestic water heater.

The water softener looks quite old however well maintained.

Component Recommendation:

A replacement of the heater is anticipated in the ten-year planning window based on expected useful life. A replacement has not been included in 5 years plan for budgeting purposes.

The water softener / salt tank and may need replacement. We have budgeted for replacement in 2022.

D30 HVAC

Item	Description
D3012 Gas Supply System	D3012 Gas Supply System
Component Condition	Good
Replacement Year / Replacement Cost	2020/$1000

Component Description:

Natural gas pipe lines supply fuel to the building heating equipment through a gas meter and pressure regulator located south side of the building. The building gas-fired heating equipment is including two rooftop units on high roof and one rooftop unit on the low roof located at west side of the building.

The gas lines pressure is between 7” to 14” WC which is classified as low-pressure system.

Component Condition:

The natural gas pipelines were observed generally to be in good condition, with some corrosion observed on their exterior on the roof.

Component Recommendation:

Based on our visual observations noted during the site assessment visit, no major repair/replacement of the natural gas pipelines is anticipated in the next five years (2020 to 2025).

However, we recommend painting for the natural gas piping located on roof which includes rust cleaning, primer application and 2 coats painting.

Item	Description
D3031.3 DX Split Systems	D3031.3 DX Split Systems – Server Room
Component Condition	Poor to Fair
Replacement Year / Replacement Cost	2020-2025 / $250,000, 2020 /$7,500 Upgraded server room / replace split units ONLY IF SERVERS ARE NOT MOVED TO NEW BUILDING NEXT DOOR.

Component Description:

Three air cooled refrigeration condenser units located on the exterior walls of the building's walls supply cooling to the server room through the indoor fan units. The equipment was manufactured by Payne Heating and Cooling, and Mitsubishi. The Payne unit has model number PA17NA060-A and serial number 1612E29150. The Mitsubishi units were not accessible as they reside on the side wall, however, they were identified as being Mr. Slim models. All equipment was installed in 2012 and temperature controls are located within the server room. The expected remained service life of the split units is 4-6 years. Indoor section of both Mitsubishi units are model number is PKA-A24KA. These units are combination units with a heat pump for heating and 2.0 Tons nominal cooling.

Component Condition:

The split systems are reported to operate as intended and are sized sufficiently to cool the server room. However, these split cooling units are not designed for server room purposes. We recommend a new precise control cooling unit system manufactured by say Liebert which has humidity and precise temperature control capability.

Also, existing air circulation in the room is not suitable for a properly designed server room. It was noticed by the office staff that the room beside server room has been disconnect from building heating and HVAC system. The room does not have proper ventilation system.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, we recommend larger server room for better air distribution with precise server cooling system upgrade in five years. However, the office room beside the server room should be connected building HVAC system. The anticipated construction cost is $7,500.

The existing server room will be taken out of service and the equipment moved to the building next door. Once this transition occurs, there will be no need to budget for this work as part of the maintenance budget. This space has been used as the server room for many years. Some work will be required to re-purpose it for a different use.

We have not included any cost to repurpose this space.

Item	Description
D3041 Air Distribution Systems	Distribution Systems – Duct System
Component Condition	Fair
Replacement Year / Replacement Cost Study Year / Study Cost Repair Year / Repair Cost	 2020/ $7,500- thermal insulation 2021 / $7,500- diffuser replacement

Component Description:

This building was originally constructed with electric radiant heating in the floor slab of the lower level and perimeter base board heaters. The radiant heating has been disconnected, but the perimeter baseboards still appear to be operating.

A system of galvanized ductwork with rectangle, round, and linear supply air diffusers distributes air in the building and is common to both the cooling and heating systems. The ductwork is built of sheet metal and varies in size. The exterior ductwork was thermally insulated.

The majority of ductwork is considered to be original to construction of the building in 1959 with the exception of the addition added in 1992. As part of the 1992 addition, a considerable amount of distribution ductwork was added, particularly to the lower level.

Multiple VVT, variable volume and temperature control dampers associated with zone thermostats provide zone temperature control in the building. The fan-coil units and rooftops have been combined with variable speed supply air fan or bypass dampers to accommodate the temperature control.

Component Condition:

The duct system and VVT control dampers are typically original to the building and are in fair condition based on age. It was evident that the exterior ductwork was insulated with polyurethane foam, but not covered with weather proof jacket. We observed that some areas of the exterior insulation have been deteriorated.

Since being constructed in 1959, the manner in which the building is being used has changed considerably. It would appear that the heating and cooling systems have been modified to service building modifications. This being the case, today, for being a relatively small building the heating and cooling is comprised of a fair number of different types of equipment at different ages.

Component Recommendation:

Expected service life of the galvanized ductwork, diffusers and VVT dampers, etc. averages 30 years. We don't expect major problem in next five years for the ductwork. However, some diffusers look very old and dirty. Consideration should be given to replacing some of these.

We also recommend repair of insulation complete with aluminum jacket for the exterior duct thermal insulation for which we have allowed cost of $7,500.

Heating and cooling for the comfort of the buildings users, energy efficiency, and control could all be dramatically improved if the existing system was removed completely and replaced with a new system designed to the requirements of a revised layout.

Item	Description
D3042 Exhaust Ventilation Systems	D3042 Exhaust Ventilation Systems
Component Condition	Good
Replacement Year / Replacement Cost	2020 / $1,500

Component Description:

Inline exhaust fans are located in each washroom and the janitor's room above the ceiling and are vented to the exterior wall or roof. Some washroom exhaust fans are very old and noisy.

There is also an inline fan associated with galvanized ductwork in the rear mechanical room of the building to exhaust air from that room.

Component Condition:

Based on observed operating condition, the janitors room exhaust fans are considered to be in poor condition. The mechanical room exhaust fan is in fair condition which we expect 5 more years with regular maintenance.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, we recommend replacement of all washroom and janitors room exhaust fans in five years.

Item	Description
D3052 Rooftop Units	Lower Roof Unit
Component Condition	Poor
Replacement Year / Replacement Cost	2021 / $95,000

Component Description:

The first floor building general office area and entrance is serviced by a rooftop unit (RTU) located on the lower roof. The RTU nameplate and manufacturer's information were not visible at the time of the assessment and the date of installation and unit capacity were not known, however, based on observed condition the RTU is assumed to be approximately 20 years old. The RTU is serviced by a natural gas line for heating fuel and electrical for cooling.

Component Condition:

The RTU was observed to be in poor condition and is reported to not operate properly. Some damage to the RTUs condenser fins was also observed.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, we recommend the replacement of the unit in next 2 years with allowed cost of $95,000. The work includes insulating the exterior ductwork with thermal insulation and weatherproof jacketing.

Item	Description
D3052 Rooftop Units	Upper Front
Component Condition	Fair
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The second-floor front area is serviced by a packaged rooftop unit (RTU) that was manufactured by Carrier in 2007. The equipment has model number 48PGEC06-A-50 and serial number 1607G40008. The system supplies both cooling and heating to the service area. The RTU uses natural gas for heating fuel and electrical for cooling. The unit is charged with ozone non-depleting R410A refrigerant.

Component Condition:

Based on observed condition, the RTU is considered to be in fair condition. Expected service life of the rooftop units are average 20 years. We expect 9 - 10 more years for the service life of the unit. The system is operating as intended.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the rooftop unit is anticipated in the next five years (2020 to 2025) with regular maintenance.

Item	Description
D3052 Package Units	Upper Back
Component Condition	Fair
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The second-floor rear area is serviced by a packaged rooftop unit (RTU) that was manufactured by Carrier in 2007. The equipment has model number 48PGEC06-A-50 and serial number 1607G40009. The system supplies both cooling and heating to the service area. The RTU uses natural gas for heating fuel and electrical for cooling. The unit has charged ozone non-depleting R410A refrigerant.

Component Condition:

Based on observed condition, the RTU is considered to be in fair condition. Expected service life of the rooftop units are average 20 years. We expect 7 more service life for the unit. The system is operating as intended.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the rooftop unit is anticipated in the next five years (2020 to 2025) with regular maintenance.

Item	Description
D3052.2 Fan Coil Units	D3052.2 Fan Coil Units – Carrier (Unit #4, #5)
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

The rear and middle of the building on the lower level is supplied with conditioned air from two Carrier units located in two mechanical rooms (rear and middle mechanical rooms). The two Carrier units have model number FE4ANF005 and, serial number of FE4ANF0050000ABAA and FY4ANFO48000AAAA manufactured in 2008 and 2009. Each unit is equipped with two dedicated air-cooled condenser units located on the rooftop for cooling that utilizes R-410A refrigerant. The units have 4.0 Tons electrical cooling and electrical heating. The system is controlled by a building automation system through VVT control dampers and thermostats.

Component Condition:

The Carrier equipment is reported to operate as intended and is considered to be in good condition based on age and reported operating condition. The expected remaining service life of the units is 5 and 6 years respectively with regular maintenance.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the fan coil units is anticipated in the next five years (2020 to 2025).

Item	Description
D3052.4 Baseboard Heater	D3052.4 Baseboard Heater - Electric
Component Condition	Poor, Expired
Replacement Year / Replacement Cost	2020 / $50,000

Component Description:

Electric baseboard heaters were observed in offices, entrance, lobby and washrooms in the building. Most of electric baseboard heaters were reported to no longer be in use. They are used as perimeter heating system and of the original heating system design requirement.

Component Condition:

The electrical baseboard heaters look original and currently in poor condition. Expected service life of the electric baseboard heaters are 10 years. Based on observed condition, the baseboard heaters are considered to be in very poor condition.

Component Recommendation:

We are not sure if the electrical baseboard heaters are still used to provide some supplemental heating. If they are used, replacement of the baseboard heaters is recommended to improve the HVAC system requirement. The new installation should consider BAS connections for the new heaters to prevent them from causing the cooling system to run.

Item	Description
D3060 HVAC Instrumentation and Controls (BAS)	D3060 HVAC Instrumentation and Controls – Building Automation System
Component Condition	Poor
Replacement Year / Replacement Cost	2020 / $2,000

Component Description:

The packaged rooftop units (RTUs) are controlled by the building automation system (BAS). We did not access the BAS system during the site inspection. We assumed three rooftop units and two fan coil units have been connected to the BAS system and the room temperatures are monitored via BAS system.

Component Condition:

There were no complaints about the BAS system.

Component Recommendation:

We recommend motion detectors for the building exhaust fans for more energy efficiency. Based on information provided and observations noted during the site assessment visit, no major repair/replacement of the BAS system is anticipated in the next five years (2020 to 2025).

D40 FIRE PROTECTION SYSTEMS

Item	Description
D4030 Fire Protection Specialties	D4030 Fire Protection Specialties
Component Condition	Good
Replacement Year / Replacement Cost	2015 / $2500

Component Description:

There are approximately 11 fire extinguishers located throughout the first and second floor of the building. The building doesn't have fire sprinkler system.

Component Condition:

The fire extinguishers are considered to be in good condition based on age and the last inspection date.

Component Recommendation:

Based on information provided and observations noted during the site assessment visit, no major issue of the fire extinguishers anticipated in the next five years (2020 to 2025). The fire extinguishers are required inspected monthly, tested annually.

D50 ELECTRICAL SYSTEMS

Item	Description
D5020 Electrical Service and Distribution	1959 Original / 1992 Addition & Reno
Component Condition	Fair / Good
Replacement Year / Replacement Cost	$10,000 (ongoing maintenance/upgrades)

Power System/ Component Description:

The available power systems that service the Administration Building are described as follows:

- Class IV - Normal Power Supply
- Class III - UPS
- Class II - Emergency Power Supply

Power Distribution:

The electrical service for the Administration Office is provided via an underground 600V service incoming from a splitter located in the Operation Building. A wall mounted step-down transformer rated at 112.5kVA 600V:120/208V located in electrical room. The main switch board is rated 600A 120/208V 3PH 4W, located in electrical room, and is being fed from the transformer and feeds the following:

The Main switch board rated 600A 120/208V 3PH 4W feed the following:

- 200A UPS PANEL
- HYDRO ONE ROOM
- HVAC #4
- CARRIER UNIT IN ELECTRICAL ROOM
- HVAC #1
- HVAC #2
- HVAC #3
- PANEL N
- LIGHT CONF ROOM
- CONF ROOM HEAT
- RECEP CONF ROOM

- PANEL T
- PANEL P
- PANEL C
- PANEL B
- PANEL W
- PANEL R

Power System / Component Recommendation:

The existing power distribution equipment appears to be in good, working condition.

It should be noted that provision for infra-red (IR) scanning and coordination study should be taken into consideration to identify issues not visible to the naked eye and to ensure the safety of the personnel.

Also, it should be noted that it is mandatory by the Ontario Electrical Safety Code (OESC) requirements that the existing major power distribution equipment shall be tested and maintained regularly (recommended every 5 years). Accordingly, provisions shall be taken to frequently update the arc-flash, short circuit fault protection, infrared scan and regular maintenance for the major power distribution equipment to avoid costly failures and to properly field mark equipment of the potential arc flash and electric shock hazards.

Item	Description
D5040 Lighting	1959 Original (old) / 1992 Add'n & Reno
Component Condition	Good
Replacement Year / Replacement Cost	Allow $2,000/year

Lighting System/ Component Description:

The existing lighting system that illuminates the Administration office consists of a combination of 4'-0" Long fluorescent suspended / surface light fixtures, recessed pot lights and 2'x2', 1'x4' & 2'x4' recessed light fixtures. Industrial 4'-0" long suspended light fixtures were used in the electrical room. The pot lighting was used in the main conference room. The 2'x2', 1'x4', 2'x4' recessed fixtures are used in the main entrance office, corridors and private offices mounted on the T bar ceiling. Lamps are standard fluorescent 32W-T8 energized by energy efficient electronic ballast while pot lights were LED. Lighting fixtures in the stair way and IT rooms are new and LED.

In general, the existing lighting system is adequate and illumination levels acceptable for the space and task being used based on the latest IESNA standards. Some lamps were burned out and need to be replaced. It is recommended to replace fixtures with new LED to improve energy efficiency and provide longer life expectancy.

Lighting is 120V powered by the light panel.

Lighting Controls:

Lighting is controlled by conventional switches located in accessible locations. Lighting relays are utilized to control outdoor lighting. Photocells are controlling for the outdoor lighting. Motion sensors are utilized in the most offices, corridor and washrooms. Hence, day light harvest sensors are also recommended to control the perimeter lighting in open areas.

Exterior Lighting:

The exterior ceiling mounted fixtures are LED.

Exit and Emergency Lighting:

Emergency head lights, emergency batteries and exit signs were found throughout the entire building covering exit pathways and corridors / halls. Exit signs are original aluminum frames.

The emergency lighting system is provided by remote battery packs (AimLite product), complete with halogen heads (MR16), located throughout the building and appear to be adequate for the occupancy and operation of the building.

Some of the emergency heads are LED.

Lamp Types:

Florescent fixtures are the main source of the interior lighting that illuminates the Administration building.

Lighting System / Component Condition:

Lighting levels are generally acceptable but, in some areas, may be below the IESNA standards.

Lighting System / Component Recommendation:

A strategic short-term and long-term plan is required for any future modifications or upgrades to the lighting system to meet the latest OBC/ SB10/ ASHRAE 90.1 standards for energy management. It’s recommended that original light fixtures to be replaced with new LED’s.

It is recommended to replace existing signs with new pictogram LED’s walking man signage.

Provide new lighting control system for service rooms, storage spaces or low traffic areas and daylight harvest system for open office space to improve the energy savings.

Item	Description
D5080 Miscellaneous Electrical Systems	Power distribution/wiring
Component Condition	Fair / Good
Replacement Year / Replacement Cost	Ongoing maintenance – as required Allow - $5,000 / year

Miscellaneous Electrical System / Component Description:

Wiring is original to the building and consists of wires in EMT conduits and armored cables (BX or TECK 90).

Miscellaneous Electrical System / Component Condition:

The current condition and type of wiring installed at this building was not entirely inspected during the site reviews. The majority of wiring/cables run in EMT conduits. Armored cables were also found in short runs to light fixtures. Flex or Teck 90 cables were also noted for the large mechanical equipment.

Miscellaneous Electrical System / Component Recommendation:

It is recommended that the wiring system be inspected on a regular basis and make any upgrades as needed if damaged or defective components are discovered.

D60 COMMUNICATIONS

Item	Description
D6010 Data Communications	D6010 Data Communications – 1959
Component Condition	Good
Replacement Year / Replacement Cost	

Public Address System / Component Description:

The PA system consists of recessed ceiling mounted speakers located throughout the building and is powered by the telephone system.

Public Address System / Component Condition:

PA system speakers have a very long life span however upgrading to the latest technology may be desirable upon replacement of deteriorated components.

Public Address System / Component Recommendation:

Upgrade the PA system and equipment as deteriorated components fail.

Item	Description
D6020 Voice Communications	D6020 Voice Communications – 1959
Component Condition	Good
Replacement Year / Replacement Cost	

Voice Data / Component Description:

Voice/Data drops for the office area is provided via outlets for system furniture.

Voice Data / Component Condition:

The current condition and type of wiring installed at this building was not entirely inspected during the site reviews.

Voice Data / Component Recommendation:

It is recommended that the wiring system be inspected on a regular basis and make any upgrades as needed if damaged or defective components are discovered.

D70 ELECTRICAL SAFETY AND SECURITY SYSTEM

Item	Description
D7050 Detection and Alarm	Security System
Component Condition	Fair
Replacement Year / Replacement Cost	2031 / unknown

Security System / Component Description:

The building's security system consists of cameras, motion detectors, and door contacts installed on each of the building entrance/exits. Door contacts are de-activated with either a 'fob', programmed and issued by IT or keycode.

Fire Alarm System / Component Condition:

The security system was apparently installed in 2010/2011 and should have an anticipated life expectancy of 20 years.

Security System / Component Recommendation

Undertake routine, annual maintenance on an ongoing basis. Right now the server room has very strict security requirements. Once the server room equipment is moved to the new building, some re-configuration of the security system should be considered.

G BUILDING SITEWORK SYSTEMS

G20 SITE IMPROVEMENTS

Item	Description
G2020.10 Paving Lot Pavement	Asphalt Paved Parking Lot
Component Condition	Fair
Replacement Year / Replacement Cost	2020 / $205,000

Component Description:

The approximately 2,200 m^2 asphalt parking area consists of two areas, the largest of which is located to the north of the building adjacent the main entrance and has two access points (Erie Street and Wellington Street). The other area is located to the east of the building adjacent to Wellington Street and consists of a rounded driveway and 3 parking spaces. As per the condition assessment completed in 2014 the asphalt was last refinished prior to 2004, so the estimated age currently would be approximately 15 years.

Component Condition:

<u>North Parking Area</u>

Although some localized areas appear to have been cut and repaved and the parking lot was recently tarred and painted, the overall condition is fair. As per the Flexible Pavement Condition Evaluation Form (Appendix G), there was raveling, rutting, distortion, and longitudinal cracks observed to be present. One indication of some of these conditions was puddling in areas where rutting and distortion had occurred.

<u>East Parking Area/Driveway</u>

Similarly, to the North Parking Area the asphalt had been recently tarred and painted and the overall condition of the asphalt is fair. The evaluation of this area shows that there raveling, and rutting were observed on-site with a small amount of cracking at the asphalt edge.

Component Recommendation:

Continuation of current maintenance (sealing cracks, tearing, etc.) will extend the useful life of the asphalt. However, a typical lifespan of asphalt is 15 years and since the asphalt is estimated to be greater than 15 years in age it is recommended for it to be resurfaced. With the current condition it is assumed that the substructure is adequate, however at the time of resurfacing it is recommended to complete investigation of the subsurface structure to confirm. Adequate subsurface structure can greatly extend the life of the asphalt. In the event the subsurface is not adequate full reconstruction would be recommended.

Item	Description
G2020.20 Parking Lot Curbs and Gutters	Concrete Curbs
Component Condition	Good - Poor
Replacement Year / Replacement Cost	2020 / $5,000 (Repair)
Replacement Year / Replacement Cost	2025 / $13,500 (Overall Replacement)

Component Description:

Approximately 270 m of concrete barrier curbs surrounds most of the parking areas and edge of pedestrian walkways, however a few locations appear to have mountable curb. From the plans available it appears that the parking area was not part of the original construction in 1958 and as such has been assumed to have been installed in the mid 1970's.

Component Condition:

Most of the curb appears to be fair to good condition, with some cracking and wearing evident. Some isolated areas / corners are in poor condition, and almost non-existent (specifically the northeast corner of the north parking area). The north edge of the entrance from Wellington Street appears to be mountable curb that is in fair condition, however typically unless it is intended to have vehicular traffic, barrier curb is more suitable for parking areas.

Component Recommendation:

Based on the information and visual inspection from the site visit there are areas of the concrete which are recommend to be repaired/replaced.

Item	Description
G2020.40 Parking Lot Pavement Markings	Pavement Markings
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Pavement markings include painted lines delineating the parking spaces, accessible parking spaces and no parking areas.

Component Condition:

The pavement markings appear to have recently been repainted and in good condition.

Component Recommendation:

At this time the pavement markings do not require re-painting, however if the asphalt is replaced it will need to be re-painted at that time.

Item	Description
G2030.10 Pedestrian Pavement (concrete)	Concrete walkways
Component Condition	Fair
Replacement Year / Replacement Cost	2063 / $9,000

Component Description:

Approximately 180 m^2 of concrete paved walkways starts at the south side of the building and continues around the west and north sides of the building. The walkways provide patrons access to the main entrance as well as employees access to the other entrances on the site.

Component Condition:

The concrete paved walkways were in fair condition, sections appeared to be recently replaced however most of it appeared to be installed recently prior to the 2014 assessment. The walkways showed evidence of heaving, cracking and degradation. A couple locations appeared to have been recently 'repaired' with a thin layer of finishing cement which has since started to crumble.

Component Recommendation:

Localized repairs are recommended of areas that are showing signs of degradation, including inspection of the base material to ensure it is not attributing to the condition of the walkways.

Item	Description
G2030.20 Exterior Steps & Ramps	Exterior Steps & Ramps
Component Condition	Poor/Good
Replacement Year / Replacement Cost	2020 / $15,000

Component Description:

Cast-in-place concrete stairs are located along the north-east of the building to provide access from the elevation of Erie Street to the elevation at Wellington St. and on the east side to provide access to the employee entrance. Both stairs are equipped with metal handrails, the north-east stairs appear to be and have been indicated to be original to construction of the 1992 addition, as per the 2014 assessment. The east stairs appear to have been replaced recently.

Component Condition:

The north-east stair appears to be in poor condition and show signs of settlement and deterioration of the concrete, however the east stairs appear to have been recently replaced and are in good condition.

Component Recommendation:

Replacement of the north-east stair is recommended.

Item	Description
G2060.60 Retaining Walls	Retaining Walls – Brick Masonry
Component Condition	Good
Replacement Year / Replacement Cost	2020 - $2,000

Component Description:

To protect the concrete paved walkways on north and west sides of the building, a 1.2 m brick wall was constructed. It was indicated in the previous assessment that the brick wall is likely original to the building construction in 1959, however it appears the portion of the wall have been repaired.

Component Condition:

The brick wall was observed to be in good condition with some minor, isolated deterioration noted.

Component Recommendation:

At this time repairs or replacement do not appear to be necessary.

Item	Description
G2080 Landscaping	Landscaping
Component Condition	Good
Replacement Year / Replacement Cost	N/A / N/A

Component Description:

Flower beds and shrubbery are located within the parking island on the north side of the site and along the stair on the north-east. There are several trees located along the north-west adjacent to Erie St. The landscaping is reportedly maintained by a contracted company appears to be in good condition. Along the west side of the building adjacent to the railway tracks there is an area of wild plants and trees that does not appear to be maintained.

Component Condition:

The intentional landscaping appears to be in good condition, however adjacent to the railway it appears to be unmaintained.

Component Recommendation:

No major repair/replacement of the landscaping is anticipated and with regular maintenance landscaping should not create significant capital cost as such costing was not included for this item.

G30 SITE CIVIL/MECHANICAL UTILITIES

Item	Description
G3010 Water Utilities	Water Service
Component Condition	Good
Replacement Year / Replacement Cost	2028 / $10,500

Component Description:

The site is serviced from the municipal water system through a service connecting to the watermains within the adjacent streets, assumed to be approximately 60 m of servicing.

Component Condition:

Deficiencies or issues such as low or inadequate capacity were not reported at the time of the assessment. The water service(s) were not directly observed but are expected to be in good condition based on reported operating condition.

Component Recommendation:

Since no deficiencies have been report major repair/replacement of the water service is anticipated however there should be consideration that it may be beneficial to complete underground services at the time of asphalt replacement.

Item	Description
G3020 Sanitary Sewerage Utilities	Sanitary Services
Component Condition	Poor
Replacement Year / Replacement Cost	2020 / $10,500

Component Description:

The site is serviced from the municipal sanitary system through a service connecting to the sanitary sewer within the adjacent streets, assumed to be approximately 60 m of servicing.

Component Condition:

There was report that since the building toilets had been replaced with newer models, at, the location where the sanitary service leaves the building there appears to be an issue which causes it to back up.

Component Recommendation:

Although there were not observed sign of failure at the time of the site visit it was reported that there are periodic failures with the sanitary service. It is recommended that this service be scoped to further identify the cause of the failure and either repair or replacement will be required.

Item	Description
G3030 Storm Drainage Utilities	Storm Sewer
Component Condition	Good/Fair
Replacement Year / Replacement Cost	2045 / $45,000

Component Description:

The stormwater management (SWM) system on-site consists of a series of storm sewer (approximately 150 m) and catch basin (4) which collect the surface runoff from the parking areas and walkways on site. The rainwater leaders from the roof are indicated to also connect to the system through underground piping. Based on the plans available the full parking lot and SWM system was not original to the 1958 construction however is prior to the 1992 expansion, as such it is assumed that they were installed in the mid 1970's

Component Condition:

During the site visit ponding due to failure of the SWM system was not observed and no issues with the piping and catch basin system was reported and appears to be in good condition. However, it was reported that there had been issues with the connections of the rainwater leaders. A scope of these pipes was completed by the owner which revealed that there were roots seen within the piping. Although it was noted that it was not felt that this was the sole cause. It was also noted that the service connecting the building rainwater leaders were installed quite shallow and this is suspected to cause backup in the winter due to freezing.

Component Recommendation:

The overall system being in good condition requires no repair or replacement, however it is recommended to have the pipes from the rainwater leaders 'snaked' to be cleaned out. Since the roots are not believed to be the sole cause it is recommended to further investigate the issue to look at pipe sizing, location etc., to better understand the cause. Consideration should be given that it may be beneficial to complete underground services at the time of asphalt replacement.

APPENDIX A – PHOTOS

A Substructure Systems


Original Building


1992 Addition


Roof raming of original section


Step crack in exterior brick wall


Minor cracks in foundation parging

B Shell Systems

Main customer entrance – power door operator


General view – circular customer service area.


Partial north elevation

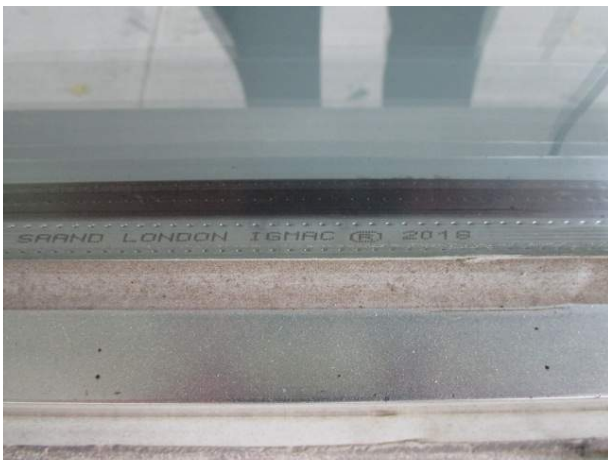

Double door, staff entrance / glass block feature wall.


1992 Addition/1959 Original building


Windows/board room doors, south elevation


Glazing tape failure in original windows


Minor corrosion on lintel



Date stamp in sealed units indicating age


Window/door sealant generally in fair condition.


Overall view – brick masonry. Note bonding course every 6th row of bricks.


Weeping hole – brick masonry wall

Tiny amount of brick deterioration – one brick.

Roof drains empty behind the front 'feature' wall.

Large overhang – soffit constructed with transite panels

Large overhang, lower level and upper level.

General view – low roof area – note debris at drain, ponding

1992 Addition / 2006 Upper roof area.


Ponded water at roof top unit.


Upper roof area – repairs completed in 2014(?).


Lower canopy roof area – debris / low parapet

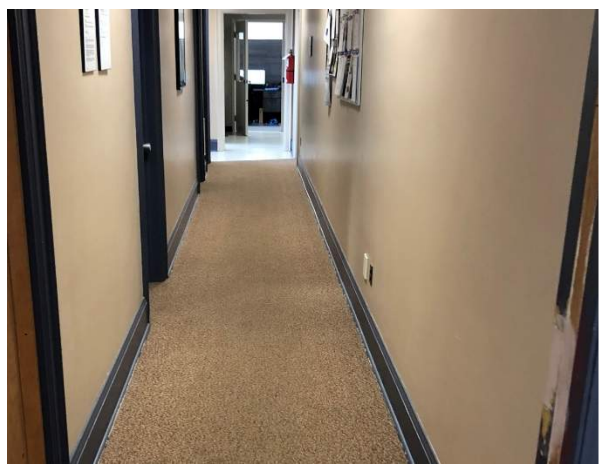

Low roof area – roof anchors added

C Interior Systems

Interior Doors – Painted Finishes

Stair Construction

Wall Finishes – Vinyl Wall Covering



Wall Finishes – Paint Wall Covering


Flooring - Vinyl Floor Tiles


Flooring - Terrazzo


Flooring - Carpet


Ceiling Finishes – Acoustic Tile


Ceiling Finishes – Acoustic Panel


Wall Finishes – Lathe & Plaster

D Service Systems

Mechanical

Heat and smoke detectors in addition

Fan Coil Unit – mechanical room

Men's washroom on first floor

Janitors room exhaust fan on first floor


Drinking water fountain


Thermostat


Return air grille


Ceiling diffuser


Baseboard heaters


Exterior duct thermal insulation


Roof drain


D3052 – Rooftop unit on high roof


Fan coil condenser on roof

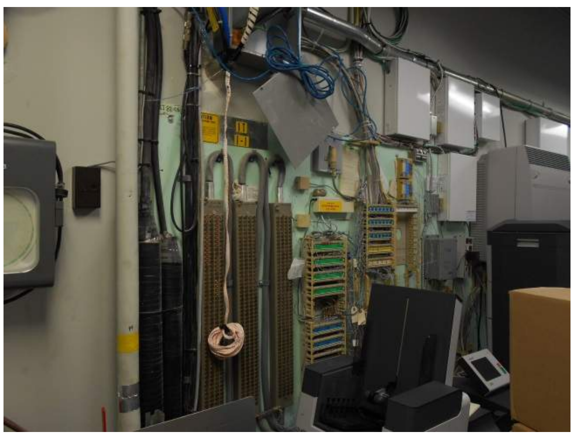

Rusty gas pipe connection


Fire extinguisher

ELECTRICAL

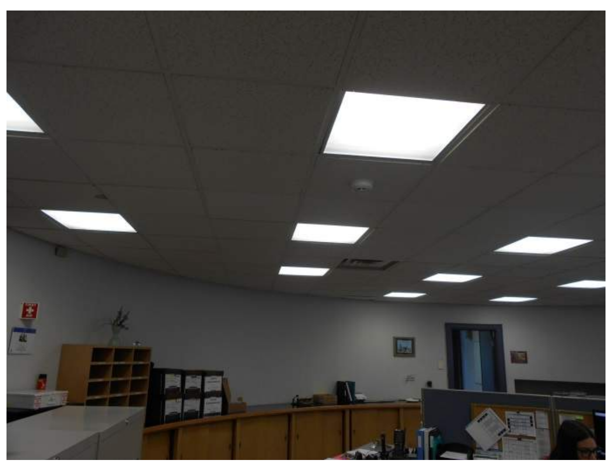

Main Incoming Service

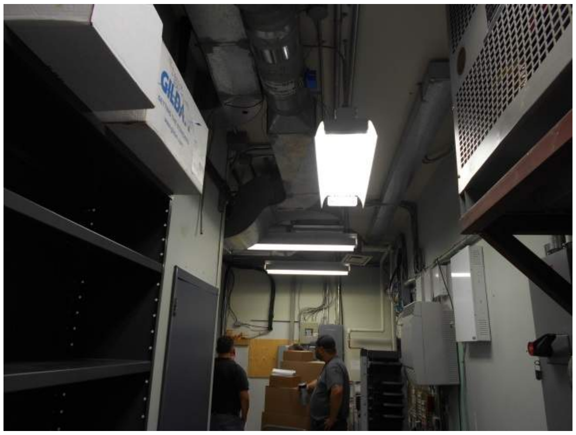
Main Transformer


Communication and security Panel

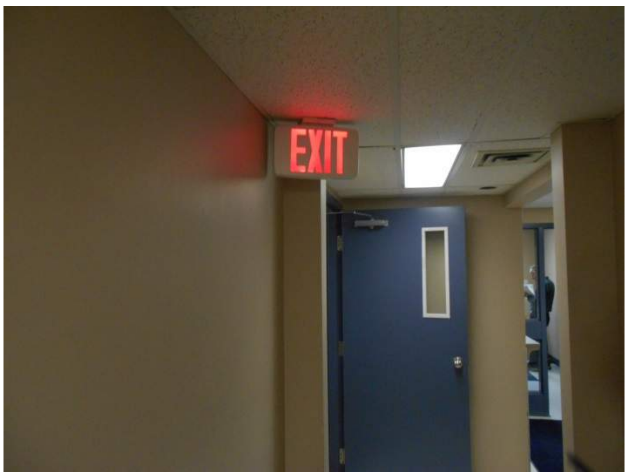

Lighting Panel

2’x4’ Recessed Light Fixture


2’x2’ Recessed Light Fixture


Surface Mounted Light Fixture


Emergency Battery with two Heads



Exit Sign

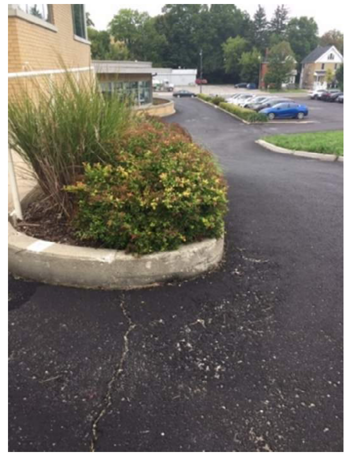
Exterior Recessed Light Fixture


Ceiling mounted Speaker Smoke Detector and Horn


Ceiling mounted Motion Sensor

G Building Sitework Systems

Longitudinal surface cracks and ponding in the north asphalt parking lot



Asphalt roadway from Wellington Street to Erie Street

Longitudinal surface cracks in the east parking area

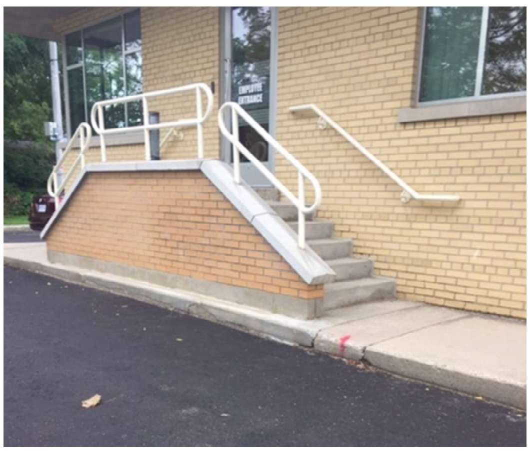
Area of deterioration on concrete curb

Area of deterioration on concrete curb

Area of deterioration on concrete walkway

Area where settlement and heave is evident on concrete walkways

North-east stairwell to ground level at Wellington St.



East stairwell to employee entrance

Efflorescence visible on wall

G30 SITE CIVIL/MECHANICAL UTILITIES

Storm Catchbasin

Storm Catchbasin

APPENDIX B - COSTING

2019 CURRENT YEAR	50 study length in years	0.06 INTEREST RATE	0.02 Inflation RATE	
NAME	Festival Hydro Adminstration Building			
ADDRESS	187Erie St., Stratford, ON	1,089,000	56,522.65	926,308
JOB NO.	19-1044			
element count 55		2,354,500		

Festival Hydro Adminstration Building

CURRENT REPLACEMENT COSTS

October 1, 2019

Uniformat Description	Element Description	Cost * (current $)	Future Repair / Replace Cycles (YR's)	Present Age (YR's)	Remaining Life (YR's)	First Year of Cycle (date)	Equivalent Annual Cost (current $'s)	Required Current Reserve Fund Balance (current $'s)
SUBSTRUCTURE								
A1010	Standard Foundations		100	63	37			
A4010	Standard Slabs-on-Grade		100	63	37			
SHELL								
B1010	Floor Construction		100	63	37			
B1020	Roof Construction		100	63	37			
B1030	Structural Support		100	63				
B1080	Stairs		100	63	37			
B2011	Exterior Walls	3,000	64	63	1	2020	46.88	2,953.13
B2011.1	Exterior Wall Sealant - Doors and Windows	5,000	2	1	1	2020	2,500.00	2,500.00
B2021	Exterior Windows (complete replacement)	200,000	65	63	2	2021	3,076.92	193,846.15
B2030	Exterior Doors and Entrances (biannual maintenance)	1,000	2	1	1	2020	500.00	500.00
B3010	Roofing	300,000	17	13	4	2023	17,647.06	229,411.76
B3015	Roof Eaves and Soffits	2,000	64	63	1	2020	31.25	1,968.75
INTERIORS								
C1030	Interior Doors		63	9	54			
C2010	Stair Construction		63	20	43			
C3012	Wall Finishes (Vinyl)		27	20	7			
C3012	Wall Finishes (Paint)		27	20	7			
C3024	Flooring (Vinyl)		27	20	7			
C3024	Flooring (Terrazo)		64	20	44			
C3025	Flooring (Carpeting)	50,000	20	11	9	2028	2,500.00	27,500.00
C2030	Ceiling Finishes - Acoustic Tile		75	63	12			
C2040	Ceiling Finishes - Suspended Acoustic Panel		35	27	8			
C2050	Ceiling Finishes (Lathe and Plaster Ceiling - Entrance)		25	5	20			
SERVICES								
D1010	Vertical Conveying Systems (no elevator)				0			
D2010	Domestic Water Distribution (repairs / maintenance)	5,000	4	3	1	2020	1,250.00	3,750.00
D2010.6	Plumbing Fixtures	10,000	27	26	1	2020	370.37	9,629.63
D2010.20	Hot Water Equipment	5,000	15	5	10	2029	333.33	1,666.67
D2010.20	Water Softener	5,000	25	24	1	2020	200.00	4,800.00
D3012	Gas Supply System	1,000	25	23	2	2021	40.00	920.00
D3020	Heating Systems				0			
D3031.3	Cooling Systems - Split DX Server Room Cooling	7,500	27	24	3	2022	277.78	6,666.67
D3041	Facility Air Distribution Systems	15,000	27	24	3	2022	555.56	13,333.33
D3042	Exhaust Ventilation Systems	3,000	27	25	2	2021	111.11	2,777.78
D3052	Rooftop Units - Lower Roof	95,000	20	18	2	2021	4,750.00	85,500.00
D3052	Rooftop Units - Upper Front / Upper Back		20	12	8			
D3052.2	Fan Coil Units (Carrier Unit#'s 4and 5)	20,000	25	20	5	2024	800.00	16,000.00
D3052.4	Electric Baseboard Heaters	10,000	64	63	1	2020	156.25	9,843.75
D4030	Fire Protection Systems (fire extinguishers)				0			
D5020	Electrical Service and Distribution	10,000	2	1	1	2020	5,000.00	5,000.00
D5040	Lighting	20,000	30	27	3	2022	666.67	18,000.00
D5080	Miscellaneous Electrical Systems (wiring/power distribution)	2,000	5	2	3	2022	400.00	800.00
D6010	Data Communications				0			
D6020	Voice Communications				0			
D7050	Fire Detection and Alarm				0			
BUILDING SITE WORKS								
G2020.1	Paving Lot Pavement	205,000	15	14	1	2020	13,666.67	191,333.33
G2020.2	Concrete Gutters - Repairs	5,000	50	49	1	2020	100.00	4,900.00
G2020.2	Concrete Gutters - Replacement	13,500	50	44	6	2025	270.00	11,880.00
G2020.4	Paving Lot Pavement Markings				0			
G2030.1	Pedestrian Pavement - Concrete walkways				0			
G2030.2	Exterior Stairs and Ramps	15,000	64	63	1	2020	234.38	14,765.63
G2060	Retaining Walls				0			
G2080	Landscaping (maintenance contract)			63	-63			
G2020.1	Exterior Stairs and Ramps	15,000	64	63	1	2020	234.38	14,765.63
SITE CIVIL / MECHANICAL UTILITIES								
G3010	Water Utilities	10,500	75	64	11	2030	140.00	8,960.00
G3020	Sanitary Sewage Utilites	10,500	64	63	1	2020	164.06	10,335.94
G2030	Storm Drainage Utilities	45,000	90	64	26	2045	500.00	32,000.00

TIME LINE OF EXPENDITURES (in thousands of dollars)

Uniformat Description	2019 (0)	2020 (1)	2021 (2)	2022 (3)	2023 (4)	2024 (5)	2025 (6)	2026 (7)	2027 (8)	2028 (9)	2029 (10)	2030 (11)	2031 (12)	2032 (13)	2033 (14)	2034 (15)	2035 (16)	2036 (17)	2037 (18)	2038 (19)	2039 (20)	2040 (21)	2041 (22)
B2011		3																					
B2011.1		5		5		5		5		5		5		5		5		5		5		5	
B2021			200																				
B2030		1		1		1		1		1		1		1		1		1		1		1	
B3010					300																	300	
B3015		2																					
C3025										50													
D2010		5				5				5				5				5				5	
D2010.6		10																					
D2010.20 (Hot Water Equipment)											5												
D2010.20 (Water Softener)		5																					
D3012			1																				
D3031.3				8																			
D3041				15																			
D3042			3																				
D3052 (Lower Roof)			95																				95
D3052.2						20																	
D3052.4		10																					
D5020		10		10		10		10		10		10		10		10		10		10		10	
D5040				20																			
D5080				2					2					2					2				
G2020.1 (Paving Lot Pavement)		205															205						
G2020.2 (Repairs)		5																					
G2020.2 (Replacement)							14																
G2030.2		15																					
G2020.1 (Exterior Stairs and Ramps)		15																					
G3010												11											
G3020		11																					
COMPONENT SUB-TOTAL ONLY	0.0	301.5	299.0	60.5	300.0	41.0	13.5	16.0	2.0	71.0	5.0	26.5	0.0	23.0	0.0	16.0	205.0	21.0	2.0	16.0	0.0	321.0	95.0
INTEREST (at 6.0%)	0.0	18.1	17.9	3.6	18.0	2.5	0.8	1.0	0.1	4.3	0.3	1.6	0.0	1.4	0.0	1.0	12.3	1.3	0.1	1.0	0.0	19.3	5.7
INFLATION (at 2.0%)	0.0	6.0	12.1	3.7	24.7	4.3	1.7	2.4	0.3	13.9	1.1	6.4	0.0	6.8	0.0	5.5	76.4	8.4	0.9	7.3	0.0	165.5	51.9
CLOSING BALANCE	**0.0**	**325.6**	**329.0**	**67.8**	**342.7**	**47.7**	**16.0**	**19.3**	**2.5**	**89.1**	**6.4**	**34.5**	**0.0**	**31.1**	**0.0**	**22.5**	**293.7**	**30.7**	**3.0**	**24.3**	**0.0**	**505.8**	**152.6**
Present value of closing balance	**0.0**	**319.2**	**316.2**	**63.9**	**316.6**	**43.2**	**14.2**	**16.8**	**2.1**	**74.6**	**5.2**	**27.8**	**0.0**	**24.1**	**0.0**	**16.7**	**214.0**	**21.9**	**2.1**	**16.7**	**0.0**	**333.7**	**98.7**

2019 CURRENT YEAR	50 study length in years
NAME	Festival Hydro Adminstration Building
ADDRESS	187Erie St., Stratford, ON
JOB NO.	19-1044
element count 55	

Festival Hydro Adminstration Building

CURRENT REPLACEMENT COSTS

October 1, 2019

Uniformat Description	Element Description	2042 (23)	2043 (24)	2044 (25)	2045 (26)	2046 (27)	2047 (28)	2048 (29)	2049 (30)	2050 (31)	2051 (32)	2052 (33)	2053 (34)	2054 (35)	2055 (36)	2056 (37)	2057 (38)	2058 (39)	2059 (40)	2060 (41)	2061 (42)	2062 (43)	2063 (44)	2064 (45)	2065 (46)	2066 (47)	2067 (48)	2068 (49)	2069 (50)
SUBSTRUCTURE																													
A1010	Standard Foundations																												
A4010	Standard Slabs-on-Grade																												
SHELL																													
B1010	Floor Construction																												
B1020	Roof Construction																												
B1030	Structural Support																												
B1080	Stairs																												
B2011	Exterior Walls																												
B2011.1	Exterior Wall Sealant - Doors and Windows	5		5		5		5		5		5		5		5		5		5		5		5		5		5	
B2021	Exterior Windows (complete replacement)																												
B2030	Exterior Doors and Entrances (biannual maintenance)	1		1		1		1		1		1		1		1		1		1		1		1		1		1	
B3010	Roofing																300												
B3015	Roof Eaves and Soffits																												
INTERIORS																													
C1030	Interior Doors																												
C2010	Stair Construction																												
C3012	Wall Finishes (Vinyl)																												
C3012	Wall Finishes (Paint)																												
C3024	Flooring (Vinyl)																												
C3024	Flooring (Terrazo)																												
C3025	Flooring (Carpeting)							50																				50	
C2030	Ceiling Finishes - Acoustic Tile																												
C2040	Ceiling Finishes - Suspended Acoustic Panel																												
C2050	Ceiling Finishes (Lathe and Plaster Ceiling - Entrance)																												
SERVICES																													
D1010	Vertical Conveying Systems (no elevator)																												
D2010	Domestic Water Distribution (repairs / maintenance)			5				5				5				5				5				5				5	
D2010.6	Plumbing Fixtures						10																						
D2010.20	Hot Water Equipment			5															5										
D2010.20	Water Softener				5																								
D3012	Gas Supply System					1																							
D3020	Heating Systems																												
D3031.3	Cooling Systems - Split DX Server Room Cooling								8																				
D3041	Facility Air Distribution Systems								15																				
D3042	Exhaust Ventilation Systems							3																					
D3052	Rooftop Units - Lower Roof																				95								
D3052	Rooftop Units - Upper Front / Upper Back																												
D3052.2	Fan Coil Units (Carrier Unit#'s 4and 5)								20																				
D3052.4	Electric Baseboard Heaters																												
D4030	Fire Protection Systems (fire extinguishers)																												
D5020	Electrical Service and Distribution	10		10		10		10		10		10		10		10		10		10		10		10		10		10	
D5040	Lighting											20																	
D5080	Miscellaneous Electrical Systems (wiring/power distribution)	2					2					2					2					2					2		
D6010	Data Communications																												
D6020	Voice Communications																												
D7050	Fire Detection and Alarm																												
BUILDING SITE WORKS																													
G2020.1	Paving Lot Pavement									205															205				
G2020.2	Concrete Gutters - Repairs																												
G2020.2	Concrete Gutters - Replacement																												
G2020.4	Paving Lot Pavement Markings																												
G2030.1	Pedestrian Pavement - Concrete walkways																												
G2030.2	Exterior Stairs and Ramps																												
G2060	Retaining Walls																												
G2080	Landscaping (maintenance contract)																												
G2020.1	Exterior Stairs and Ramps																												
SITE CIVIL / MECHANICAL UTILITIES																													
G3010	Water Utilities																												
G3020	Sanitary Sewage Utilites																												
G2030	Storm Drainage Utilities				45																								
		18.0	0.0	26.0	50.0	17.0	12.0	74.0	42.5	221.0	0.0	43.0	0.0	16.0	0.0	21.0	302.0	16.0	5.0	21.0	95.0	18.0	0.0	21.0	205.0	16.0	2.0	71.0	0.0
		1.1	0.0	1.6	3.0	1.0	0.7	4.4	2.6	13.3	0.0	2.6	0.0	1.0	0.0	1.3	18.1	1.0	0.3	1.3	5.7	1.1	0.0	1.3	12.3	1.0	0.1	4.3	0.0
		10.4	0.0	16.7	33.7	12.0	8.9	57.4	34.5	187.3	0.0	39.7	0.0	16.0	0.0	22.7	338.9	18.6	6.0	26.3	123.2	24.2	0.0	30.2	304.8	24.6	3.2	116.4	0.0
		29.5	**0.0**	**44.2**	**86.7**	**30.0**	**21.6**	**135.9**	**79.5**	**421.6**	**0.0**	**85.2**	**0.0**	**33.0**	**0.0**	**45.0**	**659.1**	**35.6**	**11.3**	**48.6**	**223.9**	**43.3**	**0.0**	**52.5**	**522.1**	**41.5**	**5.3**	**191.6**	**0.0**
		18.7	**0.0**	**27.0**	**51.8**	**17.6**	**12.4**	**76.5**	**43.9**	**228.2**	**0.0**	**44.3**	**0.0**	**16.5**	**0.0**	**21.6**	**310.5**	**16.4**	**5.1**	**21.6**	**97.5**	**18.5**	**0.0**	**21.5**	**209.9**	**16.4**	**2.0**	**72.6**	**0.0**

APPENDIX C – INTERIOR FINISHES

Room		Walls			Flooring & Base							Ceilings			Doors, Hardware, Frames			Window Coverings	Millwork	Remarks	Furniture			
					Flooring					Base					A. Hollow Metal B. Wood C. Alum.					Condition 1. Good 2. Fair 3. Poor Recommendations A. Repair &/or Repaint B. Replace C. Repaint/Reseal	Item 1. Desk 2. Desk Chair 3. Filing Cabinet 4. Kitchen Table 5. Kitchen Chair 6. Lounge Chair 7. Upolstered Chair 8. Couch 9. Chair	11. Bed 12.Storage Cabinet 13. Ottoman 14. Locker 15. Toilet Partition 16. Refrigerator 17. Range 18. Microwave 20. Dryer 21. Oven Toaster		Condition 1. Good 2. Fair 3. Poor Recommendations A. Repair &/or Repaint B. Replace C. Repaint/Reseal
No.	Name	Poured Conc.	Conc. Block	Drywall	Carpet	Non-Slip Vinyl Tile	Vinyle Composite Tile	Ceramic Mosaic	Concrete	Rubber	Ceramic Mosaic Tile	Acoustic Tile	Gypsum Board	Exposed	Door	Frame	Hardware	A. Blinds B. Curtains					Quantity	
First Floor															C	C	C	A		1	1/2/3/12		1/2/1/1	1
101	Waiting														C	C	C	A		1	1/2/12/10		3/3/1/1	1
104	General Office														C	C	C	A		1	1/2/9/3		1/1/2/1	1
102	Customer Accounts Super.														C	C	C	N/A			/		/	/
105	Accounting														C	C	C	N/A		1	14		1	1
103	-														C	C	C	N/A			10/7/1		/	8/2/3
106	Vault														C	C	C	N/A		1	16/18/21		1/2/1	1
107	Treasurer														C	C	C	N/A		1	3		3	2/3, A/B
127	Waiting														C	C	C	N/A		1	1/2/3		2/2/1	1
129	Vestiblue														C	C	C	N/A		2	7/9/14		2/1/27	2 A/B
108	Exec. Secretary														C	C	C	N/A		1	/		/	/
109	General Manager														/	/	/	/		1 / 2	/		/	/
126	-																							
110	-																							
111	-																							
112	Boardroom																							
128	Corridor																							
125	-																							
124	Billing & Corrections Super.																							
123	-																							
122	-																							
113	Coats																							
130	Mech.																							
114	Conference																							
115	Elect.																							
116	Storage																							
117	Storage																							

118	Computer																							
119	Mailing, Meter Readers, Coin Counting																							
120	Computer Operation																							
121	Progr.																							
Second Floor																								
220	Stair														B	B	C	N/A	N/A	1				
201	Electric Technologist										WD				C	C	C	A	N/A	1	1/2/7		1/2/1	1
202	Electric Super.														C	C	C	A	N/A	1	1/2/7		1/1/4	1
203	Service Super														C	C	C	A	N/A	1	1/2/7		1/1/1	1
221	Corridor										WD				B	B	C	N/A	N/A	1	N/A		N/A	N/A
204	-										WD				B	B	C	N/A	N/A		1/2/3/7			
205	-										WD				B	B	C	N/A	N/A		1/2/3/7			
206	-										WD				B	B	C	N/A	N/A		1/2/3/7		6/6/2/5	1/2 A/B
207	-										WD				B	B	C	N/A	N/A		1/2/3/7			
219	-										WD				B	B	C	N/A	N/A		1/2/3/7			
218	Men's Washroom														B	B	C	N/A		Cabinet 1 / 2, A/B	15		1	1
217	Women's Washroom														B	B	C	N/A		Sink 1/2, A/B	15		1	1
216	Lounge										CP				B	B	C	A	N/A	1 / 2, A/B				
209	Corridor														C	C	C	N/A	N/A	1 / 2, A/B	3		1	1
208	Lunch Room														B	B	C	A		Kitchenet 2/B	4/5/16/18/10		9/1/1/1/1	2/3 B/C
210	Vestiblue														B	B	C	N/A	N/A					
211	Secretary														C	C	C				1/2/3		3/4/6	1
215	Storage														C	C	C				3/12		1/1	1
212	Water Technologist														C	C	C				1/2/10/7/12		1/1/1/2/1	1
213	Water Super.														C	C	C				1/2/10/7/12		1/1/1/2/1	1
214	Consumer Serv. Rep.														C	C	C				1/2/10/7/12		1/1/1/2/1	1

Room		Walls			Flooring & Base: Flooring					Base		Ceilings			Doors, Hardware, Frames			Window Coverings	Millwork	Remarks	Furniture			
															A. Hollow Metal B. Wood C. Alum.					Condition 1. Good 2. Fair 3. Poor Recommendations A. Repair &/or Repaint B. Replace C. Repaint/Reseal	Item 1. Desk 2. Desk Chair 3. Filing Cabinet 4. Kitchen Table 5. Kitchen Chair 6. Lounge Chair 7. Upolstered Chair 8. Couch 9. Chair 10. Table 11. Bed	12.Storage Cabinet 13. Ottoman 14. Locker 15. Toilet Partition 16. Refrigerator 17. Range 18. Microwave 20. Dryer 21. Drawer storage 22. Whiteboard-Moveable		Condition 1. Good 2. Fair 3. Poor Recommendations A. Repair &/or Repaint B. Replace C. Repaint/Reseal
No.	Name	Poured Conc.	Conc. Block	Drywall / Glass	Carpet	Non-Slip Vinyl Tile	Vinyle Composite Tile	Ceramic Mosaic	Concrete	Rubber	Ceramic Mosaic Tile | WD | CP|	Acoustic Tile	Gypsum Board	Exposed	Door	Frame	Hardware	A. Blinds B. Curtains					Quantity	
Main Floor																								
	Lobby			GL							CMT				C	C	C	A			7		5	3 A/B
	Vestibule 1			GL							CMT				C	C	C	A			7		2	3 A/B
	Reception			GL							CP							A		1	7		4/4/4/4/2	3 A/B
	Workstations			D							CP				B	B	C	A		2/B	1/2/3/10/12			2 A/B
	Vestibule 2			GL							CMT				C	C	C	N/A						
	Office 1			D							CP				B	B	C			2/B	1/2/7		1/1/2	1
	Office 2			D							CP				B	B	C			2/B	1/2/7		1/1/3	1
	Office 3			D							CP				B	B	C	A		2/B	1/2/7		1/1/1/2	1
	Office 4			D							WD				B	B	C	A/B		2/B	1/2/3/7			1
	Office 5			D							CP									2/B				
	Stg Main			D							WD							N/A		1/2/A				
	STG Off 4			D							CP										3		1	
	WR - Off 4														B	B	C	N/A		2 A/B	N/A		N/A	
	WR - Mens			D											B	B	C	N/A		2 A/B	N/A			
	WR- Females			D											B	B	C	N/A		2 A/B	N/A			
	Boardroom			D							CP				B	B	C	A/B		1	10/7/21/22			1
	Office 6			D							CP				C	C	C	A/B		1	1/2/7		1/1/2	1
	Service Room			D																1	10/16/18		1/1/1	1
	Conference Room			D							CP				B	B	C	N/A		1/A	10/2/7		1/13/3	1
	Workstation I.T. 1			D							CP				C	C	C	N/A		1	1/2/12		4/4/2	1
	Service Room STG			D											C	C	C	N/A		1				
	Workstation I.T. 2			D											C	C	C	N/A		1	1/2/12		2/2/3	1
	FH1 Server Room			D											C	C	C	N/A		C	N/A		2/2/3	1
	FHS1 Server Room			D											C	C	C	N/A		C	N/A		2/2/3	1
	STG Office 1			D																1/2 A/B				
	Circle Workstation			D							CP				B	B	C				1/2/3/12		8/8/6/4	1/2 A/B

APPENDIX D – ACCESSIBILITY CHECKLIST

Section 2.0 Common Elements (Exterior and Interior)

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
2.1	**Ground and Floor Surfaces**				Yes, out dated SR strips stairs
2.1.1	SURFACE: firm, stable and slip resistant				
	JOINTS: no wider than 6mm (preferred) or 10 mm (maximum) between surfaces				In most locations
	CHANGE IN LEVEL: beveled slope 1:2 (maximum), where change in level is between 6 and 13 mm OR a slope, ramp or curb ramp, where change in level is greater than 13 mm				
2.1.2	CARPETS: securely fastened, 13 mm (maximum) high				Looks dated
2.1.3	FLOOR MATS: securely fixed, 13 mm (maximum) high with beveled edges				
2.1.4	GRATINGS AND OPENINGS: 13 mm (maximum) wide in the direction of travel				
2.2	**Ramps**				
App	Provided where ELEVATION is greater than 1:20 (5%)				
2.2.1	RUNNING SLOPE: 1:15 (6.6.7%)				
	CROSS SLOPE: 1:50 (2%)				
	SURFACE: firm, stable and slip-resistant				
	CLEAR WIDTH: 1100 mm (minimum)				
	LENGTH: 9000 mm (maximum) or provide landing				
	EDGE PROTECTION: Provision				
	EDGE PROTECTION (CURB): 75 mm high (minimum))where there is no solid enclosure or guard				
	EDGE PROTECTION (RAILING OR BARRIER): extend to within 50 mm from floor				
	COLOUR CONTRASTING STRIP: provided at slope changes				
	STRIP DIMENSION: 50 +/- 10 mm wide and equal to the width of the ramp				
	STRIP FEATURES: colour contrasted and slip-resistant				
2.2.2	LANDINGS: Provision at top, bottom, intermediate level where there is any direction change				
	LANDING CROSS SLOPE: 1:50 (2%)				
	LANDING DIMENSION: 1800 mm by 1800 mm at top, bottom, and where there is an abrupt change in direction				
	LANDING DIMENSION (IN-LINE LANDING): 1800 mm long and at least the same width as the ramp				
2.2.3	HANDRAILS: Provision				
	HANDRAIL HEIGHT: 865 to 965 mm on both sides				
	WIDTH BETWEEN HANDRAILS: 1100 mm (minimum) clear				
	HANDRAIL EXTENSION (TOP AND BOTTOM LANDING): extend horizontally 300 mm (minimum)				
	HANDRAIL RETURNS: Return to the guard / rail or wall or floor				

Section 2.0 Common Elements (Exterior and Interior)

Standard Ref #	Criteria / Requirement	Compliance			
		Yes	No	N/A	Comments / Observations
2.2.4	HANDRAIL DIMENSION (CIRCULAR X-SECTION): outside diameter 30 - 40 mm				
	HANDRAIL DIMENSION (NON CIRCULAR X-SECTION): perimeter dimension 100- 125 mm, with X-section dimension of 45 mm (maximum)				
	HANDRAIL CLEARANCE: 50 mm (minimum) between grasping surface and any adjacent surface				
2.2.5	GUARDS: Provision				
	GUARD HEIGHT: 1070 mm (minimum) above floor surface				
	GUARD DESIGN: NO member, attachment or opening located 140 - 900 mm high above the floor surface				
2.3	**Stairs**				
2.3.1	SURFACE: stable, firm, slip-resistant and non-glare				Dated - does not meet code
	RISER: 125 to 180 mm high, uniform				
	TREAD: 280 to 355 mm depth, uniform				
	OPEN RISER: not permitted				
	NOSING PROJECTION: 38 mm (maximum)				
	NOSING STRIP: Provision				
	NOSING STRIP DIMENSION: 50 mm (+/- 10 mm) deep at the leading edge of the tread, extending the full with of the tread				
	NOSING STRIP CONTRAST: high tonal contrast with adjacent surfaces				
	TACTILE WALKING SURFACE INDICATOR (TWSI): Provision				
	TWSI LOCATION: at the top of stairs starting one tread depth back from the leading edge of the top step				
	TWSI DIMENSION: 610 mm (minimum) deep, extending the full width of the stair				3
2.3.2	HANDRAILS: Provision				
	HANDRAIL HEIGHT: 865 to 965 mm on both sides				787.4mm
	WIDTH BETWEEN HANDRAILS: 1100 mm (minimum) clear				2464mm
	HANDRAIL EXTENSION (TOP LANDING): extend horizontally 300 mm (minimum)				152.4mm
	HANDRAIL EXTENSION (BOTTOM LANDING): extend diagonally for a horizontal distance equal to one tread depth beyond the bottom tread nosing, 300 mm parallel to the floor surface				152.4mm
	HANDRAIL RETURNS: Return to the guard / rail or wall or floor				
2.4.2	HANDRAIL DIMENSION (CIRCULAR X-SECTION): outside diameter 30 - 40 mm				
	HANDRAIL DIMENSION (NON CIRCULAR X-SECTION): perimeter dimension 100- 125 mm, with X-section dimension of 45 mm (maximum)				

Section 2.0 Common Elements (Exterior and Interior)

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	HANDRAIL CLEARANCE: 50 mm (minimum) between grasping surface and any adjacent surface	■			
2.5.2	GUARDS: Provision			■	
	GUARD HEIGHT: 1070 mm (minimum) above floor surface		■		1016mm (40 Inches)
	GUARD DESIGN: NO member, attachment or opening located 140 - 900 mm high above the floor surface	■			
2.4	**Guards and Handrails**		■		
2.4.1	GUARD FEATURES: prevent the passage of a sphere 100 mm (maximum)		■	■	
	GUARD HEIGHT: 1070 mm (minimum) above floor surface		■		1016mm
	GUARD DESIGN: NO member, attachment or opening located 140 - 900 mm high above the floor surface			■	
2.4.2	HANDRAIL DIMENSION (CIRCULAR X-SECTION): outside diameter 30 - 40 mm			■	
	HANDRAIL DIMENSION (NON CIRCULAR X-SECTION): perimeter dimension 100- 125 mm, with X-section dimension of 45 mm (maximum)		■		
	HANDRAIL CLEARANCE: 50 mm (minimum) between grasping surface and any adjacent surface	■			
2.5	**Overhanging and Protruding Objects**				
2.5.1	PROTRUDING OBJECT: no more than 100 mm from wall or have a cane detectable feature with leading edge at 680 mm high or lower, where projection is more than 100 mm		■		
	PROTRUDING OBJECT: clear width of route 1500 mm (minimum) for exterior and 1100 (minimum) for interior		■		
2.5.2	HEADROOM CLEARANCE: 2300 mm (minimum) or a cane detectable feature with leading edge at 680 mm high or lower, where headroom is lower than 2300 mm		■		
2.6	**Rest Areas**				
2.6.1	CONSULTATION: the public and persons with disabilities	■			
	CONSULTATION: the Grand River Accessibility Advisory Committee			■	
2.6.2	SURFACE: placed on firm, stable and slip-resistant surfaces	■			
	COLOUR CONTRAST: contrast through ground finish, texture and / or tone between the rest area and the accessible path of travel		■		
	CLEAR FLOOR SPACE: 1200 mm wide by 1350 mm long (minimum)	■			
	SEATING: Provision as per Section 2.10, Seating, Tables and Work Surfaces			■	
2.7	**Tactile Walking Surface Indicators**				
App	PROVISION: at curb ramps and depressed curbs			■	
	PROVISION: where walking surfaces between pedestrian and vehicular areas are not separated by curbs			■	

Section 2.0 Common Elements (Exterior and Interior)

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	PROVISION: at top of stairs				
	PROVISION: at both sides of ground level railway crossings				
	PROVISION: at unprotected edges with a drop off greater than 250 mm in height or where the slope down is greater than 1:3				
2.7.1	DESIGN FEATURES: Raised tactile profile, truncated domes (e.g., circular and flat-topped domes)				
	SURFACE: slip-resistant and non-glare				
	TWSI CONTRAST: high tonal contrast between the TWSI and the adjacent surfaces				
2.7.2	FLAT TOPPED DOMES: are 5 mm (+/- 1 mm) high				
	DIAMETER OF TOP DOMES: 12 to 25 mm				
	DIAMETER OF LOWER BASE OF DOMES: 10 mm (+/- 1 mm) more than the diameter of the top				
	DOMES ARRANGEMENT: in a square grid				
	DOMES SPACING: as per table below:				

Top Diameter of Flat Topped Domes (mm)	Spacing Between the Centres of Adjacent Domes (mm)
12	42 to 61
15	45 to 63
18	48 to 65
20	50 to 68
25	55 to 70

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
2.7.3	TWSI AT RAILWAY CROSSINGS LOCATION: edge of TWSI 1800 to 4600 mm from the centre line of the nearest rail				
	TWSI AT RAILWAY CROSSINGS DIMENSION: 610 mm (minimum) deep				
2.7.4	TWSI AT REFLECTING POOLS / WATER FEATURES LOCATION: 610 mm from the leading edge of any drop-off				
	TWSI AT REFLECTING POOLS / WATER FEATURES DIMENSION: 610 mm (minimum) deep, extending the full length around all unprotected edges that border the drop-off				
2.8	**Drinking Fountains**				One in main building
2.8.1	PROVISION: at least one lowered drinking fountain				

Section 2.0 Common Elements (Exterior and Interior)

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	LOCATION: adjacent to an accessible route, recessed or with a leading edge that is cane detectable at 680 mm (maximum) high, if they protrude into an accessible route				Drinking fountain does not comply (placement/ height/ design) Is mounted to high to meet code
2.8.2	CLEAR FLOOR SPACE: 915 mm wide by 1370 mm deep (minimum) for forward approach				
	CLEAR FLOOR SPACE: 1525 mm wide by 915 mm deep (minimum) for side approach				
2.8.3	CLEAR KNEE SPACE: 760 mm wide by 450 mm deep at 735 mm high (minimum)				
	CLEAR TOE SPACE: 350 mm high from a point of 300 mm back from the front edge to the wall				
	DEPTH AT BASE: 700 mm (minimum)				
2.8.4	OPERATING CONTROL: not foot-operated				
	OPERATING CONTROL: located at or near the front of the drinking fountain				
	OPERATING CONTROL: operable with one hand with force of 22N (maximum)				
2.8.5	WATER SPOUT: 915 mm high				
	WATER SPOUT: 125 mm (maximum) from the front and 380 mm (minimum) from the vertical support				
	WATER FLOW: 100 mm high (minimum)				
2.9	**Public Telephones**				None onsite
2.9.1	PROVISION: At least one accessible or as per table below:				

Total Number of Telephone Unites Located on Floor	Number of Telephone Units Required to be Accessible
1 or more single units	1 per floor
1 bank	1 per floor
2 or more banks	1 per bank

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
2.9.2	SIGNAGE: International Symbols of Accessibility and Hearing Loss				
	CLEAR FLOOR SPACE (FORWARD APPROACH): minimum 915 mm wide by 1370 mm depth				
	CLEAR FLOOR SPACE (SIDE APPROACH): minimum 1525 mm wide x 915 mm depth				
	TELEPHONE LOCATION: adjacent to an accessible route, recessed or with a leading edge that is cane detectable at 680 mm (maximum) high, if they protrude into an accessible route				
	OVERHEAD CLEARANCE: 2300 mm (minimum) high				
	STALL OR BOOTH FEATURES: sound-absorbing surfaces				

Section 2.0 Common Elements (Exterior and Interior)

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
2.9.3	OPERATING CONTROL: push button controls with large size numbers				
	OPERATING CONTROL HEIGHT: maximum 1200 mm				
	OPERATING CONTROL REACH: maximum 485 mm from front edge of phone cabinet or shelf				
	TELEPHONE CORD LENGTH: minimum 735 mm				
	TELEPHONE FEATURES: adjustable volume controls for users with hearing loss				
2.9.4	SHELVES & COUNTERS: Provision (underneath at least one telephone)				
	SHELF DIMENSION: minimum 500 mm wide by 350 mm deep				
	SHELF TOP SURFACE: 775 - 875 mm high above floor				
	KNEE CLEARANCE: minimum 740 mm high				
	CLEAR SPACE BETWEEN TOP OF SHELF AND LOWER EDGE OF TELEPHONE: minimum 250 mm high				
2.9.5	TEXT TELEPHONES (TTYs): Provision				
	SIGNAGE: International Symbols of Accessibility and Hearing Loss and symbol for TTY				
2.10	**Seating, Tables and Work Surfaces**				All furniture is dated snf for the most part does not meet code standards for height, width and adjustibility
2.10.1	BENCHES & SEATS: Provision				
	SEAT HEIGHT: 450 - 500 mm				
	SEAT DEPTH: 400 - 510 mm				
	SEAT BACK SUPPORT: Provision				
	SEAT BACK SUPPORT: extending 455 mm (minimum) above the seat surface, or affix the seat to a wall				
	ARM REST: Provision (at least one)				
	ARM REST HEIGHT: 220 - 300 mm from the seat				
2.10.2	TABLES & WORK SURFACES: Provision				
	TOP SURFACE HEIGHT: 730 mm - 865 mm high				
	CLEAR KNEE SPACE: minimum 760 mm wide by 480 mm deep by 685 mm high				
	CLEAR TOE SPACE (as required based on table design): minimum 350 mm high by 230 mm deep				
	CLEAR FLOOR SPACE (FORWARD APPROACH): minimum 760 mm wide by 1370 mm deep; 480 mm (maximum) of the length allowed to extend underneath the table				
	CLEAR FLOOR SPACE (SIDE APPROACH): minimum 1525 mm wide by 915 mm deep				

Section 2.0 Common Elements (Exterior and Interior)					
Standard Ref #	**Criteria / Requirement**	**Compliance**			
		Yes	**No**	**N/A**	**Comments / Observations**
2.11	**Accessibility During Construction**				
2.11.1	WALKWAY WIDTH: a minimum 1.5 m wide pedestrian facility along at least one side of the corridor				
	WALKWAY HEIGHT (if overhead works are required): 2.1 m clear headroom along the entire 1.5 m width				
2.11.2	BOUNDARIES: cane detectable boundary protection with edge or barrier at least 75 mm high above the ground surface				
2.11.3	SINAGE (where pedestrians must be detoured): signage at both the near side and the far side of the intersection preceding the detour				

Section 3.0 Exterior Environments

<table>
<tr><th rowspan="2">Standard Ref #</th><th rowspan="2">Criteria / Requirement</th><th colspan="3">Compliance</th><th></th></tr>
<tr><th>Yes</th><th>No</th><th>N/A</th><th>Comments / Observations</th></tr>
<tr><td>3.1</td><td>Parking</td><td></td><td></td><td></td><td></td></tr>
<tr><td>3.1.2</td><td>PROVISION: as per table below:
<table>
<tr><th>Total Number of Parking Spaces</th><th>Number of Accessible Spaces Required</th><th>Number of Type A</th><th>Number of Type B</th></tr>
<tr><td>1 - 12</td><td>1</td><td>1</td><td>0</td></tr>
<tr><td>13 - 25</td><td>1</td><td>0</td><td>1</td></tr>
<tr><td>26 - 50</td><td>2</td><td>1</td><td>1</td></tr>
<tr><td>51 - 75</td><td>3</td><td>1</td><td>2</td></tr>
<tr><td>76 - 100</td><td>4</td><td>2</td><td>2</td></tr>
<tr><td>101 - 133</td><td>5</td><td>2</td><td>3</td></tr>
<tr><td>134 - 166</td><td>6</td><td>3</td><td>3</td></tr>
<tr><td>167 - 250</td><td>7</td><td>3</td><td>4</td></tr>
<tr><td>251 - 300</td><td>8</td><td>4</td><td>4</td></tr>
<tr><td>301 - 350</td><td>9</td><td>4</td><td>5</td></tr>
<tr><td>351 - 400</td><td>10</td><td>5</td><td>5</td></tr>
<tr><td>401 - 450</td><td>11</td><td>5</td><td>6</td></tr>
<tr><td>451 - 500</td><td>12</td><td>6</td><td>6</td></tr>
<tr><td>501 - 550</td><td>13</td><td>6</td><td>7</td></tr>
<tr><td>551 - 600</td><td>14</td><td>7</td><td>7</td></tr>
<tr><td>601 - 650</td><td>15</td><td>7</td><td>8</td></tr>
<tr><td>651 - 700</td><td>16</td><td>8</td><td>8</td></tr>
<tr><td>701 - 750</td><td>17</td><td>8</td><td>9</td></tr>
<tr><td>751 - 800</td><td>18</td><td>9</td><td>9</td></tr>
<tr><td>801 - 850</td><td>19</td><td>9</td><td>10</td></tr>
<tr><td>851 - 900</td><td>20</td><td>10</td><td>10</td></tr>
<tr><td>901 - 950</td><td>21</td><td>10</td><td>11</td></tr>
<tr><td>951 - 1000</td><td>22</td><td>11</td><td>11</td></tr>
<tr><td>1000 +</td><td>11 + 1% of total</td><td colspan="2">(1) Where an even number is required, provide equal number of Type A and B.
(2) Where an odd number is required, provide an equal number of Type A and B plus an additional Type B.</td></tr>
</table>
</td><td></td><td></td><td></td><td>2 spots provided on site however not up to current code standards</td></tr>
<tr><td></td><td>MULTIPLE PARKING LOTS: number and type of accessible parking spaces for each separate parking facilities provided</td><td></td><td></td><td></td><td></td></tr>
</table>

Section 3.0 Exterior Environments

Standard Ref #	Criteria / Requirement	Compliance			Comments / Observations
		Yes	No	N/A	
3.1.3	LOCATION: as close as possible to an accessible entrance (within 30 m of accessible entrance)				
	SURFACE: firm, stable and slip-resistant				Asphalt parking lot with no slip resistant surfacing
	RUNNING SLOPE: 1:50 (2%) (maximum)				
	CROSS SLOPE: 1:50 (2%) (maximum)				
	TYPE A SPACE: 3400 mm (minimum) wide by 5500 mm long				
	TYPE B SPACE: 2400 mm (minimum) wide by 5500 mm long				
	ACCESS AISLE: Provision adjacent to parking space				No aisles rovided onsite B.F. space unload in car trafficed area
	ACCESS AISLE: 1500 mm wide, extend the full length of the parking space				
	ACCESS AISLE: connected to an accessible path of travel and curb ramp if required				
	HEADROOM CLEARANCE: 2100 mm (minimum)				
3.1.4	DIRECTIONAL SIGNAGE: if required to indicate location of accessible parking spaces				
	DIRECTIONAL SIGNAGE: if required to indicate location of accessible entrances				
	VERTICAL SIGNAGE DIMENSION: 300 mm wide by 600 high (minimum)				
	VERTICAL SIGNAGE FEATURES: mark with International Symbol of Accessibility				
	VERTICAL SIGNAGE MOUNTING HIEIGHT: 1500 mm to 2000 mm (centre)				
	TYPE A SPACE SIGNAGE: identified as "Van Accessible"				
	PAVEMENT SIGNAGE DIMENSION: 1525 mm wide by 1525 depth (minimum)				
	PAVEMENT SIGNAGE FEATURES: mark with International Symbol of Accessibility				
3.1.5	ON-STREET PARKING: Provision				
3.2	**Passenger Loading Zones**				No loading zone areas
3.2.1	LOCATION: as close as possible to the nearest accessible entrance or within 30 metres (maximum)				
	VERTICAL CLEARANCE: 3600 mm (minimum) throughout vehicular pull-up space and passenger loading zone				
	ACCESS AISLE DIMENSION: 2440 mm wide by 7400 mm long (minimum)				
	ACCESS AISLE FEATURES: colour contrasting diagonal pavement markings, extending the full length of the space				
	CURB RAMP: Provision, if there is a change in level				
	ACCESSIBLE ROUTE: 1500 mm wide, connected to the accessible entrance				
	TWSI PROVISION: where accessible route and access aisle are not separated by a curb				

Section 3.0 Exterior Environments					
Standard Ref #	**Criteria / Requirement**	**Compliance**			
		Yes	**No**	**N/A**	**Comments / Observations**
3.2.2	VERTICAL SIGNAGE DIMENSION: 300 mm wide by 600 mm high (minimum)				
	VERTICAL SIGNAGE FEATURES: mark with the International Symbol of Accessibility				
	VERTICAL SIGNAGE MOUNTING HEIGHT: 1500 mm to 2000 mm (centre)				
3.3	**Exterior Paths of Travel**				
3.3.1	SURFACE: firm, stable and slip-resistant				
	HEADROOM CLEARANCE: 2300 mm (minimum)				
	TACTILE WALKING SURFACE INDICATOR: provided along the full length of the crossing boundary where a pedestrian route crosses or joins a vehicular route and the walking surfaces are not separated by curbs, railings or other elements between the pedestrian and vehicular areas				
	REST AREA: provided at every 30 m along path of travel				
3.3.2	CLEAR WIDTH: 1500 mm (minimum)				
	PASSING AREA: 1800 mm by 1800 mm (minimum) where the clear width of exterior paths of travel is less than 1500 mm (minimum) at intervals of 30 metres or less				
	ENTRANCES (GATES, BOLLARDS): 850 mm (minimum)				No gate
3.3.3	RUNNING SLOPE: 1:20 (5%) (maximum)				
	CROSS SLOPE (ASPHALT, CONCRETE, HARD SURFACES): 1:20 (5%)				
	CROSS SLOPE (ALL OTHER SURFACES): 1:10 (10%) in all other cases				
3.3.4	CHANGE IN LEVEL: as per table below:				

Change in Level (Height)	Slope Requirements
1 - 5 mm	No bevel required
6 - 13 mm	1:2 bevel
14 - 74 mm	Maximum running slope 1:8 (12.5%) or provide a curb ramp
75 - 200 mm	Maximum running slope 1:10 (10%) or provide a curb ramp
More than 200 mm	Provide a ramp

Standard Ref #	Criteria / Requirement	Yes	No	N/A	Comments / Observations
	CURB PROTECTION: 75 mm (minimum) high, where change in level is between 200 and 600 mm				
	TWSI PROVISION: extend full width of drop-off at the edge of drop-off where slope is more than 1:3				
	GUARD PROVISION: 1070 mm (minimum), where change in level is more than 600 mm or where the adjacent surface within 1200 mm from the accessible route has a slope of more than 1:2				*Site parking is out of date. Does not comply

Section 3.0 Exterior Environments					
Standard Ref #	Criteria / Requirement	Compliance			
		Yes	No	N/A	Comments / Observations
3.4	**Curb Ramps and Depressed Curbs**				*There is no ramping on -site (sloping for B.F. spaces are sloping upwards to door entrance)
3.4.1	SURFACE: stable, firm and slip-resistant				
	ALIGNMENT: aligned with the direction of travel and curb ramp or depressed curb on the opposite side				
3.4.2	CLEAR WIDTH: 1500 mm (minimum), exclusive of flared sides				
3.4.3	RUNNING SLOPE FOR CURB RAMP: 8.33% (1:12) (maximum)				
3.4.4	RUNNING SLOPE FOR DEPRESSED CURB: 1:50 (2%) (maximum)				
	CROSS SLOPE FOR CURB RAMP: 1:50 (2%) (maximum)				
	FLARED SIDE FEATURES: clearly demarcated with grooved edges				
	FLARED SIDE SLOPE: 1:10 (10%), measured parallel to the curb line				
	LANDING: 1500 mm by 1500 mm (minimum) at top of curb ramp				
	LANDING RUNNING SLOPE: 1:50 (2%) (maximum)				
3.4.5	LANDING CROSS SLOPE: 1:50 (2%) (maximum)				
	TACTILE WALKING SURFACE INDICATOR DIMENSION: 610 mm (minimum) depth, extend full width of curb ramp				
3.4.6	TACTILE WALKING SURFACE INDICATOR LOCATION: set back 150 to 200 mm from the back edge of the curb				
3.5	**Accessible Pedestrian Signals**				Not on site
3.5.1	LOCATOR TONE: distinct from a walk indicator tone				
	LOCATION: within 1500 mm of the edge of the curb				
	LOCATION (where two APS assemblies are installed on the same corner): 3000 mm (minimum) apart				
	LOCATION (where two APS assemblies cannot be installed 3000 mm apart): single post installation; verbal announcement stating which crossing is active; push button located on the side of the post facing the pedestrian waiting area; face of each unit aligned parallel to associated crosswalk				
	MOUNTING HEIGHT: operable parts 1100 mm (maximum) high				
	TACTILE ARROW: align with the direction of crossing				
	INDICATORS: both audible and vibro-tactile walk indicators				
3.5.2	PUSH BUTTON LOCATION: adjacent to and 300 mm (maximum) from clear and level ground surface				

Section 3.0 Exterior Environments

Standard Ref #	Criteria / Requirement	Compliance			Comments / Observations
		Yes	No	N/A	
	PUSH BUTTON LOCATION: placed on the side of the post facing the pedestrian waiting area, with the face of the push button parallel to the associated crosswalk				
	PUSH BUTTON LOCATION: 600 mm (maximum) from the nearest extended crosswalk line that is farthest from the movement of parallel traffic				
	PUSH BUTTON SIGNAGE: high-contrast ratio information sign mounted above push button with the face of the sign parallel to the crossing route				

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
4.1	**Entrances**				
4.1.1	PROVISION: at least one main or primary entrance	■			
	ACCESSIBLE PROVISION: at least 50% of the total number of building entrances		■		
	LOCATION: 15 metres or less from designated accessible parking or passenger loading or drop-off zones	■			
4.1.2	ENTRANCE LANDING: 1800 mm by 1800 mm (minimum)	■			
	OVERHEAD CLEARANCE: 2750 mm (minimum)	■		■	Parking is exterior with no over-head issues
	POWER DOOR OPERATOR: Provision	■			
	CLEAR WIDTH: 915 mm (minimum)	■			
	VESTIBULE: 1500 mm (minimum), plus the width of the door swinging into the space OR turning space of 1500 mm (minimum) diameter	■			
4.2	**Doors and Doorways**				
4.2.1	DOOR CLEAR WIDTH: 915 mm (minimum)	■			
4.2.2	OPENING FORCE EXTERIOR DOOR: 38 Newtons (8.5 pounds)				Do not have device to test this
	OPENING FORCE INTERIOR DOOR: 22 Newtons (5 pounds)				
	OPENING FORCE SLIDING DOOR: 22 Newtons (5 pounds)				
4.2.3	COLOUR CONTRAST: between doors and / or door frames from the surrounding environment	■			
4.2.4	THRESHOLD: bevel at maximum slope of 1:2 (50%), where transition is between 6mm and 13 mm high	■			
4.2.5	DOOR HARDWARE TYPE: No knob hardware or thumb-latch handles		■		Had knobs
	DOOR HARDWARE MOUNTING HEIGHT: 900 mm - 1100 mm	■			
	DOOR HARDWARE FEATURES: usable with closed fist and operable with one hand (e.g., no tight grasping of hands, pinching of fingers or twisting of wrists)	■			BF operators not on all doors only Ent/Exit doors
4.2.6	REVOLVING DOORS OR TURNSTILES: adjacent gate or door with clear width of 860 mm (minimum)			■	
4.2.7	AUTOMATIC DOORS: suitable timing for safe passage			■	
4.2.8	POWER ASSISTED DOORS PROVISION: main entrances	■			
	POWER ASSISTED DOORS PROVISION: accessible washrooms		■		Not accessible (sizes are small, non-comply with any clearances needed/ doors are too small
	POWER ASSISTED DOORS PROVISION: interior doors along accessible routes and / or connecting accessible routes			■	

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	POWER ASSISTED DOORS PROVISION: doors into reception areas	■			
	POWER ASSISTED DOORS PROVISION: doors into highly used functional spaces (e.g., larger multi-purpose rooms, meeting or board rooms)		■		
	POWER ASSISTED DOORS PROVISION: doors leading to accessible exits and designated "Areas of Refuge"			■	Designated refuge area (some existing doors, not all) Not to current code
	POWER DOOR OPERATOR FEATURES: mark with International Symbol of Accessibility	■			
	POWER DOOR OPERATOR FEATURES: door remains fully open for 5 seconds (minimum)	■			
	POWER DOOR OPERATOR FEATURES: operable with a closed fist;		■		
	POWER DOOR OPERATOR MOUNTING LOCATION: clearly visible location upon approach on the latch side	■			Where they have them, yes. Only on a few doors.
	POWER DOOR OPERATOR MOUNTING LOCATION: between 600 mm and 1500 mm, on a level wall surface or separate post, beyond the door swing where the door opens towards the control	■			
	POWER DOOR OPERATOR DIMENSION: 150 mm (minimum) in diameter where it is circular OR 150 mm wide by 915 mm long (minimum) where it is a vertical extended power door operator	■			
	POWER DOOR OPERATOR MOUNTING HEIGHT: 900 mm to 1100 mm	■			
	VERTICAL EXTENDED POWER DOOR OPERATOR MOUNTING HEIGHT: extend from not more than 200 mm and not less than 900 mm high			■	
	POWER DOOR OPERATOR CLEAR FLOOR SPACE: minimum 1675 mm by 1675 mm	■	■		Yes/No depends on the room (Ex. Ent/ customer service)
4.2.9	DOOR SWINGING INTO ACCESSIBLE ROUTE: door is recessed OR cane detectable features at right angles to the wall containing the door, with the lower rail surface 680 mm high (maximum), extending 300 mm (minimum) beyond the door swing, on both sides of doors			■	
4.2.10	MANOEUVERING CLEARANCES: as per table below:		■		

Context	Floor Space Required in mm		
	Depth (min)	Width (Min)	Space Beside Latch
Side-hinged Door - Front Approach			
Pull side	1525	1600	600
Push side	1370	1250	300
Sliding Door			

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	(continued door clearance table, below)				There will be locates where it conforms, however most of the building is not B.F. (to the lowest standards)

Front approach	1370	1100	300
Side approach	1370	1550	600
Side-hinged Door - Hinge Side Approach			
Pull side	1600	1600	600
Push side	13750	1830	450
Side-hinged Door - Latch Side Approach			
Pull side	1370	1600	600
Push side	1370	1525	600
Folding Door			
Pull side	1220	n/a	n/a
Push side	1220	n/a	n/a
Recessed Door - Front Approach			
Pull side	1525	n/a	450
Push side	1220	n/a	300
Doorways Without Doors			
Front approach	1220	n/a	n/a
Side approach	1065	n/a	n/a

Standard Ref #	Criteria / Requirement	Yes	No	N/A	Comments / Observations
4.2.11	DOORS IN SERIES: 1500 mm (minimum), plus the width of the door swinging into the space OR turning space of 1500 mm (minimum) diameter				
4.2.12	GLAZED DOORS OR DOORS WITH SIDELIGHTS: continuous opaque and high colour contrast strips provision				
	GLAZING STRIPS DIMENSION: 50 mm (minimum) wide				
	GLAZING STRIPS MOUNTING HEIGHT: between 1350 mm and 1500 mm				
4.2.13	VISION PANEL DIMENSION: 75 mm (minimum) wide				
	VISION PANEL MOUNTING HEIGHT: bottom edge 900 mm (maximum) with side edge 250 mm (maximum) from latch side of the door				
4.3	**Interior Accessible Routes**				
4.3.1	SURFACE: stable, firm and slip-resistant				
	HEADROOM CLEARANCE: 2100 mm (minimum)				
	REST AREA: provision where accessible routes are more than 30 metres long				
	CLEAR WIDTH: 1100 mm (minimum) or 1500 mm (minimum) in high traffic areas				

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
4.3.2	PASSING AREA: 1800 mm by 1800 mm (minimum) at interval of 30 metres (maximum), where clear width is less than 1600 mm along a route that exceeds 30 metres				Building is old and dated. Does not support/ supply B.F. Accessibility roots/ path of trowel.
4.3.3	RUNNING SLOPE: 1:20 (5%) (maximum) OR designed as a ramp				
	CROSS SLOPE: 1:50 (2%) (maximum)				
4.3.4	CHANGE IN LEVEL: high tonal contrast marking on the edge where the change in level is less than 200 mm				
	CHANGE IN LEVEL: high tonal contrast curb or other barrier protection 75 mm (minimum) high, where change in level is between 200 and 600 mm				
	CHANGE IN LEVEL: guards with cane detectable bases, where change in level is greater than 600 mm				
4.4	**Elevating Devices**				Building does not have any elevator system
4.4.1	CAB DIMENSION AND DOOR WIDTH: as per table below:				
	HALL CALL BUTTONS MOUNTING HEIGHT: 890 - 1200 mm from floor				
	HALL CALL BUTTON CLEAR FLOOR SPACE: 760 mm wide by 1220 mm depth (minimum)				
	VISUAL AND AUDIBLE SIGNALS: at each hoistway entrance to indicate which car is answering a call and its direction of travel				
	AUDIBLE SIGNAL: sound once for the “up” direction and twice for the “down” direction, or alternatively, provide verbal annunciators				
	ELEVATOR CAR IDENTIFICATION SIGNAGE: tactile with characters 50 mm high				
	CAB OPERATING CONTROL MOUNTING HEIGHT: 1220 mm high (maximum, to centreline of control preferred), or 1370 mm high is permitted, for cars with more than 16 openings				
	HANDRAILS MOUNTING HEIGHT: 800 - 920 mm high				
	AUDIBLE AND VISUAL LOCATION INDICATOR: Provision				

Door Location	Door Clear Width	Inside Car (Side to Side)	Inside Car (Back Wall to Front Return)	Inside Car (Back Wall to Inside Face of Door)
Centred	1065	2030	1295	1370
Side (Off-centre)	915*	1725	1295	1370
Any	915*	1370	2030	2030
Any	915*	1525	1525	1525
Minimum Dimenstion of LU / LA (Limited use / limited application) Elevators				
Any	815	1065	1370	Not Specified

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	AUDIBLE LOCATION INDICATOR: verbal announcement identify floor at which car has stopped				
	EMERGENCY TWO-COMMUNICATION SYSTEM: hands-free speaker phone OR operating controls mounted at 1220 high (maximum)				
	EMERGENCY TWO-COMMUNICATION SYSTEM FEATURES: visual indicator when the system has been activated and the emergency call has been received				
4.5	**Washrooms**				Does not have one in the main building There is a B/F// Uni washroom in Shop Building
4.5.1	UNIVERSAL WASHROOM PROVISION: as per table below:				

Number of Storeys in Building	Minimum Number of Universal Washrooms per Building
1 - 3	1
4 - 6	2
6 +	3 plus 1 for each additional increment of 3 stores in excess of 6 storeys

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	ACCESSIBLE WATER CLOSER STALL PROVISION: as per table below:				-No washrooms are to any B.F. design -Clearance heights are wrong -Fixtures and furniture are non-compliant with current code

Number of Water Closets per Washroom	Minimum Number of Accessible Water Closet Stalls per Washroom
1 - 3	0, where a universal washroom is provided on the same floor level within 45 m of the washroom, or 1, where a universal washroom is not provided on the same floor level within 45 m of the washroom
4 - 9	1
10 - 16	2
17 - 20	3
21 - 30	4

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	21 – 30 | 4 30 + | 5, plus 1 for each additional increment of 10 water closets per washroom in excess of 30 water closets per washroom				
	ACCESSIBLE WASHROOM LOCATION: centrally within a facility along an accessible route, within 45 metres (maximum) of regular washrooms				
	DIRECTIONAL SIGNAGE: provision to indicate location of nearest accessible washroom on the same floor, where washrooms are not accessible				
4.5.2	MULTIPLE OCCUPANCY WASHROOMS WITH ACCESSIBLE WATER CLOSET STALLS: Provision				
	IDENTIFICATION SIGNAGE: accessibility features include braille, tactile, International Symbol of Accessibility				
	ENTRANCE: clear width 915 mm (minimum), if door provided				
	ENTRANCE: equip with power door operator				
	FLOOR CLEARANCES: 1700 mm (minimum) between the inside face of an in-swinging entrance door and the outside face of an adjacent water closet stall				
	FLOOR CLEARANCES: 1400 mm (minimum) between outside wall of stall and any wall-mounted fixtures or other obstructions				
	FLOOR CLEARANCES: 1500 mm by 1500 mm (minimum) in front of the accessible water closet stall				
	TURNING SPACE INSIDE WASHROOM CIRCULATION AREA: 1500 mm (minimum), 500 mm (maximum) of which may be under the lavatory				
	SURFACE: slip-resistant, with a maximum slope of 1:50 (2%);				
	LAVATORY: accessibility features provided as per below:				
	WASHROOM ACCESSORIES: accessibility features provided as per below				
	ACCESSIBLE WATER CLOSET STALL: provided as per below				
	AUDIBLE FIRE ALARM SYSTEM: Provision				
	VISUAL FIRE ALARM SYSTEM: Provision				
	DRAINS: out of the path of travel, if provided				
4.5.3	UNIVERSAL WASHROOM: Provision				
	LOCATION: in the same vicinity as other washrooms, along the shortest accessible route				
	IDENTIFICATION SIGNAGE: include unisex pictogram (e.g., Male and Female) and the International Symbol of Accessibility				
	ENTRANCE DOOR: 915 mm (minimum) clear width				

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	ENTRANCE DOOR: equip with power door operator				
	ENTRANCE DOOR FEATURES: locking mechanism that can be locked from the inside and released from the outside				
	ENTRANCE DOOR OPERATING MECHANISM MOUNTING HEIGHT: 900 - 1000 mm				
	DOOR HANDLE: if it is an outward swinging door, 140 mm long (minimum), on the inside with midpoint 200 mm - 300 mm from the latch side of the door				
	INTERNAL DIMENSION: 1700 mm (minimum) (2500 mm preferred) between walls				
	TURNING DIAMETER: 1700 mm (minimum) clear				
	SURFACE: firm, stable and slip-resistant				
	LAVATORY: accessibility features provided as per below:				
	WASHROOM ACCESSORIES: accessibility features provided as per below				
	ACCESSIBLE WATER CLOSET: accessibility features provided as per below				
	GRAB BARS: provided as per below				
	LIGHTING: motion sensor for automatic illumination				
	AUDIBLE FIRE ALARM SYSTEM: Provision				
	VISUAL FIRE ALARM SYSTEM: Provision				
	ADULT-SIZE CHANGE TABLE CLEAR FLOOR SPACE: 810 mm wide by 1830 mm long (minimum) in each universal washroom				
	REINFORCEMENT: installed in the wall to permit the future installation of the change table				
	CLEAR FLOOR SPACE: 760 mm wide by 1500 mm long, parallel to the long side of the adult-size change table, where installed				
	ADULT-SIZE CHANGE TABLE: provided with accessibility features as per below, if provided.				
	BABY CHANGE STATION: provided with accessibility features as per below, if provided.				
	SHELF: provided with accessibility features as per below				
	DRAINS: out of the path of travel, if provided				
	EMERGENCY CALL SYSTEM: Provision				
	EMERGENCT CALL SYSTEM FEATURES: visual and audible signal devices both inside and outside of the washroom, activated by a push control device				
	EMERGENCY CALL SYSTEM SIGNAGE: posted above emergency button				
	EMERGENCY CALL SYSTEM FEATURES: linked to a display panel at a reception / information counter or to a centrally monitored station				

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
4.5.4	AMBULATORY WATER CLOSET STALL: Provision				
	STALL DIMENSION: 1500 mm (minimum) by 890 to 940 mm width				
	STALL DOOR: 810 mm (minimum) clear width				
	STALL DOOR FEATURES: swing outward, unless the minimum dimensions of the stall are not located within the door swing				
	STALL DOOR FEATURES: spring-type or gravity hinges				
	STALL DOOR FEATURES: capable of being latched from the inside and released from the outside in case of an emergency				
	DOOR PULL: on both sides of the door, near the latch side of the door, 900 mm - 1000 mm high above				
	WATER CLOSET LOCATION: centre line is centred between the partition walls				
	GRAB BAR: L-shaped grab bars on each side of the water closet;				
	SIGNAGE: sign on door that indicates that the stall is suitable for users who may require grab bar assistance				
	COAT HOOK: 1200 mm high				
4.5.5	ACCESSIBLE WATER CLOSET STALL: Provision				
	SIGNAGE: marked with International Symbol of Accessibility				
	CLEAR FLOOR SPACE: 1500 mm diameter (minimum)				
	EMERGENCY CALL SYSTEM: provision				
	AUDIBLE AND VISUAL SIGNAL DEVICES: both inside and outside of washroom activated by a push button				
	EMERGENCY CALL SYSTEM SIGNAGE: posted above emergency button				
	EMERGENCY CALL SYSTEM FEATURES: linked to a display panel at a reception / information counter or to a centrally monitored station				
	STALL DOOR: 860 mm (minimum) clear width				
	STALL DOOR LOCATION: aligned with water closet transfer space				
	STALL DOOR FEATURES: swings outward, unless a clear floor area of 820 mm wide by 1440 mm long (minimum)				
	STALL DOOR FEATURES: self-closing with spring-type or gravity hinges				
	STALL DOOR LOCKING MECHANISM: capable of being locked from the inside by a control that is operable with a closed fist				
	STALL DOOR FEATURE: can be released from the outside				
	DOOR PULL: D-type inside and outside of the door				
	DOOR PULL LENGTH: 140 mm (minimum)				

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	DOOR PULL MOUNTING LOCATION: horizontally 900 to 1000 mm high, centered 120 to 220 mm from latch side of the door				
4.5.6	WATER CLOSET SEAT HEIGHT: 430 mm - 485 mm				
	WATER CLOSET INSTALLATION OPTION 1: centreline of water closet from adjacent side wall 460 mm - 480 mm and an unobstructed transfer space of 900 mm wide by 1500 mm deep (minimum) on the other side of the water closet				
	WATER CLOSET INSTALLATION OPTION 2: 900 mm wide by 1500 mm deep (minimum) on each side of the water closet				
	BACK SUPPORT: where there is no seat cover / lid or tank				
	SEAT FEATURES: not spring activated				
	TOILET PAPER DISPENSER MOUNTING HEIGHT: below the grab bar, 600 to 800 mm				
	TOILET PAPER DISPENSER MOUNTING LOCATION: in line with front edge or 300 mm (maximum) from the front edge of the water closet				
	FLUSH CONTROL FEATURES: operable with a closed fist				
	FLUSH CONTROL LOCATION: on transfer side				
	COAT HOOK: 1200 mm (maximum) high on a side wall, projecting 50 mm (maximum)				
4.5.7	GRAB BARS SURFACES: non-abrasive and slip-resistant				
	GRASPING SURFACE: circular in shape, 35 mm to 40 mm (diameter)				
	CLEARANCE: 38 mm to 50 mm between mounting surface and the inside surface of the grab bar				
	HORIZONTAL GRAB BAR: Provision				
	HORIZONTAL GRAB BAR LENGTH: 600 mm (minimum)				
	HORIZONTAL GRAB BAR LOCATION: centered behind water closet				
	HORIZONTAL GRAB BAR MOUNTING HEIGHT: 840 and 920 mm				
	HORIZONTAL GRAB BAR MOUNTING HEIGHT: 150 mm above the tank, where water closet has tank				
	L-SHAPED GRAB BAR: Provision				
	L-SHAPED GRAB BAR LENGTH: 760 mm (minimum) for both vertical and horizontal components				
	L-SHAPED GRAB BAR VERTICAL COMPONENT: 150 mm (maximum) from front of water closet				
	L-SHAPED GRAB BAR HORIZONTAL COMPONENT MOUNTING HEIGHT: 750 mm				
	FOLD-DOWN GRAB BAR: Provision				
	FOLD-DOWN GRAB BAR MOUNTING LOCATION: on the wall behind the water closet on transfer side				
	FOLD-DOWN GRAB BAR LENGTH: 760 mm (minimum)				

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	FOLD-DOWN GRAB BAR MOUNTING LOCATION: 390 mm and 410 mm from centreline of water closet				
	FOLD-DOWN GRAB BAR HORIZONTAL COMPONENT: 750 mm high				
	FOLD-DOWN GRAB BAR PROVISION: where transfer space is provided on both sides of the water closet, provide on each side				
4.5.8	LAVATORY: at least one accessible lavatory in each accessible washroom				No bathroom complies to the AODA & thus are not accessible: - admin building - Shop Building: has a universal B.F. washroom that also acts as a female change room (has limited) compliance
	LAVATORY LOCATION: centreline 460 mm (minimum) from adjacent side wall				
	LAVATORY TOP SURFACE HEIGHT: 820 to 840 mm				
	LAVATORY KNEE WIDTH: 920 mm				
	LAVATORY KNEE CLEARANCE: 735 mm high at front edge				
	LAVATORY KNEE CLEARANCE: 685 mm high at 205 mm back from front edge				
	TOE SPACE: 350 mm high, 300 mm back from the front edge to the wall				
	FAUCET: automatic control or lever-type faucet 485 mm (maximum) from edge of basin				
	SOAP DISPENSER: 1200 mm (maximum) high, 610 mm (maximum) from the edge of the lavatory				
	CLEAR FLOOR SPACE: 920 mm wide by 1370 mm deep (minimum), 500 mm depth is allowed under the lavatory				
	WATER PIPE: covered or insulated				
	SHELF MOUNTING HEIGHT: 1100 mm (maximum) OR 200 mm (maximum) above top surface of lavatory				Mounting heights for Lav, switches, handles are non-complying
	SHELF PROJECTION: 100 mm from mounting surface				
4.5.9	WASHROOM AMENITIES CONTROL MOUNTING HEIGHT: 900 - 1200 mm				
	WASHROOM AMENITIES DISPENSING HEIGHT: 900 - 1200 mm				
	WASHROOM AMENITIES PROJECTION: 100 mm (maximum) from wall				
	CLEAR FLOOR SPACE FRONT APPROACH: 920 mm wide by 1370 mm deep				
	CLEAR FLOOR SPACE SIDE APPROACH: 1525 mm wide by 920 mm deep				
	MIRROR MOUNTING HEIGHT: bottom edge at 1000 mm (maximum) OR inclined to the vertical				All bathrooms do not meet current B.F. accessibility
	BABY CHANGE TABLE CLEAR FLOOR SPACE FRONT APPROACH: 920 mm wide by 1370 mm depth				
	BABY CHANGE TABLE CLEAR FLOOR SPACE SIDE APPROACH: 1525 mm wide by 920 mm depth				Missing most of bathroom equipment mentioned in this list

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	BABY CHANGE TABLE SURFACE HEIGHT: 730 and 865 mm				
	BABY CHANGE TABLE KNEE CLEARANCE: 685 mm high and 480 mm depth				
	BABY CHANGE TABLE OPERATING CONTROL HEIGHT: 1200 mm				
	ADULT SIZE CHANGE TABLE CLEAR FLOOR SPACE: 760 mm wide by 1500 mm long (minimum), parallel to the long side of the table				
	ADULT SIZE CHANGE TABLE HEIGHT: adjustable, 450 mm - 500 mm (low range) 850 mm - 900 mm (high range)				
	ADULT SIZE CHANGE TABLE OPERATING CONTROL HEIGHT: 1200 mm high (maximum)				
4.5.10	URINAL: Provision, at least one accessible urinal, where more than one urinal				
	URINAL LOCATION: within accessible path of travel with no step in front				
	URINAL LOWER RIM HEIGHT: 430 mm (maximum) OR floor mounted urinal with the rim level with the floor level				
	URINAL UPPER RIM HEIGHT: 860 mm (minimum)				
	URINAL DEPTH: 345 mm (minimum)				
	URINAL FLUSH CONTROL FEATURES: automatic OR lever control operable with a closed fist, without tight grasping, pinching or twisting of the wrist				
	URINAL FLUSH CONTROL MOUNTING HEIGHT: 1200 mm (maximum)				
	URINAL CLEAR FLOOR SPACE: 915 mm wide by 1370 mm deep (minimum) centered in front				
	GRAB BARS: Provision on each side				
	GRAB BAR MOUNTING HEIGHT: vertically, with centreline at 1000 mm				
	GRAB BAR LOCATION: 380 mm to 450 mm from centreline				
	GRAB BAR LENGTH: 600 mm (minimum)				
	CENTRELINE INDICATOR: Provision				
	CENTRELINE INDICATOR DIMENSION: 50 mm wide (maximum)				
	CENTRELINE INDICATOR MOUNTING HEIGHT: extend 1300 mm (minimum) above floor but not less than 150 mm above the upper urinal rim				
	CENTRELINE INDICATOR FEATURES: high tonal contrast compared with back wall and raised 3 mm (minimum)				
	PRIVACY SCREEN: Provision				
	PRIVACY SCREEN CLEARANCE: 920 mm (minimum) between screens				
	GRAB BAR CLEARANCE: 50 mm (minimum) from privacy screen				

Section 4.0 Interior Environments					
Standard Ref #	**Criteria / Requirement**	**Compliance**			**Comments / Observations**
		Yes	**No**	**N/A**	
	PRIVACY SCREEN CONTRAST: colour contrast between screens and surrounding surfaces and vertical outer edge				
4.6	**Showers**				
4.6.1	PROVISION: as per table below: **Number of Showers Provided in a Group** / **Minimum Number of Accessilble Showers Required** 1 - 7 / 1 7 + / 1, plus 1 for each additional increment of 7 showers in a group				
4.6.2	SHOWER STALL DIMENSION: 1500 mm wide by 900 mm deep (minimum)				
	CLEAR FLOOR SPACE AT SHOWER ENTRANCE: 1500 mm wide by 900 mm deep (minimum)				
	SHOWER ENTRY: level or beveled threshold 13 mm high (maximum)				
	SURFACE: slip-resistant				
4.6.3	Controls and Accessories				
	SHOWER CONTROLS FEATURES: automatic OR level type control operable with closed fist				
	SHOWER CONTROLS MOUNTING HEIGHT: 1000 mm				
	SHOWER CONTROLS REACH: 500 mm (maximum) from the edge of the seat				
	SOAP HOLDERS MOUNTING HEIGHT: recessed, 900 mm - 1200 mm above grab bar				
	SHOWER HEAD FEATURES: hand-held shower head with flexible hose 1800 mm (minimum) long				
	SHOWER HEAD FEATURES: vertical support provided to mount shower head without obstructing grab bar				
	SHOWER SEAT: Provision				
	SHOWER SEAT FEATURES: fixed or where a non spring loaded hinged seat				
	SHOWER SEAT LOCATION: on the side wall adjacent to the controls				
	SHOWER SEAT HEIGHT: 430 mm - 485 mm, with the front edge within 500 mm of shower head and controls				
	SHOWER SEAT DIMENSION: 450 mm wide by 400 mm deep (minimum) with rear edge 65 mm from wall				
4.6.4	GRAB BAR: Provision				
	GRAB BAR FEATURES: non-abrasive, slip-resistant				
	GRAB BAR DIAMETER: 35 mm - 40 mm				
	GRAB BAR CLEARANCE: 50 mm (minimum) between mounting surface and grab bar, and / or between ends of grab bars and any adjacent wall				

Section 4.0 Interior Environments

Standard Ref #	Criteria / Requirement	Compliance			Comments / Observations
		Yes	No	N/A	
	VERTICAL GRAB BAR: Provision				
	VERTICAL GRAB BAR LOCATION: on the side wall adjacent to shower seat				
	VERTICAL GRAB BAR LENGTH: 900 mm (minimum)				
	VERTICAL GRAB BAR MOUNTING HEIGHT: bottom edge 600 mm - 650 mm high				
	VERTICAL GRAB BAR CLEARANCE: 50 mm - 80 mm from the adjacent clear floor space				
	L-SHAPED GRAB BAR: Provision				
	L-SHAPED GRAB BAR LOCATION: on wall opposite to shower entrance between the shower head and shower controls				
	L-SHAPED GRAB BAR HORIZONTAL COMPONENT LENGTH: 760 mm (minimum)				
	L-SHAPED GRAB BAR VERTICAL COMPONENT LENGTH: 760 mm (minimum)				
	L-SHAPED GRAB BAR HORIZONTAL COMPONENT MOUNTING HEIGHT: 850 mm				
	HORIZONTAL GRAB BAR: Provision				
	HORIZONTAL GRAB BAR LOCATION: on the site wall opposite from shower seat				
	HORIZONTAL GRAB BAR LENGTH: 600 mm (minimum)				
	HORIZONTAL GRAB BAR MOUNTING HEIGHT: 850 mm				

Section 5.0 Systems, Controls and Communications

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
5.1	**Controls and Operating Mechanisms**				
5.1.1	CONTROL FEATURES: operable with one hand and closed fist, no tight grasping, pinching of the fingers, or twisting of the wrist				
	CONTROL FORCE: 22 Newtons (maximum)				
	CONTROL CONTRAST: high tonal contrast between operable parts and adjacent mounting surface				
	CONTROL MINIMUM MOUNTING HEIGHT: 400 mm for all controls				
	CONTROL MOUNTING HEIGHT: 900 - 1100 mm				
	THERMOSTAT AND MANUAL FIRE ALARM PULL MOUNTING HEIGHT: 1200 mm high				
	CONTROL MOUNTING LOCATION: prominent and obvious locations				Do not have B.F. Bathrooms
5.1.2	CLEAR FLOOR SPACE FRONT APPROACH: 915 mm wide by 1370 mm depth				
	CLEAR FLOOR SPACE SIDE APPROACH: 1525 mm wide by 915 mm depth				
	MINIMUM MOUNTING HEIGHT WITH NO OBSTRUCTION: 400 mm				
	MAXIMUM MOUNTING HEIGHT WITH NO OBSTRUCTION: 1100 mm				
	MAXIMUM MOUNTING HEIGHT WITH OBSTRUCTION 860 mm (maximum): 1100 mm				
	MAXIMUM GRASPING REACH: 500 mm				
5.2	**Assistive Listening Devices**				
App	ASSISTIVE LISTENING DEVICE PROVISION: assembly areas with an area of 100 square metres or occupancy of seventy-five (75) or more fixed seats				
	ASSISTIVE LISTENING DEVICE PROVISION: assembly areas where audible communication is integral to the use of the space				
5.2.1	DESIGN FEATURES: encompasses the entire floor area				
	DESIGN FEATURES: personal amplification control				
	SIGNAGE: International Symbol For Hearing Loss pictogram and marked with a ‘T’, where T-coil usage is available				
5.2.2	ASSISTIVE LISTENING DEVICE: Provision				
	PERMANENT ASSISTIVE LISTENING DEVICE: Provision				
	PERMANENT ASSISTIVE LISTENING DEVICE RECEIVER PROVISION: 4% (minimum) of the total number of seats, but never less than two				
	PERMANENT ASSISTIVE LISTENING DEVICE RECEIVER HEARING AID COMPATIBLE PROVISION: 25% (minimum) of the total number of receivers, but never less than one				
	PORTABLE ASSISTIVE LISTENING DEVICES: Provision				

Section 5.0 Systems, Controls and Communications					
Standard Ref #	Criteria / Requirement	Compliance			
		Yes	No	N/A	Comments / Observations
	PORTABLE ASSISTIVE LISTENING DEVICES PROVISION: at least one, with a minimum of two receivers included for facilities with assembly spaces on multiple floor levels				
	PORTABLE ASSISTIVE LISTENING DEVICES FEATURES: include hearing aid compatibility				
5.3	**Public Address Systems**				
5.3.1	DESIGN FEATURES: sound level is above ambient background noise without distortion or feedback				
	SPEAKERS MOUNTING LOCATION: above head-level in corridors				
	SPEAKERS MOUNTING LOCATION: above head-level in assembly and meeting room				
	SPEAKERS MOUNTING LOCATION: above head-level in recreational facilities				
	SPEAKERS MOUNTING LOCATION: above head-level in entertainment and educational facilities				
	SPEAKERS MOUNTING LOCATION: above head-level in common use areas located in institutional settings				
5.4	**Acoustics**				
5.4.1	Design Features				
	DESIGN FEATURES: use of sound-reflective or sound absorbent material				
	DESIGN FEATURES: floor, wall and ceiling finishes do not amplify noise				
	DESIGN FEATURES: background noise minimize in meeting areas				
	DESIGN FEATURES: adequate sound insulation in room and space design				
	DESIGN FEATURES: permanent inductive loop or similar assistive listening system for high use buildings and areas				
5.5	**Security Systems**				
5.5.1	CONTROL MOUNTING HEIGHT: 900 mm - 1100 mm				
	CONTROL MOUNTING LOCATION: 600 mm (minimum) clear of the arc of any door swing				
	AUDIBLE INDICATOR: Provision to alert users when access has been granted or denied				
	VISUAL INDICATOR: Provision to alert users when access has been granted or denied				
	SYNCHRONIZED SYSTEM: activation of both proximity card readers and power door operators				
5.6	**Fire and Life Safety Systems**				
5.6.1	EVACUATION PLAN AND STRATEGIES FOR USERS OF DISABILITIES: Provision				
	EVACUATION PLAN MOUNTING HEIGHT: 1200 mm (maximum)				
	EVACUATION PLAN FONT SIZE: 14 point (minimum)				
	EVACUATION PLAN ALTERNATE FORMAT: Provision				
	FIRE AND LIFE SAFETY CONTROL MOUNTING HEIGHT: 900 mm and 1100 mm				
	MANUAL FIRE ALARM PULL MOUNTING HEIGHT: 1200 mm				

Section 5.0 Systems, Controls and Communications

Standard Ref #	Criteria / Requirement	Compliance			Comments / Observations
		Yes	No	N/A	
5.6.2	VISUAL ALARM SIGNALS: Provision				
	VISUAL ALARM SIGNAL MOUNTING HEIGHT: 2100 mm (minimum) OR 150 mm below the ceiling, whichever is lower				
	VISUAL ALARM SIGNAL LOCATION: no more than 15 metres apart				
	VISUAL ALARM SIGNAL FEATURES: at least one device is visible throughout the floor area				
	VISUAL ALARM SIGNAL FLASHING FEATURES: xenon strobe type or equivalent for light or lamp fixture				
	VISUAL ALARM SIGNAL FLASHING FEATURES: clear or nominal white colour				
	VISUAL ALARM SIGNAL FLASHING FEATURES: maximum pulse duration of 0.2 seconds, with a maximum duty cycle of 40%				
	VISUAL ALARM SIGNAL FLASHING FEATURES: intensity of the visual alarm signal raises the overall light level sharply				
	VISUAL ALARM SIGNAL FLASHING INTENSITY: 75 candela (minimum) with a flash rate between 1 Hertz - 3 Hertz				
	VISUAL ALARM SIGNAL FLASHING FEATURES: synchronize visual alarms that are located in the same proximity to flash at the same time				
5.6.3	AREA OF REFUGE: Provision				
	AREA OF REFUGE LOCATION: on an accessible route served by an exit or fire fighter’s elevator				
	AREA OF REFUGE LOCATION: clear of any adjacent door swing and away from pedestrian exit route(s)				
	AREA OF REFUGE SIGNAGE: large print, tactile features stating ‘Area of Refuge’ and marked with the International Symbol of Accessibility				
	AREA OF REFUGE CLEAR FLOOR SPACE: 1675 mm by 1675 mm (minimum)				
	AREA OF REFUGE PROTECTIVE ENCLOSURE: minimum of one-hour				
	AREA OF REFUGE COMMUNICATION SYSTEM: two-way supported by the facility’s backup generator and linked to the designated fire control centre / panel				
	AREA OF REFUGE COMMUNICATION SYSTEM: marked with signage and includes both audible and visual notification devices to indicate “help is on the way”				
	AREA OF REFUGE NOTIFICATION DEVICES: both audible and visual notification devices to indicate “help is on the way”				
	LIGHTING AND VENTILATION: emergency lighting and ventilation systems supported by a backup generator				
5.7	**Lighting**				
5.7.1	SURFACE FINISHES: matte or satin finishes				

Section 5.0 Systems, Controls and Communications					
Standard Ref #	**Criteria / Requirement**	**Compliance Yes**	**No**	**N/A**	**Comments / Observations**
	WALL FINISHES: matte or satin wall finishes				
	GLARE STRATEGIES: curtains, blinds, screens or other strategies to shield bright, natural lighting sources				
	GLARE: light fixtures that prevent or minimize any potential for direct glare				
5.8	**Sinage and Wayfinding**				
5.8.1	SIGNAGE FEATURES: matte, eggshell or non-glare finish				
	SIGNAGE FEATURES: uniform design				
	SIGNAGE FEATURES: colour contrast between signage and mounting surfaces				
	SIGNAGE FEATURES: consistently shaped, coloured and positioned				
	CHARACTER FEATURES: sans serif font type and have Arabic numerals				
	CHARACTER FEATURES: width to height ratio between 3:5 and 1:1				
	CHARACTER FEATURES: stroke width to height ratio between 1:5 and 1:10				
	CHARACTER FEATURES: not italic, oblique, script, highly decorative or of other unusual forms				
	CHARACTER FEATURES: high tonal contrast between text characters and background surface				
	CHARACTER HEIGHT: as per table below:				

Minimum Character Height (mm)	Maximum Viewing Distance (mm)
200	6,000
150	4,600
100	2,500
75	2,300
50	1,500
25	750

	PICTOGRAM: Provision				
	PICTOGRAM HEIGHT: field height of 150 mm (minimum)				
	PICTOGRAM FEATURES: text descriptors and braille directly below the pictogram field and not in the pictogram field				
	PICTOGRAM FEATURES: high tonal contrast between pictogram the field				
	PICTOGRAM FEATURES: use recognized and standardized symbols for accessibility features or other key building elements				
	BRAILLE: Provision				

Section 5.0 Systems, Controls and Communications

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	BRAILLE FEATURES: uncontracted braille (Grade 1)				
	BRAILLE FEATURES: domed or rounded shape				
	BRAILLE LOCATION: immediately below the corresponding text and / or pictogram OR where text is multi-lined, braille below the entire text				
5.8.2	TACTILE SIGNAGE: Provision				
	TACTILE SIGNAGE FEATURES: text characters and pictograms raised 0.8 - 1.5 mm				
	TACTILE SIGNAGE FEATURES: edges of the text characters gently rounded				
	TACTILE SIGNAGE FEATURES: high tonal contrast between the tactile characters and the background surface				
	TACTILE SIGNAGE FEATURES: accompanied by equivalent description in braille				
	TACTILE SIGNAGE FEATURES: text in upper case lettering				
	TACTILE SIGNAGE MOUNTING HEIGHT: between 1220 mm, measured from the baseline of the lowest tactile character and 1525 (maximum), measured from the baseline of the highest tactile character				
	TACTILE SIGNAGE MOUNTING LOCATION: consistently on the wall beside the latch edge of door, 150 mm +/- 10 mm from the door frame				
	TACTILE SIGNAGE MOUNTING LOCATION AT DOUBLE DOORS WITH ONE ACTIVE DOOR: mounted to the right of the right hand door				
	TACTILE SIGNAGE MOUNTING LOCATION WHERE NO WALL SPACE: mounted on nearest adjacent wall				
	TACTILE SIGNAGE CLEAR FLOOR SPACE: 455 mm by 455 mm (minimum), centred on the tactile characters				
	TACTILE SIGNAGE CLEAR WALL SPACE: 75 mm wide (minimum) around the sign				
5.8.3	WAYFINDING PRINCIPLES: consistent design				
	WAYFINDING PRINCIPLES: strategic placement and ideal mounting heights at key decision-making points				
	WAYFINDING PRINCIPLES: ideal mounting heights at key decision-making points				
	WAYFINDING PRINCIPLES: no information overload or cluttering of signage				
5.9	**Self-Service Kiosks**				
5.9.1	SELF-SERVICE KIOSKS PROVISION: if only one, has to accommodate both seated and standing users				
	SELF-SERVICE KIOSKS LOCATION: adjacent to an accessible route, recessed or has a cane detectable leading edge 680 mm high (maximum)				
	SELF-SERVICE KIOSKS SIGNAGE: mark accessible kiosk with International Symbol of Accessibility				
5.9.2	CLEAR FLOOR SPACE FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				

Section 5.0 Systems, Controls and Communications					
Standard Ref #	Criteria / Requirement	Compliance			
		Yes	No	N/A	Comments / Observations
	SELF-SERVICE KIOSKS KNEE CLEARANCE: 760 mm wide by 480 mm deep by 680 mm high (minimum)				
	SELF-SERVICE KIOSKS TOE CLEARANCE: 350 mm high (minimum)				
5.9.3	DISPLAY PANEL: free from obstruction above or around panel				
	DISPLAY PANEL LOCATION: position to minimize glare and reflections				
	DISPLAY PANEL TOP HEIGHT: 1380 mm (maximum), where screen is inclined and cannot be read from 750 mm away				
	DISPLAY PANEL INFORMATION HEIGHT: between 750 and 1750 mm, where panel is vertical				
5.9.4	SELF-SERVICE KIOSKS OPERATING CONTROL HEIGHT: between 400 and 1100 mm				
	SELF-SERVICE KIOSKS OPERATING CONTROL FEATURES: operable with one hand, without using tight grasp, pinching or twisting of wrist				
5.9.5	ACCESSIBILITY FEATURES: strong tonal contrast between characters and background				
	ACCESSIBILITY FEATURES: alternative mode of operation (both visual and audible output)				
	ACCESSIBILITY FEATURES: audio information with headset jacks with adjustable volume controls				
	ACCESSIBILITY FEATURES: adjustable time to complete tasks				
5.10	**Windows and Glazing**				
5.10.1	WINDOW CLEAR FLOOR SPACE FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	WINDOW CLEAR FLOOR SPACE SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
	WINDOW SILL MOUNTING HEIGHT: 1100 mm (maximum)				
	WINDOW CONTROL HEIGHT: 400 mm and 1100 mm				
	WINDOW HORIZONTAL STRUCTURE: not between 900 mm and 1300 mm				
	GLAZING STRIPS DIMENSION: 50 mm in height, extending full width of glazed area				
	GLAZING STRIPS MOUNTING HEIGHT: between 1350 mm and 1500 mm				
	GLAZING STRIPS CONTRAST: high tonal contrast				

Section 6.0 Special Facilities and Spaces					
Standard Ref #	**Criteria / Requirement**	**Compliance**			**Comments / Observations**
		Yes	**No**	**N/A**	
6.1	**Assembly Areas**				
6.1.1	ACCESSIBLE PATH OF TRAVEL: 1100 mm (minimum) throughout space for circulation				
	LIGHTING: evenly distributed throughout all accessible routes and accessible seating spaces				
	ASSISTIVE LISTENING SYSTEMS: provision based on the type of venue and audience				
6.1.2	ACCESSIBLE AND ADAPTABLE SEATING PROVISION: as per table below:				

Total Number of Fixed Seats	Minimum Number of Accessible Seating	Minimum Number of Adaptable Seating	Minimum Number of Storage for Mobility Aids
Up to 20	2	1	1
21 - 40	2	2	2
41 - 60	2	3	2
61 - 80	2	4	2
81 - 100	3	5	2
100 +	3% of seating capacity	The greater of 5 seats or 5% of the aisle seating capacity	2, plus 2 for any additional 100 seats

	ACCESSIBLE SEATING SPACE DIRECTIONAL SIGNAGE: provided to identify location of accessible seating spaces				
	ACCESSIBLE SEATING SPACE LOCATION: adjoining an accessible path of travel, without infringing on egress from any row of seating				
	ACCESSIBLE SEATING SPACE COMPANION SEAT PROVISION: at least one fixed seat adjacent to accessible seating spaces				
	ACCESSIBLE SEATING SPACE COMPANION SEAT LOCATION: within the same row, ensuring shoulder alignment for users sitting beside each other				
	ACCESSIBLE SEATING SPACE CLEAR FLOOR SPACE WHEN ENTERING FROM SIDE: 1525 mm wide by 915 mm deep (minimum)				
	ACCESSIBLE SEATING SPACE CLEAR FLOOR SPACE WHEN ENTERING FROM REAR OR FRONT: 915 mm wide by 1400 mm deep (minimum)				
	ACCESSIBLE SEATING SPACE PROVISION: at least two accessible seating space side by side				
	ACCESSIBLE SEATING SPACE VIEWING LOCATION: choice of viewing location provided with a clear view of the event				
	ACCESSIBLE SEATING SPACE LINES OF SIGHT: comparable to those for all viewing positions				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	ACCESSIBLE SEATING SPACE LINES OF SIGHT: not reduced or obstructed by standing members of the audience				
	ACCESSIBLE SEATING SPACE LINES OF SIGHT: free of any obstructions				
	ACCESSIBLE SEATING SPACE LINES OF SIGHT: space do not obstruct sight lines of other users either sitting or standing				
	ADAPTABLE SEATING SPACE LOCATION: adjacent to an accessible route without infringing on egress from any row of seating or any aisle requirements				
	ADAPTABLE SEATING SPACE FEATURES: equip with a movable or removable armrest on the side of the seat adjoining the accessible route				
	ADAPTABLE SEATING SPACE VIEWING LOCATION: choice of viewing location provided with a clear view of the event				
	MOBILITY AID STORAGE PROVISION: as per table below:				

Total Number of Fixed Seats	Minimum Number of Accessible Seating	Minimum Number of Adaptable Seating	Minimum Number of Storage for Mobility Aids
Up to 20	2	1	1
21 - 40	2	2	2
41 - 60	2	3	2
61 - 80	2	4	2
81 - 100	3	5	2
100 +	3% of seating capacity	The greater of 5 seats or 5% of the aisle seating capacity	2, plus 2 for any additional 100 seats

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	MOBILITY AID STORAGE CLEAR FLOOR SPACE: 915 mm wide by 1370 mm deep (minimum) for each space				
	MOBILITY AID STORAGE LOCATION: on the same level and in proximity to the accessible seating spaces and seats designated as adaptable seating				
6.2	**Meeting and Multi-purpose Rooms**				
6.2.1	ACCESSIBLE PATH OF TRAVEL: 1100 mm (minimum) throughout space for circulation				
	TURNING SPACE: 1675 mm (minimum) diameter within room				
	ACCESSIBLE TABLE AND WORK SURFACES: as per Section 2.10.2				
	ASSISTIVE LISTENING SYSTEMS: provision				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance			Comments / Observations
		Yes	No	N/A	
	ASSISTIVE LISTENING SYSTEMS SIGNAGE: identified with signage and International Symbol for Hearing Loss				Furniture in these spaces do not seem to comply with B.F. design
	CLEAR FLOOR SPACE AT MILLWORK FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT MILLWORK SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
6.3	**Cultural and Art Facilities**				
6.3.1	ACCESSIBLE PATH OF TRAVEL: 1100 mm (minimum) throughout space for circulation				
	FLOOR PLAN: identify the location of key spaces and amenities (e.g., displays/exhibits), integrate the provision of tactile print, braille and other accessibility features (e.g., large print, colour contrast)				
	ACCESSIBLE TABLE AND WORK SURFACES: as per Section 2.10.2				
	ASSISTIVE LISTENING SYSTEMS: provision in large assembly, meeting or performance areas				
	ASSISTIVE LISTENING SYSTEMS SIGNAGE: identified with signage and International Symbol for Hearing Loss				
	CLEAR FLOOR SPACE AT EXHIBITS FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT EXHIBITS SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
	EXHIBITS TOP SURFACE OF DISPLAY CASE: 915 mm (maximum) high				
	INTERACTIVE DISPLAYS CONTROL HEIGHT: 1100 mm (maximum) high				
6.4	**Cafeteria and Dining Facilities**				
6.4.1	ACCESSIBLE PATH OF TRAVEL: 1100 mm (minimum) throughout space for circulation				
	CLEAR FLOOR SPACE AT FOOD DISPLAYS FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT FOOD DISPLAYS SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
6.4.2	AISLE WIDTH AT SELF-SERVICE FOOD DISPLAYS: 1100 mm (minimum)				
	TRAY SLIDES MOUNTING HEIGHT: 730 - 865 mm high				
	SHELVES MOUNTING HEIGHT: at least 50% of shelves 400 - 1370 mm high for unobstructed side approach				
	MAXIMUM SIDE REACH: 500 mm				
6.4.3	SERVICE AND PAYMENT COUNTER: at least one accessible				
	CLEAR FLOOR SPACE AT SERVICE COUNTER FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT SERVICE COUNTER SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
6.4.4	DINING AREA: accessible seating spaces provided				
	ACCESSIBLE TABLE: as per Section 2.10.2				
	COMPANION SEATING: Provision adjacent to accessible table				
	CLEAR FLOOR SPACE AT ACCESSIBLE TABLE: 1675 mm by 1675 mm (minimum)				

Section 6.0 Special Facilities and Spaces					
Standard Ref #	**Criteria / Requirement**	**Compliance**			
		Yes	**No**	**N/A**	**Comments / Observations**
	ACCESSIBLE TABLE SIGNAGE: directional signage to accessible table and amenities, marked with International Symbol of Accessibility				
6.5	**Kitchens and Kitchenettes**				
6.5.1	SURFACE: slip-resistant and has a non-glare finish				
	CLEAR FLOOR SPACE AT KITCHEN AMENITIES FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT KITCHEN AMENITIES SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
	CONTROL MOUNTING HEIGHT: 1100 mm (maximum) high				
	PASS THROUGH OR GALLERY KITCHEN: Provision				
	PASS THROUGH OR GALLERY KITCHEN CLEARANCE: 1500 mm (minimum) between all opposing base cabinets, countertops or walls within kitchen work areas				
	PASS THROUGH OR GALLERY KITCHEN ENTRACE: 860 mm (minimum) clear width				
	U-SHAPED KITCHEN: Provision				
	U-SHAPED KITCHEN CLEARANCE: 1500 mm (minimum) between all opposing base cabinets, countertops or walls within kitchen work areas				
	U-SHAPED KITCHEN ENTRACE: 860 mm (minimum) clear width				
	L-SHAPED KITCHEN: Provision				
	L-SHAPED KITCHEN CLEARANCE: 1500 mm (minimum) between all opposing base cabinets, countertops or walls within kitchen work areas				
6.5.2	ACCESSIBLE COUNTER / WORK SURFACE: Provision at least one				
	ACCESSIBLE COUNTER / WORK SURFACE DIMENSION: 760 mm wide by 600 mm deep (minimum)				
	ACCESSIBLE COUNTER / WORK SURFACE TOP SURFACE: 730 mm and 865 mm high				
	ACCESSIBLE COUNTER / WORK SURFACE KNEE CLEARANCE: centred, 480 mm deep by 760 mm wide by 685 mm high (minimum)				
	ACCESSIBLE COUNTER / WORK SURFACE CLEAR FLOOR SPACE: 915 mm wide by 1370 mm (minimum), 480 mm underneath the counter / work surface				
	ACCESSIBLE COUNTER / WORK SURFACE FEATURES: no sharp or abrasive surfaces				
	ACCESSIBLE COUNTER / WORK SURFACE FEATURES: high tonal contrast with all cabinets, countertops, appliances and adjacent wall surfaces				
	ELECTRICAL OUTLET: provided at the side or front of counter or work surface				
6.5.3	KITCHEN STORAGE PROVISION: at least one(1), 1100 mm (maximum) high				

Section 6.0 Special Facilities and Spaces					
Standard Ref #	**Criteria / Requirement**	**Compliance**			**Comments / Observations**
		Yes	**No**	**N/A**	
	KITCHEN STORAGE CONTROL FEATURES: accessible hardware (e.g., D-type door pull)				
	KITCHEN STORAGE CONTROL MOUNTING HEIGHT: 1100 mm (maximum)				
	KITCHEN STORAGE CONTROL MOUNTING LOCATION: close to the bottom for upper cabinets and close to the top for base cabinets				
	KITCHEN STORAGE TOE CLEARANCE: 150 mm deep by 230 mm high (minimum)				
6.5.4	SINK LOCATION: centreline 460 mm (minimum) from a side wall				
	SINK RIM HEIGHT: 810 to 860 mm high				
	SINK KNEE CLEARANCE: 920 mm wide by 685 mm high by 200 mm deep (minimum)				
	SINK TOE CLEARANCE: 230 mm high by 230 mm deep (minimum)				
	SINK FAUCET: automatic faucet or lever-type controls that can be operated with one closed fist				
	SINK PIPES: offset to the rear and do not obstruct the knee clearance				
6.5.5	COOKTOP FEATURES: controls located away from the burners				
	CLEAR FLOOR SPACE AT COOKTOP: 915 mm wide by 1370 mm (minimum), 480 mm underneath cooktop				
	COOKTOP TOP SURFACE HEIGHT: 810 to 860 mm high				
	COOKTOP KNEE CLEARANCE: 760 mm wide by 685 mm high by 200 mm deep (minimum)				
	COOKTOP TOE CLEARANCE: 230 mm high by 230 mm deep (minimum)				
	COOKTOP FEATURES: insulation or other protection on the underside where knee clearance				
	COOKTOP WORK SURFACE: 400 mm (minimum) wide on each side and at the same height as the cooktop				
	COOKTOP WORK SURFACE FEATURES: heat resistant				
	OVEN CONTROL LOCATION: front panels of oven				
	OVEN WITH SIDE-HINGED DOOR WORK SURFACE PROVISION: heat resistant work surfaces with knee space below, adjacent to the latch side of oven door				
	OVEN WITH SIDE-HINGED DOOR WORK SURFACE PROVISION: heat resistant pull-out shelf that pulls out 250 mm (minimum) below the oven				
	OVEN WITH BOTTOM-HINGED DOOR WORK SURFACE PROVISION: work surface on one side of the door				
	MICROWAVE OVEN MOUNTING HEIGHT: mounted at counter height;				
	REFRIGERATOR AND FREEZER: self-defrosting freezer				
	REFRIGERATOR AND FREEZER FEATURES: vertical side-by-side type preferred				
	REFRIGERATOR AND FREEZER OVER-AND-UNDER TYPE: freezer shelf space 1100 mm (maximum) high				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	REFRIGERATOR AND FREEZER CLEAR FLOOR SPACE: positioned for parallel approach immediately adjacent to refrigerator / freezer, with the centreline offset 610 mm (maximum) from the front face				
6.6	**Libraries**				
6.6.1	ACCESSIBLE PATH OF TRAVEL: 1100 mm (minimum) throughout space for circulation				
	TURNING SPACE: 1675 mm (minimum) diameter within room				
	SECURITY GATE CLEAR WIDTH: 915 mm (minimum)				
	SERVICE COUNTER: at least one accessible counter at circulation, information or self-service checkout areas				
	ONLINE CATALOGUE AND WORKSTATIONS: at least 25% are accessible				
	AODA TRAINING: library staff trained with disability awareness / sensitivity training				
6.6.2	BOOK DROP SLOT LOCATION: on an accessible path of travel				
	CLEAR FLOOR SPACE AT BOOK DROP SLOT FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT BOOK DROP SLOT SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
	BOOK DROP SLOT MOUNTING HEIGHT: 900 and 1100 mm				
	BOOK DROP SLOT CONTROL FEATURES: usable with closed fist and operable with one hand				
6.6.3	CLEARANCE BETWEEN BOOK STACKS AISLE: 1100 mm (minimum)				
	LIBRARY DISABILITY POLICY: assistance for users to access items that are too high or too low				
6.6.4	SEATING TYPES: variety of flexible options				
	STUDY CARREL PROVISION: at least 10% fully accessible with knee clearances as per 2.10.2				
	STUDY CARREL FEATURES: an electric outlet provided				
6.7	**Exercise and Fitness Facilities**				
6.7.1	ACCESSIBLE PATH OF TRAVEL: 1100 mm (minimum) throughout space for circulation				
	EXERCISE EQUIPMENT ACCESSIBILITY PROVISION: at least of each type of equipment is accessible				
	CLEAR FLOOR SPACE AT EXERCISE EQUIPMENT FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT EXERCISE EQUIPMENT SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
6.7.2	CHANGE ROOM PROVISION: minimum one (1) accessible change room for each gender, with at least one universal change room or stall to accommodate parents with children, companions or care givers of the opposite sex				
6.8	**Change Rooms**				*Shop Location
6.8.1	CHANGE ROOM PROVISION: at least one universal change room or stall for each type of other regular change room facility that is provided (e.g., Male, Female or Family)				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	ACCESSIBLE CHANGE ROOM LOCATION: along an accessible route				
6.8.2	CHANGE ROOM DOOR CLEARANCE: 915 mm (minimum)				
	CHANGE ROOM POWER DOOR OPERATOR: Provision				
	ACCESSIBLE PATH OF TRAVEL: 1100 mm (minimum) throughout space for circulation				
	TURNING SPACE: 1500 mm (minimum) diameter within room				
	SURFACE: slip-resistant and allows suitable drainage				
	WASHROOM FACILITIES: as per Section 4.5, Washrooms				
	SHOWER FACILITIES: as per Section 4.6, Showers				
	EMERGENCY CALL SYSTEM: Provision				
	EMERGENCY CALL SYSTEM FEATURES: both visual and audible signal devices both inside and outside change room				
	EMERGENCY CALL SYSTEM SIGNAGE: posted above emergency button				
	EMERGENCY CALL SYSTEM FEATURES: linked to a display panel at a reception / information counter or to a centrally monitored station				
6.8.3	BENCH: Provision				
	BENCH HEIGHT: 480 to 520 mm				
	BENCH DEPTH: 510 mm to 610 mm				
	BENCH FEATURES: back support, unless seat surface is permanently positioned against a wall				
	LOCKER: Provision				
	LOCKER PROVISION: at least 10% of the total number of lockers but never less than one accessible				
	LOCKER SIGNAGE: accessible marked with International Symbol of Accessibility				
	CLEAR FLOOR SPACE AT LOCKER FRONT APPROACH: 915 mm wide by 1370 mm deep (minimum)				
	CLEAR FLOOR SPACE AT LOCKER SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
	LOCKER SHELF HEIGHT: 400 mm - 1200 mm high				
	LOCKER LOCKING MECHANISM HEIGHT: 900 mm and 1100 mm				
	LOCKER SIGNAGE: identification / number signage for all lockers				
	LOCKER SIGNAGE MOUNTING HEIGHT: 1500 mm (centre)				
	LOCKER SIGNAGE FONT SIZE: 13 mm and 19 mm high, with either raised or recessed lettering				
6.8.4	UNIVERSAL CHANGE ROOM OR STALL: Provision				
	UNIVERSAL CHANGE ROOM OR STALL SIGNAGE: marked with International Symbol of Accessibility				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance Yes	Compliance No	Compliance N/A	Comments / Observations
	UNIVERSAL CHANGE ROOM OR STALL TURNING SPACE: 1675 mm (minimum) inside of the change room or stall				
	UNIVERSAL CHANGE ROOM OR STALL SURFACE: firm, level and slip-resistant				
	UNIVERSAL CHANGE ROOM OR STALL DOOR CLEARANCE: 915 mm (minimum)				
	UNIVERSAL CHANGE ROOM OR STALL DOOR LOCKING MECHANISM: can be locked from the inside and released from the outside				
	UNIVERSAL CHANGE ROOM OR STALL POWER DOOR OPERATOR: Provision				
	UNIVERSAL CHANGE ROOM OR STALL CHANGE BENCH DIMENSION: 1830 mm long by 760 mm wide				
	UNIVERSAL CHANGE ROOM OR STALL CHANGE BENCH TOP SURFACE: 480 and 520 mm high				
	UNIVERSAL CHANGE ROOM OR STALL GRAB BAR: Provision				
	UNIVERSAL CHANGE ROOM OR STALL L-SHAPED GRAB BAR MOUNTING LOCATION: vertical component, 150 mm (minimum) from front edge of seat and clearance of 150 mm (minimum) above the bench seat				
	UNIVERSAL CHANGE ROOM OR STALL HORIZONTAL GRAB BAR LENGTH: 1200 mm (minimum)				
	UNIVERSAL CHANGE ROOM OR STALL HORIZONTAL GRAB BAR MOUNTING LOCATION: 750 to 850 mm high and centered on the long side of the bench				
	UNIVERSAL CHANGE ROOM OR STALL DOOR LIGHTING: motion sensor for automatic illumination of the interior				
	UNIVERSAL CHANGE ROOM OR STALL MIRROR: full length mirror				
6.9	**Balconies and Terraces**				
6.9.1	BALCONY AND TERRACE LOCATION: on an accessible path of travel				
	SURFACE: firm, slip-resistant with maximum gradient of 1:50 (2%)				
	BALCONY AND TERRACE DEPTH: 2000 mm (minimum)				
6.10	**Service Counters**				
6.10.1	SERVICE COUNTER PROVISION SINGLE QUEUING LINE: each service counter is accessible				
	SERVICE COUNTER PROVISION MULTIPLE QUEUING LINE: at least one (1) service counter is accessible for each type of service provided				
6.10.2	SERVICE COUNTER LOCATION: on an accessible path of travel				
	SERVICE COUNTER SIGNAGE: International Symbol of Accessibility identifies accessible service counter, where multiple queuing lines and service counters				
	CLEAR FLOOR SPACE AT SERVICE COUNTER FRONT APPROACH: 760 mm wide by 1370 mm deep (minimum)				

Section 6.0 Special Facilities and Spaces					
Standard Ref #	**Criteria / Requirement**	**Compliance**			**Comments / Observations**
		Yes	**No**	**N/A**	
	CLEAR FLOOR SPACE AT SERVICE COUNTER SIDE APPROACH: 1525 mm wide by 915 mm deep (minimum)				
	SERVICE COUNTER CONTRAST: high tonal contrast compared with adjacent surfaces				
	ACCESSIBLE SERVICE COUNTER: Lowered counter provision				
	ACCESSIBLE SERVICE COUNTER TOP SURFACE HEIGHT: 730 mm and 865 mm				
	ACCESSIBLE SERVICE COUNTER KNEE CLEARANCE: 480 mm deep by 760 mm wide by 685 mm high (minimum)				
	ACCESSIBLE SERVICE COUNTER FORWARD REACH: 635 mm deep across top				
6.10.3	LIGHTING: service counter well-lit				
	SPEAKING PORT HEIGHT: at least one 1000 mm (maximum) high				
	INFORMATION PHONE OR CALL BELL MOUNTING HEIGHT: 1100 mm (maximum)				
	TTY OR ALTERNATE DEVICES: Provision				
	ASSISTIVE LISTENING SYSTEMS: Provision				
	ASSISTIVE LISTENING SYSTEMS SIGNAGE: marked with International Symbol for Hearing Loss				
6.11	**Waiting and Queuing Areas**				
6.11.1	WAITING AREA LOCATION: clearly visible when entering the facility				
	DIRECTIONAL SIGNAGE: directional and informational signage, where waiting areas not clearly visible				
	SERVICE COUNTER: Provision of lowered accessible counter as per Section 6.10, Service Counters				
	ACCESSIBLE SEATING SPACE PROVISION: at least 3% of but in no case fewer than one, where fixed seating provided				
	ACCESSIBLE SEATING SPACE DIMENSION:915 mm wide and 1400 mm depth (minimum)				
	ACCESSIBLE SEATING SPACE LOCATION: adjacent to fixed seating / waiting area and away from the main path of travel				
	SEATING PROVISION: variety of seating options, including back and arm supports for various users				
	BUILDING DIRECTORY: provided for large facilities, especially where no rooms are assigned				
6.11.2	QUEUING AREA LOCATION: on accessible path of travel				
	DIRECTIONAL SIGNAGE: directional and informational signage to identify queuing area entry				
	FIXED QUEUING GUIDES CLEAR WIDTH: 1100 mm (minimum) between guides				
	FIXED QUEUING GUIDES TURNING SPACE: 1675 mm wide by 1675 mm deep (minimum), where queuing guides change direction and where they begin and end				
	FIXED QUEUING GUIDES CANE DETECTABLE FEATURES: lower edge or base guides 680 mm (maximum) high				
	FIXED QUEUING GUIDES CONTRAST: high tonal contrast between guide surfaces and adjacent surroundings				
6.12	**Elevated Platforms or Stages**				

Section 6.0 Special Facilities and Spaces					
Standard Ref #	**Criteria / Requirement**	**Compliance**			**Comments / Observations**
		Yes	**No**	**N/A**	
6.12.1	ELEVATED PLATFORM OR STAGE: on accessible path of travel				
	ELEVATED PLATFORM OR STAGE ACCESSIBLE ROUTE: at least one accessible route provided to both audience seating and backstage areas for public or staff use via a sloped walkway (preferred), ramp or lift				
	ELEVATED PLATFORM OR STAGE EDGES: tactile walking surface indicator (TWSI) provided				
	TACTILE WALKING SURFACE INDICATOR LOCATION: 610 mm from edge of elevated platform or stage, extending full length				
	TACTILE WALKING SURFACE INDICATOR DIMENSION: 610 mm (minimum) depth				
6.13	**Residential Properties (RESERVED)**				
	RESERVED				
6.14	**Outdoor Public Use Eating Areas**				
6.14.1	ACCESSIBLE PICNIC TABLE PROVISION: minimum of twenty percent (20%) of tables and no fewer than one (1)				
	ACCESSIBLE PICNIC TABLE: as per Section 2.10, Tables, Work Surfaces and Seating				
	ACCESSIBLE PICNIC TABLE CLEARANCE: 2000 mm (minimum) on all sides of the table				
	ACCESSIBLE PICNIC TABLE LOCATION: on an accessible path of travel or trail				
	SURFACE UNDER TABLE: firm, stable and no steeper than 1:50 (2%)				
	DIRECTIONAL SIGNAGE: at strategic locations to identify the location(s) of accessible tables				
	BARBECUES: where provided, placed away from the accessible path of travel				
	WASHROOM: at least one universal toilet room, per cluster of regular washrooms				
6.15	**Recreational Trials and Boardwalks**				
6.15.1	RECREATIONAL TRAILS CONSULTATION: the public and persons with disabilities				
	RECREATIONAL TRAILS CONSULTATION: the Grand River Accessibility Advisory Committee				
	DESIGNATED TRAIL HEADS: information signage integrated as part of the trail design, at key entrance and exit points along the trail, intermediate areas on lengthy trails or decision points				
	TRAIL ENTRANCE / EXIT CLEAR WIDTH: 850 mm (minimum) or 1480 mm (preferred) clear opening				
	TRAIL CLEAR WIDTH: 1000 (minimum) or 3000 mm (preferred)				
	TRAIL PASSING AREA: 1800 mm wide by 1800 mm (minimum) long, at intervals no more than 30 m, where trail width less than 1800 mm				
	TRAIL HEADROOM CLEARANCE: 2300 mm (minimum)				
	TRAIL SURFACE: firm and stable				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance			Comments / Observations
		Yes	No	N/A	
	GRATINGS AND OPENINGS: 20 mm (minimum) (13 mm diameter preferred) in diameter, with any elongated openings oriented perpendicular to the direction of travel				
	TRAIL RUNNING SLOPE: as gentle as possible, as permitted by the terrain				
	TRAIL CROSS SLOPE: as gentle as possible, as permitted by the terrain				
	TRAIL RAMP: Provision				
	TRAIL RAMP RUNNING SLOPE: 1:10 (10%) (maximum)				
	TRAIL RAMP: as per Section 2.2, Ramps				
	TRAIL EDGE PROTECTION PROVISION: where recreational trails are constructed adjacent to water or a drop-off				
	TRAIL EDGE PROTECTION HEIGHT: 50 mm (minimum) high above the trail surface				
	TRAIL HEAD SIGNAGE INFORMATION: the length of the trail				
	TRAIL HEAD SIGNAGE INFORMATION: the type of surface of which the trail is constructed				
	TRAIL HEAD SIGNAGE INFORMATION: average and minimum trail width				
	TRAIL HEAD SIGNAGE INFORMATION: average and maximum running and cross-slopes				
	TRAIL HEAD SIGNAGE INFORMATION: the location of features and amenities, where provided				
	TRAIL HEAD SIGNAGE INFORMATION: extreme or unique conditions (e.g., steep slopes, obstacles or narrow widths)				
6.15.2	BOARDWALK: Provision				
	BOARDWALK CLEAR WIDTH: 1000 mm (minimum) or 1500 mm (preferred)				
	BOARDWALK PASSING AREA: 1800 mm wide by 1800 mm (minimum) long, at intervals no more than 30 m, where boardwalk is less than 1800 mm				
	BOARDWALK HEADROOM CLEARANCE: 2300 mm (minimum)				
	BOARDWALK SURFACE: firm and stable				
	BOARDWALK GRATING AND OPENING: 20 mm (minimum) (13 mm diameter preferred) in diameter, with any elongated openings oriented perpendicular to the direction of travel				Unsure what this is
	BOARDWALK RUNNING SLOPE: 1:20 (5%) (maximum)				
	BOARDWALK CROSS SLOPE: minimum required for drainage				
	BOARDWALK EDGE PROTECTION: 50 mm (minimum) high				
	BOARDWALK EDGE PROTECTION FEATURES: allows suitable drainage of boardwalk surface				
6.16	**Public Transit**				
6.16.1	GENERAL: firm, stable and slip-resistant surface				

Section 6.0 Special Facilities and Spaces					
Standard Ref #	**Criteria / Requirement**	**Compliance**			**Comments / Observations**
		Yes	**No**	**N/A**	
	GENERAL: a grade with no slope steeper than 1:50 (2%)				
	GENERAL: shelters, street furniture and equipment, including benches, bus flags, garbage receptacles, bike racks, newspaper stands, etc. do not obstruct the accessible route				
6.16.2	ACCESS: station buildings and platforms are interconnected to adjacent streets, sidewalks and pathways by an accessible route				
	ROUTE TO PLATFORM: at least one fully accessible route to each station platform				
	PLATFORM SLOPE: slope of concrete platforms is uniform and where parallel to the Transitway, maintains the same slope and direction with a maximum average cross slope of 1:50 (2%)				
6.16.3	PLATFORM PASSENGER LOADING: clear length of 2400 mm, measured perpendicular to the curb or vehicular route edge and a clear width of at least 1500 mm, measured parallel to the vehicular route				
	PLATFORM EDGE: concrete with a stamped pattern placed in a recess, 610 to 650 mm in width and with a high tonal contrast with adjacent surfaces, along the front edge behind the steel facing for the full length of the platform				
	PLATFORM TACTILE WALKING SURFACE INDICATOR: a tactile walking surface indicator, composed of truncated domes: i. at curb ramps ii. at an entry into a vehicular route or area where no curbs, or other elements separate it from the pedestrian route of travel such as traffic islands and pedestrian crosswalks iii. with minimum width of 610 to 650 mm across the full length of the drop-off				
	PLATFORM LIGHTING: consistent with Section 5.7, as applicable, at all platforms				
	PLATFORM BENCHES / REST AREAS: consistent with Section 2.6 Rest Areas				
6.16.4	SHELTER SURFACE: uniform precast / poured concrete pad				
	SHELTER ACCESS: level access to the adjacent sidewalk, walkway or accessible route				
	SHELTER VIEW: unobstructed clear floor area of 1500 mm by 1500 mm diameter within the perimeter of the shelter				
	SHELTER FLOOR AREA: unobstructed clear floor area of 1500 mm by 1500 mm diameter within the perimeter of the shelter				
	SHELTER ENTRY: door or clear opening at least 920 mm wide				
	SHELTER OVERHEAD CLEARANCE: 2100 mm (minimum) at bus flag post				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	SHELTER BENCH: shelter-style bench, clear of the immediate area inside the entrance: i. with a seat height between 450 mm and 500 mm from ground ii. with armrests and a backrest iii. with high tonal contrast with surroundings to enhance visibility				
	SHELTER GLAZED PANELS: incorporate decals and other safety features, including: i. a horizontal row of red decals or a continuous strip, minimum 50 mm wide, mounted with its centre line at a height of 1350 mm to 1500 mm from the floor or ground ii. where decals are used, locate at a maximum of 150 mm from centre to centre iii. ensure decals used are 50 mm square or round, and/or of a special design (e.g., a logo) provided the solid portion of the decals provides high tonal contrast and is easy to identify by persons with vision loss iv. where frameless glass panels are used, identify exposed edge with a vertical moulding of high tonal contrast (e.g., safety yellow), applied to cap the end glass panel				
6.16.5	ON-STREET BOARDING AREAS: loading area with a clear length of 2400 mm, measured perpendicular to the curb or vehicular route edge, and a clear width of at least 1500 mm, measured parallel to the vehicular route				
	ON-STREET SHELTER SURFACE: uniform precast/poured concrete pad				
	ON-STREET SHELTER ACCESS: level access to the adjacent sidewalk, walkway or accessible route				
	ON-STREET SHELTER VIEW: a clear, unobstructed view of oncoming traffic				
	ON-STREET SHELTER FLOOR AREA: unobstructed clear floor area at least 1500 mm diameter directly inside the shelter entrance				
	ON-STREET SHLETER ENTRY: clear opening is at least 920 mm wide				
	ON-STREET SHELTER OVERHEAR CLEARANCE: 2100 mm (minimum) at bus flag post				
	ON-STREET SHELTER BENCH / REST AREA: bench, clear of the immediate area inside the entrance, consistent with Section 6.16.4 Shelter Bench				

Section 6.0 Special Facilities and Spaces

Standard Ref #	Criteria / Requirement	Compliance Yes	No	N/A	Comments / Observations
	ON-STREET SHELTER GLAZED PANELS: decals and other safety features, including: i. a horizontal red continuous strip, minimum 50 mm wide, mounted with its centre line at a height of 1350 mm to 1500 mm, measured from the base of shelter ii. where decals are used, locate at a maximum of 150 mm from centre to centre iii. ensure any decals used are 50 mm square or round, and/or of a special design (e.g., a logo) provided the solid portion of the decals provides high tonal contrast and is easy to identify by persons with vision loss iv. where frameless glass panels are used, identify exposed edge with a vertical moulding of high tonal contrast (e.g., safety yellow), applied to cap the end glass panel				
	ON-STREET SHELTER ROOF: designed to prevent rain, snow, or ice accumulation at the entrance and adjacent routes				
6.16.6	BUS STOP FLAG POLE: adjacent to the accessible route / sidewalk				
	BUS STOP SIGNAGE: signage on shelter or bus stop flag pole identifies the stop number and the routes serving the stop and is consistently located and of uniform design				
	BUS STOP BENCH: is consistent with Section 2.10.1 Benches and Seats				
	BUS STOP AREA: clear space of 915 mm wide by 1370 mm long minimum adjacent to the bench outside				
	BUS STOP EQUIPMENT: no sharp edges or corners on equipment, such as poles and signs				
	BUS STOP GARBAGE / RECYCLING: orient garbage/recycling receptacle dependent on optional advertising panels at the end of the shelters				
6.18	**Office Environments (RESERVED)**				
	RESERVED				

APPENDIX E – FLEXIBLE PAVEMENT CONDITION EVALUATION FORM

Flexible Pavement Condition Evaluation Form

Project: Festival Hydro, 187 Erie St., Stratford, On

Location : North Parking Area

				Severity of Distress					Density of Distress				
				Very Slight	Slight	Moderate	Severe	Very Severe	Few	Intermittent	Frequent	Extensive	Throughout
									<10	10-20	20-50	50-80	80-100
Pavement				1	2	3	4	5	1	2	3	4	5
Surface Defects		Ravelling & C. Agg. Loss	1				X						X
Surface Defects		Flushing	2										
Surface Deformation		Rippling and Shoving	3										
Surface Deformation		Wheel Track Rutting	4		X					X			
Surface Deformation		Distortion	5		X					X			
Cracking	Longitudinal Wheel Track	Single and Multiple	6			X				X			
Cracking	Longitudinal Wheel Track	Alligator	7	X					X				
Cracking	Centre Line	Single and Multiple	8										
Cracking	Centre Line	Alligator	9										
Cracking	Pavement Edge	Single and Multiple	10										
Cracking	Pavement Edge	Alligator	11										
Cracking	Transverse	Half, Full and Multiple	12										
Cracking	Transverse	Alligator	13										
Cracking	Longitudinal Meander and Midlane		14			X				X			
Cracking	Random		15			X				X			

Flexible Pavement Condition Evaluation Form

Project: Festival Hydro, 187 Erie St., Stratford, On

Location : East Parking Area & Driveway

				Severity of Distress					Density of Distress				
				Very Slight	Slight	Moderate	Severe	Very Severe	Few <10	Intermittent 10-20	Frequent 20-50	Extensive 50-80	Throughout 80-100
Pavement				1	2	3	4	5	1	2	3	4	5
Surface Defects		Ravelling & C. Agg. Loss	1				X						X
		Flushing	2										
Surface Deformation		Rippling and Shoving	3										
		Wheel Track Rutting	4		X				X				
		Distortion	5										
Cracking	Longitudinal Wheel Track	Single and Multiple	6										
		Alligator	7										
	Centre Line	Single and Multiple	8										
		Alligator	9										
	Pavement Edge	Single and Multiple	10										
		Alligator	11		X				X				
	Transverse	Half, Full and Multiple	12										
		Alligator	13										
	Longitudinal Meander and Midlane		14										
	Random		15	X					X				

Appendix C

FHI Strategic Plan

Powering Forward

2020 - 2024 Strategic Plan

-Reviewed & Refreshed in 2022-

Festival Hydro Inc.

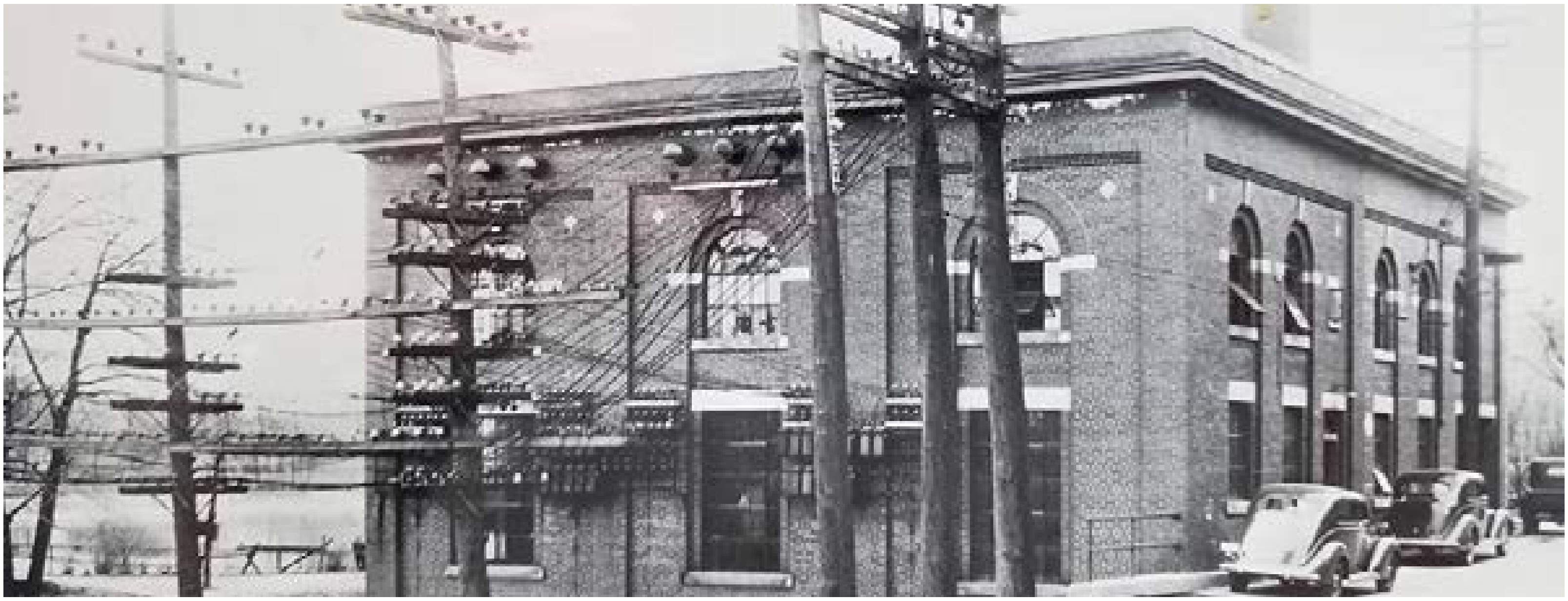


Table of Contents

Message from the CEO	2
Introduction	3
Innovation Powering Progress	4
Innovation for the Future	5
Initiative 1: Our People	6
Initiative 2: Invest in New Operational Technologies	7
Initiative 3: Collaborate with Other Local Community Stakeholders	8
Initiative 4: Create Scale in the Utilities Space	9
Financial Stability to Power Innovation	10
Empowering Our Communities	12
People First Through Positive Teamwork & Technology	13
Economic Development & Shared Services	14

Message from the CEO

One common theme throughout this document is our focus on technology as a driver for our success. We employ technology to innovate, automate processes, and change the way we produce, consume, and distribute energy across our communities. We aim to provide the highest quality service that not only meets, but exceeds, customer expectations and we look forward to the coming years that will bring more opportunities, new ideas, and exciting projects that we can share with the communities we serve.

Our Strategic Plan and the associated priorities and goals are supported by our annual Business Plans which provide the more detailed operational specifics required to ensure our work initiatives move the business forward in alignment with our strategic priorities.

Annual budgets are developed every fall, drawing on these Business Plans and available revenue. Detailed Key Performance Indicators (KPIs) are identified, measured, and tracked year over year to help highlight trends and areas of success or opportunity.

In 2022, the board and executive team undertook a midterm review of the strategic priorities identified at the planning meeting in May of 2019 to refresh, renew and realign the strategic plan and priorities to meet the changing needs of Festival Hydro Inc., our employees, our shareholder, and the communities we serve.

As you will see when you read through this document, the four key priorities for FHI over the next two years of the planning period are: our people, investment in technology to drive operational efficiencies, creating scale in the utilities space, and collaboration with strategic partners to increase business opportunities.

With these four priorities in mind, we envision a future of positive change for the organization that will continue to drive employee satisfaction with a renewed focus on technology and automation to increase process efficiencies and create increased work/life balance and job satisfaction for our Festival Hydro team. We are also dedicated to honouring our commitment to the communities we serve and are constantly striving to provide our customers, both business and residential with stable and reliable access to power, and access to beneficial programs.

Further, our focus on partnerships, collaborations, and a "people first through positive teamwork" mentality, gives a nod of recognition to the hard work of each individual and entity that comes together to create a strong foundation upon which we can build an excellent experience, opportunities for continued customer choice, and the support and empowerment of the communities we serve.

Jeff Graham

Chief Executive Officer

Meet Our Board & Executives

Geraldine Guthrie
Chair

John Tapics
Vice Chair

David Scott
Director

Mark Henderson
Director

Susan Nickle
Director

Dan Mathieson
Director

Brad Beatty
Director

Graham Bunting
Director

Jeff Graham
Chief Executive Officer

Alyson Conrad
Chief Financial Officer

Bryon Hartung
VP of Engineering and Operations

Jackie Wheal
Director, Human Resources/Health and Safety

Introduction

Festival Hydro Inc. was incorporated in 2000 and is a wholly owned subsidiary of the City of Stratford. The principal activity of FHI is to distribute electricity to the residents and businesses in the City of Stratford and the towns of Brussels, Dashwood, Hensall, Seaforth, St. Marys, and Zurich, under a license issued by the Ontario Energy Board ("OEB"). FHI is regulated by the Ontario Energy Board and adjustments to the distribution and power rates require OEB approval.

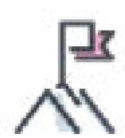
Festival Hydro Inc's (FHI) Strategic Plan establishes a roadmap for making informed decisions to meet current and future demands of FHI and its customers through the identification of four specific priorities and goals with actionable initiatives to accomplish them. Over the past 4 years, Festival Hydro has made great progress and this Plan provides an opportunity to reflect on these accomplishments while developing a path forward. The development of the 2020-2024 Strategic Plan was led by the Festival Hydro Inc. management team and Board of Directors, with input from the City of Stratford Municipal leadership and our customers.

Innovation Powering Progress

Festival Hydro Inc. is an energy company focused on providing customers with the highest level of service through innovation in infrastructure, financial responsibility, strategic partnerships, and community outreach. Although not the largest electric utility in the Province of Ontario, with just over 22,000 customers, FHI has achieved significant recognition for our accomplishments over the years by receiving numerous awards including Electricity Distribution Association's award for Innovation, as well having been honoured previously with the Safety Excellence Award, Customer Service Excellence Award and Conservation and Demand Management award.

A culture of innovation has been the driver for strategic business and community growth by offering better ways to manage power, enhance effective use of infrastructure and capital assets, and create increased process efficiencies through automation. We strive to consistently prove that local utilities can play a key role in facilitating impactful initiatives while ensuring business fiduciary expectations, customer satisfaction, and managing downside risk while providing upside potential. FHI has played a key role in investment attraction and has been sought out as a thought leader willing to participate in projects leading the future of energy management. We believe in incorporating the use of technology and leveraging strategic partnerships as enablers to reach our goals and promote continuous business improvement. These efforts have led to consistently reaching or exceeding detailed key performance indicators as measured by our board and regulator.

Mission



To responsibly provide value to our customers, communities, shareholders, and employees through cost effective distribution of reliable and safe electric power.

Vision

We enable prosperity within our communities through exceptional people, partnerships, and performance.

Purpose

Powering lives, empowering communities.

Values

- People First through Positive Teamwork
- Accountability
- Honesty
- Commitment to Customers
- Trust

Technology for the Future

The Mission and Vision Statements for Festival Hydro Inc. provide a key reference point to the corporate direction and purpose of the organization.

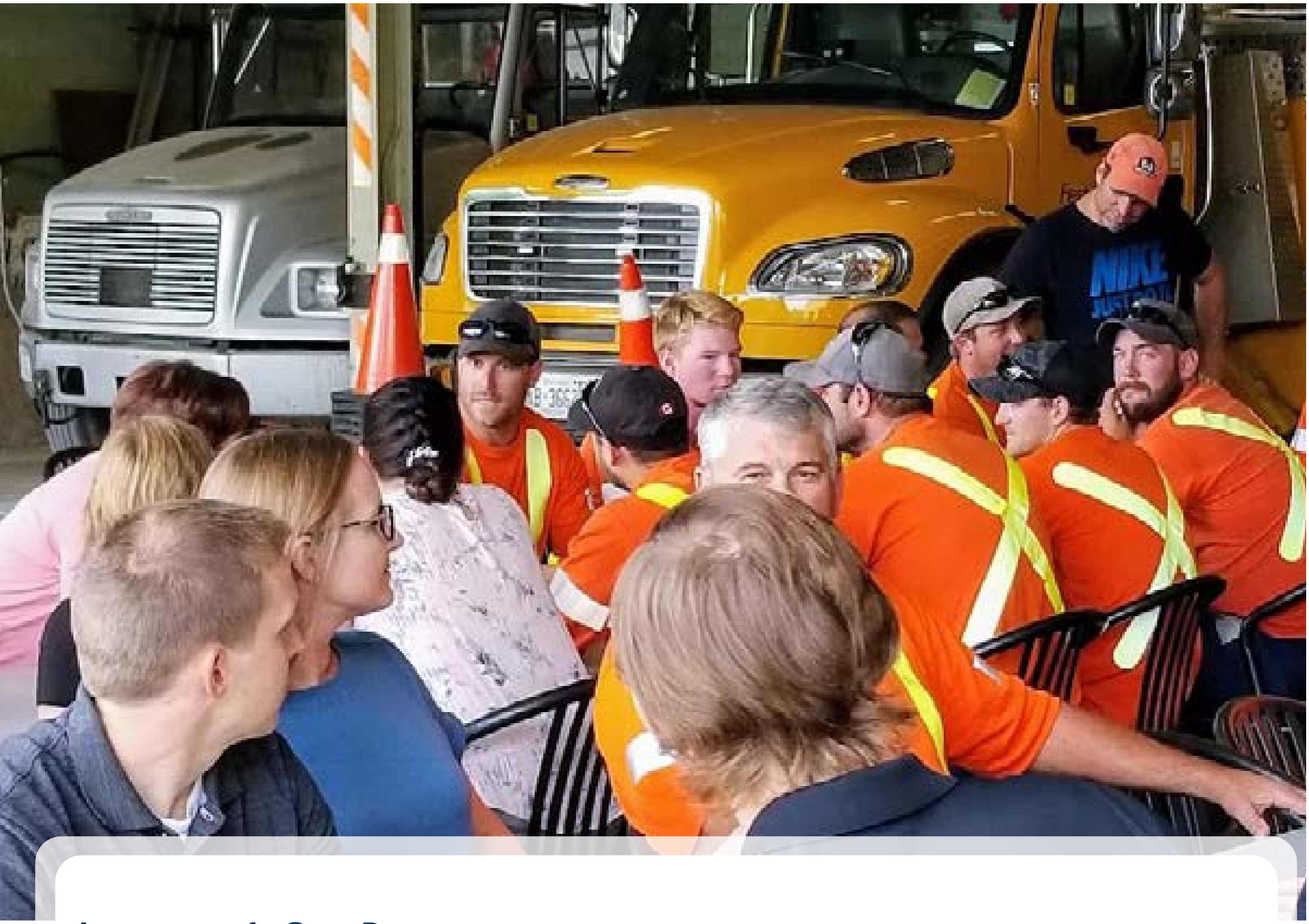
The Vision statement is further supported by the commitment to earn this reputation by:

- Being a leader in implementation and utilization of technology to support communication and automation.
- Diversifying into new areas for alternative generation to meet customer demand/ expectation.
- Increasing our scope through additional business lines.
- Continuing to meet key performance indicator (KPI) targets and operate as an efficient and effective utility in the province.
- Being recognized as a technology leader and showcase utility in the industry.

As part of the strategic planning process these corporate statements were reviewed and provided guidance for the enhancement of the four key priorities for the business over the next four years.

In developing the 2020-2024 Strategic Plan a SWOT analysis was completed to help identify areas of focus. As part of the 2022 midterm review of the plan the SWOT analysis was reviewed and updated to account for the changing industry and economic landscape.

From the analysis, the four key priority areas were strengthened with supporting goals and initiatives.



Initiative 1: Our People

The Opportunity

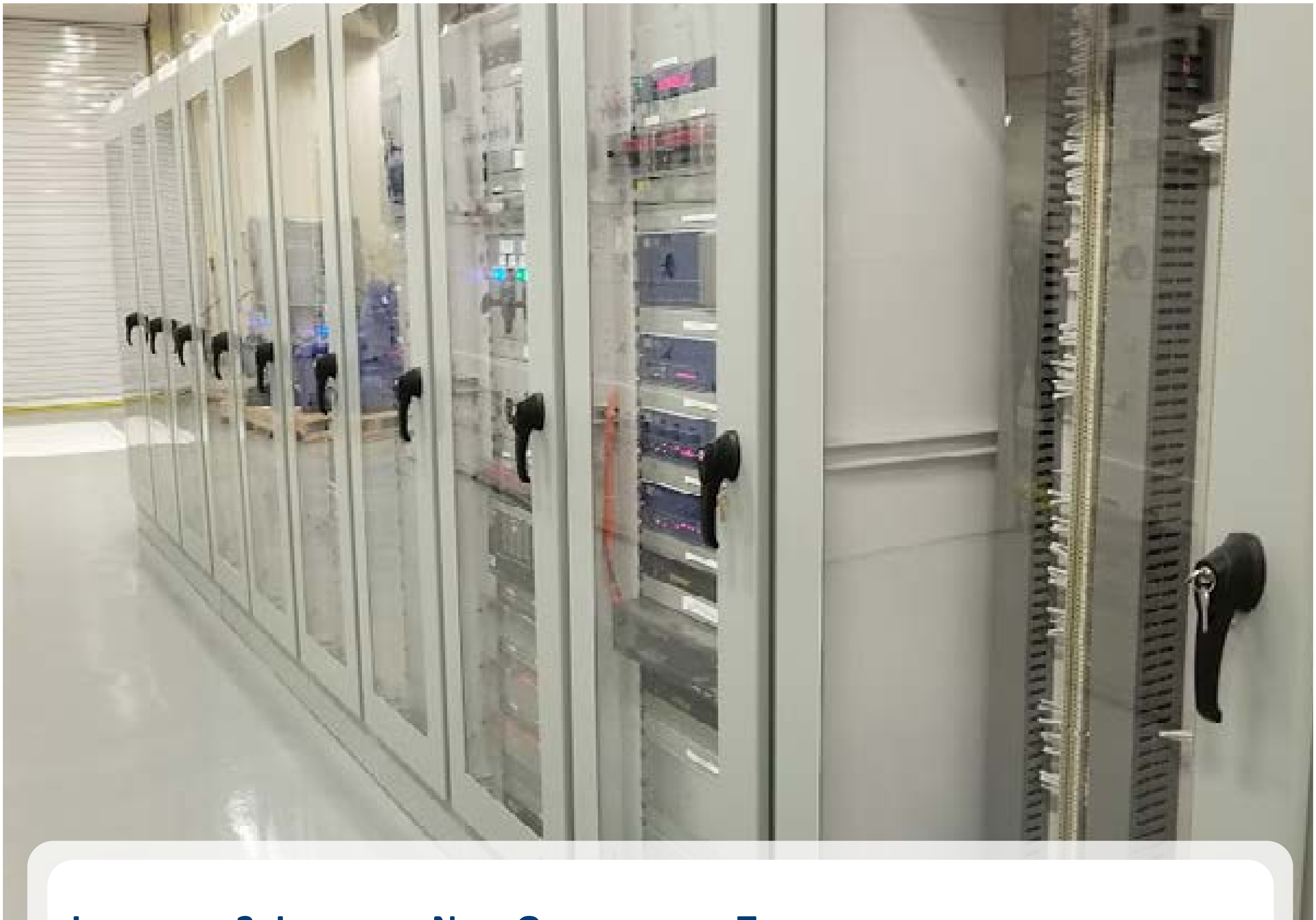
Recognizing our team of staff is the most critical component of our business success, it is imperative that the organization ensures the success of our employee's, and that the safety of our people is paramount. To sustain the organization by skillfully adapting to change and implementing efficiencies will lead to optimization of resources and capacity, enhanced service delivery, and increased value for all stakeholders.

The Goals

- To ensure the safety of our staff is paramount
- To create a sustainable, motivated workforce and enhance productivity
- To be viewed as a great place to work

The Actions

1. Create an employee retention plan
2. Ensure a competitive compensation plan is in place
3. Formal succession plan includes high-performing employee (HPE)identification with a corresponding multi-year Development Plan
4. Develop an Employee Recognition Program
5. Invest in physical facilities upgrade



Initiative 2: Invest in New Operational Technologies

The Opportunity

Technology is constantly changing and developing at a very fast pace and every day new technologies are launched that can improve upon efficiencies and processes that the business relies on. By working with our internal teams to better understand their day-to-day processes we can formulate a plan and look for technologies that fit the unique needs of our teams, help to reduce reliance on paper, and improve upon customer and employee experiences.

The Goals

- To reduce costs and improve operational efficiencies
- To improve internal and external communications
- To enhance and improve the customer experience

The Actions

1. Refresh our Technology Roadmap
2. Implementation of a new Customer Information System (CIS)
3. Invest in digital systems for handling workflows
4. Continued enhancement of security to protect confidential information and internal systems and concerns

Initiative 3: Collaborate with Other Local Community Stakeholders

The Opportunity

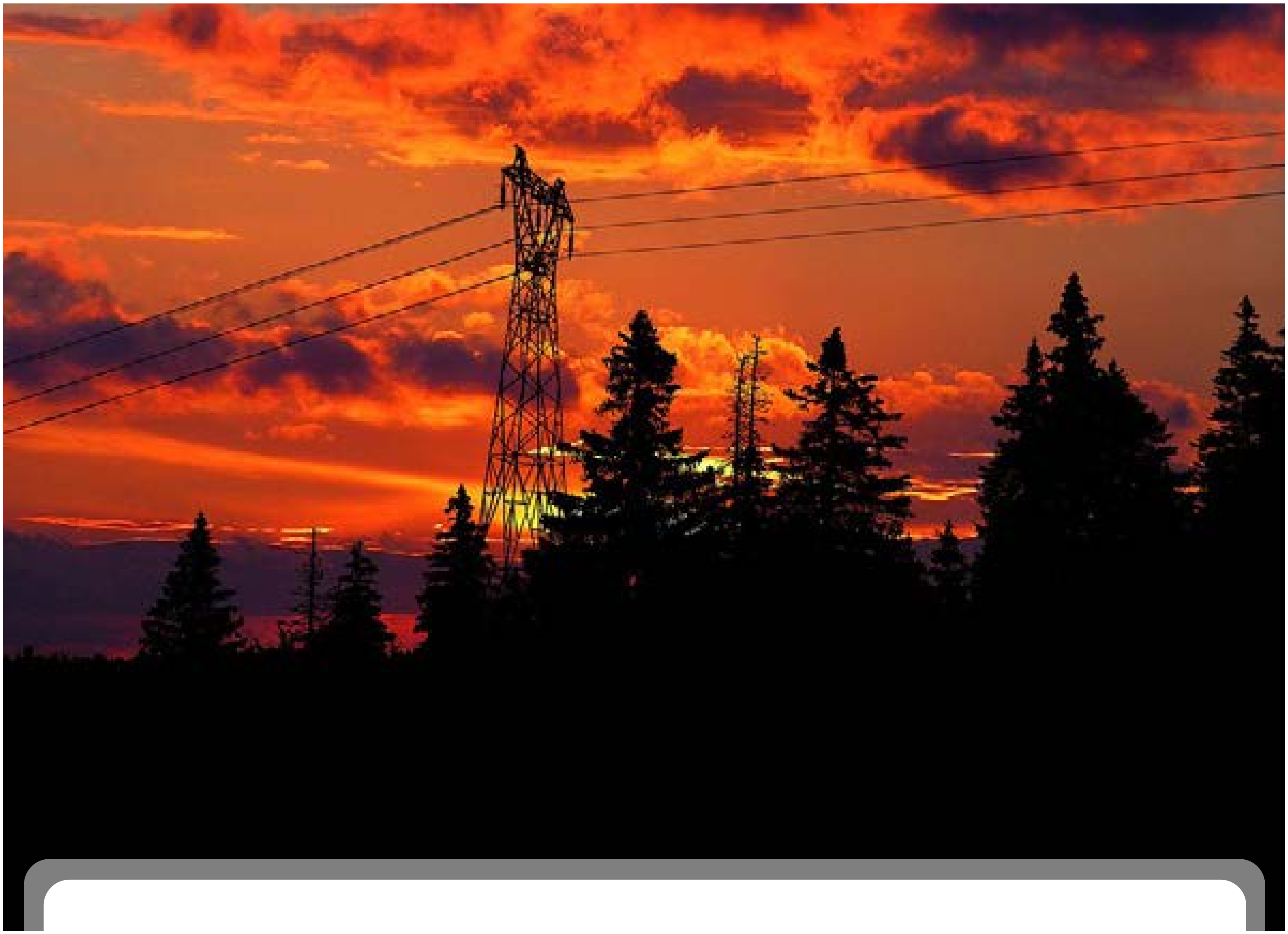
As a locally owned utility we have a unique opportunity to work in partnership with the municipality and the economic development team to attract new business, investment, and opportunities to the community and we understand the value of having strong relationships with community members and customers. Through enhanced collaboration and relationship building we can seek to better understand the goals and needs of our customers and communities to ensure that their needs are met and that we are acting as a partner in their success.

The Goals

- Enhance long term viability

The Actions

1. Partner with Invest Stratford and the City to support economic development & investment in our region.
2. Meet with large industrial customers to understand their business strategies/growth targets.
3. Build FHI brand & value by getting involved in Community events to show the value of local utility ownership



Initiative 4: Create Scale in the Utilities Space

The Opportunity

Just as we recognize the incredible value of relationship building with stakeholders in the communities we serve, we also emphasize the importance of teamwork and collaboration with our peers in the energy industry. By seeking out shared service opportunities, participating in working groups and industry councils, and forging strategic partnerships with other utilities, we have the opportunity to learn from others, leverage the power that comes from unity, better control costs, and contribute to setting the standards for industry best practices. This will help to ensure continued responsible and value-driven operation of our organization well into the future.

The Goals

- Reduce costs and enhance efficiencies,
- Ensure financial viability
- Business continuity

The Actions

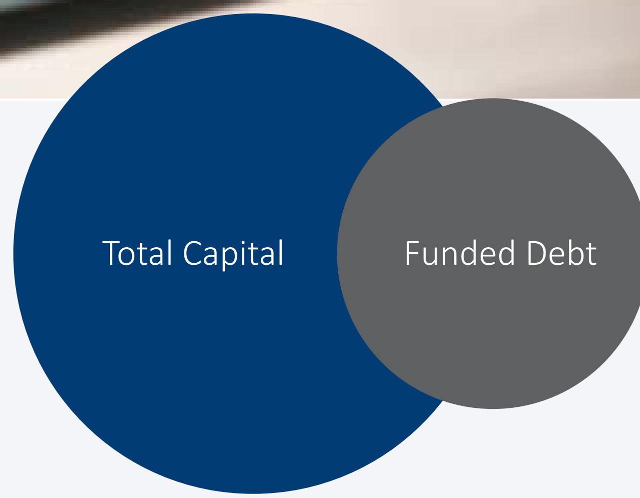
1. Continue to partner with other utilities & organizations to create future opportunities.
2. Seek out shared service opportunities with other utilities.
3. Consider joining already established industry groups that we are not currently associated with.

Financial Stability to Power Innovation

Festival Hydro Inc. has continued to meet or exceed best business practice financial measurements as well as those financial tools tracked and assessed by The Ontario Energy Board. A solid governance framework and continuous tracking of Key Performance Indicators ensures that Festival Hydro is not placed in a position of undue financial risk, or where assets are unprotected, inadequately maintained, or unnecessarily risked. This helps us to ensure that we are meeting our goal of providing a safe, reliable, and cost-effective electrical system for our customers while retaining and enhancing shareholder value.

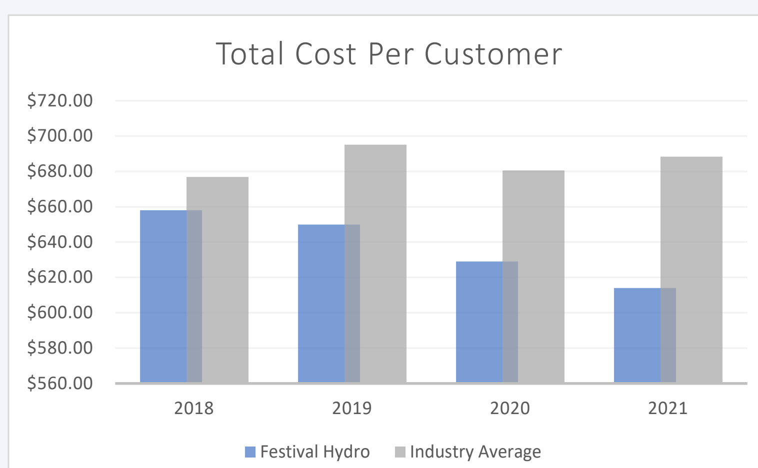
Liquidity Ratio

Often used as an indicator of financial health, a ratio that is greater than one is considered good as it indicates that the company can pay its short-term debts and financial obligations without the need to raise external capital. Festival Hydro continually exhibits a ratio of greater than one and maintains the Ratio of Funded Debt to Total Capital of no greater than 0.65:1.



Total Cost Per Customer

This is defined as the sum of all the costs incurred by the utility to provide service to its customers. The amount is then divided by the utility's total number of customers. Festival Hydro's cost per customer figure remained relatively stable for several years and has trended downward since 2018. The decrease in the cost per customer is attributable to increased grid stability that has been realized due to upgrades which thereby reduce maintenance costs, as well as reform and automation of internal processes in order to increase efficiency. By increasing operational efficiencies and controlling costs FHI has been able to maintain relatively stable pricing for customers. In 2019, FHI achieved the goal of reaching group 3 in the efficiency analysis (PEG) as reported on the OEB scorecard.



CAPITAL EXPENDITURES

All physical assets depreciate over time. Therefore, it is necessary to continually re-invest in the system in order to maintain value and integrity. We time our capital investment in such a way that replacement of depreciated assets occurs before they become unsafe, unreliable, and uneconomical.

When appropriate, Festival Hydro employs new and creative solutions with a proven track record to accommodate enhanced and expanded load growth. We believe new capital investments must enhance shareholder and customer value by improving safety, reliability, customer service, and meeting or exceeding projected consumption demand.

An Asset Management Plan is maintained and updated every year. Infrastructure is tested and inspected cyclically, and the annual results are used to adjust the forecasted number of required replacements that will be necessary to maintain or improve safety and reliability over the next five to ten years. The Asset Management Plan drives the Distribution System Plan (DSP) which identifies major projects and anticipated spending levels for the next five years.

When formulating the asset management plan, new solutions and technologies are considered that can serve to improve safety of the system, reduce outages and momentary interruptions, provide better longevity of installed infrastructure and contribute to faster restoration times in the event of a power outage. All of these factors contribute to our ability to provide our customers with stable and reliable access to power.

As a guideline, we look to keep our minimum expenditures for capital projects equal to the amount of depreciation in that year; however, we always seek to make decisions based on the best interests of Festival Hydro, our customers, our employees, and the communities we serve.

Empowering Our Communities

To us, being a partner in our communities means actively supporting and getting involved with the projects, organizations, and events that resonate with and touch the lives of our customers, and we welcome the opportunity to be partners in Powering Our Communities forward.

Some of the ways in which Festival Hydro lends support to the community include ongoing support for the Festival Hydro Community Park, supporting the United Way Perth-Huron through a workplace contribution program and other campaigns, collaboration with Upper Thames River Conservation Authority (UTRCA) and the City of Stratford on the annual Festival Hydro Tree Power program, sponsorship of numerous community festivals and events, and staff organized fundraisers such as the one in 2022 for the Canadian Cancer Association. Additionally, we conduct a quarterly draw, and the selected employee gets to direct a donation to the charity of their choice in the amount of the casual Friday collection for that quarter that every FHI employee can opt to participate in.

In 2021, we tied in our e-billing initiative to serve the community by donating $5 for each new e-billing customer to the Stratford General Hospital Foundation's "Closing the Gap" campaign to support youth mental health services.

We also aim to support the next generation in their educational goals and aspirations through the annual awarding of the Festival Hydro Scholarship. The recipient is a student who is enrolled in any post-secondary program that teaches technical, trade, or administration skills that our organization looks for in candidates applying to work within a Festival Hydro.

Through charitable giving and philanthropy, we as a corporation can make a positive contribution to the quality of life, and the number of services and supports available in the communities we serve.

People First Through Positive Teamwork & Technology

Along with the belief that our employees are the largest contributing factor to the success of Festival Hydro comes the responsibility to empower our staff members so that they thrive and to foster a healthy workplace culture. We promote an organizational culture that encourages employee growth and development and recognizes individual and team contributions.

To create a positive culture that puts people first and focuses on the employment of technology to promote efficiencies, you first need a culture of learning as a foundation that can be built upon, as well as a climate in which people want to do their best and strive for improvement both personally and professionally. We empower others and invite input from each person, share ownership and visibility for our successes, and convey that everyone's contribution is important. By fostering a two-way dialogue, we can find positive technology driven solutions that streamline efforts, reduce workloads, and improves customer experience. To allow for the continued growth of our team, and to promote personal development, Festival Hydro puts a priority on supporting the education and training of our staff.

In addition to our employees, we recognize and take pride in being able to provide a high level of service to the customers and communities that we serve. As we look at technology and consider the impacts that it will have on our internal operations, we also consider the more widespread effects that these implementations will have for our customers and consider how we can continue to progress the level of service for our end users. This includes considerations for enhanced communications during outages, automation that will decrease the length and number of outages experienced, and systems that allow staff quick access to accurate customer information that can be used to assist with inquiries and better recommend support programs that are available to those in need.

Economic Development & Shared Services

Another way in which we as locally owned distribution company can positively impact the community is through our ability to be an active participant in promoting the economic interests of those we serve. Together with our main shareholder, the City of Stratford, investStratford, the city's economic development organization, and our affiliate company Rhyzome Networks, we challenge the traditional ideas of our roles being mutually exclusive and instead share a common objective to attract new business to the areas we serve in order to drive down costs within the community; which in turn assists in attracting more business, job creation and creating a prosperous local economy.

The key element that makes this type of collaboration possible is the ownership structure of the companies. Although the City of Stratford is the sole shareholder of all three organizations, each is a separate corporation governed by separate boards. This allows each to be agile in their individual operations while still supporting a shared vision for economic health and growth within the community, as well as a collective mindset that is open to innovative technology and business streams that generally do not fall into the scope of the LDC's/ISP's and Economic Development departments of the past.

Another area where we see benefit for collaboration is among local distribution company's (LDC's) in the province. By working together in the search for services and technology that fit the needs of our industry and businesses we can learn from each other and benefit from the strengths of the group operating as a whole. The industry has unique challenges and requirements and by uniting we build the opportunity to create better tailored services, share the lessons we have learned, increased negotiating power and leverage, and reduce costs to the singular corporation through a shared structure and partnership.

Festival Hydro Inc.

Appendix D

Customer Engagement Survey Results

Festival Hydro

2023 Customer Satisfaction Survey Report

BRICKWORKS
COMMUNICATIONS

June 2023

Table of Contents

Background & Overview	3
Methodology & Logistics	3
Customer Preference Priorities	4
Power Outages	5
Smart Grid	6
Utility's Assets	7
Tree Trimming	8
New Technologies	9
Communication	10

Background & Overview

Festival Hydro commissioned Oraclepoll to conduct an engagement survey of its customers. The purpose of this survey process was to obtain customer input regarding their satisfaction with the services provided by Festival Hydro.

Brickworks and Festival Hydro designed the questionnaire. This word report contains an executive overview of the findings, while a separate report in Excel includes the results by each question.

Methodology & Logistics

Study Sample

All surveys were completed online using Computer Assisted Web Interviewing (CAWI). This was an open-online self-selection survey where respondents could connect with the survey link to complete their interview.

This is not a random sample poll based on a scientific representative sample of a defined audience.

Survey Method

All surveys were completed online using Computer Assisted Telephone Interviewing (CATI). The survey was promoted by Brickworks and Festival Hydro through its resources.

Logistics

The survey was open, and questionnaires were completed between the days of May 18 and June 2nd, 2023.

Confidence

It is not acceptable to assign online self-selection non-probability surveys a margin of error. However, a probability sample of this nature would be considered accurate ± 1.6%, 19/20 times.

Customer Preference Priorities

The following descriptive preamble was first presented to customers. They were then asked in the first question to rank in order a series of five option areas.

We are creating our business plan as part of our Cost-of-Service Rate Application for the Ontario Energy Board. As part of the process, we are reaching out to customers for their opinion as to what priorities and outcomes our 2025 capital and operating plans should focus on. We are seeking customer feedback about whether we have found the right balance between reliability, customer service, innovation, and the price you pay for electricity, or if they should consider different options.

Management has reviewed each part of Festival Hydro's business and the projects and topics identified in this survey have been recognized as providing meaningful benefits. However, their pace of implementation and timing can potentially have an impact on the overall reliability and state of the distribution system as well as the current rates customers are charged.

The survey should take less than 5 minutes. In appreciation of completing this survey, if you leave your contact information, you will be entered into a draw for 1 of 3 $100 VISA gift cards.

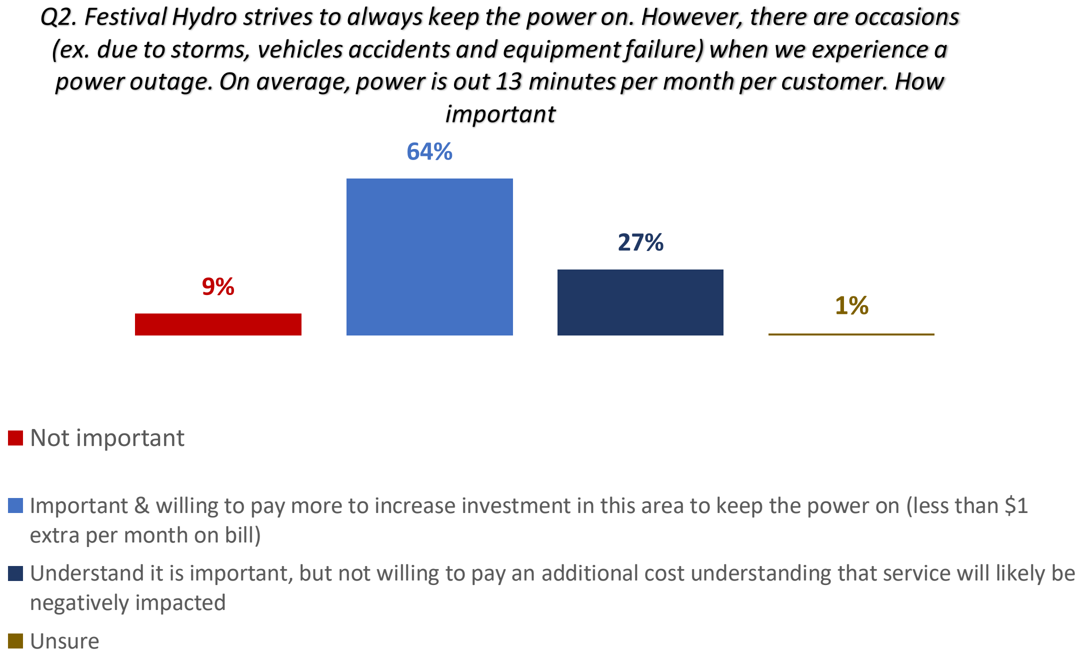
Q1. Based on these five options, rank each from one to five with one being most important and five being least important to you.

Mean Score 1-Most Important & 5- Least Important	*Mean*
Q1A. Festival Hydro provides electricity that is "reliable" and "safe" (fewer outages and focuses on public and employee safety)	2.73
Q1B. Festival Hydro prioritizes aesthetics over most cost-effective solution when constructing or replacing assets at an increased cost to customers (things such as moving overhead wires underground, and moving rear lot infrastructure to front of property)	2.83
Q1C. Festival Hydro provides electricity at low cost at the expense of reliability, green initiatives, innovation and customer service.	2.88
Q1D. Festival Hydro invests in innovative solutions such as smart grid, battery storage, electric vehicle infrastructure, solar and smart home technologies at an increased cost to customers.	3.22
Q1E. Festival Hydro provides excellent customer service	3.33

Highest ranked in terms of importance with a mean score pf 2.73 is providing electricity that is "reliable" and "safe" with fewer outages, focusing on public and employee safety. The next two mid-scored areas that ranked closely together were prioritizing aesthetics over most cost-effective solutions when constructing or replacing assets at 2.83 and then providing electricity at a low cost at the expense of reliability, green initiatives, innovation and customer service at 2.88. The two lowest ranked issues in terms of priority were investing in innovative solutions at 3.22 and for providing excellent customer service at 3.33.

Power Outages

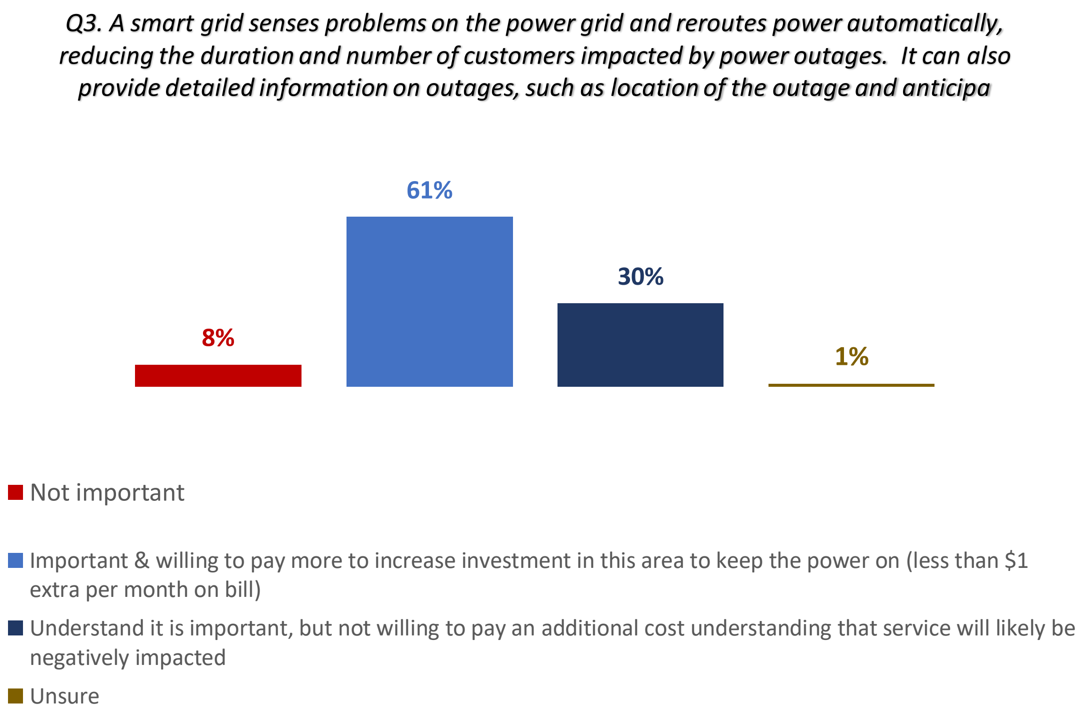
Respondents were then asked about the importance of minimizing power outages. They were presented with three options to choose from.



With respect to minimizing power outages, more than six in ten or 64% said it is important and that they are willing to pay more to increase investments to keep the power on, paying less than $1 extra per month on their bill. More than a quarter or 27% understand it is important but are not willing to pay any more each month – this despite service that may be impacted. Only 9% claimed that this is not an important issue, while 1% did not know.

Smart Grid

A definition of a smart grid was displayed after which respondents were asked how important it is to have these services provided.

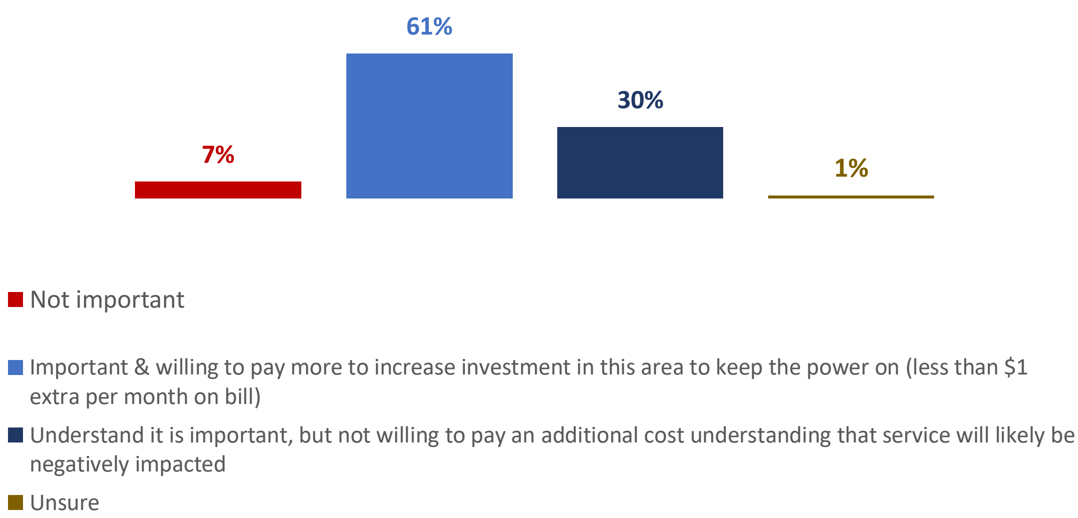


On the issue of smart grids, a 61% majority said they are important, and they would be willing to pay more to increase investments to keep the power on (at less than $1 extra per month on bill). Thirty percent understand their importance but are not willing to pay an additional cost despite understanding that service may be negatively impacted. There were 8% that stated smart grids are not important, while 1% were unsure.

Utility's Assets

Respondents were displayed a statement about the importance of maintaining assets after which they were asked about its importance. They were allowed to choose one of three options including an unsure response.

Q4. Poles, wires, and transformers typically last 40 to 50 years. To ensure an uninterrupted supply of electricity to you, we need to maintain and replace these assets when their useful life has expired. If assets are not replaced on a timely basis, outag

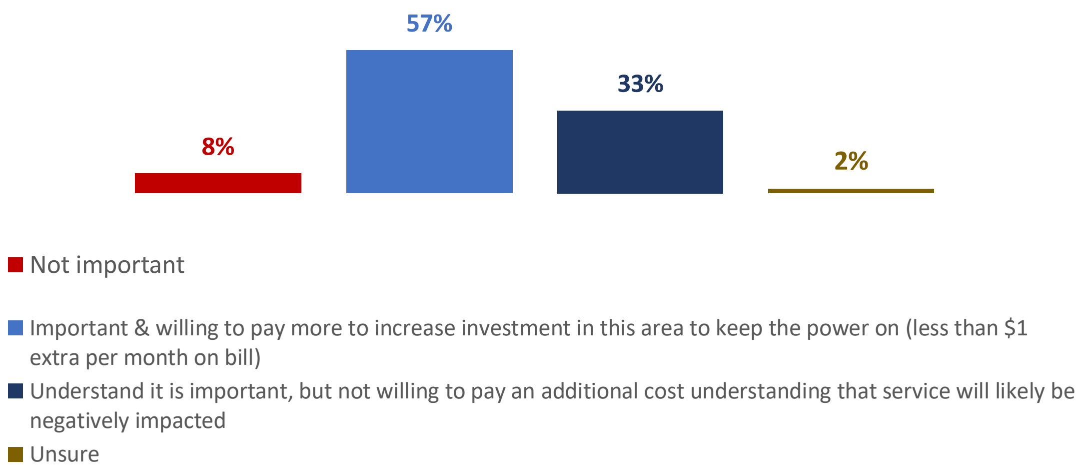


A core 61% claimed that this issue is important and are willing to pay less than $1 on their monthly bill to increase investment in this area. Three in ten while feeling this also important are not willing to pay an additional cost, fully understanding that service will be negatively impacted. The undecideds are at one percent and 7% said this is not important to them.

Tree Trimming

The next area of inquiry was about the importance of tree trimming.

Q5. Festival Hydro provides tree trimming on a cyclical basis to assist with limiting outages from tree contact and animal interference. The cost to perform tree trimming continues to increase annually. How important is maintaining the tree trimming cycle

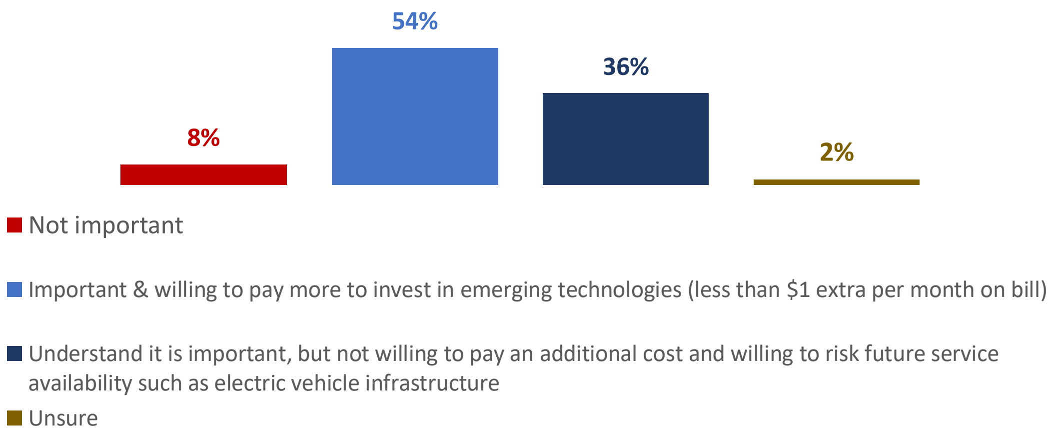


Tree trimming was deemed important to 57% that would also be willing to pay less than $1 per month to increase investment in this area. One-third while also feeling it important would not be willing to pay additional money despite the risks. A total of 8% felt the issue was not important and 2% were unsure.

New Technologies

Next a preamble was displayed about new technologies and customers were then probed about their importance.

Q6. Festival Hydro is more than just poles and wires, it is a growing forward-looking business that needs to adapt and adjust to new trends in the Electrical industry, including having Electric Vehicles and Customer owned Generators connecting to its Elec

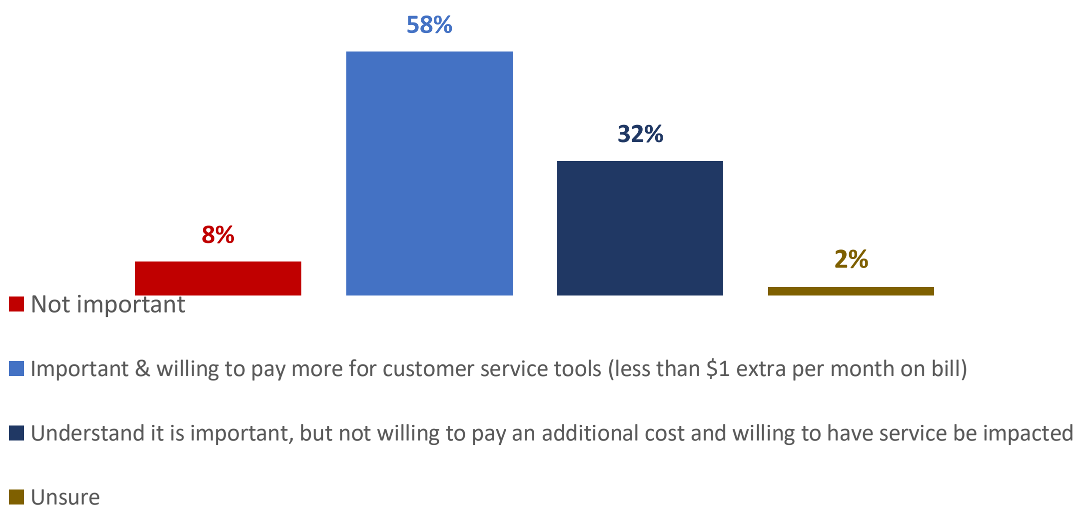


The importance and resulting willingness to pay more to invest in emerging technologies at less than $1 extra per month dropped to 54%, while the percentage of those understanding the importance but not willing to pay increased to 36%. Those saying not important (8%) or being unsure (2%) were constant.

Communication

In the final question, respondents were informed that Festival Hydro is looking to invest in automatic tools and communication methods to improve customer service. They were then asked how important these customer service tools are.

Q7. Festival Hydro is looking to invest in automated tools and communication methods for customer service. Some of these items could include website chat features for customer inquiries, an app that would display usage information and further online forms



The unimportant (8%) and unsure (2%) results remained similar. A total of 58% feel this to be important and are willing to pay $1 more a month for more customer service tools, rules while 32% deeming this also as important are not willing to pay any more.

2023 Telephone Survey Report

December 2023

Table of Contents

Background & Overview	2
Methodology & Logistics	2
Role of Festival Hydro	3
Automated Tools / Communication Methods	4
E-billing	5
Emerging Technologies	8
Legacy Metering Network	9
Tree Trimming	10
Future Renewal Expenditures	11
Rate Increases	12

Background & Overview

Festival Hydro commissioned Brickworks Communications to survey its customers. The purpose of this survey process was to obtain customer input regarding their satisfaction with the services provided by Festival Hydro.

Brickworks and Festival Hydro designed the questionnaire. This report contains an executive overview of the findings, while a separate report in Excel includes the results of each question.

Methodology & Logistics

Study Sample

Festival Hydro provided a customer database to be used as a sample frame.

Survey Method

All surveys were completed online using Computer Assisted Telephone Interviewing (CATI).

Logistics

A total of N=400 questionnaires were completed between the days of November 22nd and December 11th, 2023.

Confidence

The margin of error for this survey is ± 4.9%, 19/20 times.

Role of Festival Hydro

The following descriptive preamble was first presented to customers. They were then asked the first question about how well they understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of their bill relates to Festival Hydro.

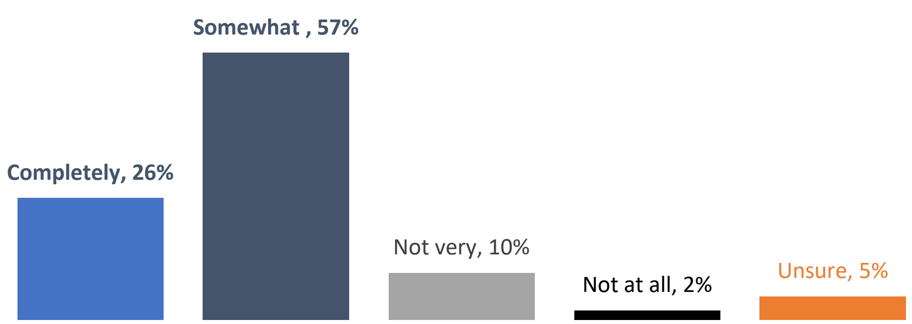
"Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It's made up of three major components: generation, transmission, and distribution. Festival Hydro is a distribution company that carries the electricity from the transformer stations to your homes. Festival Hydro manages its spending in two ways– an operating budget and a capital budget.

• Festival Hydro's operating budget covers recurring expenses, such as the maintenance of distribution system infrastructure, equipment, vehicles, buildings, properties, and tools, as well as insurance and corporate income taxes.

•Festival Hydro's capital budget covers items that have benefits over many years. This includes distribution system equipment such as poles, wires, cables, transformers, computers and information systems, vehicles, and facilities.

Managing the distribution system requires considerable investments in replacing aging equipment, connecting new customers, maintenance, and day-to-day operations. Festival Hydro's portion of the average bill is 26% of the total bill. This portion is used to maintain, enhance, and rebuild the system and includes a regulated rate of return that is used to reinvest in the system."

Q1. How well do you feel you understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of your bill relates to Festival Hydro?



A total of 57% of respondents said they somewhat understand the role that Festival Hydro plays in the electricity system, and 26% claimed to completely understand. Only 10% do not understand it very well and 2% do not at all. A total of 5% of respondents were unsure.

Automated Tools / Communication Methods

The following was fist read to customers after which they were asked which of four options they would most prefer.

"In a previous customer engagement survey from earlier this year, Festival Hydro noted that it is looking to invest in automated tools and communication methods for customer service. Some of these items could include website chat features for customer inquiries, an app that would display usage information, and further online forms. More than half of customers responded that this is important and that they were willing to pay more for customer service tools (less than $1 extra per month). Festival Hydro has built-in minor enhancements to its plans that will allow for more self-service options."

Q2. Which of the following would you prefer:

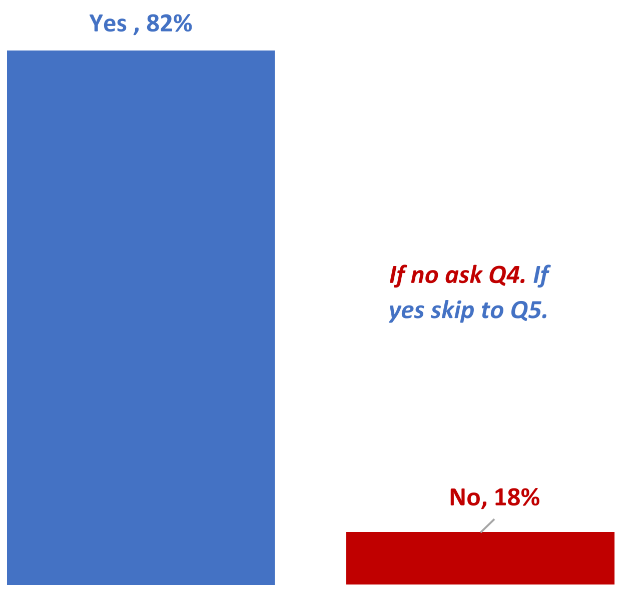
	Percentage
Increase customer service enhancements (such as an app with usage information) with increased costs.	49%
Continue with planned enhancements but do not need more tools such as an app or website chat features.	36%
Decrease costs by lowering levels of customer service than what is currently provided (this could include longer telephone wait times or email response times).	13%
Unsure	2%

Most named by almost half or 49% is having an increase in customer service enhancements, such as a usage app, even if it means increased costs. The next most referenced by 36% was to continue with planned enhancements but not with new tools or features. Only 13% wanted decreased costs by lowering customer service, while 2% were unsure.

E-Billing

Respondents were then asked if they currently receive an E-bill from Festival Hydro.

Q3. Do you currently receive an E-bill from Festival Hydro?



A total of 82% or N=328 of Festival Hydro customers currently receive an E-bill.

The 18% (N=72) of customers that do not receive an E-bill from Festival Hydro were asked Q4 as a follow-up question, while all others skipped to Q5. Customers were prompted with a list of possible responses

Q4. The cost of receiving a paper bill to customers is approximately $1 per month per customer or $12 per year. What is preventing you from registering to receive an E-bill?

	Percentage
Receiving the bill by mail is a reminder to pay.	25%
I was not aware that the cost savings of e-billing helps offset future cost increases.	17%
It is more convenient to receive the bill by mail.	15%
I am concerned about online security from receiving electronic bill.	10%
Prefer paper copy.	10%
Have not gotten to it yet.	8%
I do not have regular access to the internet.	7%
Not aware that option existed.	6%
I am not comfortable with technology.	3%

In an open-ended probe, all N=400 respondents were asked if they had any recommendations for improvements to the E-billing process.

Q5. Do you have any recommendations on improvements to the E-billing process?

	Percentage
Unsure	35%
No comment	20%
None	15%
Simplify process / streamline	9%
Be more detailed / more information	8%
Improve security / secure online payments / data security	5%
Online customer support / real-time support	2%
Send out payment reminders	2%
Able to view payment history / past billing	1%
Offer payment options	1%
Offer energy-saving tips / energy pricing	1%
Provide billing installments/payments	1%
Provide service in multi-languages	<1%
Improve user experience (general)	<1%
Send receive payment notices	<1%

Emerging Technologies

Respondents were then asked their opinions about investing in new technologies and pilot projects. They were presented with a list of options and were asked to select their top choice.

Q6. Which of the following would you prefer?

	Percentage
Invest more money in renewable energy and environmentally friendly options at an additional cost (e.g., including solar, alternative energies such as Hydrogen, etc. and electric vehicle stations)	37%
Invest more money in new technologies at an additional cost (e.g. including customer tools and automated smart switches, electric fleet vehicles)	30%
Both investing in renewables and new technologies at an additional cost	25%
Continue investing in traditional infrastructure	6%
Unsure	3%

Investing in renewable energy was most referenced, followed by investing in new technologies and then investing in both renewables and new technologies.

Legacy Metering Network

Respondents were then read a preamble explaining the multi-year replacement of its legacy metering network and assets. They were then asked which of the three options they would prefer.

"Included in Festival Hydro's plans for 2025, is a multi-year replacement of its legacy metering network and assets which will provide improved and more reliable information to Festival Hydro and its customers. One of the solutions that Festival Hydro is considering has applications on the meter that the customer could download in the future and gain better insight into electricity use by appliance, as well as potential future uses for electric vehicles and receive information on when the best time to turn on/off major appliances (e.g. Air Conditioner)."

Q7. *Which of the following would you prefer?*

	Percentage
I would be interested in this type of application and would likely use it.	60%
I might be interested but not sure if I would use it.	33%
I would not use this type of application.	6%
Unsure	1%

Most, or six in ten respondents would be interested in this type of application and would be likely to use it, 33% might be interested.

Tree Trimming

Respondents were then questioned about Festival Hydro's tree trimming policies. They read three statements and were asked which one best aligned with their views on tree trimming.

"Festival Hydro must trim trees in proximity to overhead lines to avoid trees contacting lines for safety and reliability. Currently, Festival Hydro provides tree trimming on a cyclical basis to assist with limiting outages from tree contact and animal interference. The cost of this vegetation management continues to increase annually."

Q8. Which of the following statements best aligns with your view on tree trimming by Festival Hydro?

	Percentage
I support the current Festival Hydro process of more frequent tree trimming with appropriate clearance to balance reliability, aesthetics, and environmental concerns.	44%
I would like trees trimmed more frequently where possible with branches cut back more than today, regardless of aesthetic or environmental concerns, so that fewer power outages occur and there are shorter wait times to restore power after storms, and costs are reduced.	42%
I prefer trees trimmed with less clearance and lower frequency than current practice because of aesthetic and environmental reasons and will accept more power outages, longer wait times to restore power after storms, and increases in costs for tree trimming and responding to outages.	12%
Unsure	2%

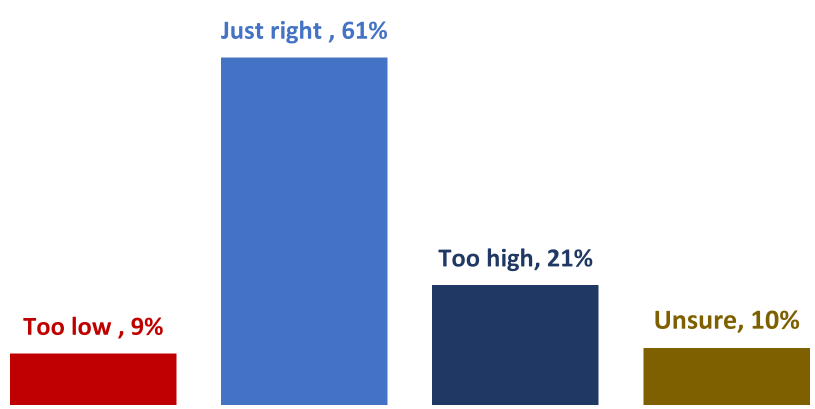
There was a near-even split between those who support the current process and those who would like more frequent trimming.

Future Renewal Expenditures

Respondents were read a statement about Festival Hydro's future renewal expenditures. They were then asked to indicate if this overall level of future system renewal expenditures was too low, just right, or too high to meet the objectives of safety, reliability, and cost.

"Asset renewal costs from 2015 and on were on average $1.9 million per year. For 2025-2029 Festival Hydro is proposing $3.6 million on average. The increase is due to the need to replace aging infrastructure to maintain the safety and reliability of the distribution system. The new levels of replacement are being done to maintain the current demographics and condition of our assets. This means that Festival Hydro will be replacing more poles, more underground cables, and more transformers each year. In addition, average material costs have increased from 40%-90% since 2019. Asset renewal costs represent about 47% of Festival Hydro's total capital investments."

Q9. In your opinion,is this proposed overall level of future system renewal expenditures too low, just right, or too high to meet the objectives of safety, reliability, and cost?



A total of 61% of respondents felt that the proposed overall level of future system renewal expenditures was just right, 21% said it was too high, and 9% indicated too low. A total of 10% were unsure.

Rate Increases

Respondents were then asked to indicate what best represented their point of view regarding the standard annual rate increase.

"Festival Hydro receives a standard increase annually that is less than inflation but is eligible to file a rate application based on current cost levels every five years. The last full-cost application was in 2015. The preliminary monthly rate impact to the average residential customer distribution portion is approximately $6.75 or 5.1% on the total bill holding other things constant (Time of Use (TOU)/Tiered/Ultra Low Overnight (ULO) Rates, Ontario Electricity Rebate). Please note that these are preliminary estimates and are subject to change as the rate application process continues.'"

Q10.Which of the following best represents your point of view on this rate increase?

	Percentage
I don't like the idea of a rate increase, but it is necessary.	51%
The rate increase is reasonable.	32%
The rate increase is unreasonable.	13%
Unsure	4%

Slightly more than half of respondents or 51% do not like the idea of a rate increase but feel it is necessary. Nearly a third or 32% feel the rate increase is reasonable, while 13% said it is unreasonable. A total of 4% were unsure.

Festival Hydro Inc.

2023 Online
Survey Report

December 2023

Table of Contents

Background & Overview	2
Methodology & Logistics	2
Role of Festival Hydro	3
Automated Tools / Communication Methods	4
E-billing	5
Emerging Technologies	8
Legacy Metering Network	9
Tree Trimming	10
Future Renewal Expenditures	11
Rate Increases	12

Background & Overview

Festival Hydro commissioned Brickworks Communications to conduct an open-online survey of its customers. The purpose of this survey process was to obtain customer input regarding their satisfaction with the services provided by Festival Hydro.

Brickworks and Festivoracal Hydro designed the questionnaire. This report contains an executive overview of the findings, while a separate report in Excel includes the results by each question.

Methodology & Logistics

Study Sample

All surveys were completed online using Computer Assisted Web Interviewing (CAWI). This was an open-online self-selection survey where respondents could connect with the survey link to complete their interview.

Survey Method

All surveys were completed online using Computer Assisted Telephone Interviewing (CATI). The survey was promoted by Festival Hydro through its resources.

Logistics

The survey was open, and questionnaires were completed between the days of November 22nd and December 11th, 2023.

Confidence

A total of N=469 questionnaires were completed.

It is not acceptable to assign online self-selection non-probability surveys a margin of error. However, a probability sample of this nature would be considered accurate ± 1.6%, 19/20 times.

Role of Festival Hydro

The following descriptive preamble was first presented to customers. They were then asked the first question about how well they understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of their bill relates to Festival Hydro.

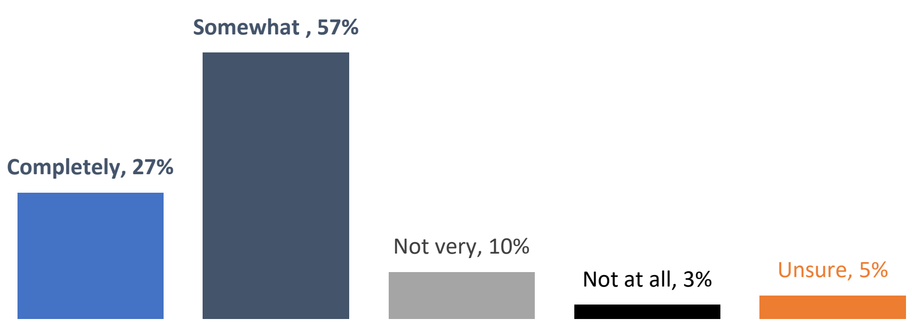
"Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It's made up of three major components: generation, transmission, and distribution. Festival Hydro is a distribution company that carries the electricity from the transformer stations to your homes. Festival Hydro manages its spending in two ways– an operating budget and a capital budget.

• Festival Hydro's operating budget covers recurring expenses, such as the maintenance of distribution system infrastructure, equipment, vehicles, buildings, properties, and tools, as well as insurance and corporate income taxes.

•Festival Hydro's capital budget covers items that have benefits over many years. This includes distribution system equipment such as poles, wires, cables, transformers, computers and information systems, vehicles, and facilities.

Managing the distribution system requires considerable investments in replacing aging equipment, connecting new customers, maintenance, and day-to-day operations. Festival Hydro's portion of the average bill is 26% of the total bill. This portion is used to maintain, enhance, and rebuild the system and includes a regulated rate of return that is used to reinvest in the system."

Q1. How well do you feel you understand the role that Festival Hydro plays in the electricity system, including where revenue comes from and what portion of your bill relates to Festival Hydro?



Automated Tools / Communication Methods

The following was first presented to customers after which they were asked which of three options they would most prefer.

"In a previous customer engagement survey from earlier this year, Festival Hydro noted that it is looking to invest in automated tools and communication methods for customer service. Some of these items could include website chat features for customer inquiries, an app that would display usage information, and further online forms. More than half of customers responded that this is important and that they were willing to pay more for customer service tools (less than $1 extra per month). Festival Hydro has built-in minor enhancements to its plans that will allow for more self-service options."

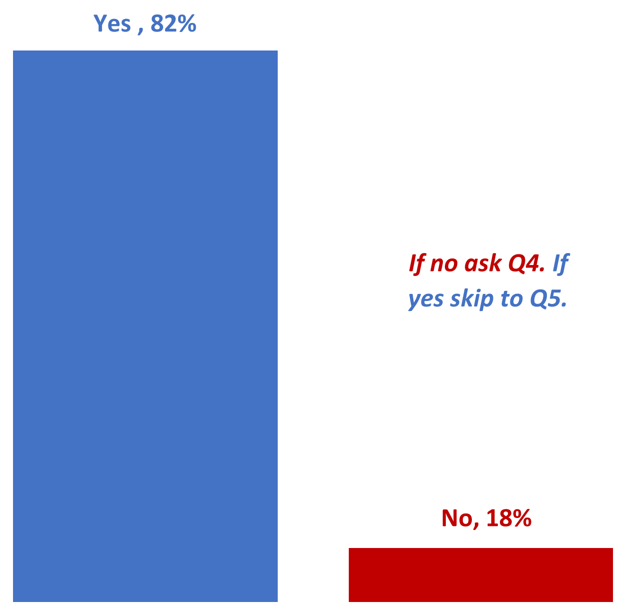
Q2. Which of the following would you prefer:

	Percentage
Increase customer service enhancements (such as an app with usage information) with increased costs.	48%
Continue with planned enhancements but do not need more tools such as an app or website chat features.	34%
Decrease costs by lowering levels of customer service than what is currently provided (this could include longer telephone wait times or email response times).	17%
Unsure	2%

E-Billing

Respondents were then asked if they currently receive an E-bill from Festival Hydro.

Q3. Do you currently receive an E-bill from Festival Hydro?



A total of 82% N=328 of Festival Hydro customers currently receive an E-bill.

The 18% (N=72) of customers that do not receive an E-bill from Festival Hydro were asked Q4 as a follow-up question, while all others skipped to Q5.

Q4. The cost of receiving a paper bill to customers is approximately $1 per month per customer or $12 per year. What is preventing you from registering to receive an E-bill?

	Percentage
Receiving the bill by mail is a reminder to pay.	26%
I was not aware that the cost savings of e-billing help offset future cost increases.	17%
It is more convenient to receive the bill by mail.	14%
I am concerned about online security from receiving electronic bills.	12%
Prefer paper copies.	11%
Have not gotten to it yet.	8%
I do not have regular access to the internet.	5%
Not aware that option existed.	6%
I am not comfortable with technology.	2%

In an open-ended probe, all N=400 respondents were asked if they had any recommendations for improvements to the E-billing process.

Q5. Do you have any recommendations on improvements to the E-billing process?

	Percentage
Unsure	35%
No comment	21%
None	17%
Simplify process / streamline	6%
Improve security / secure online payments/data security	4%
Be more detailed / more information	3%
Online customer support / real-time support	2%
Send out payment reminders	2%
Offer payment options	2%
Offer energy-saving tips/energy pricing	1%
Able to view past payment history / past billing	1%
Improve user experience (generally)	1%
Shorter billing cycle	1%
Provide an area for comments/suggestions	1%
Improve mobile capabilities / SMS	1%
Provide services in multi-languages	<1%
Provide billing installments/payments	<1%
Provide info on power outages	<1%
Dislike generally	<1%
Send payment statuses	<1%

Emerging Technologies

Respondents were then asked about their opinions about investing in new technologies and pilot projects.

Q6. Which of the following would you prefer?

	Percentage
Invest more money in renewable energy and environmentally friendly options at an additional cost (e.g., including solar, alternative energies such as Hydrogen, etc. and electric vehicle stations)	35%
Invest more money in new technologies at an additional cost (e.g. including customer tools and automated smart switches, electric fleet vehicles)	29%
Both investing in renewables & amp; new technologies at an additional cost	25%
Continue investing in traditional infrastructure	8%
Unsure	3%

A total of 35% of Festival Hydro customers would prefer if they invested more money in renewable energy and environmentally friendly options at an additional cost, while 29% would like to see them invest more money in new technologies at an additional cost. 25% of respondents would like to see them both investing in renewables and amp; new technologies at an additional cost however 8% would like Festival Hydro to continue investing in traditional infrastructure. A total of 3% were unsure.

Legacy Metering Network

Respondents were then read a preamble explaining the multi-year replacement of its legacy metering network and assets. They were then asked which option they would prefer.

"Included in Festival Hydro's plans for 2025, is a multi-year replacement of its legacy metering network and assets which will provide improved and more reliable information to Festival Hydro and its customers. One of the solutions that Festival Hydro is considering has applications on the meter that the customer could download in the future and gain better insight into electricity use by appliance, as well as potential future uses for electric vehicles and receive information on when the best time to turn on/off major appliances (e.g. Air Conditioner)."

Q7. *Which of the following would you prefer?*

	Percentage
I would be interested in this type of application and would likely use it.	59%
I might be interested but not sure if I would use it.	33%
I would not use this type of application.	7%
Unsure	1%

Tree Trimming

Respondents were then questioned about Festival Hydro's tree trimming policies. They were asked which statement best aligned with their views on tree trimming by Festival Hydro.

"Festival Hydro must trim trees in proximity to overhead lines to avoid trees contacting lines for safety and reliability. Currently, Festival Hydro provides tree trimming on a cyclical basis to assist with limiting outages from tree contact and animal interference. The cost of this vegetation management continues to increase annually."

Q8. *Which of the following statements best aligns with your view on tree trimming by Festival Hydro?*

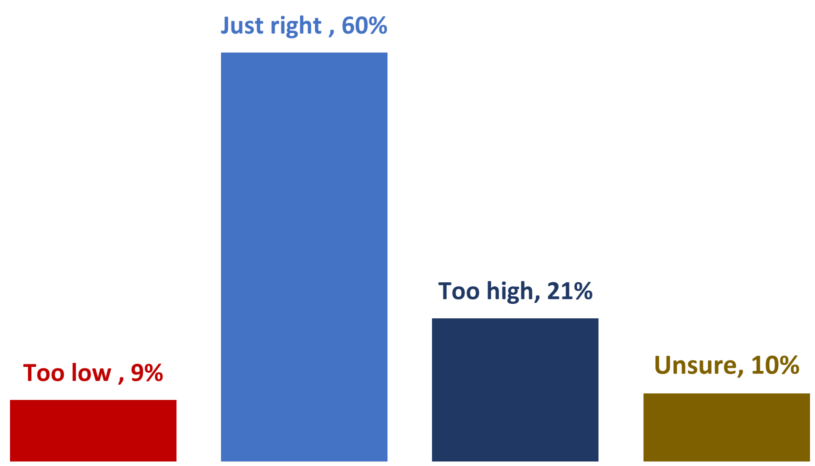
	Percentage
I support the current Festival Hydro process of more frequent tree trimming with appropriate clearance to balance reliability, aesthetic, and environmental concerns.	44%
I would like trees trimmed more frequently where possible with branches cut back more than today, regardless of aesthetic or environmental concerns, so that fewer power outages occur and there are shorter wait times to restore power after storms, and costs are reduced.	40%
I prefer trees trimmed with less clearance and lower frequency than current practice because of aesthetic and environmental reasons and will accept more power outages, longer wait times to restore power after storms, and increases in costs for tree trimming and responding to outages.	14%
Unsure	3%

Future Renewal Expenditures

Respondents were read a preamble about Festival Hydro's future renewal expenditures. They were then asked to indicate if they felt this proposed overall level of future system renewal expenditures was too low, just right, or too high to meet the objectives of safety, reliability, and cost.

"Asset renewal costs from 2015 and on were on average $1.9 million per year. For 2025-2029 Festival Hydro is proposing $3.6 million on average. The increase is due to the need to replace aging infrastructure to maintain the safety and reliability of the distribution system. The new levels of replacement are being done to maintain the current demographics and condition of our assets. This means that Festival Hydro will be replacing more poles, more underground cables, and more transformers each year. In addition, average material costs have increased from 40%-90% since 2019. Asset renewal costs represent about 47% of Festival Hydro's total capital investments."

Q9. In your opinion,is this proposed overall level of future system renewal expenditures too low, just right, or too high to meet the objectives of safety, reliability, and cost?



A total of 60% of respondents felt that the proposed overall level of future system renewal expenditures was just right, 21% too high while 9% indicated too low. A total of 10% were unsure.

Rate Increases

Respondents were then asked to indicate what best represented their point of view regarding the standard annual rate increase.

"Festival Hydro receives a standard increase annually that is less than inflation but is eligible to file a rate application based on current cost levels every five years. The last full-cost application was in 2015. The preliminary monthly rate impact to the average residential customer distribution portion is approximately $6.75 or 5.1% on the total bill holding other things constant (Time of Use (TOU)/Tiered/Ultra Low Overnight (ULO) Rates, Ontario Electricity Rebate). Please note that these are preliminary estimates and are subject to change as the rate application process continues."

Q10. Which of the following best represents your point of view on this rate increase?

	Percentage
I don't like the idea of a rate increase, but it is necessary.	52%
The rate increase is reasonable.	30%
The rate increase is unreasonable.	14%
Unsure	4%

Appendix E

HONI Needs Assessment

2019

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Greater Bruce Huron Region

Date: May 31, 2019

Prepared by: Greater Bruce-Huron Region Study Team

Distribution

Transmission

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Bruce-Huron Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Greater Bruce-Huron Region		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	April 2, 2019	**END DATE**	May 31, 2019

1. INTRODUCTION

The first cycle of the Regional Planning process for the region was initiated in spring 2016 and was completed in August 2017 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and mid-term needs at the time.

The purpose of the second cycle Needs Assessment ("NA") is to review the staus of needs identified in the previous regional planning cycle and to identify any new needs based on the new load forecast.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the increasing amount of load connection requests in 2018, the second Regional Planning cycle was triggered for the region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of any new system capacity, reliability, operation, and aging infrastructure needs.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the Greater Bruce-Huron Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs, recommend further mitigation or action plan(s) to address these needs, and determine whether further regional coordination or broader study would be beneficial.

The assessment reviewed available information including load forecasts, conservation and demand management ("CDM") and distributed generation ("DG") forecasts, reliability needs, operational issues, and major high voltage equipment identified to be at or near the end of their life and requiring replacement/refurbishment.

A technical assessment of needs was undertaken based on:

i. Planning criteria outlined in IESO-ORTAC (section 2.7.2) for analysis of current and future station capacity and transmission adequacy;
ii. Planning criteria outlined in IESO-ORTAC (section 7) for system reliability;
iii. Analysis of major high voltage equipment reaching the end of their life, in conjunction with emerging system needs; and
iv. Analysis of operational concerns relevant to Regional Planning

6. NEEDS

I. Station & Transmission Supply Capacity

i. Based on planning criteria, no station transformation capacity needs were identified in this cycle of Needs Assessment.
ii. Based on planning criteria, transmission line capacity on 115 kV circuit L7S is not adequate. Sections of the circuit are approaching their emergency and continuous thermal rating in the near and mid-term planning horizon.

II. System Reliability

Based on summer gross coincident load forecast for the region, load security and load restoration criteria can be met over the study period.

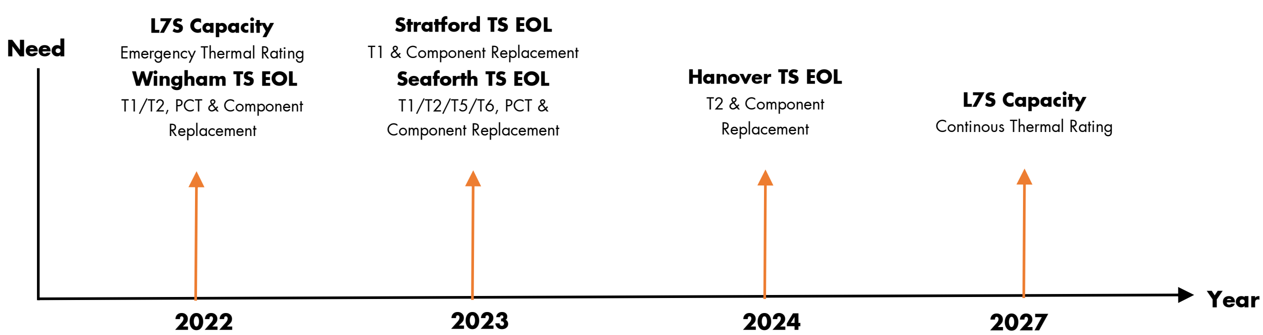
III. Aging Infrastructure – Transformer Replacements

- Future Projects:
  a. Wingham TS – T1/T2, PCT and Component Replacement (2022)
  b. Stratford TS – T1 and Component Replacement (2023)
  c. Seaforth TS – T1/T2/T5/T6, PCT & Component Replacement (2023)
  d. Hanover TS – T2 and Component Replacement (2024)

IV. Operational Concerns

No operational concerns pertaining to regional planning were identified.

<u>Needs Timeline Summary</u>



7. RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

A. Overloading of 115 kV circuits L7S (under contingency) – Options to mitigate the near-term need of upgrading the emergency thermal ratings of L7S are outlined in the Local Plan, prepared in the last Regional Planning cycle. Hydro One Transmission and the LDCs will revisit and asses the viability of the options proposed in the Local Plan.

B. Overloading of 115 kV circuits L7S (all in-service condition) – Further analysis in the Scoping Assessment phase of Regional Planning is required for the limited capacity of circuit L7S. IESO will lead the Scoping Assessment phase to recommend planning approaches to address potential load growth in the region. As a part of this assessment, a broader review of the region's system may be required to help identify solutions.

C. Replacement of end-of-life equipment does not require further regional coordination. The implementation and execution plan for these needs will be coordinated between Hydro One and the affected LDCs, where required:
   a. Wingham TS – T1/T2, PCT and Component Replacement
   b. Stratford TS – T1 and Component Replacement
   c. Seaforth TS – T1/T2/T5/T6, PCT & Component Replacement
   d. Hanover TS – T2 and Component Replacement

TABLE OF CONTENTS

1 Introduction 7
2 Regional Issue/Trigger 8
3 Scope of Needs Assessment 8
4 Regional Description and Connection Configuration 9
5 Inputs and Data 12
6 Assessment Methodology 12
7 Needs 13
7.1 Review of Needs Identified in the Last Regional Planning Cycle 13
7.2 Assessment of Station and Transmission Capacity Needs in the Region 14
7.3 Assessment of Supply Security and Restoration Needs in the Region 15
7.4 Assessment of End-Of-Life Equipment Needs in the Region 15
8 Conclusion and Recommendations 18
9 References 19
Appendix A: Greater Bruce-Huron Region Coincident & Non-Coincident Summer &Winter Load Forecast 20
Appendix B: Lists of Step-Down Transformer Stations 28
Appendix C: Lists of Transmission Circuits 29
Appendix D: Lists of LDCs in the Greater Bruce-Huron Region 30
Appendix E: Acronyms 31

List of Tables and Figures

Table 1: Greater Bruce-Huron Region Study Team Participants 7
Table 2: Greater Bruce-Huron Region Transmission Assets 10
Table 3: Needs Identified in the Previous RIP report 13

1 INTRODUCTION

This is the second cycle of Regional Planning for the Greater Bruce-Huron region. The first cycle of the Regional Planning process for the region was initiated in spring 2016 and was completed in August 2017 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs at the time.

The purpose of the second cycle Needs Assessment ("NA") is to review the staus of needs identified in the previous Regional Planning cycle and to identify any new needs based on the new load forecast.

This report was prepared by the Greater Bruce-Huron Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by Hydro One Transmission, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: Greater Bruce-Huron Region Study Team Participants

Company
Hydro One Networks Inc. (Lead Transmitter)
Entegrus
ERTH Power Corp.
Festival Hydro Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of timelines of needs identified in last RIP report, along with an increasing amount of load connection requests in 2018, the second Regional Planning cycle was triggered for the region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Greater Bruce-Huron Region and includes:

- Review of the status of needs/plans identified in the previous Regional Planing cycle; and
- Identification and assessment of any new system capacity, reliability, operation, and aging infrastructure needs.

The Study Team may identify additional needs during the next phases of the Regional Planning process, namely Scoping Assessment ("SA"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Greater Bruce-Huron Region covers the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. The boundary of the Greater Bruce-Huron Region is shown in Figure 1.

Figure 1: Geographic Area of the Greater Bruce-Huron Region

Electricity supply for the region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the region. The bulk of the electrical supply is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS. These circuits connect the region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Listed in Table 2 and shown in Figure 2, is the transmission system infrastructure in the Greater Bruce-Huron Region. In addition, the summer coincident and non-coincident regional load forecast is provided in Appendix A. Appendix B lists all step-down transformer stations, Appendix C lists transmission circuits and Appendix D lists all the LDCs in the Greater Bruce-Huron Region.

Table 2: Greater Bruce-Huron Region Transmission Assets

115 kV Circuits	230 kV Circuits	Hydro One Transformer Stations	Customer Transformer Stations
61M18, D8S, D10H, L7S, S1H	B4V/B5V, B20P/B24P, B22D/B23D, B27S/B28S	Bruce HWP B TS, Centralia TS, Douglas Point TS, Goderich TS, Hanover TS, Owen Sound TS, Palmerston TS, Seaforth TS, St. Marys TS, Stratford TS, Wingham TS	Constance DS, Festival MTS, Grand Bend East DS, Customer CTS #1, Customer CTS #2, Customer CTS #3, Customer CTS #4

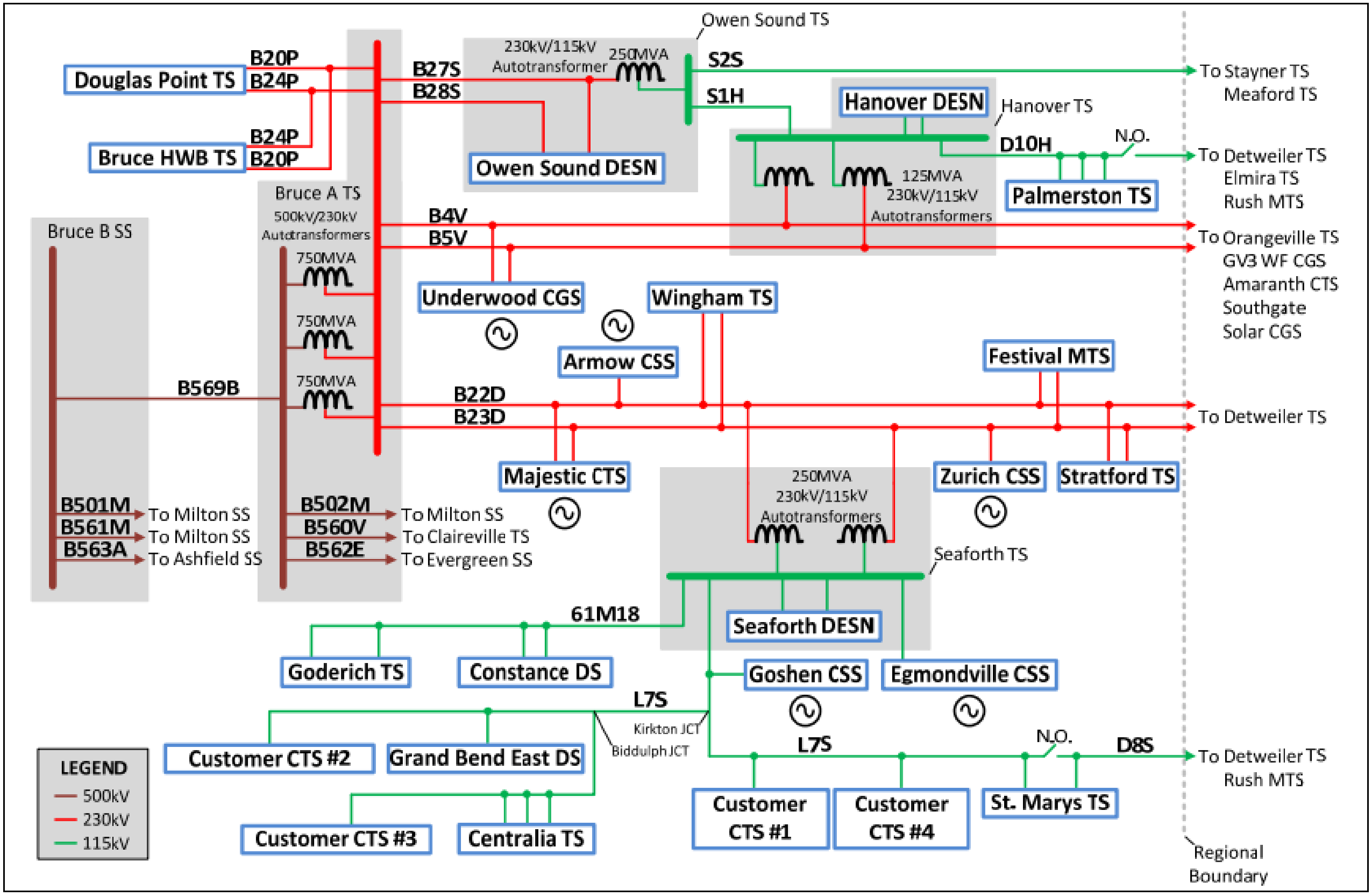


Figure 2: Greater Bruce-Huron Region – Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Greater Bruce-Huron Region NA. The information provided includes the following:

- Greater Bruce-Huron winter and summer Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end-of-life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the Greater Bruce-Huron Region.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the Greater Bruce-Huron region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Greater Bruce-Huron region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast growth rates to the actual coincident and non-coincident 2018 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. The coincident and non-coincident summer and winter load forecasts for the individual stations in the Greater Bruce-Huron region are given in Appendix A. Based on the forecasts, the equipment rating proved to be more limiting in summer than in winter. Therefore the summer load forecast was used to perform the analysis;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major high voltage transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of life which is relevant for regional planning purposes. This includes autotransformers, step-down transformers, breakers, underground cables and overhead transmission lines.

A technical assessment of needs was undertaken based on:

i. Planning criteria outlined in IESO-ORTAC (section 2.7.2) for analysis of current and future station capacity and transmission adequacy;

ii. Planning criteria outlined in IESO-ORTAC (section 7) for system reliability and operational concerns;

iii. Analysis of major high voltage equipment reaching the end of their life, in conjunction with emerging system needs; and
iv. Analysis of operational concerns relevant to Regional Planning.

7 NEEDS

This section assesses the adequacy of regional infrastructure to meet the forecasted load in the Greater Bruce-Huron Region and identify needs. The section also reviews and/or reaffirms needs already identified in the last regional planning cycle.

7.1 Review of Needs Identified in the Last Regional Planning Cycle

This section, reviews the status of needs identified in the previous cycle of Regional Planning as summarized in Table 3 below.

Table 3: Needs Identified in the Previous RIP report

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
Transmission Supply Capacity of Circuit L7S	Overload on sections of 115 kV radial single circuit line L7S	Monitor closely as per Local Plan in first cycle of regonal planning.
Delivery Point Performance for L7S	Poor performance of delivery points supplied by circuit L7S	Projects to address frequency and duration of outages to be executed over next 5 years.
Step-down Transformation Capacity in Kincardine area	Load growth expected in Kincardine area	Need deferred based on current load forecast.

a. Transmission Supply Capacity of Circuit L7S

In the last Regional Planning cycle, overloading on sections of 115 kV circuit L7S was expected in 2019, based on gross summer load forecast. A Local Plan to mitigate the overload on the circuit was developed. The preferred option at the time was to closely monitor loading and trigger mitigation in advance.
The need based on revised load forecast has been updated and discussed in Section 7.2.

b. Delivery Point Performance for circuit L7S

Delivery points supplied by circuit L7S have often been classified as Outliers for frequency and duration of unplanned outages. Based on the findings of field screening resulting from the last cycle of Regional Planning, projects to reduce the frequency and duration of interruptions have been developed. Frequent outages due to weather will be addressed by installation of inter-phase spacers along the line and improving grounding of high resistance line structures. As well the long duration of outages will be reduced by installation of, remotely operable, motorized in-line switches along L7S. These projects will be executed in the near-term to improve realibility of the circuit.

c. Step-down capacity in the Kincardine area

Station capacity at Douglas Point TS was approaching limits based on anticipated load growth in the Kincardine area, in the last Regional Planning cycle. Possible solutions to address the increase load demand, such as upsizing existing transformers, permanent load transfers to neighbouring load supply stations and building a new DESN facility were considered. Due to lack of committed load, and the incoming of natural gas in the Kincardine area, a decline in winter load demand is observed at Douglas Point TS, based on new load forecast. Therefore no mitigation is required at the time.

7.2 Assessment of Station and Transmission Capacity Needs in the Region

Based on planning criteria, no station transformation capacity needs were identified in this cycle of Needs Assessment. However, the following transmission supply capacity need has been identified during the study period of 2019 to 2028. This need is consistent with the what was identified in the last Regional Planning cycle.

a. Transmission Supply Capacity of Circuit L7S

115 kV circuit L7S runs between Seaforth TS and St. Mary's TS and is isolated from circuit D8S running between St Mary's TS and Detweiler TS with a Noramally Open switch at St. Mary's TS. Analysis was performed based on gross summer coincident load forecast for the assessing thermal load capacity of circuit L7S.

Upon the loss of circuit D8S, the entire St. Mary's station load will be supplied by L7S. When the supply from D8S is lost, L7S will exceed it's short-term emergency (STE) and long-term emergency (LTE) rating in the near-term (summer 2022).

It was also identified that under normal operating conditions, with all elements in-serivce, L7S will exceed its continuous ratings towards the end of the study period (summer 2027).

The sections of circuit that will exceed their ratings are: Seaforth Jct x Goshen Jct. and Goshen Jct x Kirkton Jct. The emergency ratings of these sections are same as the continuous ratings because they are limited by the ground clearance in some spans of the sections.

The Local Plan in the last Regional Planning cycle outlined options to address the thermal capacity need of the circuit. The preferred mitigation option will marginally improve ratings to address only the near-term summer 2022 need. However, this will not differ the capacity need of the circuit expected in year 2027.

7.3 Assessment of Supply Security and Restoration Needs in the Region

Based on planning criteria, analysis shows that load supply security and restoration capability is acceptable. Based on the gross regional coincident peak load forecast with all transmission facilities in-service and coincident with the outage of the largest local generation units, all facilities are within applicable ratings. The largest local generation unit is a 230 kV connected Bruce Nuclear unit on the 230 kV system while on the 115 kV system, Goshen windfarm is assumed out of service.

Based on gross regional coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW load by configuration, by planned load curtailment or by load rejection.

Based on gross regional coincident load forecast, the loss of two elements will not result in load interruption greater than 600 MW by configuration, by planned load curtailment or by load rejection.

Specifically, based on the load forecast, the largest load loss is expected to be 350 MW in summer 2028 for the loss of double circuit lines, B22D/B23D. By the use of existing 230 kV in-line switches at Seaforth TS, Hydro One can quickly resupply approximately 218 MW from Bruce A TS or 268 MW from Detweiler TS.

Therefore, based on the above information, load security and restoration criteria in the region are met.

7.4 Assessment of End-Of-Life Equipment Needs in the Region

Hydro One and LDCs have provided high voltage equipment information under the following categories that have been identified at this time and are likely to be replaced over the next 5 years:

- Autotransformers
- Power transformers
- High voltage breakers
- Transmission lines requiring refurbishment where an uprating is being considered for planning needs

The assessment for the EOL high voltage equipment considered the following options:

1. Maintaining the status quo/do nothing;
2. Replacing equipment with similar equipment of lower ratings (right-sizing) due to forecasted decrease in demand and built to current standards;
3. Replacing equipment with lower ratings (right-sizing) and built to current standards due to transferring load to other facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar rated equipment and built to current standards (i.e., "like-for-like" replacement); and

6. Replacing equipment with higher ratings (right-sizing) due to forecasted increase in demand or due to load transfer and built to current standards.

Note that, from Hydro One Transmission's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major high voltage equipment due to safety and reliability risk of equipment failure.

Accordingly, the following major high voltage equipment have been identified as approaching end of their life over the next 5 years.

a. Wingham TS – T1/T2 and Component Replacement

Wingham TS is a load supply station built in 1965. The station has two 50/67/83 MVA step-down transformers connected to the 230 kV circuits B22D and B23D (Bruce x Detweiler) and supplies Hydro One Distribution via four 44 kV feeders.

The current scope of this project is to replace the 230/44 kV step-down transformers, T1 and T2 and associated surge arrestors.

Based on the load forecast, similar equipment ratings are required for the EOL replacement. The planned in-service date for the project is in year 2022.

b. Stratford TS – T1 and Componenet Replacement

Stratford TS is a load supply station built in 1950. The station has two 50/67/83 MVA step-down transformers connected to 230 kV circuits B22D and B23D (Bruce x Detweiler) and supplies Festival Hydro Inc., Hydro One Distribution as well as other embedded LDCs, via eight 27.6 kV feeders. Transformers T1 and T2 are in service since 1970 and 1997 respectively.

The current scope of this project is replacement of 230/27.6 kV transformer T1 and associated equipment.

Based on the load forecast similar equipment ratings are required for EOL replacement. The planned in-service date for the project is in year 2023.

c. Seaforth TS – T5/T6/T1/T2 and Component Replacement

Seaforth TS is a major station and consists of two 230/115 kV, 150/200/250 MVA autotransformers supplied by 230 kV circuits B22D and B23D (Bruce x Detweiler). The 115 kV yard from Seaforth TS supplies nearly 200 km of single circuit supply along the circuits L7S and 61M18. Seaforth TS also consists of two 115/27.6 kV, 25/33/42 MVA step-down transformers and supplies Hydro One Distribution and embedded LDCs via four 27.6 kV feeders.

The current scope of this project is to replace 230/115 kV autotransformers T5, T6, step-down transformers T1, T2, the capacitor breaker SC1B and several high voltage and low voltage switches that are at end of their life. Operations has identified the need for refined voltage control on the 115 kV system. Therefore, the new autotransformers at Seaforth TS will be equipped with Under Load Tap Changers (ULTCs).

Based on the load forecast for the station similar equipment ratings are required for EOL replacement of all equipment discussed above. The planned in-service date for the project is in year 2023.

d. Hanover TS – T2 and Component Replacement

Hanover TS consists of two 230/115 kV, 75/100/125 MVA autotransformers supplied by 230 kV circuits B4V and B5V (Bruce x Orangeville). The 115 kV yard has connectivity to Detweiler TS via 115 kV transmission circuit D10H with a Normally Open point at Palmerston TS. Another 115 kV transmission circuit S1H connects to Owen Sound TS. Hanover TS also consists of two 115/44 kV, 50/67/83 MVA step-down transformers connecting to six feeders and one capacitor bank, supplying Hydro One Distribution and embedded LDCs.

The current scope of this project is to replace 230 kV motorized switches, 115/44 kV step-down transformer T2 and associated equipment, 115 kV motorized swithes, surge arrestors, auto-ground switches and potential transformers.

Based on the load forecast for the station similar equipment ratings are required for EOL replacement. The planned in-service date for the project is in year 2023.

8 CONCLUSION AND RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

A. The study team has reaffirmed the overloading of 115 kV circuit L7S, under contingency. Options to mitigate the near-term need of upgrading the emergency thermal ratings of L7S are outlined in the Local Plan prepared in the last Regional Planning cycle. Hydro One Transmission and the LDCs will revisit and asses the viability of the options proposed in the Local Plan.

B. The study team has identified the overloading of 115 kV circuit L7S, with all elements in-service. Further analysis in the Scoping Assessment phase of Regional Planning is required for the limited capacity of circuit L7S. IESO will lead the Scoping Assessment phase to recommend planning approaches to address potential load growth in the region. As a part of this assessment, a broader review of the region's system may be required to help identify solutions.

C. Replacement of end-of-life equipment does not require further regional coordination. The implementation and execution plan for these needs will be coordinated between Hydro One and the affected LDCs, where required:
    a. Wingham TS – T1/T2 and Component Replacement
    b. Stratford TS – T1 and Component Replacement
    c. Seaforth TS – T5/T6/T1/T2 and Component Replacement
    d. Hanover TS – T2 and Component Replacement

9 REFERENCES

[1] Greater Bruce-Huron Region RIP Report – August 2017
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterbrucehuron/Documents/RIP_Report_Greater_Bruce_Huron_August_2017_FINAL.pdf

[2] Local Plan for L7S Thermal Capacity – November 2016
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterbrucehuron/Documents/Local%20Planning%20Report%20-%20L7S%20Thermal%20Overload.pdf

[3] Planning Process Working Group Report to the OEB - https://www.oeb.ca/oeb/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

[4] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 – August 2007
IESO_ORTAC_Issue_5.0_August_2007

Appendix A: Greater Bruce-Huron Region Coincident & Non-Coincident Summer &Winter Load Forecast

Table A-1: Summer Regional Coincident Peak Load Forecast (MW)

Transformer Station	Summer LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	62.0	Load	25.0	25.2	25.4	25.5	25.7	25.9	26.1	26.3	26.5	26.7
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.4	0.5	0.5	0.6	0.7	0.8	0.8	0.9	1.0
		Net (MW)	**24.7**	**24.7**	**24.9**	**25.0**	**25.1**	**25.2**	**25.3**	**25.5**	**25.6**	**25.7**
Centralia TS*	61.1	Load	29.9	33.2	33.6	36.8	37.2	37.5	37.8	38.1	38.4	38.7
		DG	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		CDM	0.3	0.6	0.6	0.8	0.9	1.0	1.1	1.2	1.4	1.4
		Net (MW)	**29.6**	**32.4**	**32.7**	**35.7**	**36.0**	**36.2**	**36.4**	**36.6**	**36.8**	**37.0**
Douglas Point TS	97.2	Load	51.0	60.6	69.7	77.6	78.6	79.5	80.4	81.3	82.3	83.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.5	1.0	1.3	1.7	1.9	2.2	2.4	2.6	2.9	3.1
		Net (MW)	**50.5**	**59.5**	**68.4**	**75.9**	**76.6**	**77.3**	**78.0**	**78.7**	**79.4**	**80.2**
Goderich TS	126.5	Load	31.8	32.2	35.2	37.2	37.6	37.9	38.2	38.5	38.8	39.1
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.4	1.5
		Net (MW)	**31.5**	**31.7**	**34.5**	**36.4**	**36.7**	**36.9**	**37.0**	**37.2**	**37.4**	**37.7**
Hanover TS (T1/T2 DESN)	109.9	Load	75.9	78.5	80.4	83.7	85.8	88.9	90.9	93.0	95.2	97.5
		DG	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
		CDM	0.8	1.3	1.5	1.8	2.1	2.4	2.7	3.0	3.4	3.7
		Net (MW)	**74.6**	**76.6**	**78.4**	**81.3**	**83.1**	**85.9**	**87.6**	**89.5**	**91.3**	**93.3**
Owen Sound TS (T3/T4 DESN)	208.5	Load	92.7	94.8	95.7	96.7	97.8	98.4	98.9	99.5	100.1	100.8
		DG	1.7	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
		CDM	0.9	1.6	1.8	2.1	2.4	2.7	3.0	3.2	3.5	3.8
		Net (MW)	**90.0**	**91.1**	**91.8**	**92.5**	**93.3**	**93.6**	**93.8**	**94.2**	**94.5**	**94.9**
Palmerston TS	83.3	Load	52.3	55.0	57.3	58.4	59.2	60.0	60.5	61.1	61.8	62.4
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.5	0.9	1.1	1.2	1.5	1.6	1.8	2.0	2.2	2.3
		Net (MW)	**51.8**	**54.0**	**56.2**	**57.2**	**57.8**	**58.3**	**58.7**	**59.2**	**59.6**	**60.1**
Seaforth TS (T1/T2 DESN)	45.1	Load	29.7	32.1	32.6	33.2	33.7	34.3	34.8	35.3	35.9	36.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.3	1.4
		Net (MW)	**29.4**	**31.6**	**32.0**	**32.5**	**32.9**	**33.3**	**33.7**	**34.2**	**34.6**	**35.1**
St. Marys TS*	52.8	Load	22.7	22.9	23.9	23.2	23.4	23.5	23.6	23.7	23.9	24.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.9
		Net (MW)	**22.4**	**22.5**	**23.5**	**22.7**	**22.8**	**22.9**	**22.9**	**23.0**	**23.0**	**23.1**
Stratford TS	117.3	Load	73.6	75.7	76.3	78.2	78.9	79.4	79.9	80.5	81.0	81.6
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.7	1.3	1.4	1.7	1.9	2.2	2.4	2.6	2.9	3.1
		Net (MW)	**72.8**	**74.4**	**74.9**	**76.5**	**76.9**	**77.2**	**77.5**	**77.9**	**78.2**	**78.5**

Transformer Station	Summer LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Wingham TS	97.0	Load	36.9	38.8	44.7	52.2	52.4	52.4	52.4	52.5	52.7	52.8
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.4	0.7	0.8	1.1	1.3	1.4	1.6	1.7	1.9	2.0
		Net (MW)	**36.5**	**38.2**	**43.9**	**51.1**	**51.1**	**50.9**	**50.9**	**50.9**	**50.8**	**50.8**
Constance DS	25.0	Load	17.4	17.7	17.8	17.9	18.0	18.1	18.1	18.2	18.2	18.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7
		Net (MW)	**17.3**	**17.4**	**17.5**	**17.5**	**17.6**	**17.6**	**17.6**	**17.6**	**17.6**	**17.6**
Grand Bend East DS*	31.3	Load	16.5	17.3	17.9	18.1	18.3	18.4	18.5	18.6	18.7	18.8
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7
		Net (MW)	**16.4**	**17.0**	**17.5**	**17.7**	**17.8**	**17.9**	**17.9**	**18.0**	**18.1**	**18.1**
Bruce HWP B TS	113.2	Load	4.3	4.6	4.6	4.5	4.5	4.4	4.3	4.3	4.3	4.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
		Net (MW)	**4.3**	**4.6**	**4.5**	**4.4**	**4.3**	**4.3**	**4.2**	**4.1**	**4.1**	**4.1**
Customer CTS #1*	NA	Load	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
		Net (MW)	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
Customer CTS #2*	NA	Load	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
		Net (MW)	**4.9**	**4.9**	**4.9**	**4.9**	**4.9**	**4.8**	**4.8**	**4.8**	**4.8**	**4.8**
Customer CTS #3*	NA	Load	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Net (MW)	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Customer CTS #4*	NA	Load	13.9	13.9	13.9	18.6	18.6	18.6	18.6	18.6	23.2	23.2
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.8	0.9
		Net (MW)	**13.8**	**13.7**	**13.7**	**18.2**	**18.1**	**18.0**	**18.0**	**18.0**	**22.4**	**22.3**

*Load forecast all stations connected to L7S is coincident with peak load flow on circuit L7S
NA – Not Available

Table A-2: Summer Regional Non-coincident Peak Load Forecast (MW)

Transformer Station	Summer LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	62.0	Load	32.6	32.9	33.1	33.4	33.6	33.9	34.1	34.4	34.6	34.9
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3
		Net (MW)	**32.3**	**32.3**	**32.5**	**32.7**	**32.8**	**33.0**	**33.1**	**33.3**	**33.4**	**33.6**
Centralia TS	61.1	Load	34.5	38.2	38.6	42.3	42.8	43.2	43.5	43.8	44.2	44.6
		DG	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		CDM	0.3	0.7	0.7	0.9	1.1	1.2	1.3	1.4	1.6	1.7
		Net (MW)	**34.1**	**37.3**	**37.7**	**41.2**	**41.5**	**41.7**	**41.9**	**42.2**	**42.4**	**42.6**
Douglas Point TS	97.2	Load	51.2	60.8	70.0	77.9	78.9	79.8	80.7	81.6	82.6	83.6
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.5	1.0	1.3	1.7	1.9	2.2	2.4	2.6	2.9	3.1
		Net (MW)	**50.7**	**59.7**	**68.7**	**76.2**	**76.9**	**77.6**	**78.2**	**79.0**	**79.7**	**80.5**
Goderich TS	126.5	Load	38.2	38.7	42.2	44.7	45.2	45.5	45.9	46.2	46.6	47.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.4	0.7	0.8	1.0	1.1	1.2	1.4	1.5	1.6	1.8
		Net (MW)	**37.8**	**38.1**	**41.4**	**43.8**	**44.0**	**44.3**	**44.5**	**44.7**	**45.0**	**45.2**
Hanover TS (T1/T2 DESN)	109.9	Load	75.9	78.5	80.4	83.7	85.8	88.9	90.9	93.0	95.2	97.5
		DG	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
		CDM	0.8	1.3	1.5	1.8	2.1	2.4	2.7	3.0	3.4	3.7
		Net (MW)	**74.6**	**76.6**	**78.4**	**81.3**	**83.1**	**85.9**	**87.6**	**89.5**	**91.3**	**93.3**
Owen Sound TS (T3/T4 DESN)	208.5	Load	104.1	106.4	107.4	108.6	109.9	110.5	111.1	111.7	112.4	113.1
		DG	1.7	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
		CDM	1.0	1.8	2.0	2.3	2.7	3.0	3.3	3.6	4.0	4.2
		Net (MW)	**101.3**	**102.5**	**103.3**	**104.2**	**105.1**	**105.4**	**105.6**	**106.0**	**106.4**	**106.8**
Palmerston TS	83.3	Load	62.6	65.8	68.5	69.9	70.9	71.8	72.4	73.2	73.9	74.7
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.1	1.3	1.5	1.7	1.9	2.2	2.3	2.6	2.8
		Net (MW)	**62.0**	**64.7**	**67.3**	**68.4**	**69.1**	**69.8**	**70.3**	**70.8**	**71.3**	**71.9**
Seaforth TS (T1/T2 DESN)	45.1	Load	31.4	33.9	34.4	35.0	35.6	36.2	36.7	37.3	37.9	38.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.6	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.4
		Net (MW)	**31.0**	**33.3**	**33.8**	**34.3**	**34.7**	**35.2**	**35.6**	**36.1**	**36.6**	**37.1**
St. Marys TS	52.8	Load	24.9	25.1	26.2	25.4	25.6	25.8	25.9	26.0	26.2	26.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.4	0.5	0.5	0.6	0.7	0.8	0.8	0.9	1.0
		Net (MW)	**24.6**	**24.7**	**25.7**	**24.9**	**25.0**	**25.1**	**25.1**	**25.2**	**25.3**	**25.3**
Stratford TS	117.3	Load	82.2	84.5	85.2	87.3	88.0	88.6	89.2	89.8	90.5	91.1
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.8	1.4	1.6	1.9	2.2	2.4	2.7	2.9	3.2	3.4
		Net (MW)	**81.3**	**83.1**	**83.6**	**85.4**	**85.9**	**86.2**	**86.5**	**86.9**	**87.3**	**87.7**

Transformer Station	Summer LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Wingham TS	97.0	Load	51.2	53.9	62.1	72.5	72.7	72.7	72.8	72.9	73.1	73.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.5	0.9	1.1	1.5	1.8	2.0	2.2	2.3	2.6	2.7
		Net (MW)	**50.7**	**53.0**	**60.9**	**70.9**	**70.9**	**70.7**	**70.6**	**70.6**	**70.5**	**70.5**
Constance DS	25.0	Load	18.2	18.4	18.5	18.6	18.8	18.8	18.9	18.9	19.0	19.1
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7
		Net (MW)	**18.0**	**18.1**	**18.2**	**18.2**	**18.3**	**18.3**	**18.3**	**18.3**	**18.3**	**18.3**
Grand Bend East DS	31.3	Load	22.1	23.1	23.9	24.1	24.4	24.5	24.7	24.8	25.0	25.2
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9
		Net (MW)	**21.9**	**22.7**	**23.4**	**23.6**	**23.8**	**23.9**	**23.9**	**24.0**	**24.1**	**24.2**
Bruce HWP B TS	113.2	Load	8.3	8.9	8.8	8.7	8.6	8.4	8.3	8.2	8.2	8.2
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
		Net (MW)	**8.2**	**8.8**	**8.6**	**8.5**	**8.3**	**8.2**	**8.1**	**7.9**	**7.9**	**7.9**
Customer CTS #1	NA	Load	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		Net (MW)	**3.4**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
Customer CTS #2	NA	Load	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
		Net (MW)	**5.7**	**5.7**	**5.7**	**5.7**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**
Customer CTS #3	NA	Load	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
		Net (MW)	**4.5**	**4.5**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**
Customer CTS #4	NA	Load	15.0	15.0	15.0	20.0	20.0	20.0	20.0	20.0	25.0	25.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.9	0.9
		Net (MW)	**14.8**	**14.7**	**14.7**	**19.6**	**19.5**	**19.5**	**19.4**	**19.4**	**24.1**	**24.1**

NA – Not Available

Table A-3: Winter Regional Coincident Peak Load Forecast (MW)

Transformer Station	Winter LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	66.7	Load	28.0	25.6	25.8	26.0	26.2	26.4	26.6	26.8	27.0	27.2
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.9	0.9
		Net (MW)	**27.7**	**25.2**	**25.4**	**25.5**	**25.6**	**25.8**	**25.9**	**26.0**	**26.1**	**26.3**
Centralia TS	65.4	Load	30.6	33.6	33.9	37.0	37.3	37.5	37.7	37.9	38.1	38.3
		DG	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		CDM	0.3	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3
		Net (MW)	**30.3**	**32.8**	**33.0**	**36.1**	**36.2**	**36.3**	**36.4**	**36.6**	**36.7**	**36.8**
Douglas Point TS	109.8	Load	62.4	76.3	82.4	89.1	88.9	88.6	88.3	88.0	87.7	87.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.2	1.4	1.6	1.9	2.1	2.4	2.5	2.8	3.0
		Net (MW)	**61.8**	**75.1**	**81.0**	**87.5**	**87.0**	**86.4**	**85.9**	**85.4**	**84.9**	**84.5**
Goderich TS	132.0	Load	31.3	31.7	34.7	36.8	37.2	37.5	37.8	38.1	38.4	38.7
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3
		Net (MW)	**31.0**	**31.2**	**34.2**	**36.2**	**36.4**	**36.6**	**36.8**	**37.0**	**37.2**	**37.4**
Hanover TS (T1/T2 DESN)	124.7	Load	68.8	70.1	70.7	72.4	73.2	74.8	75.4	76.0	76.7	77.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.1	1.2	1.3	1.6	1.8	2.0	2.2	2.4	2.6
		Net (MW)	**68.2**	**69.0**	**69.5**	**71.1**	**71.6**	**73.0**	**73.3**	**73.8**	**74.2**	**74.7**
Owen Sound TS (T3/T4 DESN)	232.5	Load	109.6	111.5	112.4	113.3	114.5	115.1	115.7	116.4	117.2	117.9
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	1.0	1.8	1.9	2.1	2.5	2.8	3.1	3.4	3.7	4.0
		Net (MW)	**108.5**	**109.7**	**110.5**	**111.2**	**112.0**	**112.3**	**112.6**	**113.0**	**113.4**	**113.9**
Palmerston TS	83.3	Load	70.1	73.4	75.0	77.8	78.7	79.6	80.3	81.0	81.7	82.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.2	1.3	1.4	1.7	1.9	2.1	2.3	2.6	2.8
		Net (MW)	**69.4**	**72.3**	**73.7**	**76.4**	**77.0**	**77.7**	**78.1**	**78.6**	**79.1**	**79.7**
Seaforth TS (T1/T2 DESN)	55.4	Load	28.7	30.8	31.0	31.3	31.5	31.6	31.8	32.1	32.3	32.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.5	0.5	0.6	0.7	0.8	0.9	0.9	1.0	1.1
		Net (MW)	**28.5**	**30.3**	**30.5**	**30.7**	**30.8**	**30.9**	**31.0**	**31.1**	**31.2**	**31.4**
St. Marys TS	59.0	Load	21.9	21.9	22.0	22.2	22.3	22.3	22.4	22.5	22.5	22.6
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.8
		Net (MW)	**21.7**	**21.5**	**21.6**	**21.8**	**21.8**	**21.8**	**21.8**	**21.8**	**21.8**	**21.9**
Stratford TS	128.6	Load	68.5	70.5	71.0	72.9	73.5	74.0	74.4	75.0	75.5	76.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.1	1.2	1.3	1.6	1.8	2.0	2.2	2.4	2.6
		Net (MW)	**67.9**	**69.4**	**69.8**	**71.5**	**71.9**	**72.2**	**72.5**	**72.8**	**73.1**	**73.4**

Transformer Station	Winter LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Wingham TS	107.9	Load	40.5	42.3	46.6	51.9	52.4	52.8	53.1	53.5	53.9	54.4
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.4	0.7	0.8	1.0	1.1	1.3	1.4	1.5	1.7	1.8
		Net (MW)	**40.1**	**41.6**	**45.8**	**51.0**	**51.3**	**51.5**	**51.7**	**52.0**	**52.2**	**52.5**
Constance DS	35.0	Load	16.8	17.0	17.1	17.1	17.2	17.3	17.3	17.4	17.5	17.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6
		Net (MW)	**16.7**	**16.7**	**16.8**	**16.8**	**16.9**	**16.9**	**16.9**	**16.9**	**16.9**	**16.9**
Grand Bend East DS	40.0	Load	11.8	12.6	13.2	13.3	13.4	13.5	13.6	13.6	13.7	13.8
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.5
		Net (MW)	**11.7**	**12.4**	**13.0**	**13.0**	**13.1**	**13.2**	**13.2**	**13.2**	**13.3**	**13.4**
Bruce HWP B TS	114.8	Load	10.4	11.2	11.1	10.9	10.8	10.6	10.5	10.3	10.3	10.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
		Net (MW)	**10.3**	**11.0**	**10.9**	**10.7**	**10.5**	**10.4**	**10.2**	**10.0**	**10.0**	**10.0**
Customer CTS #1	NA	Load	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
		Net (MW)	**2.6**	**2.6**	**2.6**	**2.6**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**
Customer CTS #2	NA	Load	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		Net (MW)	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
Customer CTS #3	NA	Load	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Net (MW)	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Customer CTS #4	NA	Load	13.8	13.8	13.8	18.4	18.4	18.4	18.4	18.4	23.0	23.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.7	0.8
		Net (MW)	**13.7**	**13.6**	**13.6**	**18.1**	**18.0**	**17.9**	**17.9**	**17.9**	**22.3**	**22.2**

NA – Not Available

Table A-4: Winter Regional Non-coincident Peak Load Forecast (MW)

Transformer Station	Winter LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	66.7	Load	29.7	27.2	27.4	27.6	27.8	28.1	28.3	28.5	28.7	28.9
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.4	0.5	0.5	0.6	0.7	0.8	0.8	0.9	1.0
		Net (MW)	**29.5**	**26.8**	**27.0**	**27.1**	**27.2**	**27.4**	**27.5**	**27.7**	**27.8**	**27.9**
Centralia TS	65.4	Load	33.3	36.7	36.9	40.4	40.7	40.9	41.1	41.3	41.6	41.8
		DG	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		CDM	0.3	0.6	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.4
		Net (MW)	**33.0**	**35.8**	**36.0**	**39.4**	**39.5**	**39.6**	**39.7**	**39.9**	**40.0**	**40.1**
Douglas Point TS	109.8	Load	63.1	77.2	83.3	90.2	89.9	89.6	89.3	89.0	88.7	88.5
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.2	1.4	1.7	2.0	2.2	2.4	2.6	2.8	3.0
		Net (MW)	**62.6**	**75.9**	**81.9**	**88.5**	**88.0**	**87.4**	**86.9**	**86.4**	**85.9**	**85.5**
Goderich TS	132.0	Load	35.8	36.2	39.7	42.1	42.4	42.8	43.1	43.5	43.8	44.2
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.6	0.7	0.8	0.9	1.0	1.2	1.3	1.4	1.5
		Net (MW)	**35.4**	**35.6**	**39.0**	**41.3**	**41.5**	**41.7**	**42.0**	**42.2**	**42.4**	**42.7**
Hanover TS (T1/T2 DESN)	124.7	Load	72.0	73.4	74.0	75.8	76.6	78.3	78.9	79.5	80.2	80.9
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.7	1.2	1.2	1.4	1.7	1.9	2.1	2.3	2.5	2.7
		Net (MW)	**71.3**	**72.2**	**72.8**	**74.4**	**74.9**	**76.4**	**76.8**	**77.2**	**77.7**	**78.2**
Owen Sound TS (T3/T4 DESN)	232.5	Load	109.9	111.9	112.8	113.7	114.8	115.5	116.1	116.8	117.6	118.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	1.0	1.8	1.9	2.1	2.5	2.8	3.1	3.4	3.7	4.0
		Net (MW)	**108.9**	**110.1**	**110.9**	**111.6**	**112.3**	**112.7**	**113.0**	**113.4**	**113.8**	**114.3**
Palmerston TS	83.3	Load	70.3	73.7	75.3	78.1	79.0	79.9	80.6	81.3	82.0	82.8
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.2	1.3	1.4	1.7	1.9	2.2	2.3	2.6	2.8
		Net (MW)	**69.7**	**72.5**	**74.0**	**76.7**	**77.3**	**78.0**	**78.4**	**78.9**	**79.4**	**80.0**
Seaforth TS (T1/T2 DESN)	55.4	Load	34.8	37.3	37.5	37.9	38.1	38.3	38.6	38.8	39.1	39.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.3	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3
		Net (MW)	**34.5**	**36.7**	**36.9**	**37.2**	**37.3**	**37.4**	**37.5**	**37.7**	**37.8**	**38.0**
St. Marys TS	59.0	Load	23.7	23.7	23.8	23.9	24.0	24.1	24.2	24.3	24.3	24.4
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.4	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8
		Net (MW)	**23.4**	**23.3**	**23.4**	**23.5**	**23.5**	**23.5**	**23.5**	**23.6**	**23.6**	**23.6**
Stratford TS	128.6	Load	71.9	74.0	74.5	76.5	77.1	77.6	78.1	78.7	79.2	79.8
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.7	1.2	1.2	1.4	1.7	1.9	2.1	2.3	2.5	2.7
		Net (MW)	**71.2**	**72.8**	**73.3**	**75.1**	**75.4**	**75.7**	**76.0**	**76.4**	**76.7**	**77.1**

Transformer Station	Winter LTR (MVA)	Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Wingham TS	107.9	Load	62.6	65.3	71.9	80.2	81.0	81.5	82.1	82.7	83.3	84.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.6	1.0	1.2	1.5	1.8	2.0	2.2	2.4	2.6	2.8
		Net (MW)	**62.0**	**64.3**	**70.7**	**78.7**	**79.2**	**79.6**	**79.9**	**80.3**	**80.7**	**81.1**
Constance DS	35.0	Load	16.9	17.1	17.2	17.3	17.4	17.4	17.4	17.5	17.6	17.6
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6
		Net (MW)	**16.8**	**16.8**	**16.9**	**16.9**	**17.0**	**17.0**	**17.0**	**17.0**	**17.0**	**17.0**
Grand Bend East DS	40.0	Load	13.0	14.0	14.6	14.7	14.9	14.9	15.0	15.1	15.2	15.3
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.5	0.5
		Net (MW)	**12.9**	**13.8**	**14.4**	**14.4**	**14.5**	**14.6**	**14.6**	**14.7**	**14.7**	**14.8**
Bruce HWP B TS	114.8	Load	12.1	13.0	12.8	12.7	12.5	12.3	12.1	12.0	12.0	12.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4
		Net (MW)	**11.9**	**12.8**	**12.6**	**12.4**	**12.2**	**12.0**	**11.8**	**11.6**	**11.6**	**11.6**
Customer CTS #1	NA	Load	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
		Net (MW)	**3.4**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
Customer CTS #2	NA	Load	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
		Net (MW)	**5.8**	**5.8**	**5.8**	**5.8**	**5.8**	**5.8**	**5.7**	**5.7**	**5.7**	**5.7**
Customer CTS #3	NA	Load	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
		Net (MW)	**4.6**	**4.6**	**4.6**	**4.5**	**4.5**	**4.5**	**4.5**	**4.5**	**4.5**	**4.5**
Customer CTS #4	NA	Load	15.0	15.0	15.0	20.0	20.0	20.0	20.0	20.0	25.0	25.0
		DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		CDM	0.1	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.8	0.8
		Net (MW)	**14.9**	**14.8**	**14.7**	**19.6**	**19.6**	**19.5**	**19.5**	**19.4**	**24.2**	**24.2**

NA – Not Available

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations
1.	Bruce HWP B TS
2.	Centralia TS
3.	Douglas Point TS
4.	Goderich TS
5.	Hanover TS
6.	Owen Sound TS
7.	Palmerston TS
8.	Seaforth TS
9.	St. Marys TS
10.	Stratford TS
11.	Wingham TS
12.	Constance DS
13.	Festival MTS
14.	Grand Bend East DS
15.	Customer CTS #1
16.	Customer CTS #2
17.	Customer CTS #3
18.	Customer CTS #4

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	B4V/B5V	Bruce A TS	Orangeville TS	230
2.	B20P/B24P	Bruce A TS	Douglas Pt. TS/ Bruce HWP B TS	230
3.	B22D/B23D	Bruce A TS	Detweiler TS	230
4.	B27S/B28S	Bruce A TS	Owen Sound TS	230
5.	61M18	Seaforth TS	Goderich TS	115
6.	L7S	Seaforth TS	St. Mary's TS	115
7.	S1H	Owen Sound TS	Hanover TS	115
8.	D10H	Hanover TS	Detweiler TS	115

Appendix D: Lists of LDCs in the Greater Bruce-Huron Region

Sr. No.	Company	Connection Type (Transmission/Distribution)
1.	Entegrus	Distribution
2.	ERTH Power Corp.	Distribution
3.	Festival Hydro Inc.	Transmission/Distribution
4.	Hydro One Networks Inc. (Distribution)	Transmission/Distribution
5.	Wellington North Power Inc.	Distribution
6.	Westario Power Inc.	Distribution

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Festival Hydro Inc.

Appendix F

IESO Scoping Assessment Outcomes Report 2019

Greater Bruce/Huron Region Scoping Assessment Report

Contents

Greater Bruce/Huron Region Participants 3

1. Introduction 4

2. Team 5

3. Categories of Needs, Analysis and Results 6

4. Conclusion 14

List of Acronyms 15

Appendix A: Southern Huron-Perth Sub-region IRRP Terms of Reference 16

Greater Bruce/Huron Region Participants

Companies

Independent Electricity System Operator

Hydro One Networks Inc. (Transmission)

Hydro One Networks Inc. (Distribution)

Festival Hydro

Entegrus Powerlines Inc.

ERTH Power

Wellington North Power Inc.

Westario Power Inc.

Scoping Assessment Outcome Report Summary

Region: Greater Bruce/Huron

Start Date: Jun 26, 2019

End Date: September 19, 2019[1]

[1] Updated September 17, 2020

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board (OEB)'s regional planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first cycle of regional planning for the Greater Bruce/Huron region was completed in August 2017. Needs were identified in the near- to medium-term time frames, and a number of solutions were recommended to address them.

The second cycle of the regional planning process for the Greater Bruce/Huron region was triggered in April 2019. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the study team led by Hydro One Networks Inc. (Hydro One). The needs identified in the resulting report, issued on May 31, 2019, identified a number of needs. These needs are inputs to the scoping process to determine the planning process required.

During the Scoping Assessment process, regional participants reviewed the nature and timing of known needs to determine the most appropriate planning approach going forward, as well as the best geographic grouping of the needs in order to efficiently facilitate further studies. The planning approaches considered include:

- An Integrated Regional Resource Plan (IRRP), where regional coordination is needed and there is a potential for wide range of options including both wires and non-wires options;
- A Regional Infrastructure Plan (RIP), which considers wires-only options; and
- A local plan undertaken by the transmitter and the affected local distribution company (LDC), where no further regional coordination is needed.

This report:

- Lists the needs requiring more comprehensive planning and regional coordination;
- Reassesses the areas that need to be studied and the geographic grouping of needs;
- Determines the appropriate regional planning approach and scope for each sub-region where a need for regional coordination or more comprehensive planning is identified;
- Creates terms of reference for an IRRP if one is required; and
- Establishes the composition of the Working Group for the IRRP.

2. Team

The Scoping Assessment was carried out by a study team of the following Regional Participants:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Transmission)
- Hydro One Networks Inc. (Distribution)
- Festival Hydro Inc.
- Entegrus Powerlines Inc.
- ERTH Power
- Wellington North Power Inc.
- Westario Power Inc.

3. Categories of Needs, Analysis and Results

I. Overview of the Region

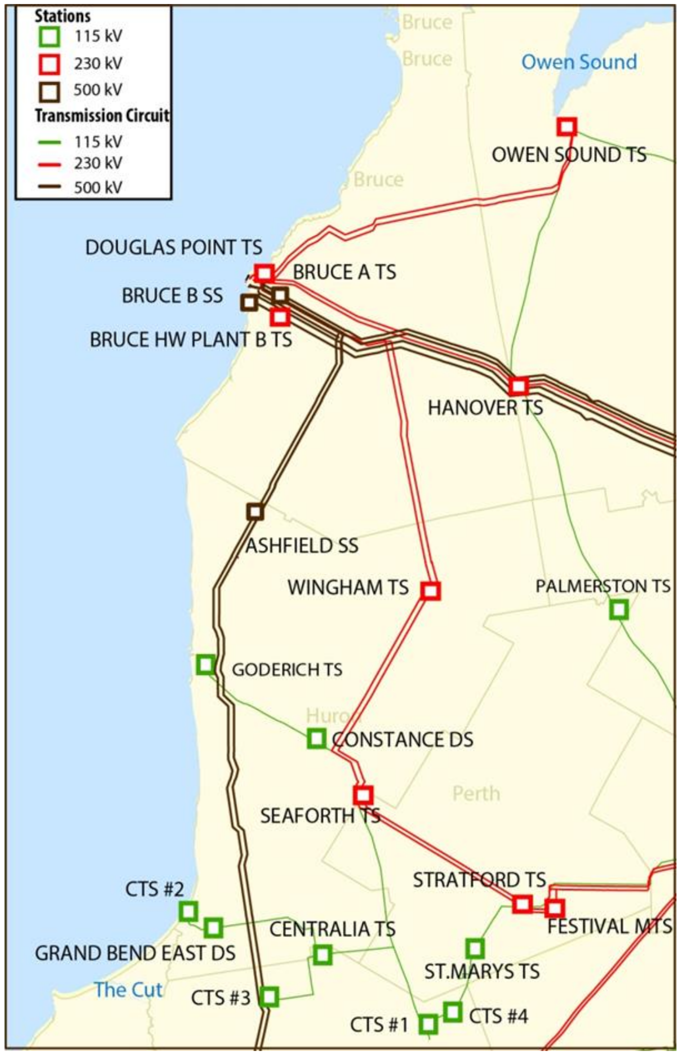
The Greater Bruce/Huron region is located in southwestern Ontario, and comprises the counties of Bruce, Huron and Perth, as well as portions of Grey, Lambton, Wellington, Waterloo, Oxford, Lambton, and Middlesex counties.

Several Indigenous communities reside in the region, including Saugeen First Nation, Nawash First Nation, Chippewas of the Thames First Nation, Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Historic Saugeen Métis and Métis Nation of Ontario.

The electricity infrastructure supplying the Greater Bruce/Huron region is shown in Figure 1.

Local distribution companies (LDCs) that serve this region include Hydro One Distribution, Festival Hydro Inc., Entegrus Powerlines Inc., ERTH Power, Wellington North Power Inc., and Westario Power Inc.

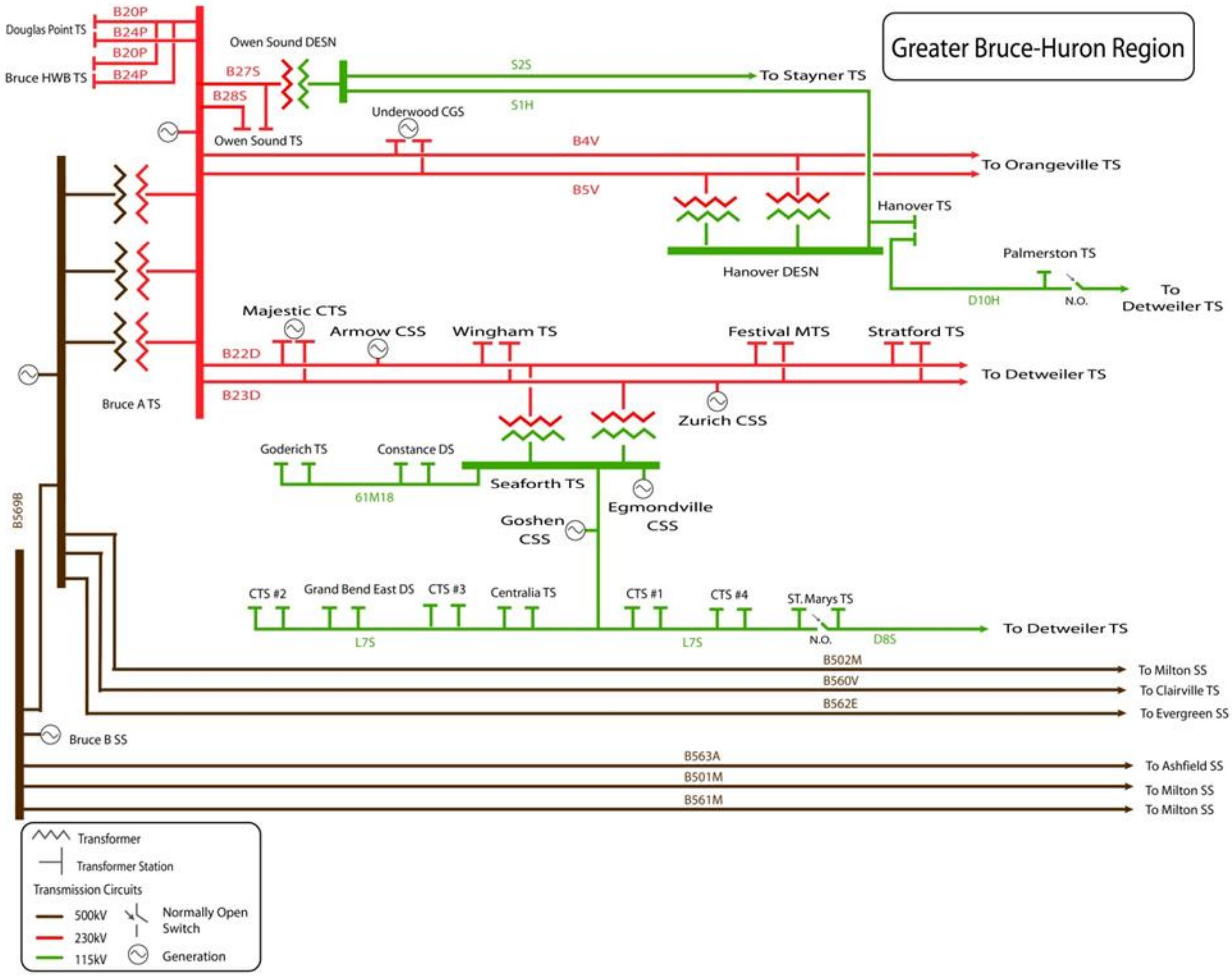
Figure 1: Electricity Infrastructure in the Greater Bruce/Huron Region2



The region is supplied by the 230 kilovolt (kV) and 115 kV transmission lines and stations shown in Figure 1. Main sources of supply come from the Bruce Nuclear Generating Station and local renewable generation facilities. The Bruce A transformer station (TS) and stations in adjacent regions, such as South Georgian Bay/Muskoka and Kitchener-Waterloo-Cambridge-Guelph (KWCG), are connected through 230 kV circuits B4V/B5V, B22D/B23D, B27S/B28S. The recent identified capacity needs in NA are on the 115 kV circuit L7S, located in the southern portion of the region. The L7S circuit provides supply from Seaforth TS and a local wind farm to seven local load stations, including Centralia TS, Grand Bend East DS, St. Marys TS, and four customer transformer stations (CTS). The D8S circuit further connects St. Marys TS to Detweiler TS in the KWCG region.

[2] The region is defined by electricity infrastructure; geographical boundaries are approximate

Figure 2: Single Line Diagram of Greater Bruce/Huron Region[3]



II. Background: the previous planning process

The regional planning process was formalized by the OEB in August 2013. To manage this process, Ontario was organized into 21 regions, each of which was assigned to one of three groups by order of priority, with Group 1 regions scheduled to be reviewed first. Greater Bruce/Huron was assigned to Group 3.

The first cycle of regional planning for Greater Bruce/Huron was triggered in February 2016. Completed in May 2016, the NA – the initial stage in the regional planning process identified a number of near- and medium-term needs. Following the NA, the study team agreed that there was no need for further integrated regional planning for the region and localized wires-only plans would be developed to address identified needs.

---

[3] The 500kV side of Bruce A TS, Bruce B SS, and 500 kV lines are not included in the Greater Bruce/Huron study area.

In August 2016, a Regional Infrastructure Plan (RIP) was published that summarized findings from local planning, and reviewed new needs from updated load forecasts in the Kincardine area. The Local Planning Report and RIP recommended: monitoring loading on L7S and increasing the emergency rating once loading approaches capacity; a two-stage plan to reduce frequency and duration of interruptions due to adverse weather; and monitoring load growth in the Kincardine area to identify any potential step-down transformation capacity needs at Douglas Point TS.

These recommendations and current status are summarized in Section III.

The second cycle of regional planning was triggered due to potential incremental load from customer connection requests received in 2018 that would exceed the capacity of L7S. The second cycle started in early 2019 with the NA report published by Hydro One on May 31.

The needs identified in this report form the basis of the analysis for this scoping assessment, and are discussed in further detail in Section III.

III. Needs Identified

Based on the most up-to-date sustainment plans and 10-year demand forecast, Hydro One's NA identified a number of needs in the Greater Bruce/Huron region. This section outlines the needs and projects/plan identified in the previous cycle of regional planning, and the needs to be addressed in the new cycle.

Needs and plans identified in the last cycle of Greater Bruce/Huron regional planning

The needs and plans recommended in the first cycle of regional planning for the Greater Bruce/Huron region are summarized in Table 1, including summaries of their current statuses.

Table 1: Status of needs and plans from the first cycle of regional planning

Type of Need	Plan	Status
Delivery Point Performance	Enhance delivery point performance for L7S to reduce frequency and duration of outages by installing spacers, ground rods, and remote-controlled load interrupting switches.	Projects to install spacers and ground rods to be initiated and completed in 2020. Installation of remote-controlled load interrupting switches at Kirkton JCT, Biddulph JCT, and St Marys TS are currently in execution phase, expected to be in service by end of 2020.
Capacity	Monitor loading on L7S, and execute solutions from Local Plan that increase emergency thermal rating once loading is anticipated to exceed capacity.	L7S capacity has been re-assessed in the recent NA and capacity needs will be addressed in the new cycle of regional planning.
Capacity	Monitor load growth in Kincardine area connected to Douglas Point TS, and execute solutions when load is anticipated to exceed capacity.	Need is deferred because of slower load growth from latest forecast.

Needs to be addressed in the new regional planning cycle

The needs identified in the 2019 NA are summarized in Table 2 below and are grouped by type. Needs that arise in the next five years are marked as near-term while those arise in the five to ten-year time frame are marked as medium-term timeframe.

Table 2: Needs to be addressed in the new planning cycle

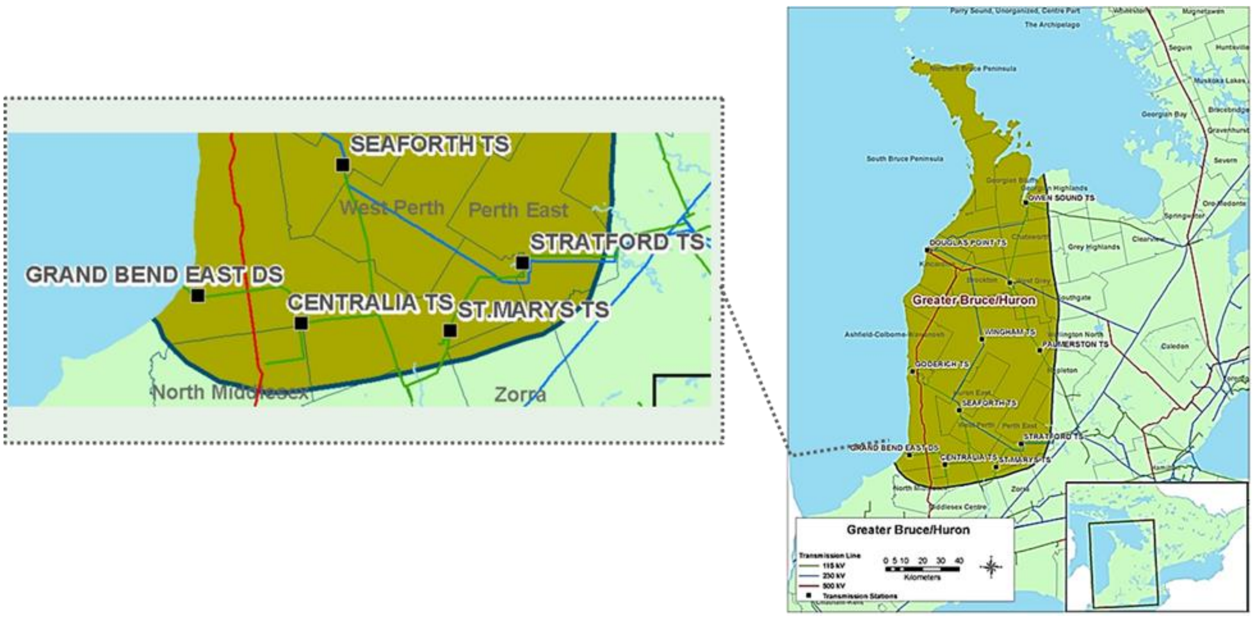
Type of Need	Facilities	Need Date
Equipment End-of-Life	Wingham TS T1/T2 supply transformers and component replacement	2022 (near-term)
Equipment End-of-Life	Stratford TS T1 supply transformer and component replacement	2023 (near-term)
Equipment End-of-Life	Seaforth TS T1/T2/ supply transformers, T5/T6 autotransformers, and component replacement	2023 (near-term)
Equipment End-of-Life	Hanover TS T2 supply transformer and component replacement	2024 (near-term)
Capacity	L7S emergency rating exceeded under contingency (with one element D8S out)	2022 (near-term)
Capacity	L7S continuous rating exceeded with all elements in service	2027 (medium-term)

IV. Analysis of Needs and Identification of Sub-Regions

A number of factors were considered in determining recommended planning approaches to address identified needs in NA, and the overall approach for further study in this area. Broadly speaking, where there is a need for regional coordination, and a potential for a wide range of solutions – including conservation, generation, new technologies, wires infrastructure, and non-wires solutions – an integrated approach is optimal.

The Regional Participants have discussed the needs in the Greater Bruce/Huron region and have identified one sub-region for further study through the regional planning process. The sub-region, "Southern Huron Perth" is shown in Figure 3.

Figure 3: Southern Huron-Perth Sub-Region



Southern Huron-Perth Sub-Region

An integrated approach is recommended to address the capacity needs in the Southern Huron Perth sub-region. This sub-region is summer-peaking, and includes the following infrastructure:

- 115 kV Connected Stations – Grand Bend East DS, Centralia TS, St. Marys TS,
- Four customer owned transformer stations
- 115 kV Transmission Lines – L7S, B8S

Customers in this sub-region are supplied by Entegrus Powerlines Inc., Festival Hydro Inc. or Hydro One Distribution. However, the sub-region's transmission connected customers are supplied directly by Hydro One Transmission.

There are potential opportunities to assess wires and non-wires solutions to meet the needs in the area, and coordinate end-of-life needs within the context of updated forecast data.

The section below provides additional details on needs to be assessed in the IRRP planning process.

Integrated capacity planning in the Southern Huron-Perth Sub-region

The NA identified both near- and medium-term capacity needs on L7S resulting from load growth in the area it supplies.

This near-term need is expected to arise in 2022, when the emergency rating will be exceeded once D8S is out of service. This need was first identified in the previous cycle of regional planning, and the Local Planning Report, L7S Thermal Overload, was developed in 2016 to evaluate alternatives and recommended solutions.

In the medium-term, the continuous rating of L7S will be exceeded in 2027, even when all facilities are in service. While the existing infrastructure cannot accommodate the 20-year demand forecast in this area, with the slow load growth, non-wires solutions – such as integration of community energy plans, demand response, distributed generation, and storage – should be explored alongside wires solutions. A capacity margin also needs to be considered to prepare for potential additional load growth.

Opportunities to optimize end-of-life investments

Facilities reaching end-of-life provide an opportunity to re-examine their current use and configuration in the context of the latest load forecast and generation data. This will ensure that any new assets installed in their place will continue to appropriately service both the impacted LDCs and their customers, over their lifetime. To allow enough lead time to conduct planning for facilities that are reaching end-of-life, expected service life (ESL) information will be considered to optimize future end-of-life investment.

The study team recommends that the assessment of needs outlined above will benefit from an integrated view. There are potential opportunities to assess wires and non-wires solutions to meet the needs in the area, and to address multiple needs in an optimal manner. The study team recommends that capacity needs in the area supplied by L7S be studied through an IRRP that focuses on the Southern Huron-Perth sub-region, and opportunities for optimizing future end-of-life investments be investigated.

Local Planning

The remaining needs identified in the 2019 Greater Bruce/Huron NA report are related to end-of-life needs at four transformer stations, as noted in Table 3 below.

Local planning is recommended to address these needs as they are singular in nature, and there is limited opportunity to reconfigure and resize the facilities to align with other regional needs. In addition, given that all of these end-of-life needs will arise in the near-term, the study team recommends local planning involving the transmitter and the impacted LDCs as the optimal approach for ensuring reliable supply in the region.

Table 3: Needs to be addressed through local planning

Type of Need	Facilities	Need Date	Planning Approach
Equipment End-of-Life	Wingham TS T1/T2 supply transformers and component replacement	2022 (near-term)	Local Planning
Equipment End-of-Life	Stratford TS T1 supply transformer and component replacement	2023 (near-term)	Local Planning
Equipment End-of-Life	Seaforth TS T1/T2/ supply transformers, T5/T6 autotransformers, and component replacement	2023 (near-term)	Local Planning
Equipment End-of-Life	Hanover TS T2 supply transformer and component replacement	2024 (near-term)	Local Planning

In addition, the IESO has identified low voltage issues at Hanover TS upon the loss of 230 kV circuits B4V/B5V. This issue will be further investigated in a bulk study of the Bruce area.

4. Conclusion

The Scoping Assessment concludes that:

- An IRRP be undertaken for the Southern Huron-Perth sub-region to:
    - Plan for near- and medium-term capacity needs in the sub-region supplied by L7S, taking into account of non-wires alternatives
    - Explore opportunities to optimize end-of-life investments
- Additional needs identified in the NA (outlined below) will be addressed through local planning involving the transmitter and relevant LDC:
    - End-of-life replacements
        - T1/T2 transformers and components at Wingham TS
        - T1 transformer and component at Stratford TS
        - T5/T6 autotransformers, and T1/T2 transformers at Seaforth TS
        - T2 transformer and component at Hanover TS
- Hanover TS voltage issue upon loss of 230 kV circuits B4V/B5V will be further investigated in a bulk study of the Bruce area.

The draft Terms of Reference for the Southern Huron-Perth sub-region IRRP is attached in Appendix A.

List of Acronyms

Acronym	Description
CDM	Conservation and Demand Management
DG	Distributed Generation
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

Appendix A: Southern Huron-Perth Sub-region IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for the Southern Huron-Perth sub-region, as part of the Greater Bruce Huron Region.

Based on the needs identified within the sub-region, including opportunities for coordinating demand and supply options with capacity needs in the sub-region supplied by L7S, an integrated regional resource planning approach for the Southern Huron-Perth sub-region is recommended.

The Greater Bruce/Huron Region

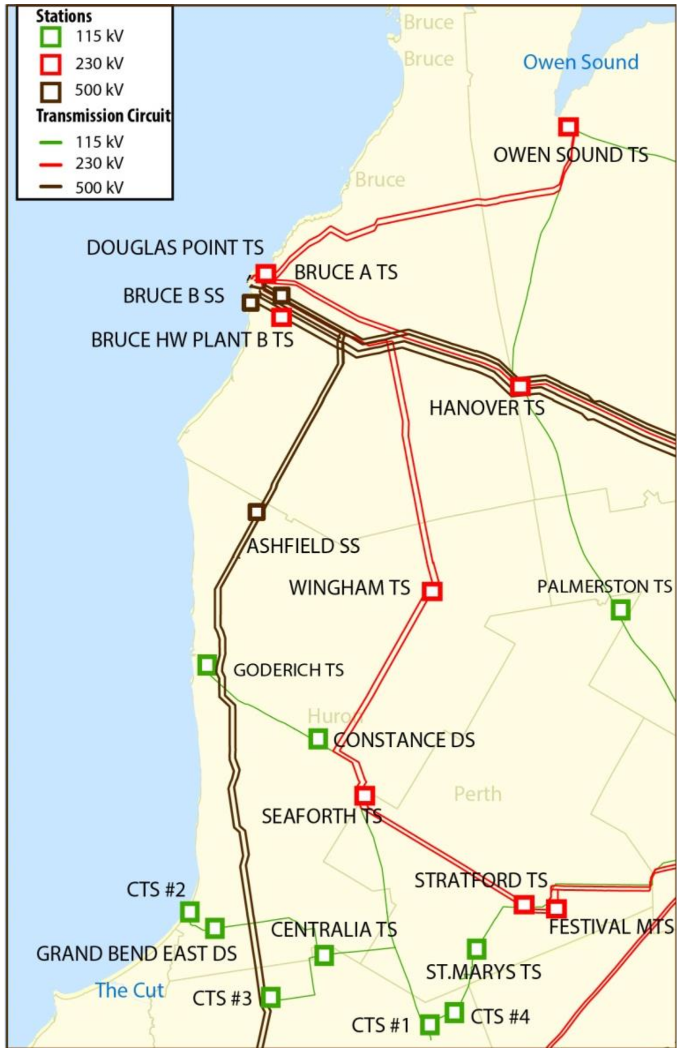
The Greater Bruce/Huron region is located in southwestern Ontario that comprises the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford, Lambton, and Middlesex counties. Several Indigenous communities reside in the region, including Saugeen First Nation, Nawash First Nation, Chippewas of the Thames First Nation, Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Historic Saugeen Métis and Métis Nation of Ontario.

The Southern Huron-Perth Sub-Region

This IRRP is for the Southern Huron-Perth sub-region supplied by L7S, which includes municipalities of Bluewater, South Huron, Lambton Shores, Lucan Biddulph, Middlesex Centre, North Middlesex, Thames Centre, Zorra, Perth South, Town of St. Marys, and West Perth.

The approximate geographical boundaries of the sub-region are shown in Figure A-1.

Figure A-1: Electricity Infrastructure in the Southern Huron-Perth Sub-Region[4]

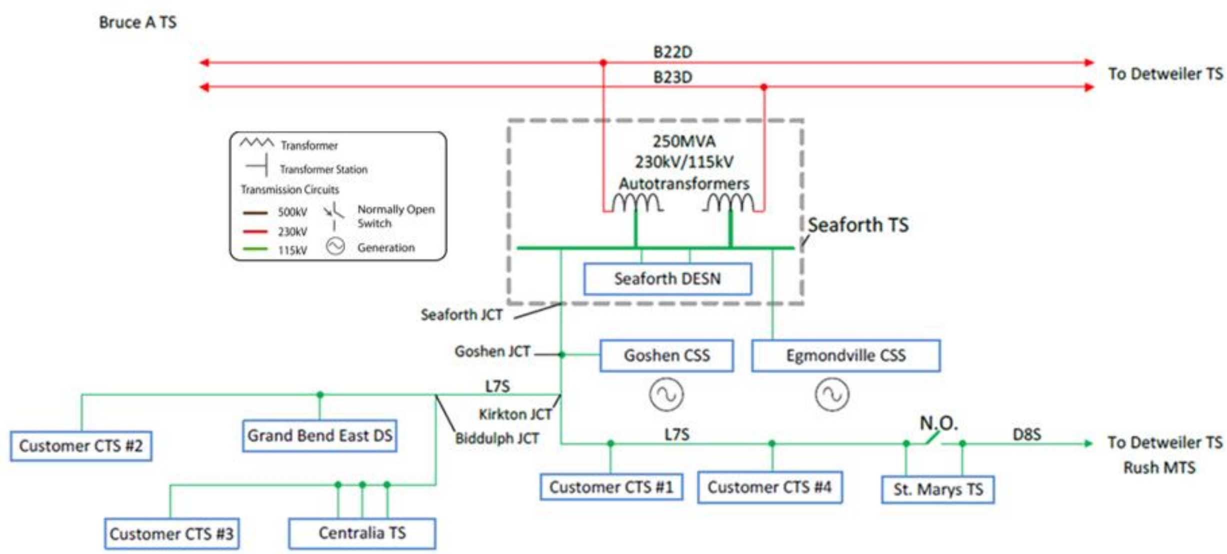


[4] The region is defined by electricity infrastructure; geographical boundaries are approximate

Greater Bruce/Huron Region Electricity System

The Greater Bruce/Huron region's electricity demand is comprised of a mix of residential, commercial and industrial loads. It is a winter-peaking region, although the Southern Huron-Perth sub-region, which is the focus of this IRRP, is summer-peaking. The Greater Bruce/Huron region is supplied by 230 kV and 115 kV transmission lines and stations as shown in Figure A-2. In the Southern Huron-Perth sub-region, L7S provides supply from Seaforth TS and a local wind farm to seven local load stations, including Centralia TS, Grand Bend East DS, St. Marys TS, and four customer transformer stations (CTS). The D8S circuit further connects St. Marys TS to Detweiler TS in the KWCG region.

Figure A-2: Single Line Diagram of Southern Huron-PerthSub-Region



1. Background

The regional planning process was formalized by the OEB in August 2013. To manage the regional planning process, Ontario was organized into 21 regions, each of which was assigned to one of three groups by order of priority, where Group 1 region were reviewed first. Greater Bruce/Huron was assigned to Group 3.

The first cycle of regional planning of the Greater Bruce/Huron region started in February 2016 with the Needs Assessment (NA) process, and proceeded to local planning. Subsequently, and in accordance with the OEB's process, Hydro One Transmission published a regional infrastructure plan (RIP) in August 2017.

The second cycle of regional planning, triggered primarily by connection requests in the Southern Huron-Perth sub-region, launched in early 2019, starting with the NA process. Hydro One published its NA report on May 31, 2019. Multiple needs identified in the report require an integrated regional consideration. The Scoping Assessment led by the IESO with Hydro One and LDCs in the region has concluded that an IRRP be undertaken to address these needs in the Southern Huron-Perth sub-region.

2. Objectives

The Southern Huron-Perth IRRP will assess the adequacy of electricity supply to customers in the sub-region supplied by L7S, explore opportunities to optimize future end-of-life investments, and make recommendations to maintain reliability of supply to the sub-region over the next 20 years. Specifically, the IRRP will:

- Assess the adequacy of electricity supply to customers in the study area over the next 20 years;
- Determine whether there is a need to initiate development work or to fully commit infrastructure investments in this planning cycle;
- Identify and coordinate major asset renewal needs with customer needs, and develop a flexible, comprehensive, integrated electricity plan for Greater Bruce/Huron; and,
- Develop an implementation plan, while maintaining the flexibility required to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs in the Southern Huron-Perth sub-region within the Greater Bruce/Huron region. The plan is a joint initiative involving the IESO, Hydro One Transmission, and LDCs in this sub-region including Hydro One Distribution, Festival Hydro Inc., and Entegrus Powerlines Inc., which are the five members of the Working Group for the SHPIRRP.

The IRRP will focus on these specific items in order of priority:

- Integrated planning for capacity needs for the Southern Huron-Perth sub-region supplied by L7S, including documentation of outcomes and rationale of capacity needs related to L7S emergency rating, and the development of plans for longer term needs related to the L7S continuous rating; and,
- Opportunities to optimize future end-of-life investments

Like all IRRPs, in its identification or confirmation of any capacity or restoration needs, an analysis of options for addressing end-of-life needs, the plan will integrate:

- Forecast electricity demand growth, conservation and demand management (CDM) with transmission;
- Distribution system capability
- Relevant community plans
- Other bulk system developments; and,
- Distributed energy resources (DER) uptake

Based on the identified needs, the Southern Huron-Perth IRRP process will:

1) Create an updated 20-year demand forecast for the study area
2) Confirm the adequacy of transformer station ratings and the area's load meeting capability and reliability through:
    a. Identification or confirmation of transformer station capacity needs and sufficiency of the area's load meeting capability for the study period using the updated load forecast
    b. Confirmation of identified restoration needs using the updated load forecast

c. Collection of information on any known reliability issues and load transfer capabilities from the local distribution companies (LDCs)

3) For confirmed needs, carry out an assessment of options using decision-making criteria included, but not limited to, technical feasibility, economics, reliability performance, and environmental and social factors

   The options analysis has been divided into groupings based on the priority/timing of the needs, any known lead time information, and the depth of analysis required

4) Develop long-term recommendations and the implementation plan
5) Complete the IRRP report, and document near-, mid-, and long-term needs and recommendations

In order to carry out this scope of work, the working group will consider the data and assumptions outlined in section 4 below.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident and non-coincident peak demand information for the region
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios by region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified results and CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers based on planned provincial CDM activities
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities
    - Load segmentation data for each TS based on customer type (e.g., residential, commercial, industrial, agricultural) and the proportion of LDC service territory within the study area

- Local resources
    - Existing local generation, including distributed generation (DG), district energy, customer-based generation, non-utility generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future resource proposals as relevant

- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans, Indigenous Community Energy Plans, and Municipal Energy Plans
    - Municipal Growth Plans
    - Any transit plans impacting electricity use or tied to community developments
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
        - Supply capability
        - Load security
        - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- End-of-life asset considerations and sustainment plans
    - Transmission assets
    - Distribution assets
    - Impact of ongoing plans and projects on applicable facility ratings
- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representatives from the following organizations including embedded LDCs that have identified needs in the Southern Huron-Perth sub-region:

- Independent Electricity System Operator (Team Lead for IRRP)
- Hydro One Distribution
- Festival Hydro Inc.
- Entegrus Power Lines Inc.
- Hydro One Transmission

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended by the IESO and adopted by the provincial government to enhance the regional planning and siting processes in 2013. The Working Group is committed to conducting plan-level engagement throughout the development of the Southern Huron-Perth IRRP.

The first step in engagement will consist of meetings with municipalities (lower tier and upper tier) and Indigenous communities within the planning area to discuss regional planning, the development of the Southern Huron-Perth IRRP, and integrated solutions.

Regional and community engagement will continue throughout the development and completion of the plan. The Working Group will develop a comprehensive stakeholder engagement plan, according to the Activities Timeline shown in Section 6.

7. Activities, Timeline and Primary Accountability

Table A-1: Summary of IRRP Timelines and Activities

#	Activity	Lead Responsibility	Deliverable(s)	Time frame
1	**Prepare Terms of Reference considering stakeholder input**	IESO	Finalized Terms of Reference	July-Sept 2019
2	**Develop the planning forecast for the sub-region**	-	-	-
2	Establish historical coincident and non-coincident peak demand information	IESO	Long-term planning forecast scenarios	Sept-Nov 2019
2	Establish historical weather correction, median and extreme conditions	IESO	Long-term planning forecast scenarios	Sept-Nov 2019
2	Establish gross peak demand forecast and high/low growth scenarios	LDCs	Long-term planning forecast scenarios	Sept-Nov 2019
2	Establish existing, committed and potential DG	LDCs	Long-term planning forecast scenarios	Sept-Nov 2019
2	Establish near- and long-term conservation forecasts based on planned CDM activities	IESO	Long-term planning forecast scenarios	Sept-Nov 2019
2	Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	IESO	Long-term planning forecast scenarios	Sept-Nov 2019

#	Activity	Lead Responsibility	Deliverable(s)	Time frame
3	**Provide information on load transfer capabilities under normal and emergency conditions**	LDCs	Load transfer capabilities under normal and emergency conditions	Sept-Nov 2019
4	**Provide and review relevant community plans, if applicable**	LDCs and IESO	Relevant community plans	Sept-Nov 2019
5	**Review expected service life (ESL) information to optimize future end-of-life (EOL) investment**	IESO and Hydro One Transmission	Summary of ESL/EOL review findings regarding optimization opportunities	Sept-Nov 2019
6	**Capacity planning of the Southern Huron-Perth subregion**	-	-	-
6	Obtain PSS/E base case, include bulk system assumptions as identified in the key assumptions	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2019 – Q2 2020
6	Apply reliability criteria as defined in ORTAC to demand forecast scenarios	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2019 – Q2 2020
6	Confirm and refine the need(s) and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2019 – Q2 2020
7	**Develop options and alternatives**	-	-	-
7	Develop conservation options	IESO and LDCs	Develop flexible planning options for forecast scenarios	Q2-Q4 2020
7	Develop local generation options	IESO and LDCs	Develop flexible planning options for forecast scenarios	Q2-Q4 2020
7	Develop transmission (see Action 7 below) and distribution options	Hydro One, and LDCs	Develop flexible planning options for forecast scenarios	Q2-Q4 2020
7	Develop options involving other electricity initiatives (e.g., smart grid, storage)	IESO/ LDCs with support as needed	Develop flexible planning options for forecast scenarios	Q2-Q4 2020
7	Integrate with bulk needs	IESO	Develop flexible planning options for forecast scenarios	Q2-Q4 2020

#	Activity	Lead Responsibility	Deliverable(s)	Time frame
7	Develop portfolios of integrated alternatives	All	Develop flexible planning options for forecast scenarios	Q2-Q4 2020
7	Complete technical comparison and evaluation	All	Develop flexible planning options for forecast scenarios	Q2-Q4 2020
8	**Plan and undertake community and stakeholder engagement**	-	-	-
8	Early engagement with local municipalities and Indigenous communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	All	• Community and stakeholder engagement plan • Input from local communities	Q4 2019
8	Develop communications materials	All	• Community and stakeholder engagement plan • Input from local communities	Q4 2019
8	Undertake community and stakeholder engagement	Input from local communities	• Community and stakeholder engagement plan • Input from local communities	Q3-Q4 2020
8	Summarize input and incorporate feedback	All	• Community and stakeholder engagement plan • Input from local communities	Q3-Q4 2020
9	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	IESO	• Implementation plan • Monitoring activities and identification of decision triggers • Hand-off letters • Procedures for annual review	Q4 2020 - Q1 2021
10	**Prepare the IRRP report detailing the recommended near-, medium- and long-term plan for approval by all parties**	IESO	IRRP report	Q1-Q2 2021

Appendix G

IRRP – South Huron – Perth Sub Region

Southern Huron-Perth Sub-Region Integrated Regional Resource Plan

Part of the Greater Bruce/Huron Planning Region

September 2021

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

1 Introduction 7

2 The Integrated Regional Resource Plan 11

2.1 Reference Scenario Needs 11

2.2 High Growth Scenario Needs 11

2.3 Conservation and Demand Management 12

3 Development of the Plan 14

3.1 The Regional Planning Process 14

3.2 Southern Huron-Perth and IRRP Development 14

4 Background and Study Scope 15

4.1 Study Scope 15

5 Electricity Demand Forecast 17

5.1 Demand Forecast Methodology 17

5.2 Historical Electricity Demand 18

5.3 Gross and Net Demand Forecast 19

5.4 Contribution of Conservation to the Forecast 20

5.5 Contribution of Distributed Generation to the Forecast 22

5.6 Demand Forecast Scenarios 22

5.7 Project to Consider for Next Cycle 23

6 Needs 24

6.1 Needs Assessment Methodology 24

6.2 Needs Identified 25

7 Plan Options and Recommendations 26

7.1 Long-term Needs 26

8 Engagement 30

8.1 Engagement Principles 30

8.2 Creating an Engagement Approach for Southern Huron-Perth 30

8.3 Engage Early and Often 31

8.4 Bringing Communities to the Table 32

8.5 Engaging with Indigenous Communities 32

9 Conclusion 33

Appendix A. Methodology and Assumptions for Demand Forecast 34

A.1 Method for Accounting for Weather Impact on Demand 34

A.2 Hydro One Forecast Methodology 35

A.3 Festival Hydro Forecast Methodology 36

A.4 Entegrus Powerlines Inc. Forecast Methodology 37

A.5 Conservation Assumptions in Demand Forecast 38

Appendix B. Solution Options to Supply Capacity Need in the High Growth Scenario 43

Appendix C. Development of the Plan 44

C.1 The Regional Planning Process 44

C.2 IESO's Approach to Regional Planning 46

List of Tables and Figures

List of Tables

Table A.1 | Growth Rates for Ontario's GDP (%) 36

Table A.2 | Ontario's Housing Starts (in thousands) 36

Table A.3 | Reference Summer Non-Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region 40

Table A.4 | Reference Summer Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region 40

Table A.5 | High Growth Summer Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region 41

Table A.6 | CDM and DG Contribution (MW) Considered in Reference Coincident Extreme Peak Demand Forecast 41

Table A.7 | Reference Summer LDC Coincident Gross Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region 42

List of Figures

Figure 1.1 | Map of the Southern Huron-Perth Sub-Region 8

Figure 1.2 | Electricity Infrastructure in the Southern Huron-Perth Sub-Region 9

Figure 1.3 | Single Line Diagram of the Southern Huron-Perth Sub-Region, exclusive of the 230 kV system 9

Figure 5.1 | Development of Demand Forecast 17

Figure 5.2 | Measured & Weather Corrected Coincident Net and Gross Historical Peak Demand in the Southern Huron-Perth sub-region 18

Figure 5.3 | Normal/Extreme Weather Corrected Coincident Net and Gross Peak Demand in the Southern Huron-Perth sub-region 19

Figure 5.4 | Reduction to Demand Forecast due to Conservation by Sector (2019-2020 CDM Framework, 2015-2020 Conservation First Framework and Codes and Standards) 21

Figure 5.5 | Reduction to Demand Forecast due to Conservation by Program 21

Figure 5.6 | Reduction to Demand Forecast due to DG and Conservation 22

Figure 5.7 | Demand Forecast Scenarios 23

Figure 6.1 | Needs Identified for the Southern Huron-Perth sub-region 25

Figure 7.1 | CDM Savings Potential under the High Growth Scenario 28

Figure 8.1 | The IESO's Engagement Principles 30

Figure A.1 | Method for Determining the Weather-Normalized Peak 35
Figure A.2 | Entegrus' Licensed Utility Service Area within Southern Huron-Perth – Parkhill 37

List of Abbreviations

CDM	Conservation Demand Management
CTS	Customer Transformer Station
DER	Distributed Energy Resources
DG	Distributed Generation
FIT	Feed-in Tariff
GDP	Gross Domestic Product
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TS	Transformer Station
Working Group	Technical Working Group of the Southern Huron-Perth sub-region

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Southern Huron-Perth sub-region which included the following members:

- Entegrus Powerlines Inc.
- Festival Hydro
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator

The Working Group assessed the adequacy of electricity supply to customers in the Southern Huron-Perth sub-region over a 20-year period beginning in 2019; developed a plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Southern Huron-Perth Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations.

The Southern Huron-Perth Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1 Introduction

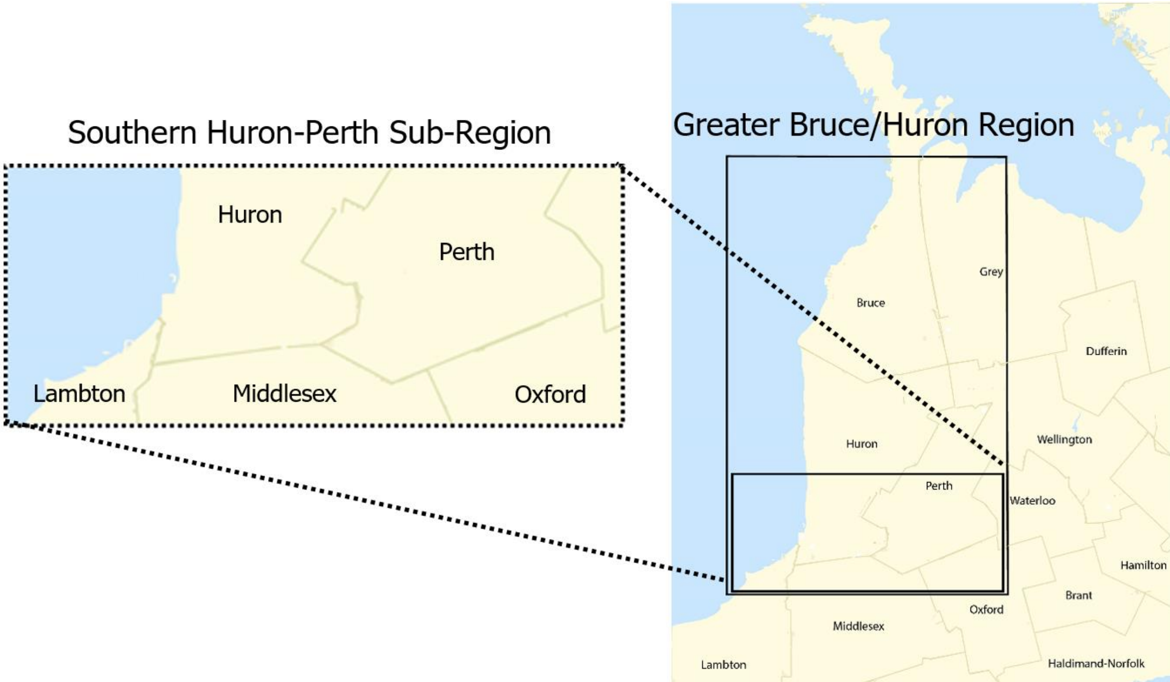
This Integrated Regional Resource Plan (IRRP) addresses the regional electricity needs for the Southern Huron-Perth sub-region for the next 20 years (the "study period").

Southern Huron-Perth is a sub-region of the Greater Bruce/Huron region. The Greater Bruce/Huron region is located in southwestern Ontario and comprises the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford, Lambton, and Middlesex counties.

Several Indigenous communities reside in the sub-region or may have interests in the sub-region, including Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Chippewas of the Thames, Nawash First Nation, Saugeen First Nation, Historic Saugeen Métis, MNO Great Lakes Métis Council, Six Nations of the Grand River and Haudenosaunee Chiefs Confederacy Council.

The Scoping Assessment recommended a focused IRRP for the Southern Huron-Perth sub-region. This sub-region consists of the area supplied by the 115 kV circuit L7S, which includes municipalities of Bluewater, South Huron, Lambton Shores, Lucan-Biddulph, Middlesex Centre, North Middlesex, Thames Centre, Zorra, Perth South, Town of St. Marys, and West Perth. The approximate geographical boundaries of the sub-region are shown in Figure 1.1.

Figure 1.1 | Map of the Southern Huron-Perth Sub-Region



The Southern Huron-Perth sub-region is summer peaking and is served via 115 kV circuit L7S from Seaforth TS and a local wind farm. These facilities supply seven local load stations, including Centralia TS, Grand Bend East DS, St. Marys TS, and four customer transformer stations (CTS). The sub-region has an alternate supply point via 115 kV circuit D8S, which connects a portion of St. Marys TS to Detweiler TS in the adjacent Kitchener-Waterloo-Cambridge-Guelph region under normal operating conditions. The electricial system is illustrated in Figure 1.2 and the single line diagram in Figure 1.3.

Figure 1.2 | Electricity Infrastructure in the Southern Huron-Perth Sub-Region[1]

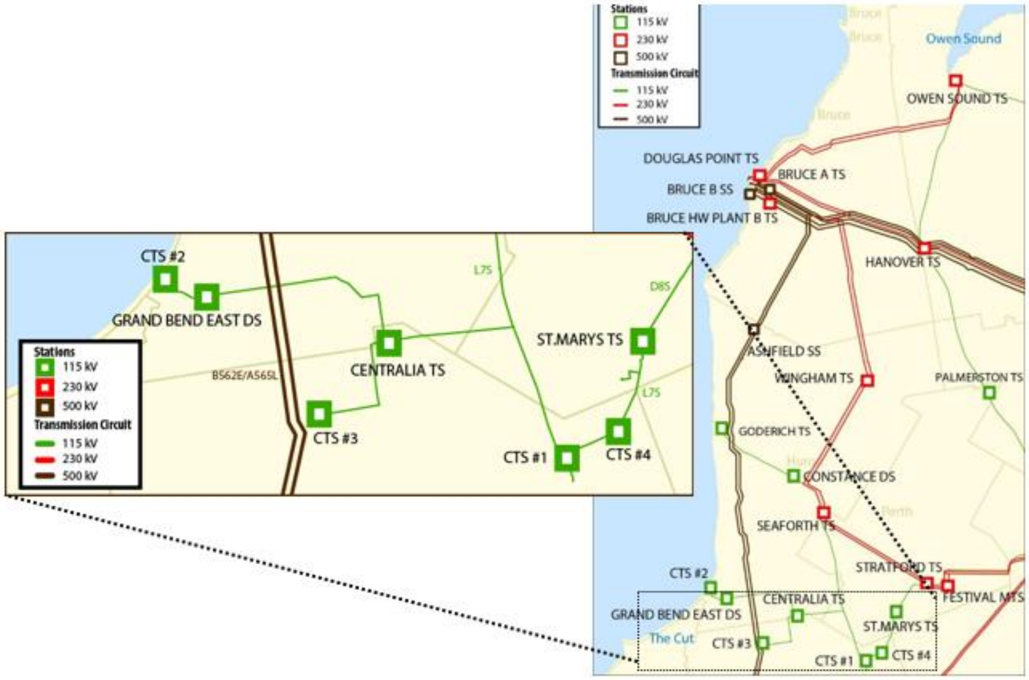
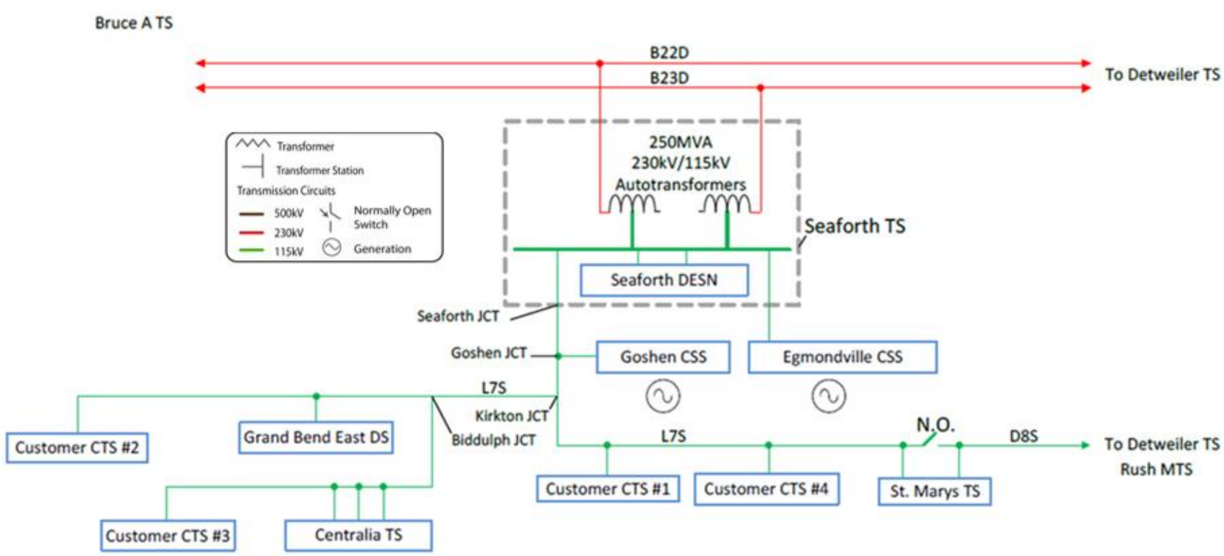


Figure 1.3 | Single Line Diagram of the Southern Huron-Perth Sub-Region, exclusive of the 230 kV system



Development of the Southern Huron-Perth IRRP was initiated in September 2019 following the publication of Hydro One's Needs Assessment report on May 31, 2019 and, subsequently, the IESO's Scoping Assessment Outcome Report and Terms of Reference on Sept 19, 2019, which identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

---

[1] The region is defined by electricity infrastructure; geographical boundaries are approximate.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, including the Southern Huron-Perth sub-region, at least once every five years. The process allows a regional planning cycle to be triggered before the five-year mark due to material changes such as demand or resource changes. The active part of this cycle is made up of Needs Assessment, Scoping Assessment, IRRP, and Regional Infrastructure Plan (RIP) stages, which take up approximately half of the typical five-year timeframe. In many regions, this period of active planning is followed by a period when plan implementation begins, and the Working Group monitors demand trends until the next cycle begins. The complexity of issues requires the Working Group to continue to be engaged in integrated planning throughout the regional planning cycle, after the completion of the IRRP.

Further information on the process can be found in Appendix C. The IESO has also recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

The last regional planning cycle for the Greater Bruce/Huron region did not identify any needs requiring regional coordination and proceeded to three seperate local plans, the last of which was conlcuded in May 2017, and was further consolidated and documented in a RIP for the region in August 2017, resulting in two recommendations which have since been completed. Those recommendations were: i) to install spacers and ground rods along the L7S circuit, and ii) to install motorized switches on L7S at Kirkton junction, Biddulph junction and St Marys TS, both of which are meant to enhance the delivery point performance for L7S and improve the performance reliability by reducing outage duration.

In addition to the needs reviewed in this IRRP for the Southern Huron-Perth sub-region, a few near-term end-of-life asset replacement needs were identified for the broader Greater Bruce/Huron region and proceeded to local planning. As well, an identified voltage issue at Hanover TS for the loss of 230 kV circuits B4V/B5V will be investigated in a subsequent bulk study. These outcomes were captured in the Greater Bruce/Huron Scoping Assessment.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement to date and moving forward is provided in Section 8; and
- A conclusion is provided in Section 0.

2 The Integrated Regional Resource Plan

The Southern Huron-Perth IRRP provides recommendations to address the electricity needs for the region over the next 20 years based on application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC). The needs were identified over three main planning horizons: from the base year when the forecast was originated (2019) through the near term (up to an including 2023), medium term (six to 10 years, from 2024 to 2028 inclusive), and long-term (11 to 20 years, or from 2029 to 2038). These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. The recommendations have been developed in consideration of a number of factors including reliability, cost, technical feasibility, environmental and social factors, and maximization of the use of the existing electricity system, where it is economic to do so.

The Needs Assessment identified a capacity need in this sub-region, however, given changes to customers' growth plans, the triggering loads for that need were deferred with no firm in-service date. In order to conduct a fulsome long-term plan, two forecast scenarios were developed and evaluated for the purposes of this IRRP: i) a Reference Scenario and ii) a High Growth Scenario. The Reference Scenario represents the firm load requests and projected residential and commercial growth, while the High Growth Scenario also includes the industrial loads initially projected, but shifted to the mid- to long-term to determine what may be required if/when that load materializes.

The following sections provide details of the needs and recommendations to address the identified need under both scenarios.

2.1 Reference Scenario Needs

Based on the IRRP load forecast and ongoing work in the area, no needs have been identified under the Reference Scenario.

2.2 High Growth Scenario Needs

While no needs have been identified under the Reference Scenario, potential long-term supply capacity needs were identified under the High Growth Scenario. In 2035, flows on circuit L7S exceed its thermal ratings following the loss of D8S, the 115 kV circuit from Detweiler TS to St Marys TS, which forms the only other supply circuit into the Southern Huron-Perth sub-region. Approximately, 11 MW of supply is needed to mitigate the overload. Considering outage conditions, in 2030, flows on L7S exceed its thermal ratings for the loss of Seaforth T6, one of the two autotransformers at Seaforth TS, under an outage to D8S. Both of these contingencies result in all loads within the Southern Huron-Perth sub-region being supplied via L7S.

A combination of conservation and demand management (CDM) beyond what is committed and planned through existing provincial and federal programs, along with distribution load transfers, could resolve the High Growth needs identified. These are both cost-effective measures that could be implemented within one to three years, as required. At this time, none of the supply capacity needs identified over the long term require early development work for major infrastructure projects in the Southern Huron-Perth sub-region. There may be opportunities for communities and local utilities to manage their future electricity demand through the development of community-based solutions that may evolve between planning cycles.

When load levels are within approximately 4 MW of the sub-region's supply capacity, projected to occur within the next 5 years based on the Reference scenario, CDM programs can be pursued and load transfers can be implemented to bridge any potential gap.

The Working Group will continue to monitor load growth in this area and re-evaluate these needs periodically, including in the next regional planning cycle, to take action as necessary when load tends towards the High Growth Scenario to ensure there are no reliability impacts.

Recognizing the most cost-effective solution involves additional conservation, the Working Group should also seek regulatory clarity on implementation mechanisms for this solution type in advance of the long-term need materializing, noting that multiple LDCs are supplied by the L7S circuit (i.e., would require clarification of approach if existing CDM Guidelines were to be leveraged for implementation) and the opportunity to leverage some existing mechanisms (i.e., the Local Initiatives Program) may or may not align with when the need materializes.

2.3 Conservation and Demand Management

Conservation is important in managing demand in Ontario and plays a key role in maximizing the utilization of existing infrastructure and maintaining a reliable supply of electricity.

As part of the reference forecast, conservation savings from codes and standards and the 2019-2020 CDM programs were accounted for, based on the best known information at the time.

Following the development of the planning forecast, on September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework, which follows the conclusion of the 2019-2020 Interim Framework. The new 2021-2024 CDM Framework will focus on cost-effectively meeting the needs of Ontario's electricity system, including by focusing on the achievement of provincial peak demand reductions, as well as targeted approaches to address regional and/or local electricity system needs. The savings that will be achieved through the 2021-2024 CDM Framework will help reduce supply capacity needs identified under the High Growth scenario.

In addition, there is the opportunity for up to 16.1 MW in further peak CDM savings that could be achieved in this sub-region, based on the 2019 Achievable Potential Study.

It is recommended that the Working Group monitor the progress of the 2021-2024 CDM Framework and the contribution of savings from its programs to reducing net demand in the region, and to explore the opportunity for participation in the Local Initiatives Program as an option to help address needs in the long term.

In addition, the IESO’s Indigenous Community Energy Plan Program supports First Nation and Métis communities and organizations to develop and maintain an updated community energy plan designed to enhance community energy security. The IESO is also working with Indigenous communities to develop their community energy plan, which documents the communities’ energy baseline and analyses and recommends efficiency and conservation measures and retrofits.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region.

The process consists of four main components:

- A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
- A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
- An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
- A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix C.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning.

The IESO has recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

3.2 Southern Huron-Perth and IRRP Development

The process to develop the Southern Huron-Perth IRRP was initiated following the release of the Needs Assessment report for the region by Hydro One in May 2019 and the subsequent Scoping Assessment report produced by the IESO in September 2019, which recommended needs identified for the Southern Huron-Perth sub-region be further pursued through an IRRP. This was due to the potential for coordinated solutions and non-wires alternatives. Shortly after, the Working Group was formed to develop terms of reference for the IRRP, gather data, identify near- to long-term needs in the area, and recommend near- to long-term solutions. In September 2020, the Scoping Assessment was revised and reissued to reflect changes to the study scope and timelines.

4 Background and Study Scope

This is the second cycle of regional planning for the Greater Bruce/Huron region. The first cycle of regional planning started in February 2016 with the Needs Assessment, and proceeded to local planning. In August 2016, a Regional Infrastructure Plan (RIP) was published that summarized findings from local planning, and reviewed new needs from updated load forecasts in the Kincardine area. The Local Planning Report and RIP recommended:

- Monitoring loading on L7S and increasing the emergency rating once loading approaches capacity;
- A two-stage plan (to install spacers and ground rods along the L7S circuit, and to install motorized switches on L7S) to reduce frequency and duration of interruptions due to adverse weather; and
- Monitoring load growth in the Kincardine area to identify any potential step-down transformation capacity needs at Douglas Point TS.

The 2019 Needs Assessment identified that under outage conditions, L7S – the 115 kV circuit that provides supply to Southern Huron-Perth through Seaforth TS – would be thermally overloaded by 2022, when the emergency rating will be exceeded with D8S out of service. Under all elements in service conditions, the circuit would be thermally overloaded by 2027. As such, Hydro One initiated a project to increase the sag clearance of limiting sections from Seaforth to Kirkton junction, scheduled for 2021/2022, which partly addressed the identified supply capacity need.

Even after Hydro One increases the sag clearance of the limiting section, there is still a remaining supply capacity need on L7S circuit requiring further regional coordination and, hence, an IRRP was initiated, focused on the Southern Huron-Perth sub-region. This report presents an integrated regional electricity plan for the next 20-year period starting from 2019.

4.1 Study Scope

This IRRP develops and recommends options to meet the supply needs of the Southern Huron-Perth sub-region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, CDM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The needs addressed in this IRRP include adequacy, security, and relevant end-of-life asset considerations.

The following transmission facilities were included in the scope of this study:

- **115 kV connected stations:** Seaforth TS, Grand Bend East DS, Centralia TS, St Marys TS and four customer-connected transformer stations;
- **115 kV transmission lines:** L7S, D8S; and
- **230/115 kV autotransformers:** Seaforth TS T1/T2.

Supply to the Southern Huron-Perth sub-region is provided from the broader Greater Bruce/Huron region through the autotransformers at Seaforth TS, which connect to the 115 kV circuit L7S, and the 115 kV circuit D8S, connected to the adjacent Kitchener/Waterloo/Cambridge/Guelph region through Detweiler TS.

The Southern Huron-Perth IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with transmission asset owners, along with other relevant asset demographic information;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

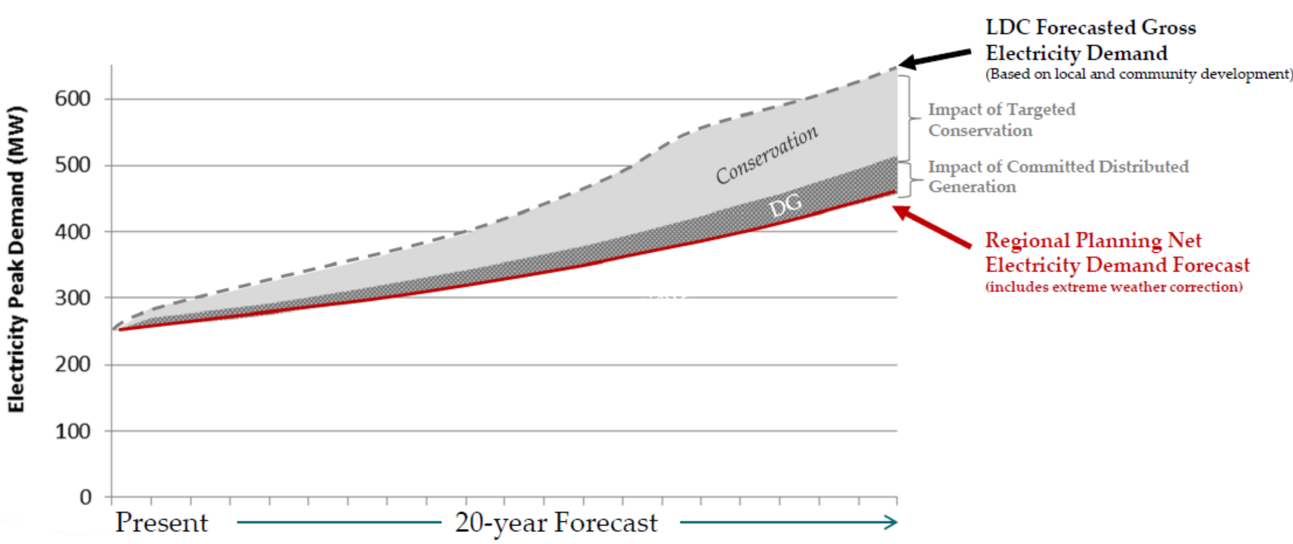
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region. This section describes the specific details of the development of the demand forecast for the Southern Huron-Perth sub-region. It highlights the assumptions made for peak demand forecasts, including the contribution of conservation and distributed generation (DG) to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon as explained in the next section.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum, also called the coincident peak demand. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether the stations' peaks occur at different times. Within the Southern Huron-Perth sub-region, the peak loading hour for each year occurs in the summer.

5.1 Demand Forecast Methodology

For the purpose of this IRRP, a 20-year regional peak demand forecast was developed to assess supply and reliability needs for the Southern Huron-Perth sub-region. The steps taken to perform this are depicted in Figure 5.1. Gross demand forecasts, which assume the weather conditions of an average year based on historical data and referred to normal weather, were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of the 2019-2020 provincial conservation programs and future savings from codes and standards, as well as DG contracted through provincial programs such as FIT and microFIT, and then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This forecast was then used to assess the electricity needs in the region. Additional details related to the development of the demand forecast are provided in Appendix A.

Figure 5.1 | Development of Demand Forecast

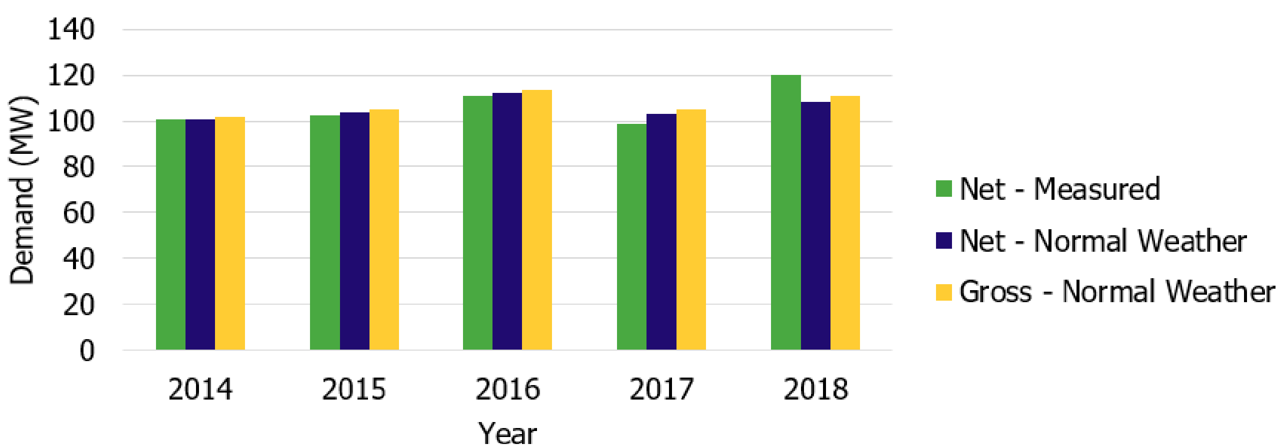


5.2 Historical Electricity Demand

The Southern Huron-Perth sub-region electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to building materials manufacturing. While the industrial and commercial sector is the largest consumer of electricity, high-energy-consuming end uses such as air conditioning also play a significant role in contributing to peak electricity demand. During the summer months, peak demand can also be influenced by extreme weather conditions, with peaks in demand typically occurring after several days of high temperatures. More recently, there has been a shift towards increased residential growth in various parts of the sub-region, primarily driven from nearby urban centers (City of London, Region of Waterloo and City of Guelph), stemming from workplace flexibility as a result of the COVID-19 pandemic.

As shown in Figure 5.2, the historical summer peak demand has fluctuated between 100 MW to 120 MW in the recent years. This figure also shows the weather corrected net and gross coincident peak demand for normal weather. The gross demands on the station level in 2018 were the reference starting points for LDCs to forecast their 20-year gross demand as discussed in the next section. Note, the net measure load in 2018 was significantly higher than expected, driven by unseasonably hot summer conditions resulting in higher campground and trailer park load over the Canada Day long weekend, as well as load that was transferred to Grand Bend East DS. This was accounted for through the weather correction and an adjustment made to the reference starting point to account for the load transfer.

Figure 5.2 | Measured & Weather Corrected Coincident Net and Gross Historical Peak Demand in the Southern Huron-Perth sub-region



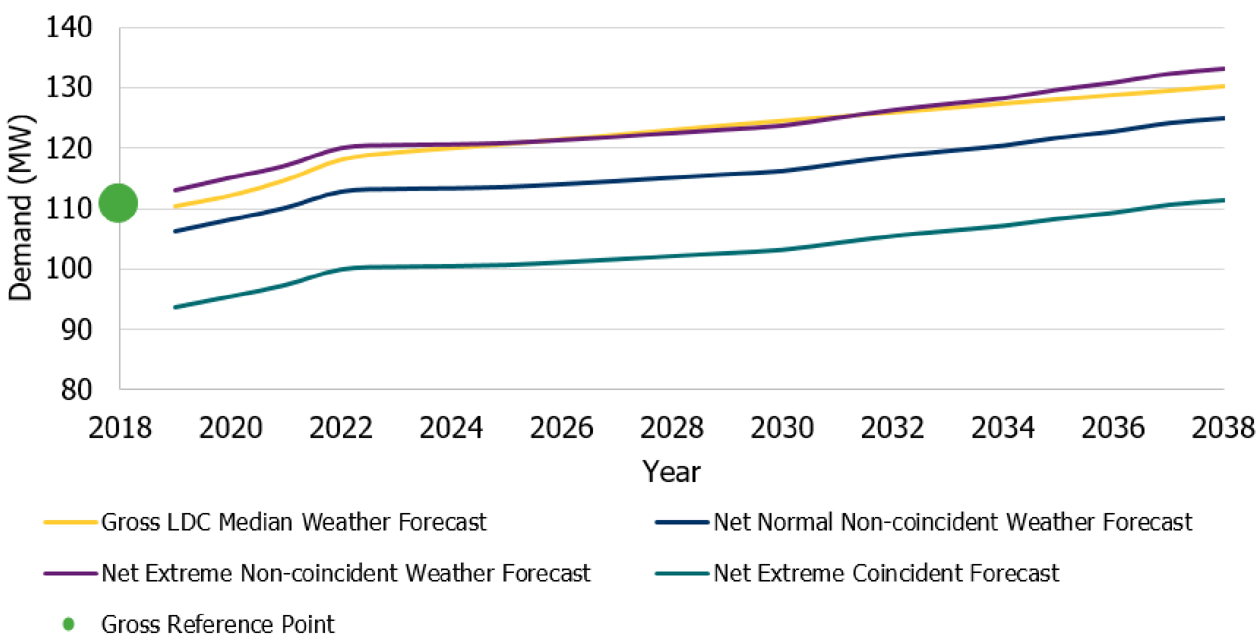
5.3 Gross and Net Demand Forecast

Each participating LDC in the Southern Huron-Perth sub-region prepared gross non-coincident demand forecasts at the station level, or at the station bus level for multi-bus stations. Gross demand forecasts account for increases in demand from new or intensified development. LDCs are expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, or "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and conservation programs, which will be accounted for by the IESO as discussed in Section 5.1.

LDCs have the best information on customer and regional growth expectations in the near and medium term, since they have the most direct involvement with their customers. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand for similar customer types. More details on the LDCs' load forecast assumptions can be found in Appendix A.

Figure 5.3 shows the total gross non-coincident demand forecast in the next 20 years as provided by LDCs, based on the IESO's reference point for normal weather. Figure 5.3 also shows the net non-coincident normal weather forecast compiled by the IESO, which accounts for the impacts of conservation and DG on peak demand, along with the IESO's net non-coincident demand forecasts corrected to extreme weather, referred to as the planning demand forecast, used for the assessments in the IRRP. This was then converted to a coincident forecast using coincidence factors from the base year (2018). The contribution of conservation and DG to the planning demand forecast is discussed in the following sections.

Figure 5.3 | Normal/Extreme Weather Corrected Coincident Net and Gross Peak Demand in the Southern Huron-Perth sub-region



5.4 Contribution of Conservation to the Forecast

Conservation is a clean and cost effective resource for helping to meet Ontario's electricity needs and has been an integral part of ensuring a reliable and sustainable electricity system in provincial and regional planning. Conservation is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

The following section describes the conservation assumptions included in the forecast. These include savings due to codes and standards, and IESO-delivered conservation programs in 2019 and 2020.[2]

The estimates of demand reduction due to the codes and standards are based on the expected improvement in the codes for new and renovated buildings and for specified categories of consumers, i.e. residential, commercial and industrial, through the regulation of minimum efficiency standards for equipment.

The IESO centrally delivers programs on a province wide basis to serve business and low-income customers, as well as Indigenous communities. Save on Energy programs will result in new savings, reducing energy and peak demand in the sub-region. The forecast included savings achieved through the wind-down of 2015-2020 Conservation First Framework and the 2019-2020 Interim Framework. While these programs are not targeted to a given area, it is assumed that a portion of participation will occur in the sub-region. Savings associated to large transmission-connected industrial loads are highly dependent on actions by the individual customers.

Zonal average CDM savings for industrial loads amalgamate savings across a diverse range of industries. As such, the zonal average may not be completely representative of industrial savings on a more localized scale, such as within Southern Huron-Perth which may not align with that industrial loads mixture. Thus, the conservation savings for large industrial customers were based on known conservation initiatives being undertaken by these customers rather than estimated based on the zonal average.

Figure 5.4 shows the yearly estimate of the reduction to the demand forecast due to conservation for each of the residential, commercial and industrial consumers. As shown, conservation in the residential sector accounts for the largest contribution. Additional details are provided in Appendix A.

[2] Includes savings achieved through the wind-down of 2015-2020 Conservation First Framework and the 2019-2020 Interim Framework.

Figure 5.4 | Reduction to Demand Forecast due to Conservation by Sector (2019-2020 CDM Framework, 2015-2020 Conservation First Framework and Codes and Standards)

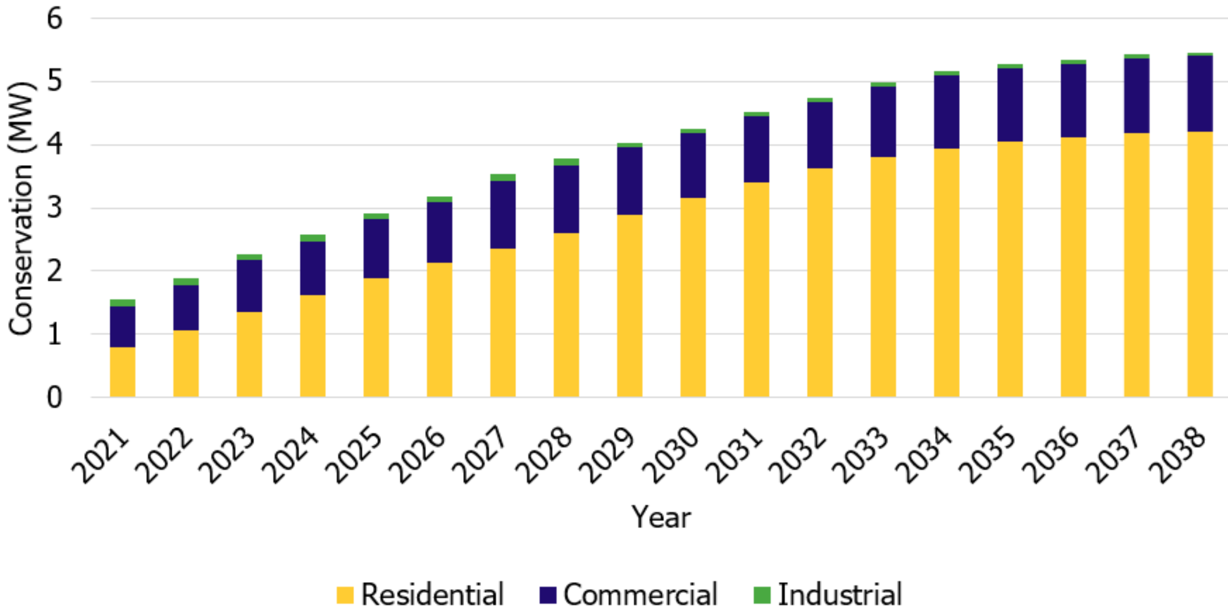
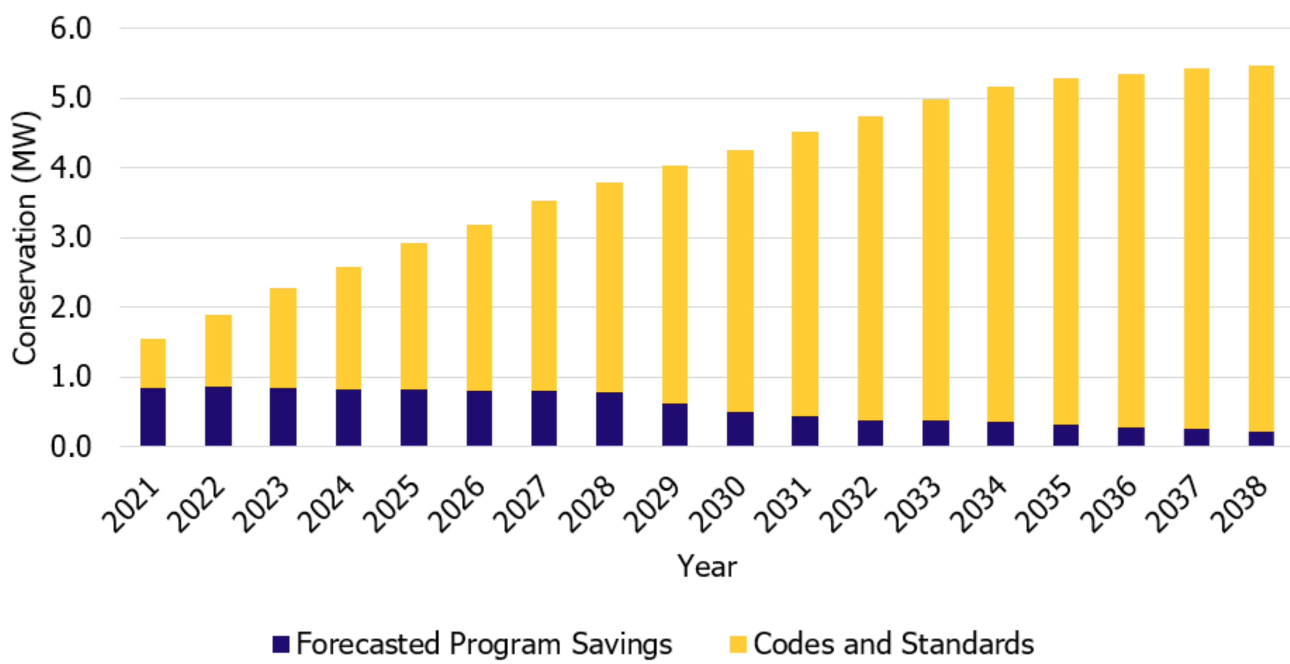


Figure 5.5 shows the yearly estimate of the reduction to the demand forecast due to conservation broken down by regulations and programs. As shown, codes and standards account for the largest contribution to conversation savings in this sub-region. The savings associated with the conservation programs considered in the forecast peaked in 2019-2020 – the target years for the Interim Framework – after which, savings begin to diminish as the conservation measures approach their effective useful life.

Figure 5.5 | Reduction to Demand Forecast due to Conservation by Program



On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework starting in January 2021. As this directive was received after the Southern Huron-Perth sub-region's load forecast was finalized its impact is not included in the forecast nor the above figure. However, it was factored into the conservation calculations during the options analysis in Section 7.

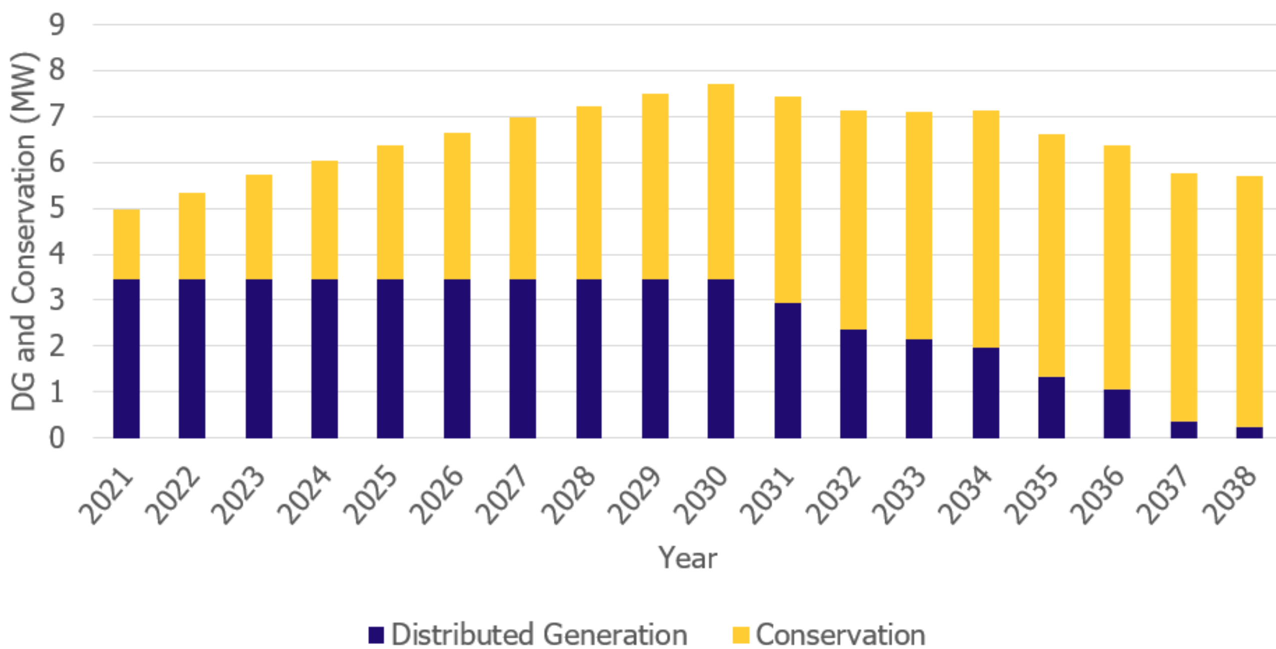
5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Southern Huron-Perth sub-region is also forecast to offset peak-demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's past FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted DG in the region.

Figure 5.6 shows the combined impact of the conservation and DG on reducing the demand forecast. In the long term, as the DG contribution diminishes due to contract expiry, conservation further contributes to reducing the demand and as a result the combined impact remains relatively constant.

Figure 5.6 | Reduction to Demand Forecast due to DG and Conservation



Note that any facilities without a contract are not currently included in the DG forecast.

5.6 Demand Forecast Scenarios

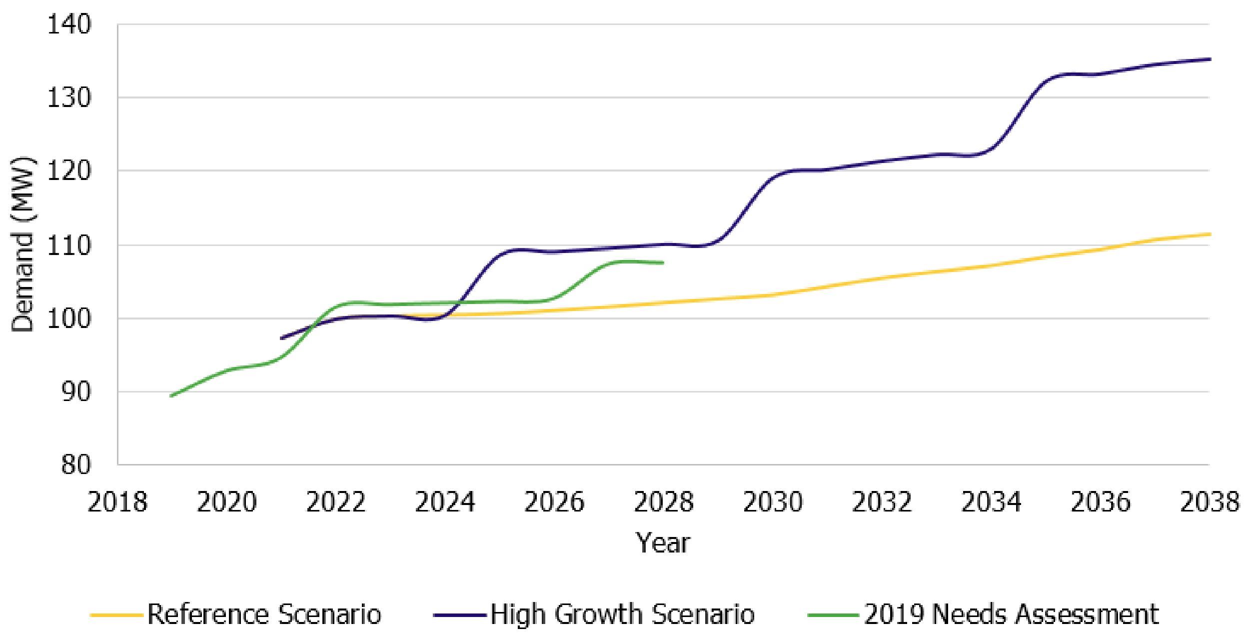
During the Needs Assessment, a significant industrial load project was expected in the sub-region, resulting in anticipated supply capacity needs. When the forecast was refined within the IRRP process, that industrial load project was deferred for at least five years, but with no firm target date. As well, subsequent updates received from stakeholders and communities have indicated there may be unforeseen impacts to the sub-region's demand as the COVID-19 pandemic has changed the way many people live and work.

In order to conduct a comprehensive assessment to identify solutions to address a supply capacity need, if/when the load growth materializes, two forecast scenarios were created:

- Reference Scenario: Following the process described in Section 5.1; and
- High Growth Scenario: The Reference Scenario, with additional 8 MW blocks of industrial growth every five years, starting in 2025.
- The intent of this approach is to identify actions required to address the reference scenario needs, and establish a plan to address the High Growth Scenario needs should they materialize, including if there are near-term actions required to maintain those long-term options. While the impetus for developing a High Growth Scenario was based on projected industrial load growth, this scenario also serves to understand what may be required if and when further load growth materializes, irrespective of the load growth driver.

The two planning forecast scenarios are shown in Figure 5.7, along with what was previously estimated in the 2019 Greater Bruce/Huron Needs Assessment.

Figure 5.7 | Demand Forecast Scenarios



5.7 Project to Consider for Next Cycle

The industrial load expansion project identified in the Needs Assessment was not accounted for in the Reference load forecast during this IRRP cycle because the in-service date was subsequently deferred and so it did not have a confirmed status or connection point. They were modelled in the High Growth Scenario, to outline actions that would be required to address needs if and when the load growth materialized. The Working Group will continue to monitor the situation and if required, a new IRRP cycle or addendum will be launched.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast (extreme weather, net demand), system capability, the transmitter's identified end-of-life asset replacement plans, and the application of ORTAC and North American Electric Reliability Corporation (NERC) TPL 001-4 Standard, the Working Group assessed electricity needs in the near-, medium- and long-term timeframe for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL 001-4. LMC studies are conducted using power system simulations analysis.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.
- **End-of-life Asset Replacement Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based asset demographics (e.g. equipment age). As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

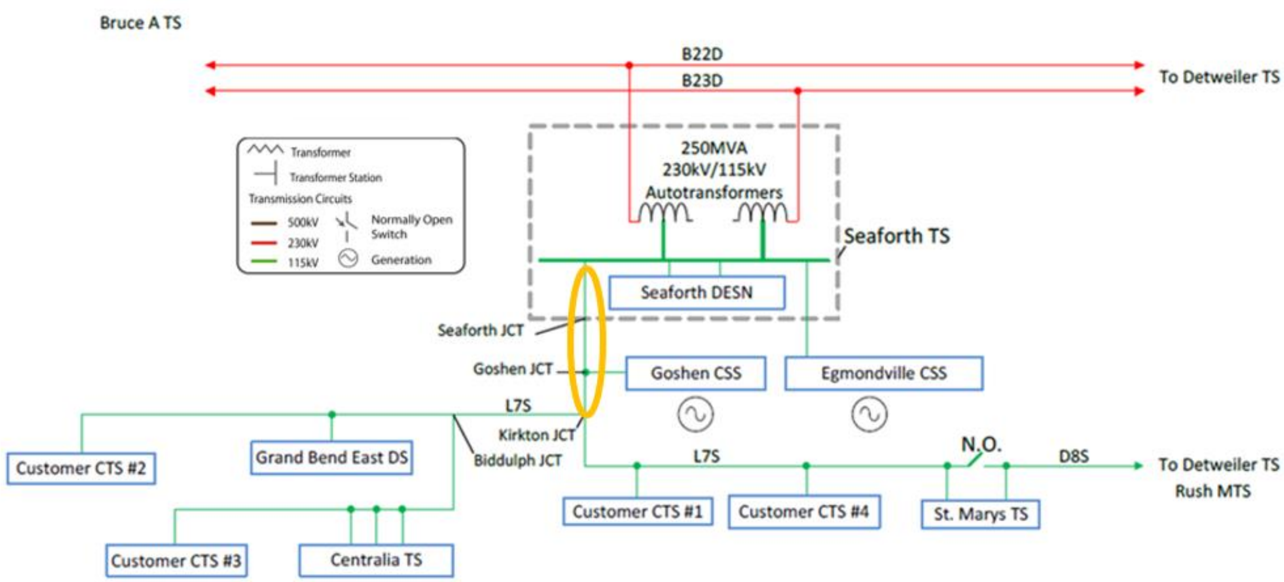
6.2 Needs Identified

The system was analyzed for all in-service conditions and single element contingencies, according to planning standards applicable to this sub-region. Within the Southern Huron-Perth sub-region, no needs were identified under the Reference Scenario, however, long-term supply capacity needs were observed under the High Growth Scenario for the Southern Huron-Perth sub-region. The needs are listed below:

- Possible long-term supply capacity needs under the High Growth Scenario on L7S, the 115 kV circuit from Seaforth TS, following the loss of 115 kV circuit D8S, of up to 11 MW by 2035; and
- Possible long-term supply capacity needs under the High Growth Scenario on L7S following the loss of Seaforth T6 with a prior outage on D8S, of up to 21 MW by 2030.

These supply capacity needs are limited by the same section of L7S circuit, as illustrated in Figure 6.1. As such these supply capacity needs overlap and are not cumulative.

Figure 6.1 | Needs Identified for the Southern Huron-Perth sub-region



7 Plan Options and Recommendations

In developing the plan, the Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

7.1 Long-term Needs

A potential long-term supply capacity need emerging in 2035, reaching 11 MW by 2038, was identified on L7S under the High Growth Scenario, following the loss of D8S. Under outage conditions to D8S, the supply need emerging in 2030, reaching 21 MW by 2038, was identified on L7S under the High Growth Scenario, following the loss of Seaforth T6.

The following sections outline the three main options considered to alleviate the potential supply capacity need:

- Load Transfers;
- Conservation and Demand Management; and
- L7S circuit upgrade.

Further details are provided in Appendix B.

Load Transfer

There is the ability to transfer up to 4.4 MW of load from Centralia TS to Seaforth TS, which is upstream of the limiting L7S supply circuit. This would cost approximately $6-12M for distribution buildout. While this would not alleviate the entire supply capacity need, it would defer the High Growth Scenario need until 2035 and could be achieved in a short period of time, i.e. within the year.

Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. The IESO is mandated to centrally deliver province-wide conservation and demand management programs for Ontario that target businesses, select residential customers and First Nations communities. The IESO offers incentives and rebates to electricity customers through a suite of Save on Energy programs, which provide a valuable and cost-effective system resource that helps customers better manage their energy costs.

Conservation savings that are expected to be achieved through codes and standards and IESO programs delivered in 2019 and 2020, have already been included in the planning forecast scenarios as described in Section Contribution of Conservation to the Forecast5.4.

Since the reference forecast for this IRRP was developed, new energy efficiency programs have been planned beyond 2020 by both federal and Ontario agencies, including the new 2021-2024 CDM Framework. The IESO's new 2021-2024 CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensure energy efficiency can continue to play a role in meeting the sub-region's needs.

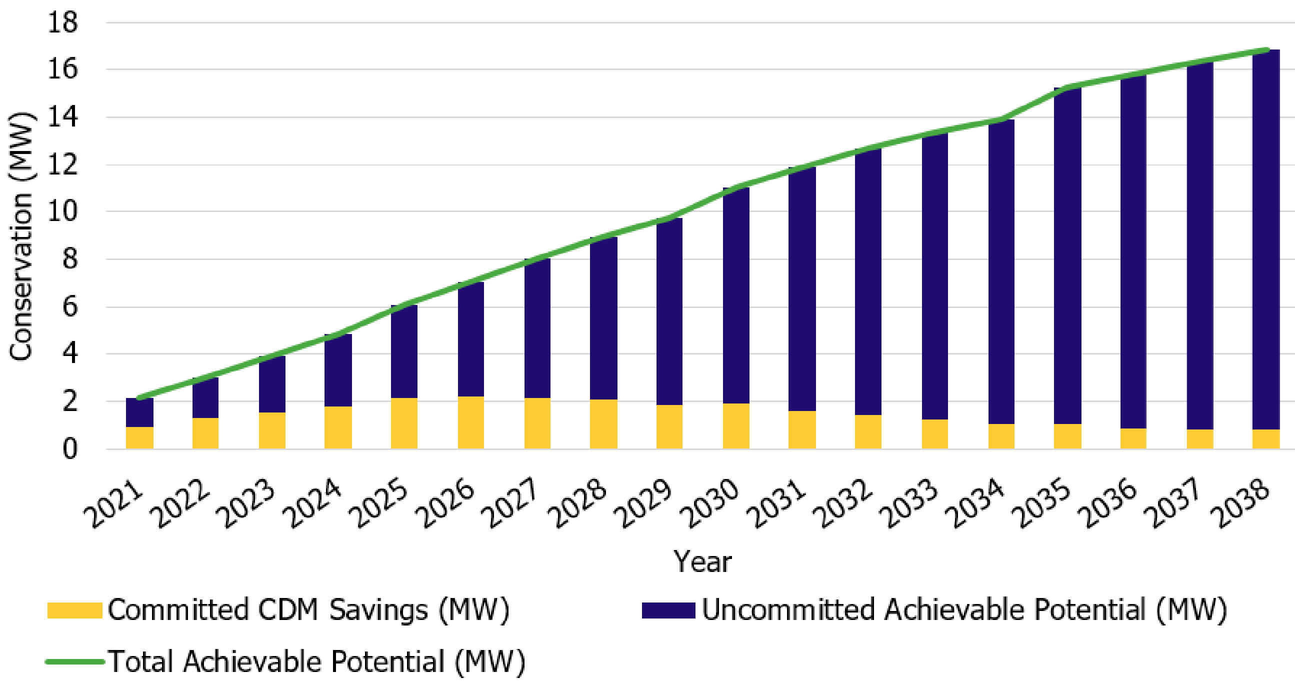
The delivery of the new CDM framework and new federal programs will result in planned reductions in net demand in the region beyond what was included in the forecast. These programs are expected to deliver 0.6 MW of planned savings under the High Growth Scenario by 2038, the end of the study period.[3]

Beyond the forecasted savings expected from the 2021-2024 CDM Framework and new federal programs, there is the potential for further demand reductions from conservation activities. In 2019, the IESO completed an integrated electricity and natural gas conservation Achievable Potential Study in partnership with the Ontario Energy Board. The 2019 Achievable Potential Study identified significant and sustained potential for conservation across all customer sectors throughout the study period. The study results were used to estimate uncommitted conservation opportunities within the Southern Huron-Perth sub-region that are cost effective from the system perspective (i.e., whether the incentive costs are outweighed by the benefits to the electricity system) and not already committed to be delivered under the 2021-2024 CDM Framework and federal programs. Some value is attributed to non-energy benefits, such as customer comfort or improved business productivity.

Based on the demand forecasted under the High Growth Scenario for this region, the total expected achievable potential for conservation savings that is cost effective to the system is 16.7 MW by 2038, as illustrated in Figure 7.1. An estimated 0.6 MW of this potential is expected to be achieved through the 2021-2024 CDM Framework and federal programs. Thus, there is 16.1 MW of uncommitted potential by 2038 under the High Growth Scenario. Implementing both committed and uncommitted savings would defer the need until 2035, for an estimated program cost of $26M, net present value. Although the cost is $26M, for the purpose of this non-wires options assessment a cost of $0 was assumed because these conservation savings are cost-effective to the system, meaning that there is a net benefit when comparing the program investment (cost) against the provincial average avoided costs of providing electricity (benefit).

[3] Similar to the forecasted conservation savings described in Section 5.5, savings expected under this program peak during the target program years, reaching up to 2.2 MW.

Figure 7.1 | CDM Savings Potential under the High Growth Scenario



Note, unlike the savings assumed in the forecast in Section 5.5, this does include potential CDM savings for the forecast industrial loads. Since the zonal average may not be completely representative of industrial savings on a more localized scale, conversations with the new industrial load customers may be required to better understand planned CDM activities. Excluding the savings associated to the new industrial loads,[4] the total achievable potential is 14.8 MW, approximately 14 MW of which is uncommitted.

The Local Initiatives Program (LIP) under the 2021-2024 CDM Framework can target CDM programs to regional and/or local areas to address local supply issues, in addition to, provincial supply issues. The IESO should explore options to target cost effective uncommitted savings to this area using the LIP and other mechanisms.

There are other potential benefits to non-wires investments, such as customer cost savings and reducing GHG emissions. As some of these other objectives may align with municipal energy plans in the sub-region, this may be useful input for identifying the potential for projects and strategies at the local level, while identifying where electrical system benefits and infrastructure deferral value may also exist.

[4] Note, the forecasts for existing transmission-connected industrial customers are calculated based on known CDM activities specific to those facilities, rather than using the zonal averages. Refer to Appendix A.5 for further details.

Transmission Upgrade

The final option considered was upgrading the L7S circuit. While reconductoring would only be required for the limiting section of L7S (between Seaforth TS and Kirkton JCT), this would require installation of new poles along the whole section. While this would provide 50 MW of capacity, more than meeting the supply need identified, it would take 4-5 years, and would cost $10-15M.

Recommendation

While the first two options cannot fully mitigate the High Growth Scenario needs individually, in combination, load transfers and CDM can address the identified need for a total cost of $6-12M and together represent the most cost-effective option. If CDM measures change, this combined option would still provide sufficient lead time to trigger an L7S upgrade, as required. When load levels are within approximately 4 MW of the sub-region's supply capacity, projected to occur within the next 5 years based on the Reference scenario, CDM programs can be pursued and load transfers can be implemented to bridge any potential gap.

Since the appropriate solution for this need is highly dependent on future electricity demand growth, namely the timing and magnitude of the projected industrial load described in Section 5, it is recommended to continue monitoring the situation and devise an appropriate solution when any new demand growth and associated future developments are sufficiently certain.

There may be opportunities for the Working Group to work with communities and local utilities to manage future electricity demand through the development of community-based solutions under the IESO's new CDM Framework, the Indigenous Community Energy Plan Program, or other mechanisms or opportunities that may evolve between planning cycles.

The IESO will monitor the situation and explore long-term solutions with the Working Group and communities, as appropriate, if the need can no longer be addressed without impacting reliability.

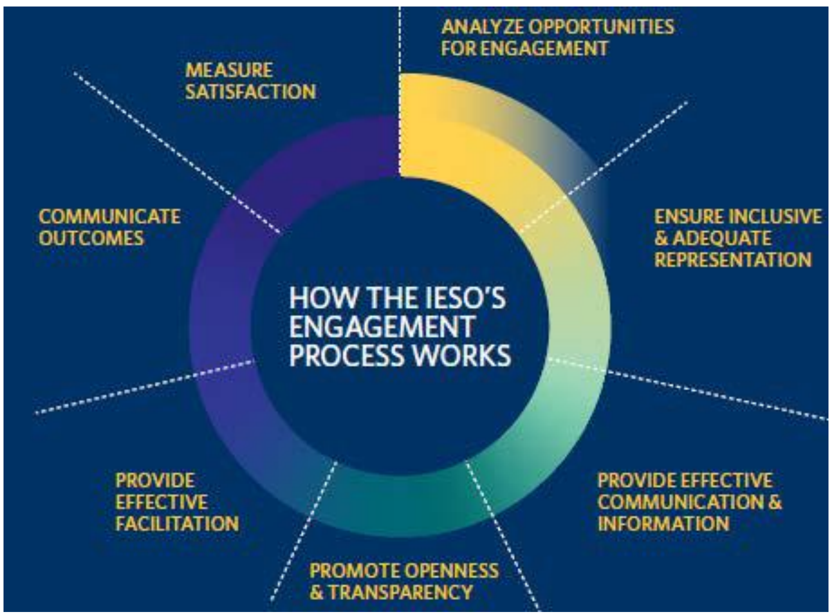
8 Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Southern Huron-Perth IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8.1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Southern Huron-Perth

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Targeted discussions to help inform the engagement approach for the planning cycle;
- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and

- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Face-to-face meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region.

An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft Greater Bruce/Huron Scoping Assessment Report before it was finalized. Community feedback was received on increased expected economic development being driven by high growth in nearby urban centers such as the City of London that is pushing into areas such as Lucan-Biddulph and West Perth, as well as increased growth in agricultural, residential and industrial developments.

Following a written comment window, the final Scoping Assessment Outcome Report was published in September 2019 that identified the need for a coordinated planning approach done through an IRRP for the Southern Huron-Perth sub-region.

Following these initial discussions and finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the Greater Bruce/Huron region to ensure that all interested parties were made aware of this opportunity for input. Two public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. Both webinars received strong participation with cross-representation of stakeholders and community representatives attending the webinar, and submitting written feedback during a 21-day comment period.

The two stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work
2. The defined electricity needs for the sub-region, options evaluation and draft IRRP recommendations

All interested parties were kept informed throughout this engagement initiative via email to Greater Bruce/Huron region subscribers, municipalities and communities as well as the members of the Southwest Regional Electricity Network.

Based on the discussions both through the Southern Huron-Perth IRRP engagement initiative and broader network dialogue, it is clear that there is broad interest in several Southwestern Ontario communities to further discuss the potential for solutions that incorporate non-wires alternatives. The long-term nature of the Southern Huron-Perth sub-region's potential future electricity needs presents a valuable opportunity for communities to mobilize projects and initiatives to meet local growth targets and energy priorities. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Southern Huron-Perth IRRP engagement webpage.

8.4 Bringing Communities to the Table

The IESO held meetings with communities to seek input on their planning and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Southern Huron-Perth electricity planning sub-region or that may have interests in the sub-region throughout the development of the plan. This includes the communities of Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Chippewas of Kettle and Stony Point, Chippewas of the Thames, Nawash First Nation, Saugeen First Nation, Historic Saugeen Métis, MNO Great Lakes Métis Council, Six Nations of the Grand River and Haudenosaunee Chiefs Confederacy Council. Further, the IESO endeavoured to identify opportunities for energy projects and initiatives in Indigenous Community Energy Plans for consideration in the long-term electricity planning for the Southern Huron-Perth sub-region. The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9 Conclusion

This report documents an IRRP that has been developed for the Southern Huron-Perth sub-region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. While no needs have been identified under the Reference Scenario, the IRRP lays out actions to monitor, defer, and address long-term needs projected under the High Growth Scenario.

To support the development of the plan, this IRRP includes recommendations with respect to monitoring load growth and efficiency achievements, such as through local initiatives and the Indigenous Community Energy Plan Program. Responsibility for these actions has been assigned to the appropriate members of the Working Group.

The Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Appendix A. Methodology and Assumptions for Demand Forecast

The sections that follow describe the IESO's methodology to adjust the forecast for extreme weather, LDC methodologies to forecast demand in their respective service area, and the energy efficiency assumptions used to modify the demand based on expected energy efficiency savings. Table A.3 and Table A.4 show the final non-coincident and coincident extreme demand forecast, respectively, per station used for the Reference Scenario assessments. Table A.5 shows the final coincident extreme demand forecast per station used for the High Growth Scenario assessments. The coincident load forecast includes the estimated reduction due to CDM plus DG with the values shown in Table A.6. Table A.7 also shows the gross demand forecast per station as provided by LDCs.

A.1 Method for Accounting for Weather Impact on Demand

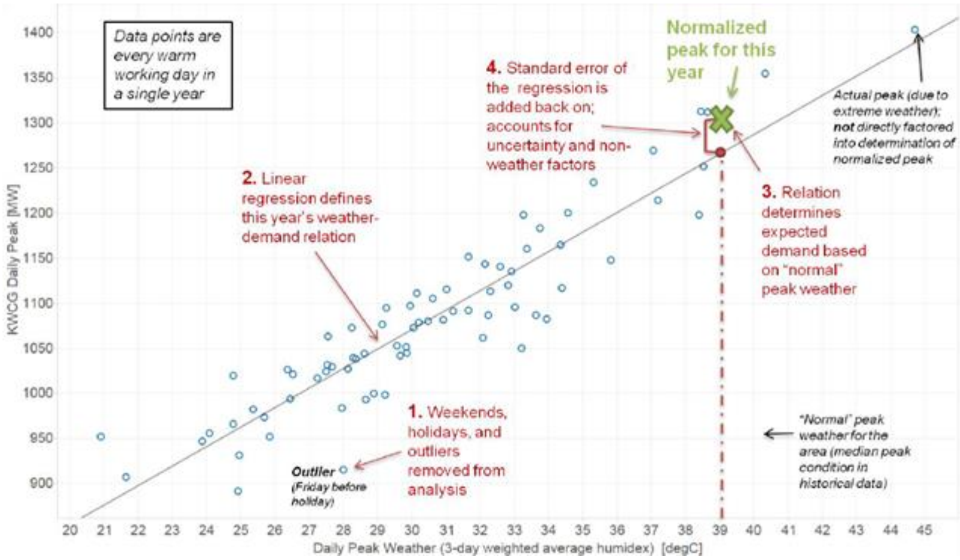
Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (in this case 2018). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure A.1.

The 2018 median weather peak on a station and LDC load basis was provided to each LDC. This data was used as a reference stating point from which to develop 20-year demand forecasts, using the LDCs preferred methodology (described in the next sections).

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves) are generally when the electricity system infrastructure is most stressed.

Figure A.1 | Method for Determining the Weather-Normalized Peak



A.2 Hydro One Forecast Methodology

Hydro One Distribution provides service across Ontario, including the to counties and townships within Southern Huron-Perth. Three step-down stations supply the distribution-connected customers in the area from the transmission system as follows:

- 115/27.6 kV Centralia TS supplied by 115 kV circuit L7S
- 115/27.6 kV Grand Bend East DS supplied by 115 kV circuit L7S
- 115/27.6 kV St. Marys TS supplied by 115 kV circuits L7S and D8S

There are about 1.4 million Hydro One Distribution retail customers directly connected to Hydro One's distribution system, of which Southern Huron-Perth represents about 8.7% of Hydro One's total electrical load. Hydro One Distribution's customer base within Southern Huron-Perth is comprised of primarily residential (68%) and commercial loads (25%), with some industrial loads (7%). There are two embedded LDCs connected to Hydro One's distribution system within Southern Huron-Perth.

A.2.1 Factors that Affect Electricity Demand

In the Southern Huron-Perth sub-region overall, the agricultural sector and population growth are the main factors of electrical demand growth, impacting the organic residential and commercial growth to support the economic development. The growth is expected to continue to occur around the developed areas in the sub-region. Summer peaks are also impacted by seasonal campground and trailer park loads. There is also an industrial manufacturing load, which may expand over the next few years, which has been accounted for in the High Growth Scenario.

A.2.2 Forecast Methodology and Assumptions

The methodology used was a combination of econometric and end-use forecasting models. These models measured growth from a predetermined baseline demand and took into account the effect of CDM. The following tables outline the growth rate and housing start assumptions used as inputs to the model to account for both provincial and local information.

Table A.1 | Growth Rates for Ontario's GDP (%)

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Growth rate	2.8	2.2	1.7	1.7	1.9	2.0	2.0	2.0	2.0	2.0

Table A.2 | Ontario's Housing Starts (in thousands)

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Housing Starts	9.1	78.4	72.1	70.4	71.7	71.1	71.0	68.7	68.9	68.3

A.3 Festival Hydro Forecast Methodology

Festival Hydro owns and operates the electricity distribution system in its licensed service areas of Stratford, Brussels, Dashwood, Hensall, St. Marys, Seaforth and Zurich, providing power to 20,000 people.

The stations of concern for this IRRP are the following:

- 115/27.6 kV Grand Bend East DS supplied by 115 kV circuit L7S
- 115/27.6 kV St. Marys TS supplied by 115 kV circuits L7S and D8S

These stations represent 15-20% of Festival Hydro's total electrical load. Festival Hydro's customer base within Southern Huron-Perth is comprised of primarily residential (21%) and industrial loads (56%), along with commercial loads (18%) and mixed commercial/industrial use loads (5%). These loads are supplied through the Hydro One transmission system at primary voltages of 115 kV. Electricity is then distributed through Festival Hydro's service area by two transformer stations within Southern Huron-Perth.

A.3.1 Factors that Affect Electricity Demand

The main variable affecting electricity demand within Festival Hydro's service territory within Southern Huron-Perth is related to population growth and economic development, typically attributed to residential service upgrades and new in-fill development. There is little to no residential development or commercial/industrial load growth is known at this time.

A.3.2 Forecast Methodology and Assumptions

Festival Hydro's load forecast was based on 5-year average plus 0.5% growth each year starting in 2019, following the trend of the last 5 years.

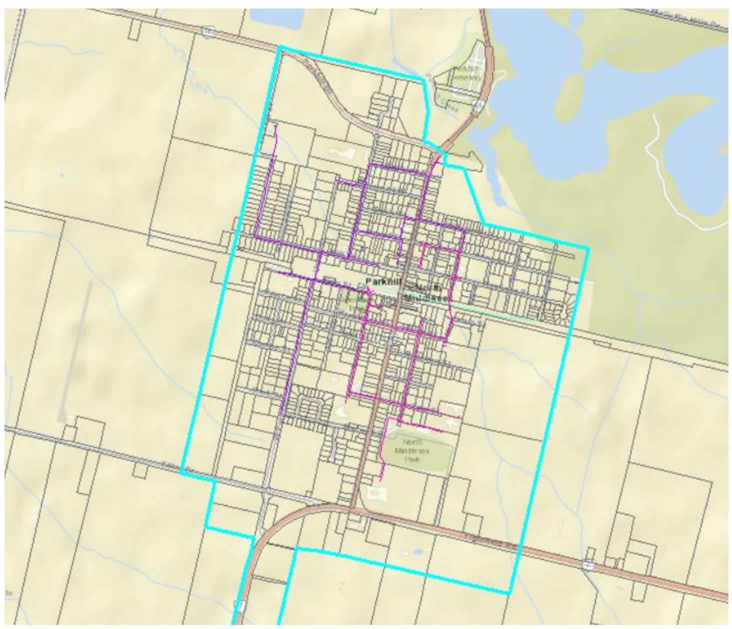
There is also small distribution-connected battery storage facility within Festival Hydro's Southern Huron-Perth service area. For the purposes of this IRRP forecast, this was not relied on to provide any capacity relief because of uncertainties in their behavior at the time of peak demand as it is a non-contracted behind-the-meter facility.

A.4 Entegrus Powerlines Inc. Forecast Methodology

Entegrus is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity and carry on the business of an electricity distributor within its licensed service area. Entegrus owns, operates and manages the assets associated with the distribution of electrical power to approximately 59,000 customers in 17 Southwestern Ontario communities. Entegrus is owned by the Municipality of Chatham-Kent, the City of St. Thomas, and Corix utilities, and is made up of four divisions, including Entegrus Powerlines Inc.

Entegrus provides safe, sustainable and reliable power to Entegrus customers in Blenheim, Bothwell, Chatham (including a portion of the Township of Raleigh known as the "Bloomfield Business Park"), Dresden, Dutton, Erieau, Merlin, Mount Brydges, Newbury, Parkhill, Ridgetown, St. Thomas, Strathroy, Thamesville, Tilbury, Wallaceburg and Wheatley. For the Southern Huron Perth sub-region, the only area served by Entegrus in this region is the town of Parkhill. Entegrus serves approximately 774 customers within this town. This town represents the furthest North community served by Entegrus. The image below represents the Parkhill Entegrus service boundaries. Entegrus' customer base within Southern Huron-Perth is comprised of primarily residential (87%) and commercial loads (13%), supplied through the Hydro One transmission system at primary voltages of 115 kV. Electricity is then distributed through Entegrus' service area by one transformer station within Southern Huron-Perth.

Figure A.2 | Entegrus' Licensed Utility Service Area within Southern Huron-Perth – Parkhill



A.4.1 Factors that Affect Electricity Demand

Parkhill has not seen a lot of growth, nor does the town have any pending connection or generation requests at this time. Projected growth is based on organic

Note, the type of forecasts provided varies based on region and amount of information Entegrus knows at the time of the forecast generation. For example, other areas served by Entegrus with known development, municipal growths plans, and large spot load connections will be incorporated into the forecast. Parkhill historically has been very stable with little growth.

A.4.2 Forecast Methodology and Assumptions

The historical peaks generated in the load forecast template are measured from the Entegrus demarcation wholesale meter and occurred under normal operating conditions. The historical peaks are the metered values for summer and winter. The forecast provided is the net load, i.e., gross peak load minus any existing distributed generation. The town of Parkhill has little generation offsetting the peak. The town is only fed from one supply, so there is no ability for Entegrus to consider load transfers when recording peak data. The town is summer peaking, but the differential between winter and summer month peaks are minor, approximately 300 kW. The town of Parkhill's net load summer peak represents approximately 1% of the entire Entegrus aggregated system peak. The load forecast for Parkhill is primarily based off linear regression (historical net load trend).

A.5 Conservation Assumptions in Demand Forecast

Conservation measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and Conservation Programs. The assumptions used for the Southern Huron-Perth IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2019 Annual Planning Outlook, which was the latest provincial planning product when this IRRP was developed, the savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from provincial level to the Southwest transmission zone and then allocated to Southern Huron-Perth sub-region. This appendix describes the process and methodology used to estimate energy efficiency savings for the Southern Huron-Perth sub-region and provides more detail on how the savings for the two categories were developed.

A.5.1 Estimate Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the Southwest zone and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region.

Consistent with the gross demand forecast, 2018 was used as the base year. New peak demand savings from codes and standards were estimated from 2019 to 2038. The residential annual peak reduction percentages of each year were applied to the forecast residential demand at each station to develop an estimate of peak demand impacts from codes and standards. By 2038, the residential sector in the region is expected to see about 7.1% peak demand savings through standards. The same is done for the commercial sector, which will see about 4.9% peak-demand savings through codes and standards by 2038. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. There are no savings from codes and standards considered to be associated with the industrial sector.

A.5.2 Estimate Savings from Conservation Programs

In addition to codes and standards, the delivery of conservation programs reduces electricity demand. The impact of existing and committed conservation programs were analyzed, which include the Conservation First Framework wind-down and the Interim Framework. A top down approach was used to estimate the peak demand reduction due to the delivery of 2019 and 2020 programs, from provincial to Southwest zone to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages of program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Southwest transmission zone. They were then applied to sectoral gross peak forecast of each station in the region. By 2020, the residential sector in the region is expected to see about 0.6% peak demand savings through programs, while commercial sector and industrial sector will see about 2.3% and 0.7% peak reduction respectively. Those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

Note, for all larger industrial customers, this general method is not used to allocate savings to the specific locations. Instead, specific activities undertaken by those facilities are identified based on targeted engagement to include only the savings that are planned.

Since the demand forecast was established in 2019, the subsequent federal and Ontario 2021-2024 programs were not included in the estimated savings. However, when calculating the total achievable potential savings, this is accounted for under the committed savings amount, with costs allocated to the existing program. Accounting for both federal and Ontario programs between 2019-2024, by 2024 the residential sector in the region is expected to see about 0.6% peak demand savings through programs, while commercial sector and industrial sector will see about 6% and 3.2% peak reduction respectively. Similarly, those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

A.5.3 Total Conservation Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector for each forecast category, and totalled for each station in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

Table A.3 | Reference Summer Non-Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	37	40	41	41	41	41	42	42	42	42	43	43	44	44	44	45	46	46
Grand Bend East DS	22	22	22	22	22	22	22	22	22	22	23	23	23	23	24	24	24	24
St. Marys TS	28	28	28	28	28	29	29	29	29	30	30	30	31	31	31	31	32	32
CTS #4	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
CTS #1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
CTS #3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
CTS #2	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total	117	120	121	121	121	122	122	123	124	124	125	126	127	128	129	130	132	133

Table A.4 | Reference Summer Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	34	36	37	37	37	37	37	38	38	38	38	39	39	40	40	40	41	42
Grand Bend East DS	16	16	16	16	16	17	17	17	17	17	17	17	17	17	18	18	18	18
St. Marys TS	25	26	26	26	26	26	27	27	27	27	27	28	28	28	29	29	29	30
CTS #4	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
CTS #1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CTS #3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #2	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total	97	100	100	101	101	102	102	103	103	104	104	105	106	107	108	109	110	111

Table A.5 | High Growth Summer Coincident Extreme Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	34	36	37	37	40	40	40	40	41	44	44	45	45	46	49	50	51	51
Grand Bend East DS	16	16	16	16	16	16	17	17	17	17	17	17	17	17	18	18	18	18
St. Marys TS	25	26	26	26	31	31	31	31	32	37	37	38	38	38	44	44	44	45
CTS #4	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
CTS #1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CTS #3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #2	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total	97	100	100	100	109	109	110	110	111	119	120	121	122	123	132	133	135	135

Table A.6 | CDM and DG Contribution (MW) Considered in Reference Coincident Extreme Peak Demand Forecast

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	2.8	3.0	3.2	3.4	3.5	3.7	3.9	4.0	4.2	4.3	4.1	3.8	3.9	3.9	3.9	3.7	3.1	3.1
Grand Bend East DS	1.3	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2.0	2.1	2.0	2.1	2.0	2.0	1.5	1.5	1.5	1.5
St. Marys TS	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.3	1.3	1.4	1.3	1.3	1.2	1.2	1.3	1.3	1.2	1.1
CTS #4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTS #2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	5.0	5.3	5.7	6.0	6.4	6.6	7.0	7.2	7.5	7.7	7.4	7.1	7.1	7.1	6.6	6.4	5.8	5.7

Table A.7 | Reference Summer LDC Coincident Gross Peak Demand Forecast (MW) per Station in Southern Huron-Perth Sub-Region

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Centralia TS	37	40	41	41	42	42	42	43	43	43	44	44	44	45	45	45	46	46
Grand Bend East DS	21	21	21	21	22	22	22	22	22	22	22	23	23	23	23	23	23	23
St. Marys TS	26	27	27	27	28	28	28	28	29	29	29	29	30	30	30	30	31	31
CTS #4	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
CTS #1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
CTS #3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
CTS #2	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total	115	118	119	120	121	121	122	123	124	124	125	126	127	127	128	129	129	130

Appendix B. Solution Options to Supply Capacity Need in the High Growth Scenario

Table B.1 | Comparison of Solution Options for High Growth Scenario Needs

Option	Description	Load Supply Capability (MW)	Total Cost	Cost per Additional MW of Supplied Load
1	Transfer load from Centralia TS to Seaforth TS	4.4*	$6-12M	$136-273k
2	Conservation and Demand Management	16.1**	$26M***	$1.62M***-
3	Upgrade limiting section of L7S 115 kV circuit	50	$10-15M	$200-300k

*This is will will require a new feeder position at Seaforth TS, included in the costs.
**Maximum uncommitted CDM potential, net of the 0.9 MW of comitted CDM from forecast and planned provincial and federal CDM programs. This potential would be achieved through new initiatves. Costs are based on historic CDM program costs.
*** Cost for these system cost-effective resources will be recovered through a provincial program.

Appendix C. Development of the Plan

C.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the OEB convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a needs assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a scoping assessment to determine what type of planning is required for a region. A scoping assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused RIP can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure C.1, three levels of electricity system planning are carried out in Ontario:

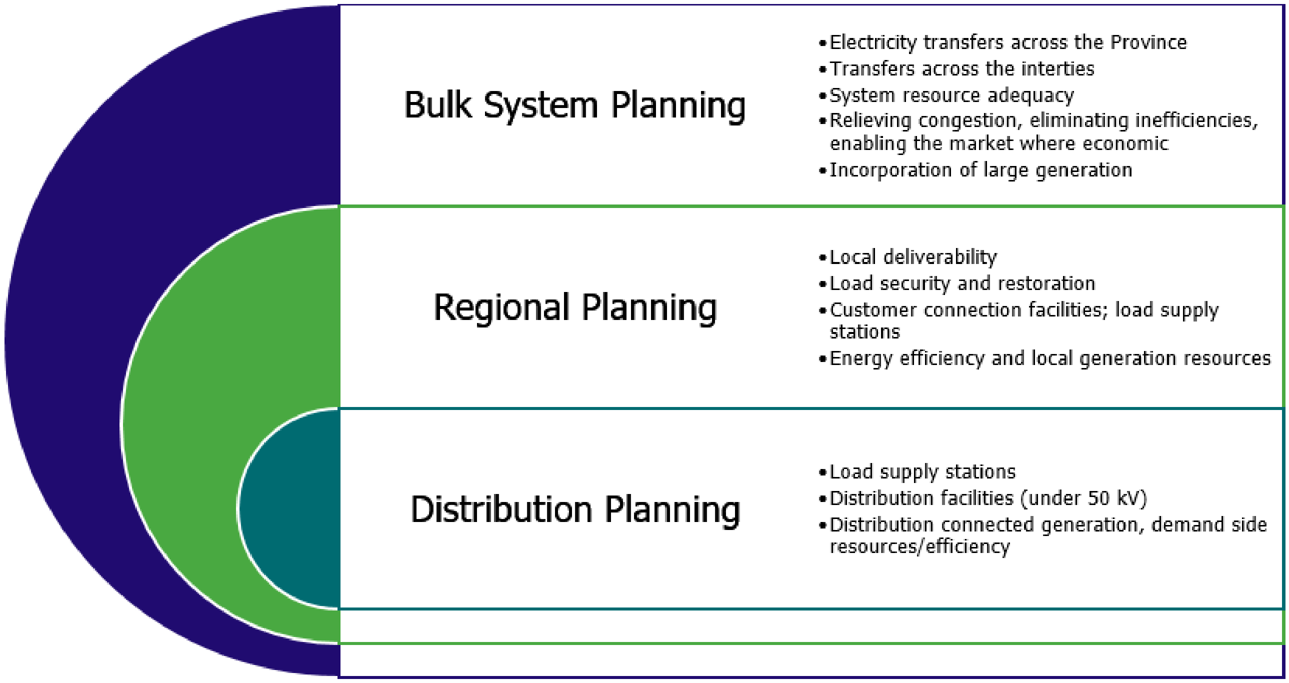
- Bulk system planning;
- Regional system planning; and
- Distribution system planning.

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Figure C.1 | Levels of Electricity System Planning



C.2 IESO's Approach to Regional Planning

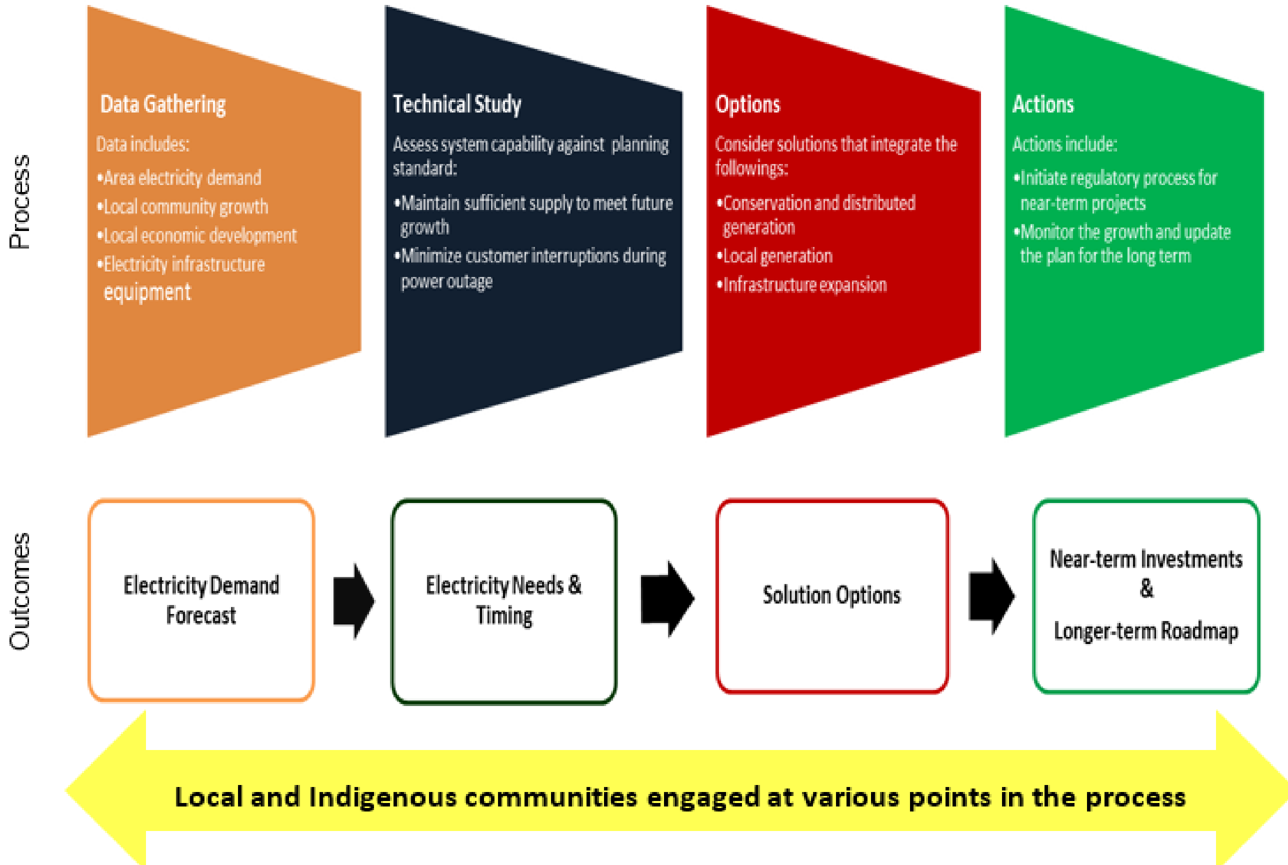
IRRPs assess electricity system needs for a region over a 20-year period, enabling near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

The IRRP describes the Working Group's recommendations for mitigating reliability and cost risks related to end-of-life asset replacement and demand forecast uncertainty associated with large load customers or due to any changes in the existing provincial conservation targets. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

In developing an IRRP, the IESO and the study team follow a process, with a clearly defined series of steps (see Figure C.2). These includes developing electricity demand forecasts; conducting technical studies to determine electricity needs and the timing of these needs; considering potential options; and creating a plan with recommended actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and Indigenous communities who may have an interest in the area.

The IRRP report documents the inputs, findings and recommendations developed through this process, and outlines recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP triggers the initiation of the transmitter's RIP process to develop those options. Other recommendations in the IRRP may include: development of conservation, local generation, community engagement, or information gathering to support future iterations of the regional planning process in the region or sub-region.

Figure C.2 | Steps in the IRRP Process



Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.

Appendix H

RIP Greater Bruce-Huron

2022

Greater Bruce - Huron

Regional Infrastructure Plan

April 25, 2022

[This page is intentionally left blank]

Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Entegrus Power Lines Inc.
ERTH Power Corporation
Festival Hydro Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

[This page is intentionally left blank]

Disclaimer

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs (2019-2028) identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

[This page is intentionally left blank]

Executive Summary

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GREATER BRUCE-HURON (GBH) REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Entegrus Power Lines Inc.
- ERTH Power Corporation
- Festival Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Wellington North Power Inc.
- Westario Power Inc.

In the first cycle of the Regional Planning (RP) process for the GBH Region, a Needs Assessment ("NA") was published in May 2016 and recommended that an Integrated Regional Resource Plan ("IRRP") was not required. The first cycle of RP process was completed in August 2017 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This RIP is the final phase of the second cycle of the regional planning process for the Greater Bruce-Huron Region, which follows the completion of the South Huron-Perth Sub-Region IRRP in September 2021 and the GBH Needs Assessment in May 2019. This report provides a consolidated summary of needs and recommended plans for the Greater Bruce-Huron Region for the near-term (up to 5 years) and mid-term (5 to 10 years). Long term needs (10 to 20 years) in the region, include circuit L7S capacity (which has transitioned to the mid-term with recent new connection requests) and Hanover TS capacity. The delivery point performance along circuit L7S continues to be monitored to confirm whether recent upgrades have resulted in improvements, and to determine if additional plans are required.

Investments planned for the Greater Bruce-Huron Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the table below.

No.	Project	In-Service Date	Cost
1	Increase Capacity of Limiting Section of L7S	2023-2025	$550k - TBD
2	Continued assessment of L7S condition to address deteriorating components	TBD	TBD

In accordance with the Regional Planning process, the RIP should be reviewed and/or updated at least every five years. The Region will continue to be monitored and should there be a need that emerges earlier due to a change in load forecast or any other reason, the next regional planning cycle will be started to address the need.

Table of Contents

1. Introduction 11
   1.1 Objective and Scope 12
   1.2 Structure..12
2. Regional Planning Process 13
   2.1 Overview 13
   2.2 Regional Planning Process 13
   2.3 RIP Methodology..16
3. Regional Characteristics 17
4. Transmission Facilities Completed Over Last Ten Years Or Currently Underway 20
5. Load Forecast And Study Assumptions 22
   5.1 Load Forecast 22
   5.2 Study Assumptions 25
6. Adequacy Of Facilities and Regional Needs Over the 2019-2028 Period 26
   6.1 230 kV Transmission Facilities...28
   6.2 500/230 kV and 230/115 kV Transformation Facilities 28
   6.3 Supply Capacity of the 115 kV Network 29
   6.4 Step-down Transformer Stations...29
   6.5 Other Items Identified During Regional Planning 30
   6.6 Long-Term Regional Needs 31
7. Regional Plans 33
   7.1 Transmission Circuit Capacity...33
   7.2 Customer Delivery Point Performance 33
   7.3 Transmission Sustainment Plans 35
8. Conclusion 37
9. References...38
Appendix A: Step-Down Transformer Stations in the Greater Bruce-Huron Region.................39
Appendix B: Regional Transmission Circuits in the Greater Bruce-Huron Region....................40
Appendix C: Distributors in the Greater Bruce-Huron Region..41
Appendix D: Regional Load Forecast (2019-2028)..42
Appendix E: List of Acronyms..50

List of Figures

Figure 1-1. Greater Bruce Huron Region 11
Figure 2-1. Regional Planning Flowchart 15
Figure 2-2. RIP Methodology 16
Figure 3-1. Geographical Area of the Greater Bruce-Huron Region with Electrical Layout 18
Figure 3-2. Greater Bruce-Huron Region Single-Line Diagram 19
Figure 5-1. Greater Bruce-Huron Region Winter Coincident Forecast 23
Figure 5-2. Greater Bruce-Huron Region Summer Coincident Forecast 23

List of Tables

Table 6-1: Near and Mid-term Regional Needs 27
Table 7-1: Hydro One Transmission Major Sustainment Initiatives 35
Table 8-1: Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates 37

1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GREATER BRUCE-HURON REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the joint study carried out by Hydro One, Entegrus Power Lines Inc., ERTH Power Corporation, Festival Hydro Inc., Hydro One Distribution, the Independent Electricity System Operator ("IESO"), Wellington North Power Inc. and Westario Power Inc. in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

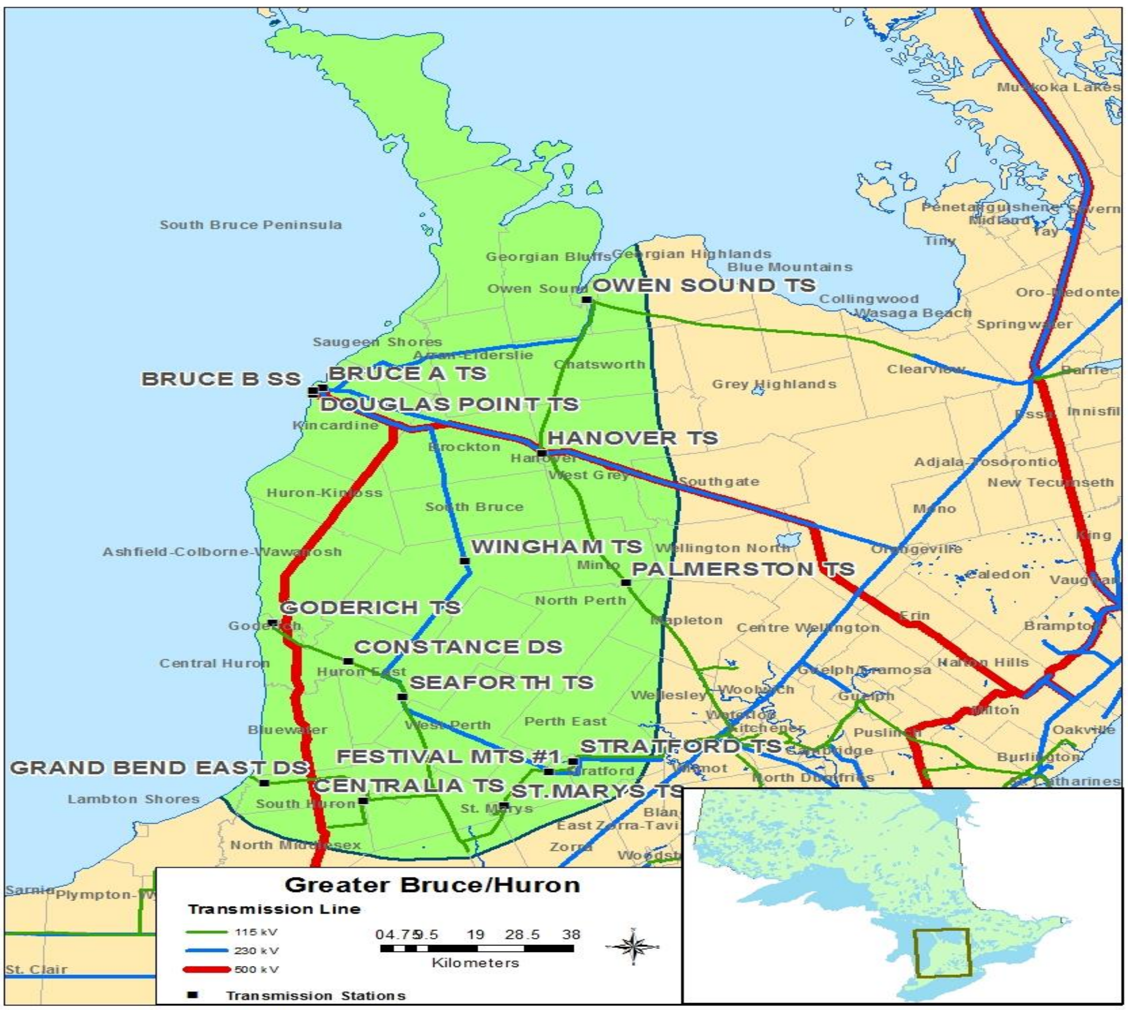


Figure 1-1. Greater Bruce Huron Region

The Greater Bruce-Huron Region includes the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. Electrical supply to the Region is provided from six 230 kV and twelve 115 kV step-down transformer stations. The boundaries of the Region are highlighted in Figure 1-1 above.

1.1 Objective and Scope

This RIP report examines the needs in the Greater Bruce-Huron Region. Its objectives are:

- To develop a wires plan to address needs identified in previous planning phases for which a wires only alternative was recommended by the Working Group
- To identify new supply needs that may have emerged since previous planning phases (e.g. Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan)
- To provide the status of wires planning currently underway or completed for specific needs
- To identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region

The RIP reviewed factors such as the load forecast, major high voltage sustainment work, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management (CDM), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2019-2028) identified in previous planning phases (Needs Assessment or Local Plan)
- Identification of any new needs over the 2019-2028 period
- Develop a plan to address any longer term needs identified by the Working Group

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process
- Section 3 describes the region
- Section 4 describes the transmission work completed over the last ten years
- Section 5 describes the load forecast and study assumptions used in this assessment
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies needs
- Section 7 summarizes the Regional Plan to address the needs
- Section 8 provides the conclusion and next steps

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013, through amendments to the Transmission System Code ("TSC") and the Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment ("NA"), the Scoping Assessment ('SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource options (e.g. CDM, generation and Distributed Energy Resources ("DER")) at a higher or more macro level but sufficient to permit a comparison of options. If the IRRP process identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend the preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution was determined to be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timeliness provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the Greater Bruce-Huron region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, IRRP, and LP phases of regional planning.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

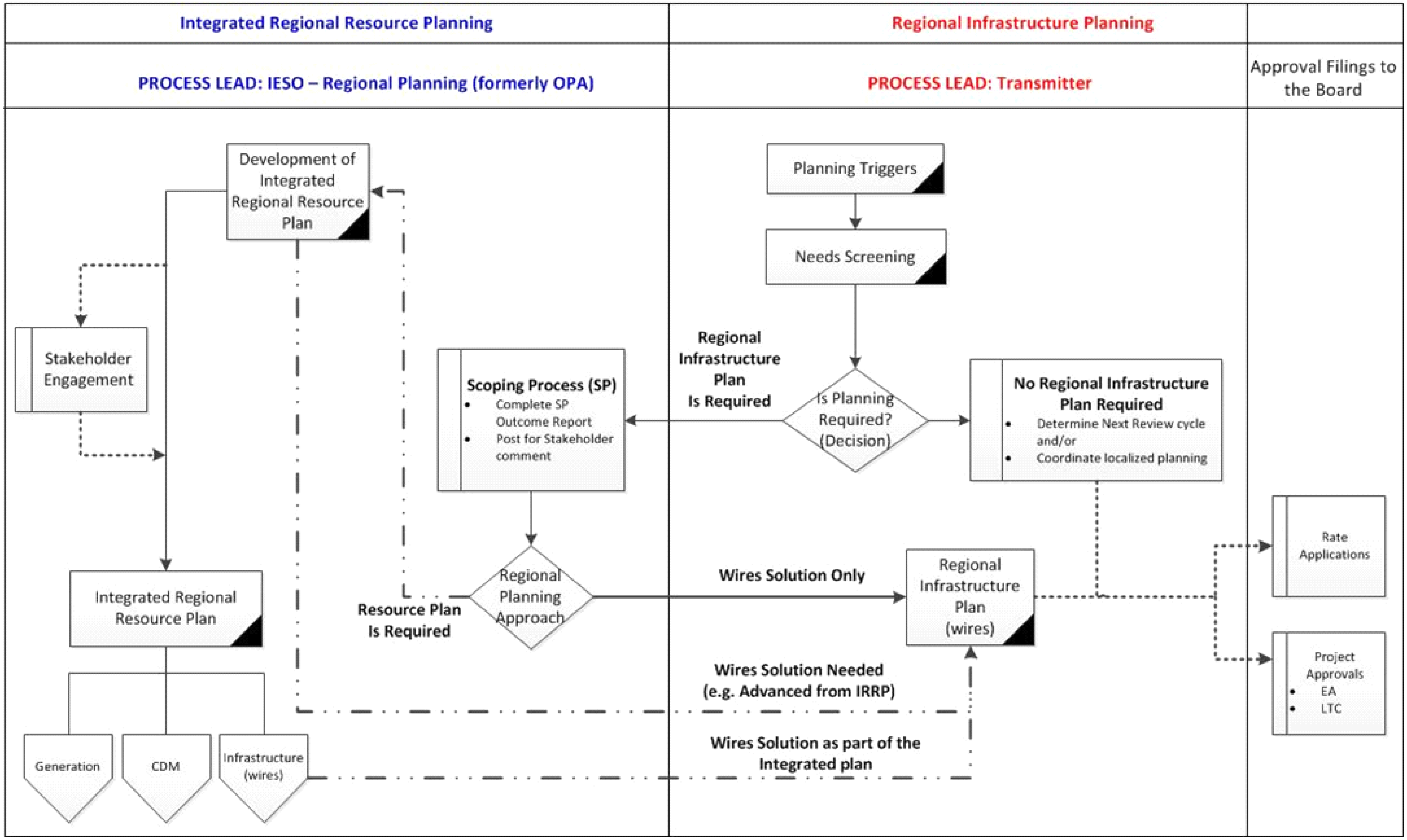


Figure 2-1. Regional Planning Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP phase is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
    - Gross and net peak demand forecast at the transformer station level. This includes the effect of any distributed generation and/or conservation and demand management programs.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

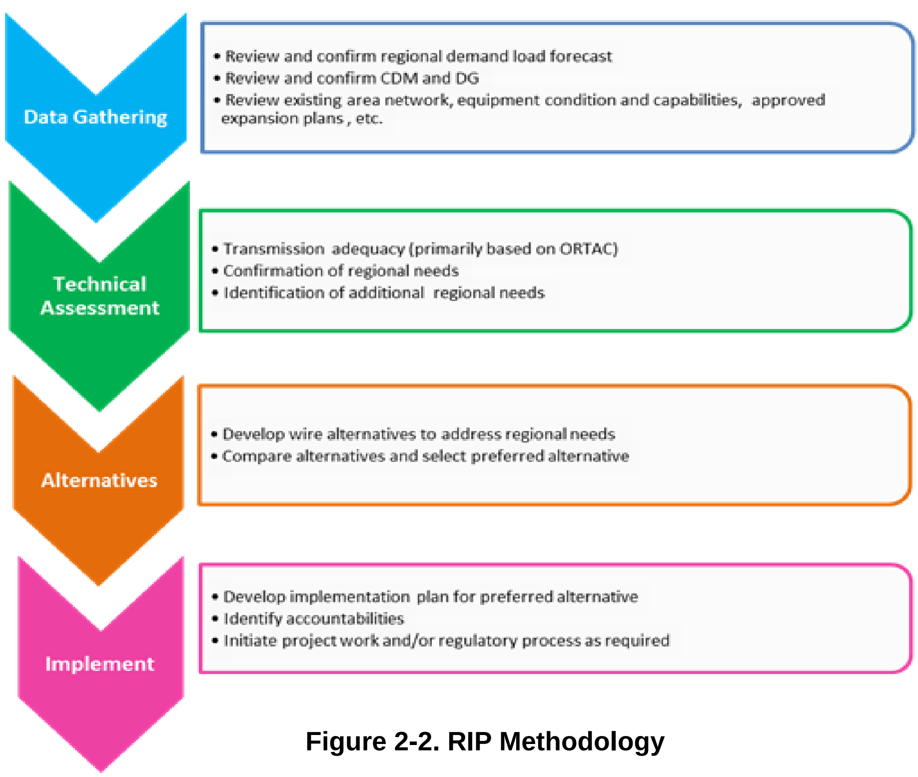


Figure 2-2. RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GREATER BRUCE-HURON REGION COMPRISES OF THE COUNTIES OF BRUCE, HURON, AND PERTH, AS WELL AS PORTIONS OF GREY, WELLINGTON, WATERLOO, OXFORD, AND MIDDLESEX COUNTIES AS SHOWN IN FIGURE 3-1.

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the Region. The majority of the electrical supply in the region is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS. These circuits connect the Region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Within the Region, electricity is delivered to the end users of LDCs and directly-connected industrial customers by eleven Hydro One step-down transformation stations, as well as seven customer-owned transformer or distribution stations supplied directly from the transmission system. Appendix A lists all step-down transformer stations in the Region. Appendix B lists all transmission circuits and Appendix C lists LDCs in the Region. The Single Line Diagram for the Greater Bruce-Huron Region transmission system facilities is shown below in Figure 3-2.

Figure 3-1. Geographical Area of the Greater Bruce-Huron Region with Electrical Layout

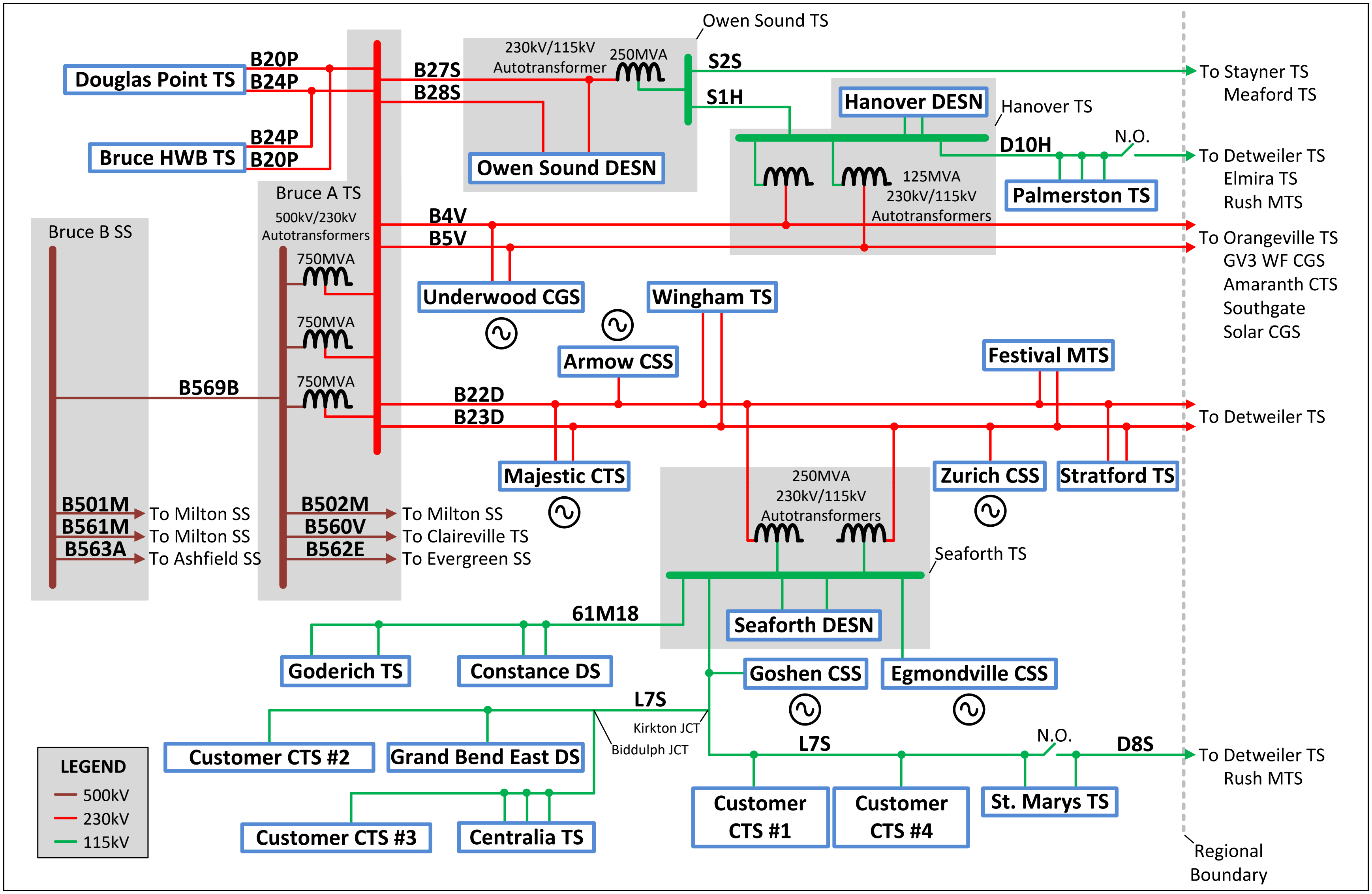


Figure 3-2. Greater Bruce-Huron Region Single-Line Diagram

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GREATER BRUCE-HURON REGION.

In addition to Hydro One's ongoing transmission station and line sustainment programs, specific projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For bulk power system transfer needs:

- 500 kV double circuit line from the Bruce Nuclear Complex to Milton SS in 2011
- 230 kV Static Var Compensator (SVC) at Detweiler TS in 2011
- Bruce Reactor Switching Scheme (RSS) modifications in 2018

For major station refurbishment needs based on asset condition assessment:

- Goderich TS in 2017
- Centralia TS in 2018
- Palmerston TS in 2019
- Stratford TS in 2021

For renewable generation connection needs:

- 230 kV Dufferin Wind Farm into Orangeville TS in 2014
- 500 kV Jericho/Adelaide/Bornish Wind Farms into Evergreen SS in 2014
- 230 kV Grand Valley 3 Wind Farm onto circuit B4V in 2015
- 115 kV Bluewater Wind Farm into Seaforth TS in 2015
- 115 kV Goshen Wind Farm onto circuit L7S in 2015
- 500 kV K2 Wind Farm into Ashfield SS in 2015
- 230 kV Grand Bend Wind Farm onto circuit B23D in 2016
- 230 kV Armow Wind Farm onto circuit B22D in 2016
- 230 kV Southgate Solar Farm onto circuit B4V in 2016

The following projects are underway:

- Bruce A TS 230 kV switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q2 2022.
- Wingham TS switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q2 2023
- Seaforth TS switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q4 2024
- Bruce B SS 500 kV switchyard is currently undergoing major station refurbishment work with a projected in-servicing by Q4 2024.

5. LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Greater Bruce-Huron Region is forecast to increase annually between 2019 and 2028. The growth rate varies across the Region with most of the growth concentrated in the County of Bruce and more specifically in the Kincardine area. The Region's 2022 RIP load forecasts are provided in Appendix D and were prepared by the Working Group upon initiation of the RIP phase. The RIP forecasts are identical to the Needs Assessment forecast except as otherwise noted in Appendix D.

As per the load forecasts in Appendix D, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.7% annually from 2019-2028 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 2.3% from 2019-2028.

As per the load forecasts in Appendix D, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 1.2% annually from 2019-2028 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 1.9% from 2019-2028.

Figure 5-1 shows the Region's gross and net *winter* coincident forecasts while Figure 5.2 shows the Region's gross and net *summer* coincident forecasts. The regional-coincident (at the same time) forecast represents the total peak load of all 18 step-down transformer stations in the Region.

Based on historical load and on the coincident load forecasts, the Region's winter coincident peak load is larger than its summer coincident peak load. Based on historical load and the non-coincident load forecasts, the Region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than winter due to ambient temperature. Based on these factors, assessment for this Region was conducted for both summer and winter peak load.

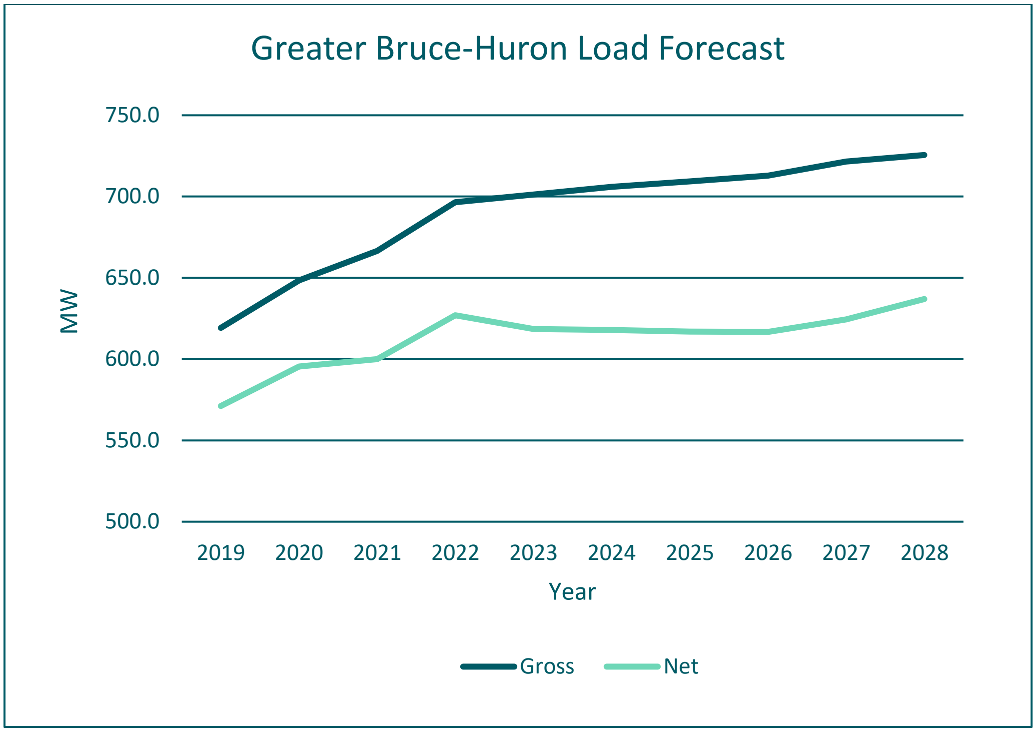


Figure 5-1. Greater Bruce-Huron Region Winter Coincident Forecast

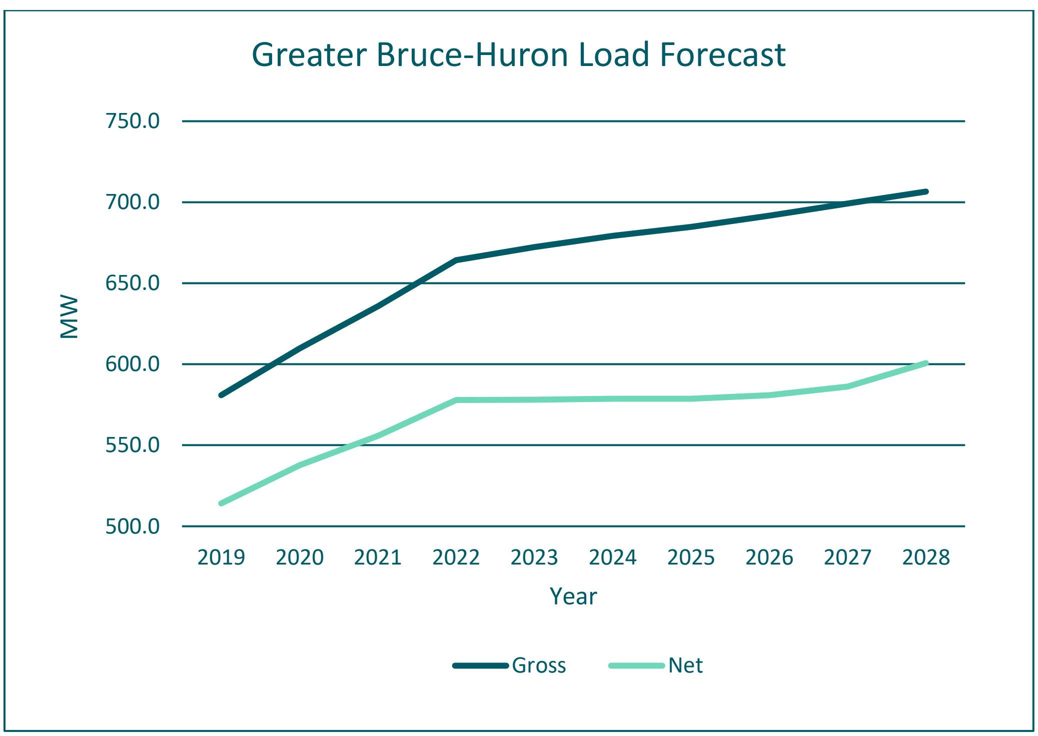


Figure 5-2. Greater Bruce-Huron Region Summer Coincident Forecast

5.2 Study Assumptions

The following assumptions are made in this report.

1) The study period for the RIP assessments is 2019-2028.

2) All planned facilities listed in Section 4 are assumed to be in-service.

3) The Region contains some stations that are summer peaking and others that are winter peaking. The assessment is therefore based on both summer and winter peak loads.

4) Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer and winter 10-Day Limited Time Rating (LTR), as appropriate.

5) Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2019-2028 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STEP-DOWN TRANFORMATION STATION FACILITIES SUPPLYING THE GREATER BRUCE-HURON REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle, three regional assessments have been conducted for the Greater Bruce-Huron Region. The findings of these studies are input to the RIP. The studies are:

1) Needs Assessment Report - Greater Bruce-Huron Region, May 2019
2) Greater Bruce-Huron Region Scoping Assessment Report, September 2019
3) Southern Huron-Perth Sub-Region IRRP, September 2021

This RIP reviewed the loading on transmission lines and stations in the Greater Bruce-Huron Region based on the RIP load forecast. Sections 6.1-6.6 presents the results of this review and Table 6-1 lists the Region’s needs identified in both the Needs Assessment and the RIP phases.

In addition, this RIP reviewed an updated list of Hydro One transmission lines and station major sustainment work over the next several years to determine if there are opportunities to consolidate with any emerging development needs within the Region. Section 7.5 presents the results of this review.

Table 6-1: Near and Mid-term Regional Needs

Type	Section	Needs	Timing
Needs and Timing Identified in the Needs Assessment Report [1]			
Transmission Circuit Capacity	7.2	Overload on sections of 115 kV single circuit line, L7S	2022 (emergency rating exceeded based on NA summer gross coincident load forecast)
			2027 (continuous rating exceeded based on NA summer gross load forecast)
End-Of-Life Equipment Needs	7.4	Wingham TS	2022
		Stratford TS	2021
		Seaforth TS	2023
		Hanover TS (T2)	2023

6.1 230 kV Transmission Facilities

Half of the 230 kV transmission circuits in the Greater Bruce-Huron Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the KWCG, Georgian Bay and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-2):

1) Bruce A TS to Orangeville TS 230kV transmission circuits B4V/B5V – supplies Hanover TS
2) Bruce A TS to Detweiler TS 230kV transmission circuits B22D/ B23D – supplies Wingham TS, Seaforth TS, Festival MTS #1, and Stratford TS
3) Bruce A TS to Owen Sound TS 230kV transmission circuits B27S/B28S – supplies Owen Sound TS
4) Bruce A TS to Douglas Point TS 230kV transmission circuits B20P/B24P – supplies Douglas Point TS and Bruce HWP B TS

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.2 500/230 kV and 230/115 kV Transformation Facilities

Bulk power supply to the Greater Bruce-Huron Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

1) Three (3) 500/230kV autotransformers at Bruce A TS
2) Two (2) 230/115kV autotransformers at Seaforth TS
3) Two (2) 230/115kV autotransformers at Hanover TS

The RIP review shows that based on current forecast station loadings and bulk transfers, the auto-transformation supply capacity is adequate over the study period.

6.3 Supply Capacity of the 115 kV Network

The Greater Bruce-Huron Region contains four (4) single circuit 115 kV lines. This 115 kV network serves local area load. These circuits are as follows (see Figure 3-2):

1) Hanover TS to Detweiler TS 115 kV transmission circuit D10H with Normally Open (N/O) point at Palmerston TS – supplies Palmerston TS & Elmira TS
2) Seaforth TS to Goderich TS 115 kV transmission circuit 61M18 – supplies Constance DS and Goderich TS
3) Seaforth TS to St. Marys TS 115 kV transmission circuit L7S – supplies Grand bend East DS, Lake Huron WTP CTS, Centralia TS, McGillivray R&BP CTS, Enbridge Bryanston CTS and St. Marys Cement CTS
4) Hanover TS to Owen Sound TS 115 kV transmission circuit S1H

The RIP review shows that based on current forecast station loadings, the supply capacity of the 115 kV network is adequate over the study period. The Needs Assessment coincident forecast identified that circuit L7S will exceed its short- and long-term emergency rating in 2022 and its continuous rating in 2027, however, the updated IRRP forecast resulted in these needs being deferred to the long-term period (2029-2038).

6.4 Step-down Transformer Stations

There are 18 step-down transformer stations within the Greater Bruce-Huron Region. Fourteen supply electricity to LDCs and four are transmission-connected industrial customer stations. These stations are listed in Appendix C. Of the 18 stations, 3 of them are owned and operated by LDCs.

As part of the Needs Assessment, IRRP, as well as this RIP, step-down transformation station capacity was reviewed. Since the May 2019 Needs Assessment, the load forecasts at stations supplied by L7S were updated during the IRRP phase of Regional Planning, while the other station forecasts remained unchanged; refer to Appendix D for the updated forecasts. The analysis showed that the gross load forecasts at all stations can be accommodated over the study period.

6.5 Other Items Identified During Regional Planning

6.5.1 End-Of-Life Equipment Replacement Needs

Wingham TS – T1/T2 and Component Replacement

Wingham TS is a load supply station built in 1965. The station has two 50/67/83 MVA step-down transformers connected to the 230 kV circuits B22D and B23D (Bruce x Detweiler) and supplies Hydro One Distribution via four 44 kV feeders.

The current scope of this project is to replace the 230/44 kV step-down transformers, T1 and T2 and associated surge arrestors.

Based on the load forecast, similar equipment ratings are required for the EOL replacement. This project is underway and the planned in-service date for the project is in year 2023.

Stratford TS – T1 and Component Replacement

Stratford TS is a load supply station built in 1950. The station has two 50/67/83 MVA step-down transformers connected to 230 kV circuits B22D and B23D (Bruce x Detweiler) and supplies Festival Hydro Inc., Hydro One Distribution as well as other embedded LDCs, via eight 27.6 kV feeders. Transformers T1 and T2 are in service since 1970 and 1997 respectively.

The current scope of this project included the replacement of 230/27.6 kV transformer T1 and associated equipment.

Based on the load forecast similar equipment ratings are required for EOL replacement. The planned in-service date for the project was set for 2023, however the project work was advanced and completed in 2021.

Seaforth TS – T5/T6/T1/T2 and Component Replacement

Seaforth TS is a major station and consists of two 230/115 kV, 150/200/250 MVA autotransformers supplied by 230 kV circuits B22D and B23D (Bruce x Detweiler). The 115 kV yard from Seaforth TS supplies nearly 200 km of single circuit supply along the circuits L7S and 61M18. Seaforth TS also consists of two 115/27.6 kV, 25/33/42 MVA step-down transformers and supplies Hydro One Distribution and embedded LDCs via four 27.6 kV feeders.

The current scope of this project is to replace 230/115 kV autotransformers T5, T6, step-down transformers T1, T2, the capacitor breaker SC1B and several high voltage and low voltage switches that are at end of their life. Operations has identified the need for refined voltage control on the 115 kV system. Therefore, the new autotransformers at Seaforth TS will be equipped with Under Load Tap Changers (ULTCs).

Based on the load forecast for the station similar equipment ratings are required for EOL replacement of all equipment discussed above. The planned in-service date for the project is in year 2024.

Hanover TS – T2 and Component Replacement

Hanover TS consists of two 230/115 kV, 75/100/125 MVA autotransformers supplied by 230 kV circuits B4V and B5V (Bruce x Orangeville). The 115 kV yard has connectivity to Detweiler TS via 115 kV transmission circuit D10H with a Normally Open point at Palmerston TS. Another 115 kV transmission circuit S1H connects to Owen Sound TS. Hanover TS also consists of two 115/44 kV, 50/67/83 MVA step-down transformers connecting to six feeders and one capacitor bank, supplying Hydro One Distribution and embedded LDCs.

The scope of this project included the replacement of 230 kV motorized switches, 115/44 kV step-down transformer T2 and associated equipment, 115 kV motorized switches, surge arrestors, auto-ground switches and potential transformers. This work was planned to be completed in 2028, however due to a recent transformer tap changer failure, T2 and its associated transformer switch are being replaced immediately and are expected in-service by the end of 2022. The remaining component replacements that were planned as part of the T2 work will be bundled with the replacement of T1 and have an expected in-service date of 2031.

6.6 Long-Term Regional Needs

115kV L7S Circuit

In analyzing the updated IRRP coincident load forecast for stations supplied by L7S, no capacity needs were identified during the study period (2019-2028), however long-term capacity needs were observed under the high growth scenario following a single element contingency. Following the loss of D8S, a long-term capacity need was identified to emerge in 2035. Furthermore, with a planned outage to D8S, a capacity need begins to emerge in 2030, following the loss of Seaforth T6. With the uncertainty of how the forecast will develop over the next 5-10 years the working group will continue to monitor load growth to determine when an L7S upgrade is required. In the meantime, CDM programs and load transfers can be implemented to mitigate overloading the L7S circuit.

Recently, there have been connection requests at Grand Bend East DS which will result in increased loading on L7S, bringing the demand on the circuit closer to its Load Meeting Capability (LMC). The L7S capacity is limited by sub-standard clearance on certain spans of the section of circuit between Seaforth TS and Kirkton JCT, and this has triggered a re-assessment of this section to address these clearance constraints that are limiting the circuit's capacity.

Hanover TS

In the long-term (2029-2038), Hanover TS is expected to exceed its gross summer load forecast in 2034, however accounting for DER and CDM, the need for additional capacity at the station is deferred to 2038. The end-of-life replacements planned for 2031 will likely increase the station's 10-day LTR by 5-10 MW, further deferring the need. Since the capacity need at Hanover TS does not arise for another 12-16 years, it is recommended to monitor load growth and re-evaluate the need in the next regional planning cycle.

7. REGIONAL PLANS

THIS SECTION SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS LISTED IN TABLE 6-1.

7.1 Transmission Circuit Capacity

7.1.1 Circuit L7S

L7S is a single 115 kV circuit transmission line operated radial from Seaforth TS to St. Marys TS. As per the updated IRRP coincident load forecast for stations supplied by L7S, no capacity needs were identified during the study period, however, the recent connection requests at Grand Bend East DS have triggered a re-assessment of the L7S section between Seaforth TS and Kirkton JCT to address the sub-standard clearances that are limiting the circuit's capacity.

Recommended Plan and Current Status

To address the potential need for additional capacity on L7S, it is recommended that Hydro One Transmission proceed with the re-assessment of the limiting section of L7S, currently underway, to increase the limiting spans' sag temperature from 83°C to 125°C. Addressing these sub-standard clearances will result in an L7S capacity increase of more than 10 MW. The Development Plan was initially detailed in the 2016 Local Planning – L7S Thermal Overload [3]. The Development Plan specified that when loading on L7S is expected to exceed its limits within a 3 year period, Hydro One Transmission will increase the thermal rating of the limiting spans of circuit L7S. The cost to increase the rating was estimated to be approximately $550k. An updated estimate will be available once the scope is confirmed, following the completion of the re-assessment. Strengthening L7S will be sufficient for supplying load connected to L7S load for the study period and into the long-term. Loading beyond the study period's forecast may then require additional voltage support and Hydro One Transmission will continue to monitor this need. Capacity cost allocation will be as per the Transmission System Code.

7.2 Customer Delivery Point Performance

7.2.1 Customers Supplied from Circuit L7S

The performance of delivery points supplied from circuit L7S, specifically Centralia TS, Grand Bend East DS, St. Marys TS and the 4 industrial customer connections, were reviewed. Specifically, the Centralia TS and McGillivray CTS delivery points, which are supplied by the same branch on L7S, were classified as outliers due to interruptions to this section of the circuit.

While the performance of the McGillivray CTS delivery point, with respect to frequency of outages, has been fluctuating between 1 and 8 interruptions per year since 2015, its performance with respect to duration of outages has drastically improved.

On the other hand, the Centralia TS delivery points were showing exemplary performance with respect to frequency and duration of outages until they were recently classified as outliers with respect to frequency and duration, due to a number of weather and equipment related outages experienced on the L7S circuit in 2019 and 2020.

Current Status and Recommended Plan

In 2021, remotely-operated switches were installed at three locations on the L7S circuit, namely, at Kirkton JCT, Biddulph JCT, and St. Marys TS. These switches will reduce the outage duration and improve restoration by quickly isolating the problematic sections while resupplying the healthy sections of the line. Hydro One's line sustainment and wood pole replacement programs will continue to assess the condition of this circuit to determine where deteriorating components exist and refurbish the sections of concern to improve the integrity of the circuit. Hydro One will continue to monitor the delivery point performance to determine whether further improvement are required. Capital contribution from customers is not anticipated at this time. If, however, capital contribution is required from customers such financial obligation will be determined using methodology set out in the Transmission System Code.

7.2.2 Customers Supplied from Hanover TS

The performance of the Hanover TS delivery points supplied from circuits D10H and S1H, were reviewed. The delivery point performance at Hanover TS with respect to frequency has been excellent over the last 10 years, averaging less than 1 interruption per year. Other than 2019, its performance with respect to duration has also been very good. The delivery points at Hanover TS had not been classified as outliers until 2020 due to a human triggered P&C failure which resulted in a 3-4 hour interruption.

Hanover TS is typically a very reliable station as it is supplied by two 230kV lines and two 115kV lines and the unique event that cause the delivery points to become outliers is very unlikely to reoccur.

Current Status and Recommended Plan

The on-demand replacement of the Hanover T2 transformer and its associated disconnect switch is expected to be completed in 2022, and Hanover T1 transformer and component replacement is planned to be completed in 2031. It is recommended to proceed with the capital plans and continue to monitor the delivery points which are expected to perform reliably.

7.3 Transmission Sustainment Plans

As part of Hydro One's transmitter requirements, Hydro One continues to ensure a reliable transmission system by carrying out maintenance programs as well as periodic replacement of equipment based on their condition. Table 7.1 lists Hydro One's major transmission sustainment *projects* in the Region that are currently planned or underway. There is currently no major line sustainment *projects* planned within the next 5 years. Maintenance *programs* such as insulator, shield wire, structure replacements will continue to be carried out in the Region as required based on equipment/asset condition assessments.

Table 7-1: Hydro One Transmission Major Sustainment Initiatives[1]

Station	General Description of Work	Planning In Service Date
Bruce A TS	• Replacement of 230 kV circuit breakers and switches • Uprating of station strain buses • Replacement of Protection and Control relay building	2022
	• Replacement of 500 kV circuit breakers and switches • Replacement of 2 autotransformers 500/230 kV • Upgrading of Protection and Control equipment	2027
Bruce B SS	• Replacement of 500 kV circuit breakers and switches	2024
Bruce HWP B TS	• Replacement of T7/T8 transformers and associated switches • Replacement of low voltage transformer breakers • Replacement of Protection and Control systems	2028
Douglas Point TS	• Replacement of T3/T4 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems	2028
Hanover TS	• Replacement of T1 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems and CVT's *Additional scope of work currently under development*	2031
Owen Sound TS	• Replacement of T4/T5 transformers and associated switches • Replacement of low voltage circuit breakers and switches • Replacement of Protection and Control systems	2028
	• Replacement of T3 transformer and associated switches • Replacement of low voltage transformer breaker	2031

[1] Scope and dates as of April 2022 and are subject to change

Seaforth TS	• Replacement of 2 autotransformers 230/115 kV • Replacement of 2 step-down transformers 115/27.6 kV • Replacement of 230kV switches • Upgrade Protection and Control systems • Updated AC & DC station service	2024
Wingham TS	• Complete station refurbishment	2023

Based on the needs identified in the region thus far and the transmission sustainment plans listed in Table 7-1, consolidation of sustainment and development needs is not necessary at this time.

8. CONCLUSION

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GREATER BRUCE-HURON REGION.

Two near and mid-term needs were identified for the Greater Bruce-Huron Region. They are:

I. Transmission Circuit Capacity on L7S (mid-term)

II. Customer delivery point performance review on the 115 kV system

This RIP report addresses both of these needs and has concluded that regional plans are required. Next Steps, Lead Responsibility, and Timeframes for implementing the regional plans to address needs I and II are summarized in the Table 8-1 below.

Table 8-1: Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

No.	Project	Next Steps	Lead Responsibility	In-Service Date	Cost	Needs Mitigated
1	Increase Capacity of Limiting Section of L7S	Assessment of Limiting Section	Hydro One Transmission	2023-2025	$550k - TBD	I
2	Continued assessment of L7S condition to address deteriorating components	Monitor performance & assess condition	Hydro One Transmission	TBD	TBD	II

In accordance with the Regional Planning process, the Regional Plan should be reviewed and/or updated at least every five years. The region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1] Hydro One, “Needs Assessment Report, Greater Bruce-Huron Region”, 31 May 2019. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterbrucehuron/Documents/Greater%20Bruce-Huron%20Needs%20Assessment%20Report%20-%20May%202019.pdf

[2] IESO, “Greater Bruce-Huron Scoping Assessment Report”, 19 September 2019. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Bruce-Huron/greater-bruce-huron-20190919-scoping-assessment-outcome-report.ashx

[3] IESO, “South Huron-Perth Sub-Region Integrated Regional Resource Planning”, September 2021. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Bruce-Huron/Southern-Huron-Perth-IRRP-20210916.ashx

APPENDIX A: STEP-DOWN TRANSFORMER STATIONS IN THE GREATER BRUCE-HURON REGION

Station	Voltage (kV)	Supply Circuits
Bruce HWP B TS	230 kV	B20P/B24P
Douglas Point TS	230 kV	B20P/B24P
Hanover TS	115 kV	B4V/B5V
Owen Sound TS	230 kV	B27S/B28S
Seaforth TS	115 kV	B22D/B23D
Stratford TS	230 kV	B22D/B23D
Wingham TS	230 kV	B22D/B23D
Festival MTS #1	230 kV	B22D/B23D
Palmerston TS	115 kV	D10H
Goderich TS	115 kV	61M18
Constance DS	115 kV	61M18
St. Marys TS	115 kV	L7S
Customer CTS #1	115 kV	L7S
Centralia TS	115 kV	L7S
Grand Bend East DS	115 kV	L7S
Customer CTS #2	115 kV	L7S
Customer CTS #3	115 kV	L7S
Customer CTS #4	115 kV	L7S

APPENDIX B: REGIONAL TRANSMISSION CIRCUITS IN THE GREATER BRUCE-HURON REGION

Location	Circuit Designation	Voltage (kV)
Bruce A TS – Orangeville TS	B4V/B5V	230 kV
Bruce A TS – Detweiler TS	B22D/ B23D	230 kV
Bruce A TS – Owen Sound TS	B27S/B28S	230 kV
Bruce A TS – Douglas Point TS	B20P/B24P	230 kV
Hanover TS – Palmerston TS	D10H-North	115 kV
Seaforth TS – Goderich TS	61M18	115 kV
Seaforth TS – St. Marys TS	L7S	115 kV
Owen Sound TS – Hanover TS	S1H	115 kV

APPENDIX C: DISTRIBUTORS IN THE GREATER BRUCE-HURON REGION

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc.	Constance DS	Tx
	Centralia TS	Dx
	Grand Bend East DS	Tx
	Douglas Point TS	Dx
	Goderich TS	Dx
	Hanover TS	Dx
	Owen Sound TS	Dx
	Palmerston TS	Dx
	Seaforth TS	Dx
	St. Marys TS	Dx
	Stratford TS	Dx
	Wingham TS	Dx
Entegrus Powerlines Inc.	Centralia TS	Dx
ERTH Power Corporation	Constance DS	Dx
	Goderich TS	Dx
	Seaforth TS	Dx
	Stratford TS	Dx
Festival Hydro Inc.	Grand Bend East DS	Dx
	Seaforth TS	Dx
	St. Marys TS	Dx
	Stratford TS	Dx
	Festival MTS #1	Tx
Lake Huron Primary Water Supply System	Lake Huron WTP CTS	Tx
Lake Huron Primary Water Supply System	McGillivray R&BP CTS	Tx
Wellington North Power Inc.	Hanover TS	Dx
	Palmerston TS	Dx
Westario Power Inc.	Douglas Point TS	Dx
	Hanover TS	Dx
	Palmerston TS	Dx
	Wingham TS	Dx
Enbridge Pipeline Inc.	Enbridge Bryanston CTS	Tx
St. Marys Cement Inc.	St. Marys Cement CTS	Tx

APPENDIX D: REGIONAL LOAD FORECAST (2019-2028)

Table D-1. Gross Winter Regional-Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	28.0	25.6	25.8	26.0	26.2	26.4	26.6	26.8	27.0	27.2
Centralia TS	65.4	30.6	33.6	33.9	37.0	37.3	37.5	37.7	37.9	38.1	38.3
Douglas Point TS	109.8	62.4	76.3	82.4	89.1	88.9	88.6	88.3	88.0	87.7	87.5
Goderich TS	132.0	31.3	31.7	34.7	36.8	37.2	37.5	37.8	38.1	38.4	38.7
Hanover TS	124.7	68.8	70.1	70.7	72.4	73.2	74.8	75.4	76.0	76.7	77.3
Owen Sound TS	232.5	109.6	111.5	112.4	113.3	114.5	115.1	115.7	116.4	117.2	117.9
Palmerston TS	147.2	70.1	73.4	75.0	77.8	78.7	79.6	80.3	81.0	81.7	82.5
Seaforth TS	55.4	28.7	30.8	31.0	31.3	31.5	31.6	31.8	32.1	32.3	32.5
St. Marys TS	59.0	21.9	21.9	22.0	22.2	22.3	22.3	22.4	22.5	22.5	22.6
Stratford TS	128.6	68.5	70.5	71.0	72.9	73.5	74.0	74.4	75.0	75.5	76.0
Wingham TS	107.9	40.5	42.3	46.6	51.9	52.4	52.8	53.1	53.5	53.9	54.4
Constance DS	35.0	16.8	17.0	17.1	17.1	17.2	17.3	17.3	17.4	17.5	17.5
Grand Bend East DS	NA	11.8	12.6	13.2	13.3	13.4	13.5	13.6	13.6	13.7	13.8
Bruce Power HWB TS	114.8	10.4	11.2	11.1	10.9	10.8	10.6	10.5	10.3	10.3	10.3
Customer CTS #1	NA	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Customer CTS #2	NA	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Customer CTS #3	NA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Customer CTS #4	NA	13.8	13.8	13.8	18.4	18.4	18.4	18.4	18.4	23.0	23.0

Table D-2. Gross Summer Regional-Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	25.0	25.2	25.4	25.5	25.7	25.9	26.1	26.3	26.5	26.7
Centralia TS *	61.1	29.9	33.2	34.0	36.0	37.0	37.0	37.0	37.0	37.0	38.0
Douglas Point TS	97.2	51.0	60.6	69.7	77.6	78.6	79.5	80.4	81.3	82.3	83.3
Goderich TS	126.5	31.8	32.2	35.2	37.2	37.6	37.9	38.2	38.5	38.8	39.1
Hanover TS	109.9	75.9	78.5	80.4	83.7	85.8	88.9	90.9	93.0	95.2	97.5
Owen Sound TS	208.5	92.7	94.8	95.7	96.7	97.8	98.4	98.9	99.5	100.1	100.8
Palmerston TS	132.2	52.3	55.0	57.3	58.4	59.2	60.0	60.5	61.1	61.8	62.4
Seaforth TS	45.1	29.7	32.1	32.6	33.2	33.7	34.3	34.8	35.3	35.9	36.5
St. Marys TS *	52.8	22.7	22.9	25.0	26.0	26.0	26.0	26.0	26.0	27.0	27.0
Stratford TS	117.3	73.6	75.7	76.3	78.2	78.9	79.4	79.9	80.5	81.0	81.6
Wingham TS	97	36.9	38.8	44.7	52.2	52.4	52.4	52.4	52.5	52.7	52.8
Constance DS	25	17.4	17.7	17.8	17.9	18.0	18.1	18.1	18.2	18.2	18.3
Grand Bend East DS *	NA	16.5	17.3	16.0	16.0	16.0	16.0	16.0	17.0	17.0	17.0
Bruce Power HWB TS	113.2	4.3	4.6	4.6	4.5	4.5	4.4	4.3	4.3	4.3	4.3
Customer CTS #1 *	NA	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Customer CTS #2 *	NA	5.0	5.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Customer CTS #3 *	NA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer CTS #4 *	NA	13.9	13.9	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0

*Updated to align with South Huron-Perth IRRP Forecast

Table D-3. Gross Winter Non-Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	29.7	27.2	27.4	27.6	27.8	28.1	28.3	28.5	28.7	28.9
Centralia TS	65.4	33.3	36.7	36.9	40.4	40.7	40.9	41.1	41.3	41.6	41.8
Douglas Point TS	109.8	63.1	77.2	83.3	90.2	89.9	89.6	89.3	89.0	88.7	88.5
Goderich TS	132.0	35.8	36.2	39.7	42.1	42.4	42.8	43.1	43.5	43.8	44.2
Hanover TS	124.7	72.0	73.4	74.0	75.8	76.6	78.3	78.9	79.5	80.2	80.9
Owen Sound TS	232.5	109.9	111.9	112.8	113.7	114.8	115.5	116.1	116.8	117.6	118.3
Palmerston TS	147.2	70.3	73.7	75.3	78.1	79.0	79.9	80.6	81.3	82.0	82.8
Seaforth TS	55.4	34.8	37.3	37.5	37.9	38.1	38.3	38.6	38.8	39.1	39.3
St. Marys TS	59.0	23.7	23.7	23.8	23.9	24.0	24.1	24.2	24.3	24.3	24.4
Stratford TS	128.6	71.9	74.0	74.5	76.5	77.1	77.6	78.1	78.7	79.2	79.8
Wingham TS	107.9	62.6	65.3	71.9	80.2	81.0	81.5	82.1	82.7	83.3	84.0
Constance DS	35.0	16.9	17.1	17.2	17.3	17.4	17.4	17.4	17.5	17.6	17.6
Grand Bend East DS	NA	13.0	14.0	14.6	14.7	14.9	14.9	15.0	15.1	15.2	15.3
Bruce Power HWB TS	114.8	12.1	13.0	12.8	12.7	12.5	12.3	12.1	12.0	12.0	12.0
Customer CTS #1	NA	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Customer CTS #2	NA	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Customer CTS #3	NA	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Customer CTS #4	NA	15.0	15.0	15.0	20.0	20.0	20.0	20.0	20.0	25.0	25.0

Table D-4. Gross Summer Non-Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	32.6	32.9	33.1	33.4	33.6	33.9	34.1	34.4	34.6	34.9
Centralia TS *	61.1	34.5	38.2	37.0	40.0	41.0	41.0	41.0	41.0	42.0	42.0
Douglas Point TS	97.2	51.2	60.8	70.0	77.9	78.9	79.8	80.7	81.6	82.6	83.6
Goderich TS	126.5	38.2	38.7	42.2	44.7	45.2	45.5	45.9	46.2	46.6	47.0
Hanover TS	109.9	75.9	78.5	80.4	83.7	85.8	88.9	90.9	93.0	95.2	97.5
Owen Sound TS	208.5	104.1	106.4	107.4	108.6	109.9	110.5	111.1	111.7	112.4	113.1
Palmerston TS	132.2	62.6	65.8	68.5	69.9	70.9	71.8	72.4	73.2	73.9	74.7
Seaforth TS	45.1	31.4	33.9	34.4	35.0	35.6	36.2	36.7	37.3	37.9	38.5
St. Marys TS *	52.8	24.9	25.1	28.0	28.0	28.0	28.0	28.0	29.0	29.0	29.0
Stratford TS	117.3	82.2	84.5	85.2	87.3	88.0	88.6	89.2	89.8	90.5	91.1
Wingham TS	97	51.2	53.9	62.1	72.5	72.7	72.7	72.8	72.9	73.1	73.3
Constance DS	25	18.2	18.4	18.5	18.6	18.8	18.8	18.9	18.9	19.0	19.1
Grand Bend East DS *	NA	22.1	23.1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Bruce Power HWB TS	113.2	8.3	8.9	8.8	8.7	8.6	8.4	8.3	8.2	8.2	8.2
Customer CTS #1 *	NA	3.4	3.4	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Customer CTS #2 *	NA	5.8	5.8	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Customer CTS #3 *	NA	4.5	4.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Customer CTS #4 *	NA	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0

*Updated to align with South Huron-Perth IRRP Forecast

Table D-5. Net Winter Regional Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	27.7	25.2	25.7	25.8	25.5	25.5	25.5	25.6	25.6	25.7
Centralia TS	65.4	30.3	32.8	33.0	36.0	35.5	35.5	35.4	35.4	35.4	35.4
Douglas Point TS	109.8	47.7	61.0	67.9	74.3	72.5	71.5	70.7	70.0	69.2	80.7
Goderich TS	132.0	31.0	31.2	34.1	36.0	35.6	35.6	35.6	35.7	36.2	36.3
Hanover TS	124.7	50.5	51.3	52.8	54.2	53.6	54.6	54.7	54.9	55.1	55.3
Owen Sound TS	232.5	108.5	109.7	107.9	108.4	107.5	107.4	107.3	107.4	111.0	111.2
Palmerston TS	147.2	69.4	72.3	74.1	76.6	76.1	76.4	76.6	76.9	77.2	77.5
Seaforth TS	55.4	17.8	19.6	20.2	20.3	19.9	19.8	19.7	19.7	19.7	19.7
St. Marys TS	59.0	21.7	21.5	21.8	21.9	21.6	21.4	21.4	21.3	21.3	21.2
Stratford TS	128.6	67.9	69.4	69.5	71.1	70.3	70.2	70.3	70.4	70.4	70.5
Wingham TS	107.9	40.1	41.6	33.6	38.6	37.7	37.5	37.3	37.3	37.2	37.2
Constance DS	35.0	16.7	16.7	16.9	16.9	16.7	16.7	16.6	16.6	16.5	16.5
Grand Bend East DS	NA	11.7	12.4	12.0	12.1	11.9	11.9	11.9	11.9	11.9	11.9
Bruce Power HWB TS	114.8	10.3	11.0	11.0	10.8	10.5	10.2	10.0	9.8	9.7	9.7
Customer CTS #1	NA	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.5	2.5
Customer CTS #2	NA	3.3	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Customer CTS #3	NA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Customer CTS #4	NA	13.7	13.6	13.6	18.1	18.0	17.9	17.9	17.9	22.3	22.2

Table D-6. Net Summer Regional Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	24.7	24.7	25.0	24.9	24.7	24.7	24.6	24.6	24.5	24.5
Centralia TS *	61.1	29.6	32.4	31.6	33.3	33.8	33.5	33.2	33.0	32.6	33.4
Douglas Point TS	97.2	36.0	45.0	54.4	61.6	61.7	62.0	62.3	62.7	63.1	75.6
Goderich TS	126.5	31.5	31.7	34.0	35.7	35.6	35.5	35.5	35.5	35.9	36.0
Hanover TS	109.9	56.1	58.1	60.5	63.0	64.2	66.5	67.8	69.3	70.7	72.3
Owen Sound TS	208.5	90.0	91.1	88.8	88.9	88.9	88.5	88.3	88.2	91.5	91.5
Palmerston TS	132.2	51.8	54.0	54.8	55.4	55.4	55.6	55.6	55.7	55.8	56.0
Seaforth TS	45.1	17.9	20.1	20.8	21.0	21.2	21.4	21.7	22.0	22.3	22.6
St. Marys TS *	52.8	22.4	22.5	24.2	25.0	24.7	24.5	24.3	24.1	24.9	24.7
Stratford TS	117.3	72.8	74.4	73.6	74.8	74.5	74.3	74.2	74.1	74.0	74.0
Wingham TS	97	23.6	25.2	31.1	37.9	37.3	36.7	36.3	35.9	35.5	35.2
Constance DS	25	17.3	17.4	17.2	17.1	17.0	16.9	16.9	16.8	16.7	16.7
Grand Bend East DS *	NA	15.1	15.7	14.5	14.3	14.0	13.9	13.7	14.6	14.4	14.3
Bruce Power HWB TS	113.2	4.3	4.6	4.5	4.3	4.2	4.1	4.0	3.9	3.8	3.8
Customer CTS #1 *	NA	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Customer CTS #2 *	NA	4.9	4.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	5.8
Customer CTS #3 *	NA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer CTS #4 *	NA	13.8	13.7	12.7	12.6	12.5	12.5	12.4	12.4	12.2	12.1

*Updated to align with South Huron-Perth IRRP Forecast

Table D-7. Net Winter Non-Coincident Forecast (MW)

Transformer Station Name	Winter LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	29.5	26.8	27.3	27.4	27.1	27.1	27.2	27.2	27.3	27.4
Centralia TS	65.4	33.0	35.8	36.1	39.3	38.9	38.8	38.8	38.8	38.8	38.9
Douglas Point TS	109.8	48.5	61.8	68.9	75.3	73.5	72.6	71.8	71.0	70.3	81.7
Goderich TS	132.0	35.4	35.6	39.0	41.2	40.8	40.9	41.0	41.1	41.6	41.8
Hanover TS	124.7	53.7	54.5	56.1	57.5	57.0	58.1	58.2	58.5	58.7	59.0
Owen Sound TS	232.5	108.9	110.1	108.3	108.8	107.9	107.8	107.7	107.8	111.4	111.6
Palmerston TS	147.2	69.7	72.5	74.4	76.9	76.4	76.7	76.9	77.2	77.5	77.8
Seaforth TS	55.4	23.9	26.0	26.7	26.9	26.5	26.4	26.5	26.5	26.5	26.6
St. Marys TS	59.0	23.4	23.3	23.6	23.7	23.3	23.2	23.2	23.1	23.1	23.1
Stratford TS	128.6	71.2	72.8	73.0	74.7	73.9	73.9	74.0	74.1	74.1	74.3
Wingham TS	107.9	49.4	51.6	59.0	66.9	66.2	66.2	66.3	66.5	66.6	66.8
Constance DS	35.0	16.8	16.8	17.0	17.1	16.8	16.8	16.7	16.7	16.7	16.6
Grand Bend East DS	NA	12.9	13.8	13.4	13.5	13.4	13.4	13.4	13.4	13.4	13.4
Bruce Power HWB TS	114.8	11.9	12.8	12.8	12.6	12.2	11.9	11.7	11.5	11.4	11.3
Customer CTS #1	NA	3.4	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Customer CTS #2	NA	5.8	5.8	5.8	5.8	5.8	5.8	5.7	5.7	5.7	5.7
Customer CTS #3	NA	4.6	4.6	4.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Customer CTS #4	NA	14.9	14.8	14.7	19.6	19.6	19.5	19.5	19.4	24.2	24.2

Table D-8. Net Summer Non-Coincident Forecast (MW)

Transformer Station Name	Summer LTR (MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Festival MTS #1	NA	32.3	32.3	32.8	32.7	32.6	32.6	32.6	32.7	32.7	32.7
Centralia TS *	61.1	34.1	37.3	34.6	37.3	37.8	37.5	37.2	37.0	37.6	37.4
Douglas Point TS	97.2	50.7	59.7	54.7	61.8	62.0	62.3	62.6	63.0	63.4	75.9
Goderich TS	126.5	37.8	38.1	41.1	43.2	43.2	43.2	43.2	43.3	43.8	43.9
Hanover TS	109.9	56.1	58.1	60.5	63.0	64.2	66.5	67.8	69.3	70.7	72.3
Owen Sound TS	208.5	101.3	102.5	100.6	100.8	100.9	100.6	100.4	100.4	103.9	103.9
Palmerston TS	132.2	62.0	64.7	66.1	66.9	67.1	67.4	67.5	67.8	68.0	68.3
Seaforth TS	45.1	19.6	21.9	22.6	22.9	23.1	23.3	23.6	24.0	24.3	24.6
St. Marys TS *	52.8	24.6	24.7	27.2	27.0	26.7	26.5	26.3	27.1	26.9	26.7
Stratford TS	117.3	81.3	83.1	82.4	83.9	83.6	83.5	83.5	83.5	83.5	83.5
Wingham TS	97	50.7	53.0	48.5	58.1	57.6	57.0	56.6	56.3	56.0	55.7
Constance DS	25	18.0	18.1	17.9	17.9	17.8	17.7	17.6	17.5	17.5	17.4
Grand Bend East DS *	NA	21.9	22.7	20.5	20.3	20.0	19.9	19.7	19.6	19.4	19.3
Bruce Power HWB TS	113.2	8.2	8.8	8.7	8.5	8.3	8.1	7.9	7.8	7.7	7.7
Customer CTS #1 *	NA	3.4	3.3	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Customer CTS #2 *	NA	5.7	5.7	6.9	6.9	6.9	6.8	6.8	6.8	6.8	6.8
Customer CTS #3 *	NA	4.5	4.5	4.9	4.9	4.9	4.9	4.9	4.9	4.8	4.8
Customer CTS #4 *	NA	14.8	14.7	14.7	14.6	14.5	14.5	14.4	14.4	14.1	14.1

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DER	Distributed Energy Resources
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme